A. Tower Heights

1. Trends in Wind Turbine Heights Over the Last 25 Years
2. Wind Turbines: the Bigger, the Better
3. Berkeley Lab study shows significant potential for further turbine scaling
4. The World's Largest Wind Turbine Will Smash Previous Records
5. Journalism for energy transition
6. Vestas Powers up first of its huge flagship offshore wind turbines
7. Huge new wind turbines face backlash
8. huge flagship offshore wind turbines
9. Examining the trends of 35 years growth of key wind turbines components
10. Increasing Wind Turbine Tower Heights: Opportunities and Challenges
11. Land-Based Wind Market Report- Executive Summary
12. Land-Based Wind Market Report
13. World's Tallest Wind Turbine Begins Construction in Schipkau/ Gicon Launches 365m Project in Germany
14. Using the United States Wind Turbine Database to Identify Increasing Turbine Size, Capacity and Other Development Trends
15. Randy Abrahamson- Harvest Hills Wind Project Updates and Fieldwork Notification
16. Wind farm powers up on the Palouse

Trends in Wind Turbine Heights Over the Last 25 Years

Tom Thompson / Dec 2025

Preface Notes:

- The proposed project at Horse Heaven Hills is for 494 feet high, but the developer is pushing for 671 feet high tall turbines as of Dec 2025.

- The potential project in Whitman County (Harvest Hills) has so far stated their towers would be 699 feet tall.

- Tallest land based turbine as of Dec 2025 is in Schipkau, Germany at 1,194 feet high

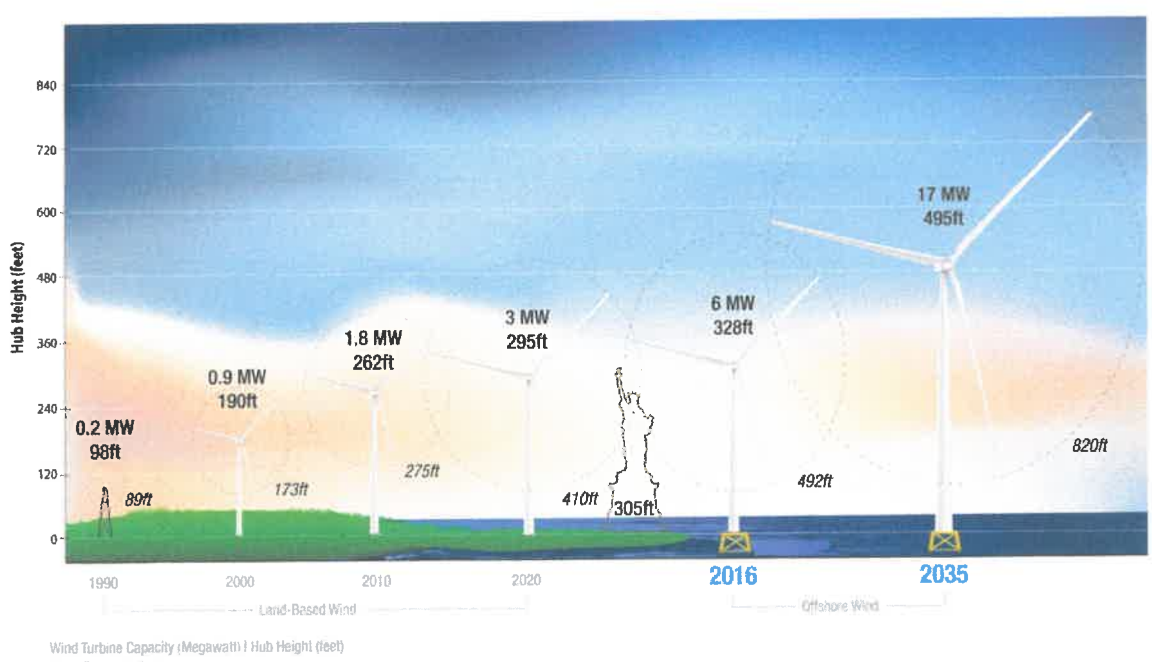
Wind turbines have grown significantly taller and larger since the late 1990s, driven by advancements that improve energy capture, access stronger winds at higher altitudes, and reduce costs per megawatt. Key metrics include **hub height** (tower top where rotor attaches), **rotor diameter** (blade sweep), and total tip height (often exceeding 200-250 meters today).

In the U.S. (with well-documented data representative of global trends), average values have risen dramatically:

- **Hub height** → increased ~83% from ~56 meters in 1998–1999 to 103.4 meters in 2023.
- **Rotor diameter** → grew ~178% to 133.8 meters in 2023 (swept area up ~670%).
- **Nameplate capacity** → rose ~375% to 3.4 MW in 2023.

These changes enable turbines to generate more electricity, especially in lower-wind-speed sites.

Here are visualizations of these trends from authoritative sources:



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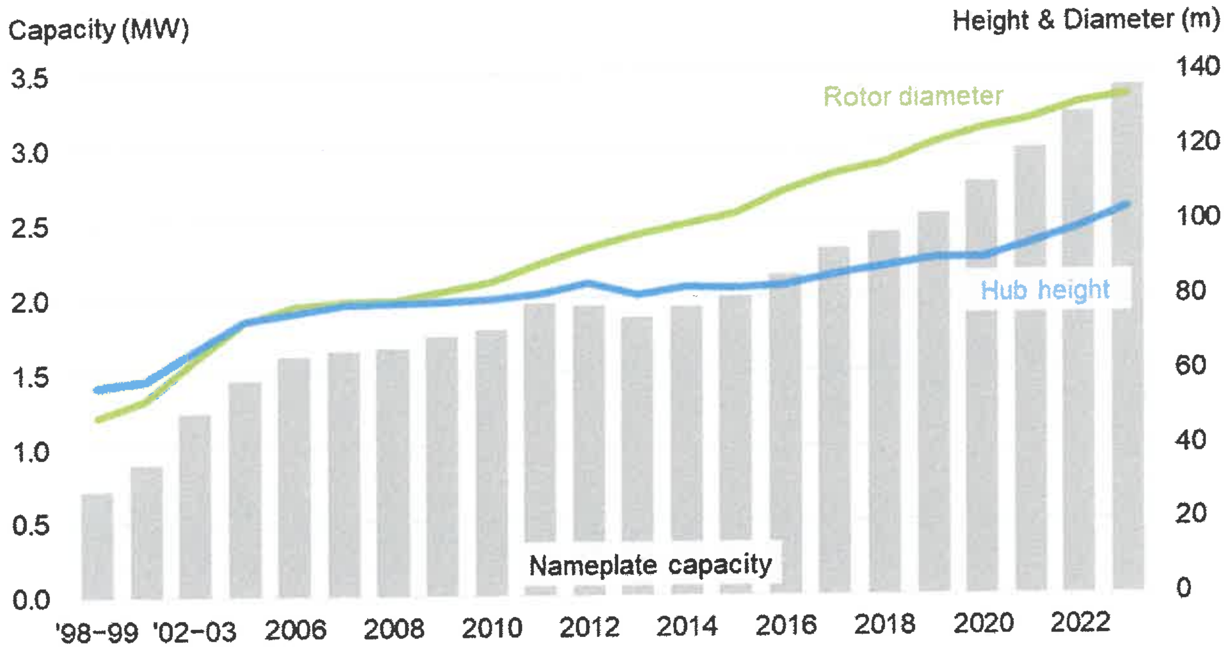

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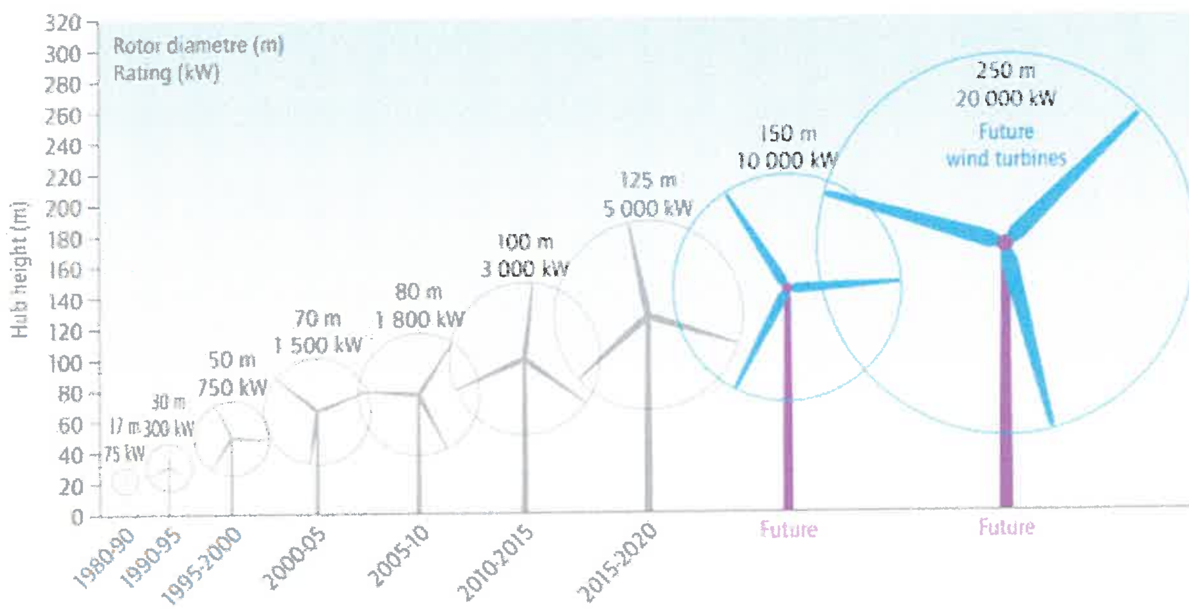
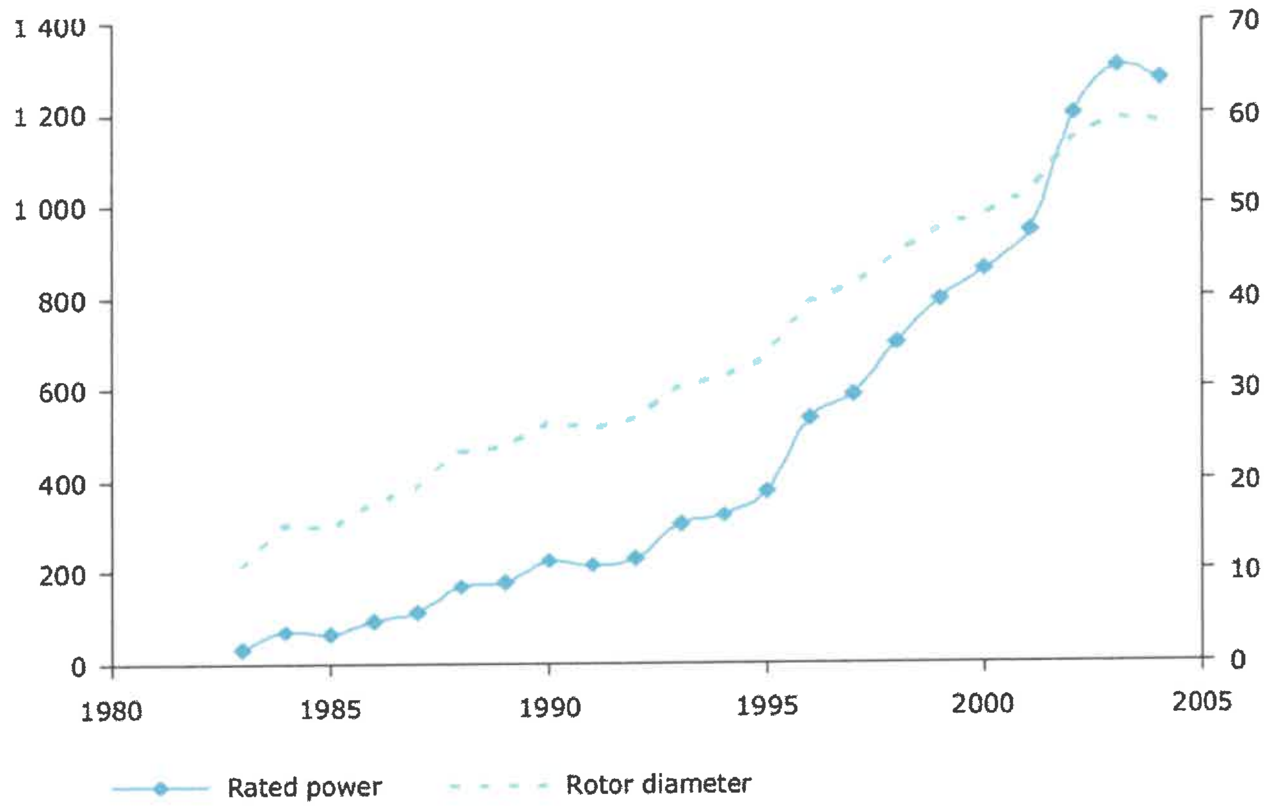


Source: adapted from EWEA, 2009.

researchgate.net



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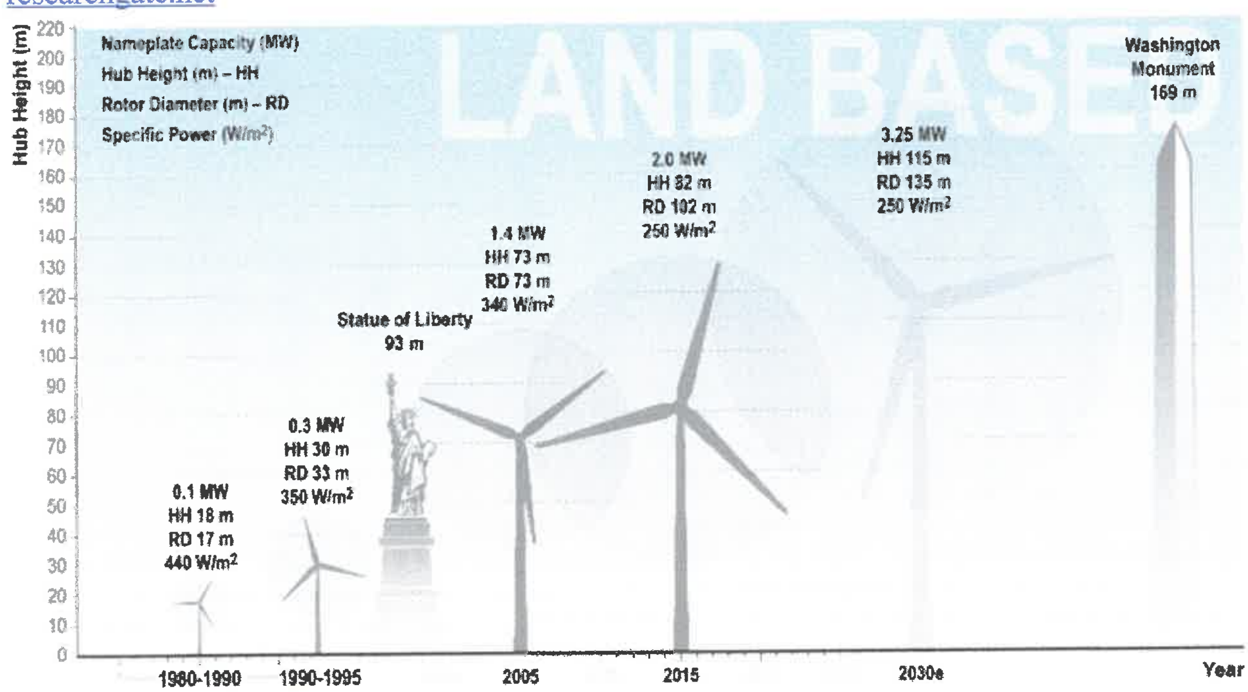

windpowerengineering.com

Key Studies and Reports

- **Land-Based Wind Market Report: 2024 Edition** (Lawrence Berkeley National Laboratory, funded by U.S. DOE): Annual series details U.S. turbine trends since 1998, with figures on hub height, rotor diameter, and capacity growth.
- **Wind Turbines: the Bigger, the Better** (U.S. Department of Energy, 2024 update): Summarizes scaling benefits and provides the 83% hub height increase statistic.

- **Examining the trends of 35 years growth of key wind turbine components** (Journal of Energy for Sustainable Development, 2019): Analyzes multi-megawatt turbine inventions from ~1980s to 2010s, showing exponential growth in sizes.
- **Increasing Wind Turbine Tower Heights** (NREL, 2019): Explores opportunities and challenges of taller towers.
- IEA Wind Energy pages: Note global trend toward taller hubs and larger rotors for offshore and onshore.

News Articles Highlighting the Trend…included in hard copy documents

- **The World's Largest Wind Turbine Will Smash Previous Records** (Scientific American, Nov 2025) — Discusses massive new turbines exceeding previous height records.
- **Construction of world's tallest wind turbine starts** (Clean Energy Wire, 2024) — Covers a 364-meter total height turbine in Germany.
- **Huge new wind turbines face backlash** (E&E News, 2023) — Addresses challenges from increasingly tall offshore turbines.

This upscaling continues, with projections for even taller turbines (e.g., 130m+ average hub heights by 2035) to further boost efficiency.

U.S. DEPARTMENT of ENERGY

Turbine Height

BLOG

Wind Turbines: the Bigger, the Better

Since the early 2000s, wind turbines have grown in size—in both height and blade lengths—and generate more energy. What's driving this growth? Let's take a closer look.

Office of Critical Minerals and Energy Innovation

August 21, 2024

4 min

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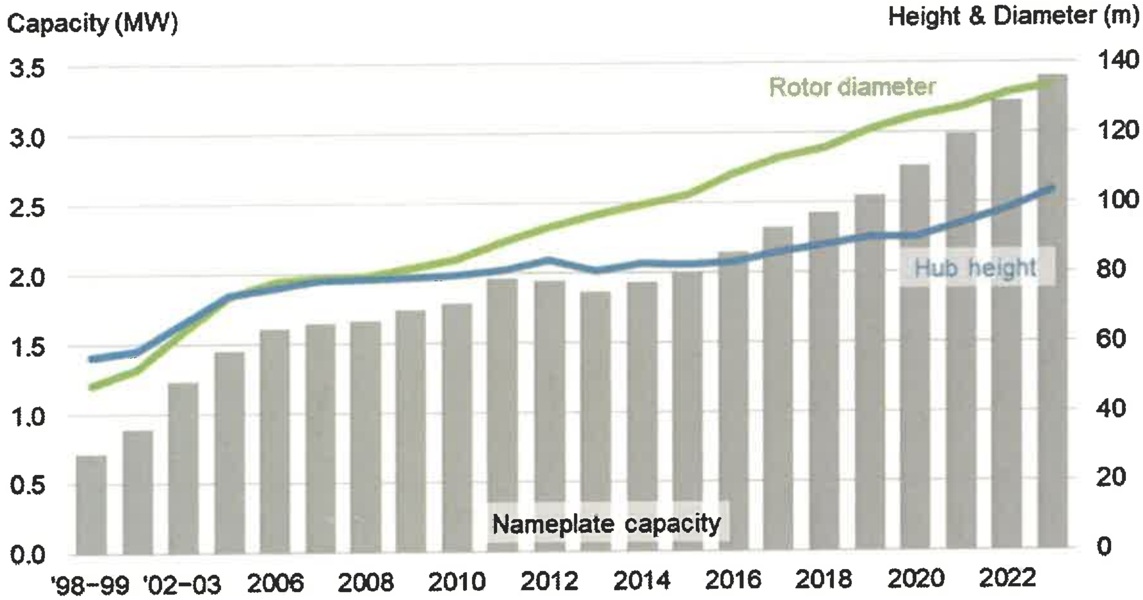


Average turbine hub height, rotor diameter, and nameplate capacity for land-based wind projects from the [Land-Based Wind Market Report: 2024 Edition](#).

Hub Height

A wind turbine's hub height is the distance from the ground to the middle of the turbine's rotor. The hub height for utility-scale land-based wind turbines has increased 83% since 1998–1999, to about 103.4 meters (~339 feet) in 2023. That's taller than the Statue of Liberty! The average hub height for offshore wind turbines in the United States is projected to grow even taller—from 100 meters (330 feet) in 2016 to about 150 meters (500 feet), or about the height of the Washington Monument, in 2035.

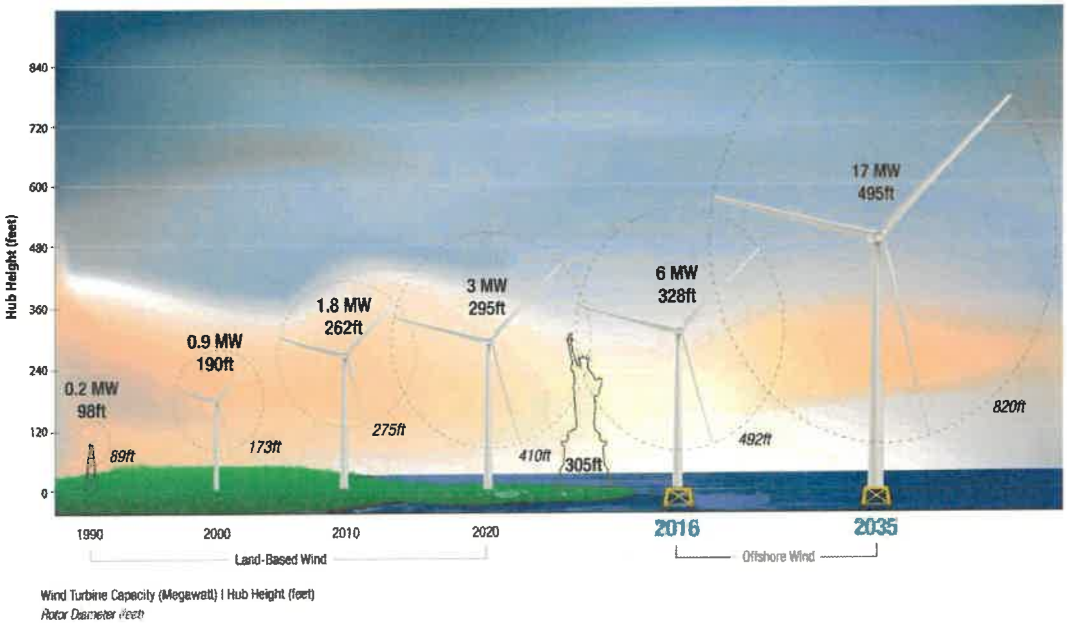
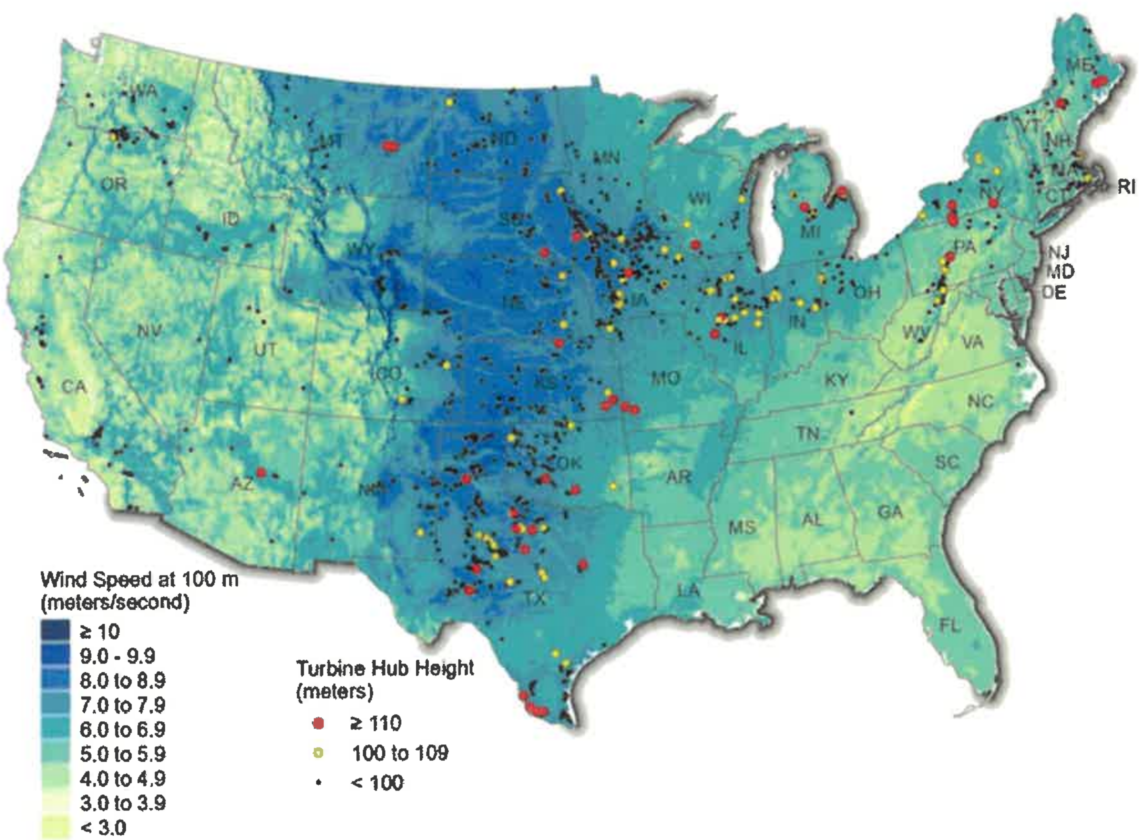


Illustration of increasing turbine heights and blades lengths over time.



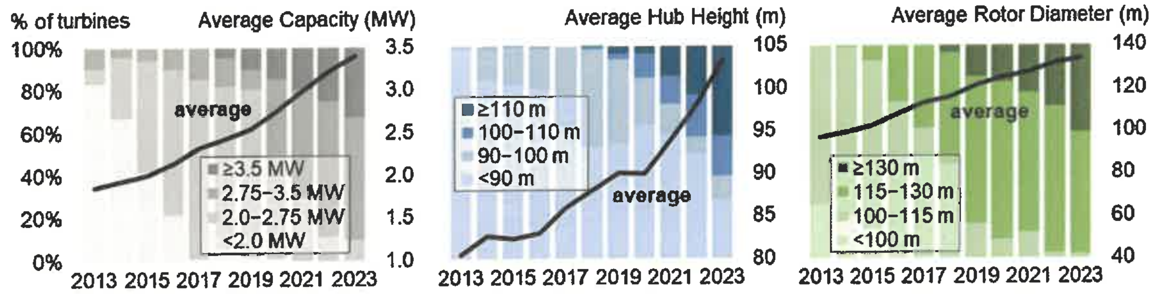
Location of tall-tower turbine installations from the [Land-Based Wind Market Report: 2024 Edition](#).

Turbine towers are becoming taller to capture more energy, since winds generally increase as altitudes increase. The change in wind speed with altitude is called wind shear. At higher heights above the ground, wind can flow more freely, with less friction from obstacles on the earth's surface such as trees and other vegetation, buildings, and mountains. Most wind turbine towers taller than 100 meters tend to be concentrated in the Midwest and Northeast, two regions with higher-than-average wind shear.

Rotor Diameter

A turbine's rotor diameter, or the width of the circle swept by the rotating blades (the dotted circles in the second illustration), has also grown over the years. Back in 2013, no turbines in the United States employed rotors that were 115 meters (380 feet) in diameter or larger, while in 2023 98% of newly installed turbines featured such rotors. In 2023, the average rotor diameter of newly-installed wind turbines was over 133.8 meters (~438 feet)—longer than a football field, or about as tall as the Great Pyramid of Giza.

Larger rotor diameters allow wind turbines to sweep more area, capture more wind, and produce more electricity. A turbine with longer blades will be able to capture more of the available wind than shorter blades—even in areas with relatively less wind. Being able to harvest more wind at lower wind speeds can increase the number of areas available for wind development nationwide. Due to this trend, rotor swept areas have grown around 670% since 1998–1999.



Trends in turbine nameplate capacity, hub height, and rotor diameter from the Land-Based Wind Market Report: 2024 Edition.

Nameplate Capacity

In addition to getting taller and bigger, wind turbines have also increased in maximum power rating, or capacity, since the early 2000s. The average capacity of newly installed U.S. wind turbines in 2023 was 3.4 megawatts (MW), up 5% since 2022 and 375% since 1998–1999. In 2023, there was an increase in the proportion of turbines installed in the size category of 3.5 MW or larger. Higher capacity turbines mean that fewer turbines are needed to generate the same amount of energy across a wind plant—ultimately leading to lower costs.

Transportation and Installation Challenges

If bigger is better, why aren't even larger turbines used currently? Although turbine heights and rotor diameters are increasing, there are a few limitations. Transporting and installing large turbine blades for land-based wind is not easy, since they cannot be folded or bent once constructed. This limits the routes trucks can take and the radius of their turns. Turbine tower diameters are also difficult to transport, since they may not fit under bridges or highway overpasses. DOE is addressing these challenges through its research projects. For instance, DOE is researching turbines with more slender and flexible blades that can navigate through curves in roads and rail lines that conventional blades cannot. DOE has also supported efforts to develop tall turbine towers that can be produced on site, thus eliminating tower transportation issues. Two companies pioneering these efforts are Keystone Power Systems, which uses spiral-welding in order to minimize the need for costly steel, and GE Renewables, using 3D printing to create customizable tower bases.

Learn More

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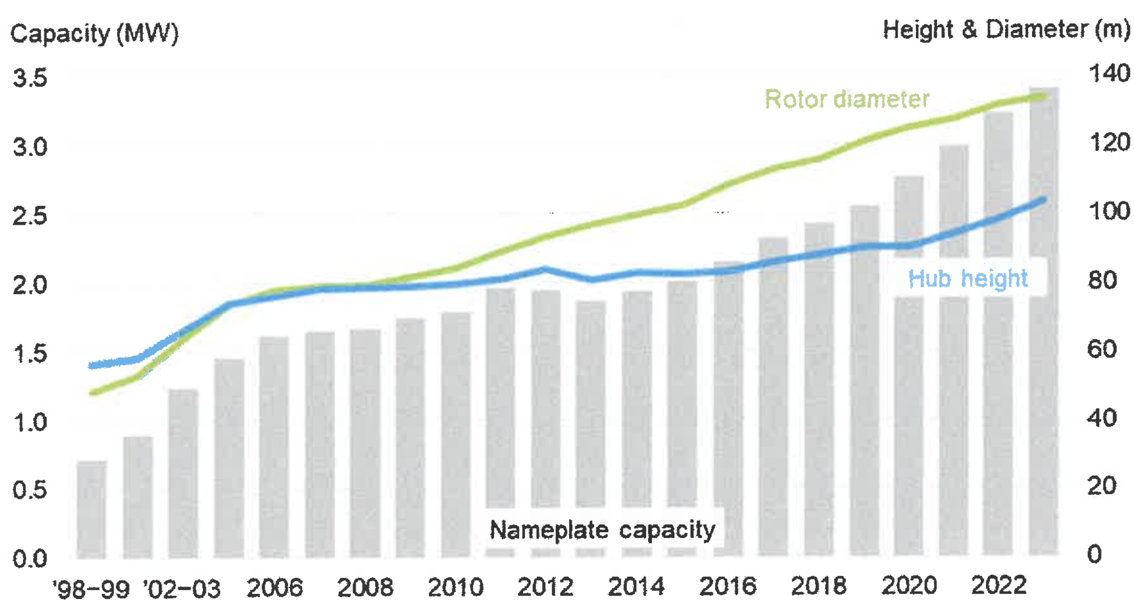

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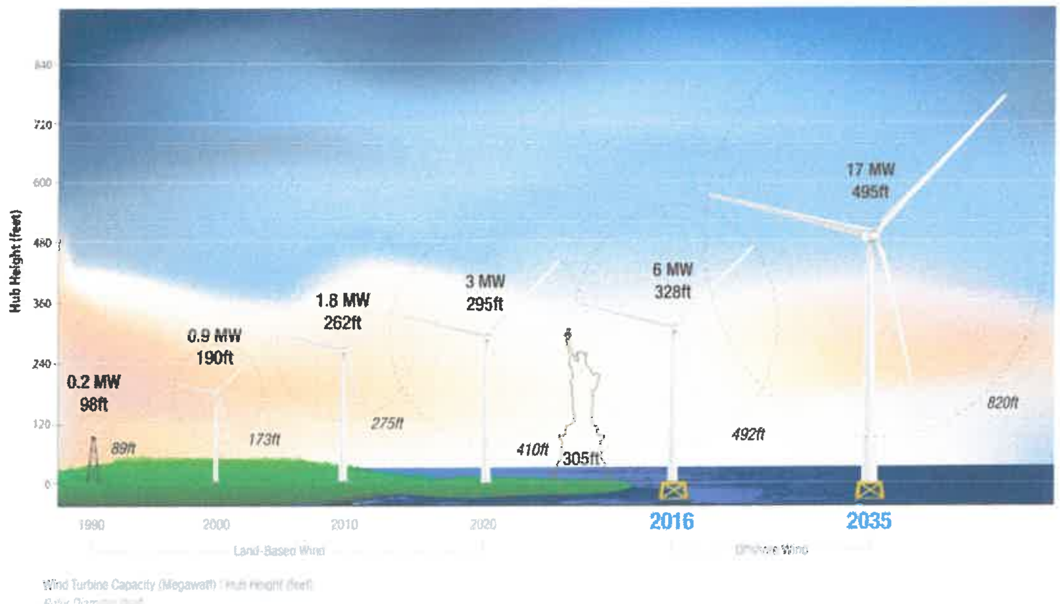

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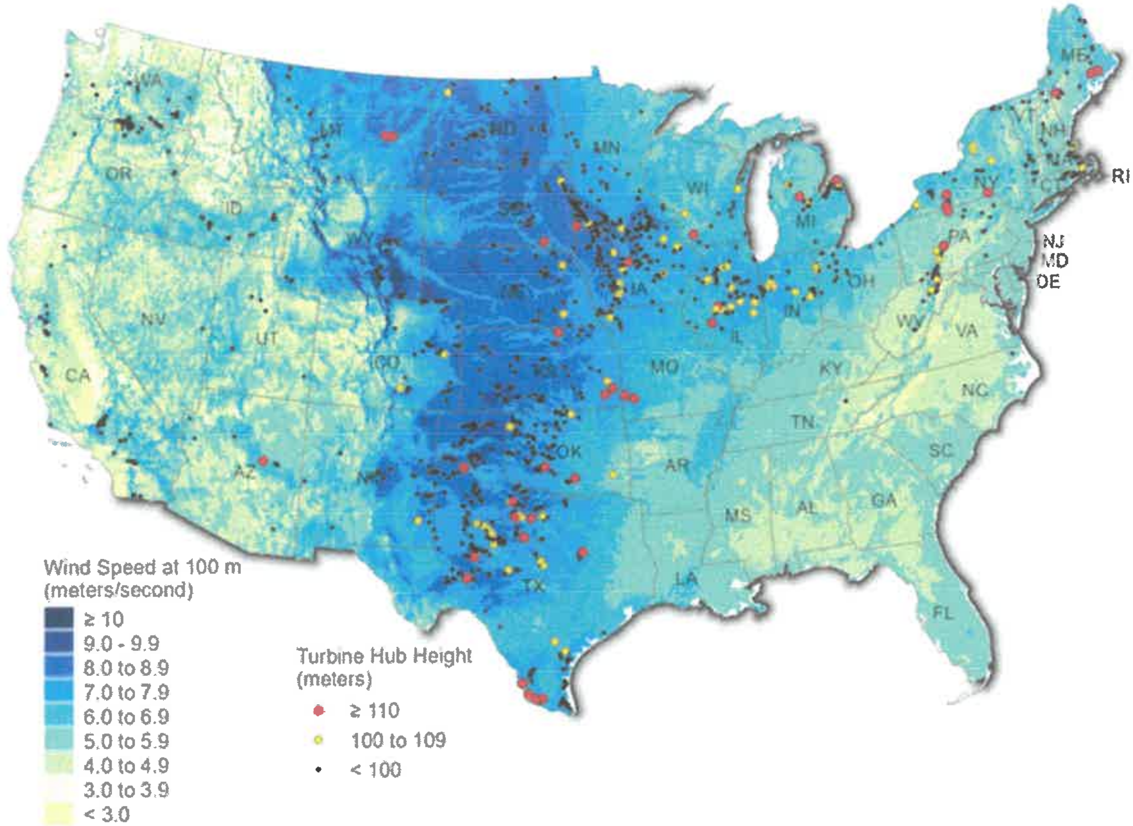

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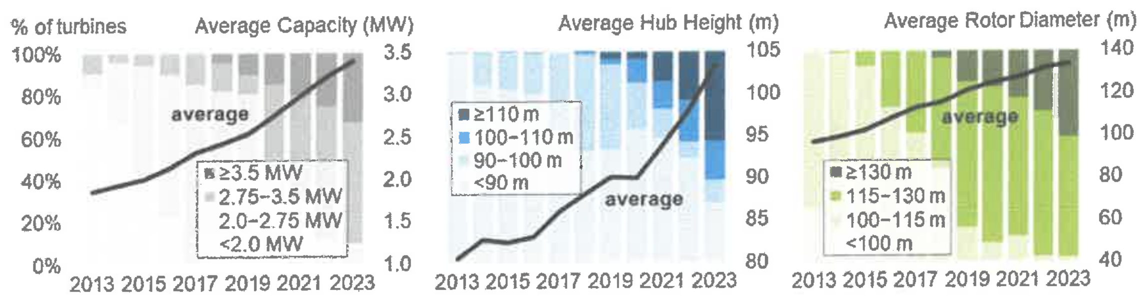

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Liz Hartman

Communications Lead, Wind...

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Berkeley Lab study shows significant potential for further turbine scaling

By Paul Dvorak | November 28, 2016
Ryan Wiser, Maureen Hand, Joachim Seel, and Bentham Paulos

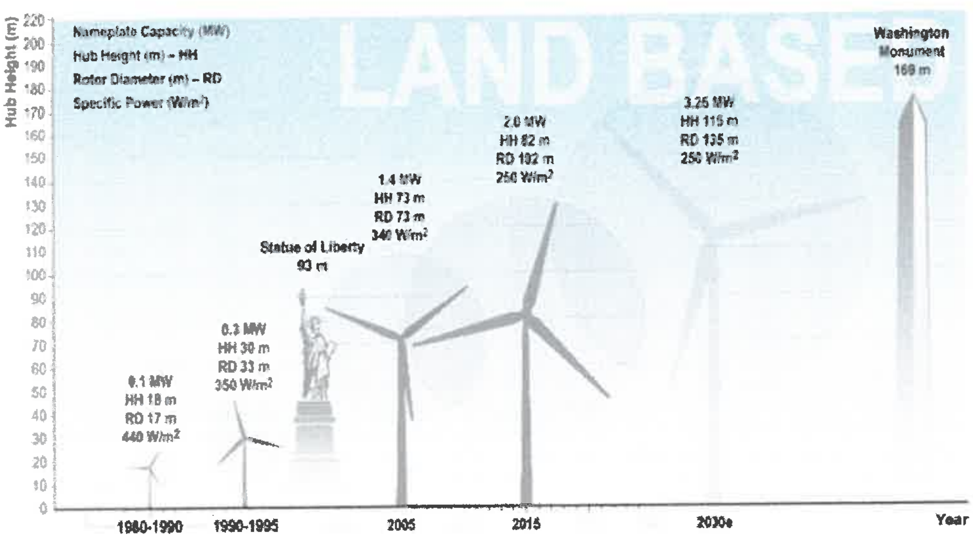
The growing size of wind turbines has helped lower the cost of wind energy to the point that it is economically competitive with fossil-fuel alternatives in some locations. But can turbines continue to scale in the future, or are they running into physical or logistical constraints? Recent research published in the journal *Nature Energy* suggests that land-based wind turbines and, especially, offshore turbines

A-3

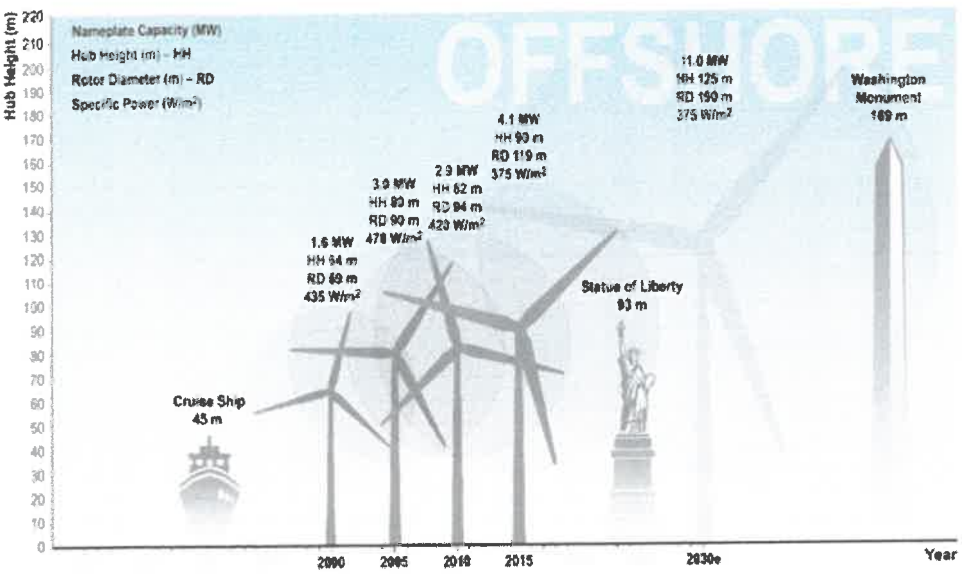
have room to grow, offering the promise that this already-mature energy technology will see still lower costs in the future.

The new study summarizes a global survey of 163 of the world's foremost wind energy experts to gain insight into the possible magnitude and sources of future wind energy cost reductions. It represents the largest-ever 'expert elicitation' survey on an energy technology, and was led by Berkeley Lab, NREL, University of Massachusetts, and participants in the IEA Wind Technology Collaboration Programme Task 26.

According to the wind experts, larger turbines are on the horizon, enabling further reduction in the cost of wind energy on land and offshore. Turbine design will continue to vary by market and project site, but the experts forecast continued evolutionary growth in average turbine size on land, and more revolutionary growth offshore. Figure 1 depicts the historical growth in land-based turbine size in the United States, while also presenting survey-based average forecasted turbine size in North American in 2030. *Expected growth in offshore*, meanwhile, shows historical global offshore turbine size trends and survey-based average forecasted size globally, also in 2030.



Expected growth in land-based turbine size in North America



Expected growth in offshore turbine size globally

Turbine design optimization in an historical context

The story of wind power is a story of machine size. From the beginnings of the U.S. industry in California to the present, the typical generation capacity of wind turbines deployed in the United States has increased 20 fold, from the 100 kW turbines typical in the 1980s to the 2 MW machines common today. Modern turbines feature 80 meter towers, and 100 meter rotor diameters: big enough to sweep an area 50% larger than an American football field.

With that scale has come both decreased up-front costs (partly through economies of scale and reduced balance-of-plant costs on a per megawatt basis) and increased turbine performance (through taller towers and longer blades). In combination, these trends have reduced the levelized cost of wind energy (LCOE).

Of course, turbine size varies by market, by wind resource and site topography, and by whether turbines are deployed on land, or at sea. There is no single 'optimal' turbine across all sites and, as technology has developed, turbine designs have also shifted.

As documented in the DOE's 2015 Wind Technologies Market Report, the most notable recent trend in the United States on land has been towards longer blades and the resultant increase in swept rotor area (also see Figure 1). Yet average turbine generator capacity has stayed roughly the same since 2011. In other words, companies are attaching bigger blades to the same generator size, thus increasing energy capture. And because the additional up-front capital cost of doing so is modest, the overall trend has been towards a lower overall levelized cost of wind energy. The ratio of generator size to rotor swept area is known as 'specific power,' and is an important and underappreciated development in wind technology.

Though the new generation of low specific power machines was originally designed for lower wind speed sites, they are now being deployed in some of the windiest parts of the country. This is enabled by the low-turbulence winds often seen in the U.S. interior and by improved turbine materials and control systems. The result: the average capacity factor of recently built projects exceeds 40%, a level unheard of even a few years ago (Figure 3).

Specific power has declined in other markets, but the U.S. is unique in the speed and degree of decline. In 2015, average turbines installed in the U.S. had a specific power of 250 W/m^2, compared to 330 W/m^2 in Germany and 350 W/m^2 in Denmark. In contrast, many European markets feature larger average generator ratings (2 MW in the U.S. in 2015, compared to 2.7 MW in Germany and 3.1 MW in Denmark). And some markets, most notably Germany, have seen far greater growth in hub heights (82 m in the U.S. in 2015, 123 m in Germany).

These trends are, in part, related to the limited number of developable high-quality wind resource sites that exist in much of densely-populated Europe, constraints that support the deployment of turbines that maximize energy production from every single turbine pad. The tall and high capacity turbines that meet these needs do not yet generally feature the outsized rotors (and low specific power) that have become common on smaller turbine platforms. As design and logistical challenges to longer blades are addressed, this may change.

Offshore, the wind sector is less mature. Nonetheless, the 1.6 MW global average size of turbines installed in 2000 has given way to an average size of more than 4 MW in 2015 (*Expected growth in offshore*). Hub heights and rotor diameters have similarly increased, with a modest trend towards lower specific power and with a resultant increase in capacity factors (*Capacity factors*, also see here).

Sources: land based capacity factor, offshore capacity factor

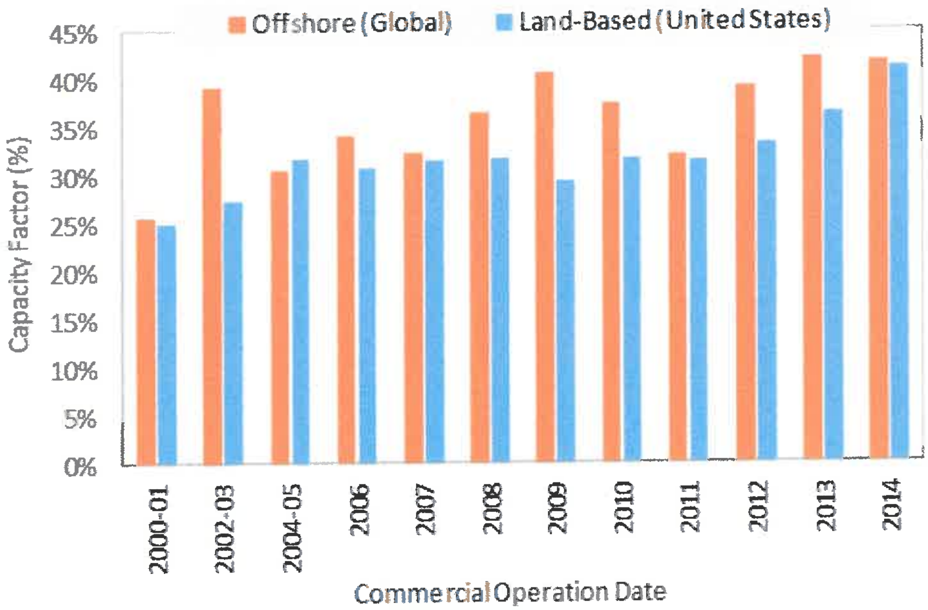


Figure 3. Capacity factors of U.S. land-based and global offshore wind projects by operation date

Offshore turbines will continue to grow, with most projects in planning today expecting to use turbines in the 6 to 8 MW range. In part this is due to the easier logistics of transporting massive components by sea. But, in addition, the non-turbine costs of building offshore wind plants (and especially the cost of the foundation and installation) are enormous. Minimizing those costs on a per-MW basis through growth in turbine size is a decided advantage.

Survey says... still larger machines on the horizon

With each turbine design evolution, there have been questions about whether the technology has hit its limits: whether physical scaling laws or transportation and other logistical challenges mean that the 'optimal' turbine size has been reached, and that additional size will just add costs. And as a relatively mature technology, one might wonder how much more cost can be squeezed out of the system through continued growth in turbine size.

According to the 163 wind experts surveyed in the *Nature Energy* article, still-larger turbines offer promise, and will be regularly used by 2030.

For land-based applications in North America (Figure 1), the experts anticipate evolutionary growth in average turbine generator size (2 MW in 2015 to 3.25 MW in 2030) and average hub heights (82 meters in 2015 to 115 meters in 2030). Rotor diameters also increase, keeping specific power at the current low level already seen in the United States. European projects are expected to feature, on average, bigger generators (3.75 MW) and witness a strong reduction in specific power, converging with those in North America. Overall, these trends are consistent with recent commercial product offerings just being released by many of the major turbine manufacturers.

Offshore wind is expected to see more dramatic changes, with 11 MW turbines being regularly deployed in fixed-bottom applications by 2030 (Figure 2). Turbines of this scale are expected to feature hub heights averaging 125 meters and rotors averaging 190 meters in diameter, making a swept area more than five times the size of a football field. Average specific power is forecasted to remain at current levels.

Offshore turbines this big go well beyond current commercial product offerings, which largely focus on turbines 8 MW and below, but are consistent with the plans of major manufacturers to have prototypes of 10+ MW turbines by 2020. Turbines deployed in North America are forecasted to be somewhat smaller than in Europe (9 MW), perhaps reflecting the fact that North America is currently lagging Europe in offshore development.

Reducing costs, enhancing value, and increasing developable areas with turbine design

The increasing size of wind turbines is a core contributor to lower LCOE, according to the experts in the survey. The cost of land-based wind is expected to fall by, on average, 24% by 2030 and 35% by 2050 under the median (best guess) scenario. Fixed-bottom offshore cost declines are even greater, at 30% by 2030 and 41% by 2015. And costs could be lower for both applications: experts predict a 10% chance that costs will decline by more than 40% by 2030 and more than 50% by 2050.

Though many factors can drive energy cost reductions, turbine size is key. Experts assessed 28 different possible means of reducing LCOE, with the top 5 listed in Table 1. Land-based wind benefits most from increased rotor size (and reduced specific power), rotor design advancements, and increased tower heights. For fixed-bottom offshore wind, the single largest driver is increased turbine generator capacity ratings and rotor diameters, with specific power maintaining current levels.

	Wind technology, market, or other change	% of Experts rating "Large expected impact"	Rating Distribution 3- large impact 2- medium impact 1- small impact 0- no impact
Land-Based	Increased rotor diameter such that specific power declines	58%	
	Rotor design advancements	45%	
	Increased tower height	33%	
	Reduced financing costs and project contingencies	32%	
	Improved component durability and reliability	31%	
Fixed-Bottom Offshore	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	55%	
	Foundation and support structure design advancements	53%	
	Reduced financing costs and project contingencies	49%	
	Economies of scale through increased project size	48%	
	Improved component durability and reliability	48%	

Drivers for reduced levelized cost of energy from wind power

The survey also asked how reductions in up-front capital costs (CapEx) and operating expenses (OpEx), increases in capacity factors and turbine design life, and improvements in the cost of financing would affect energy costs.

For land-based wind, experts anticipate that LCOE reductions will be primarily influenced by improvements in capacity factors and CapEx. The taller towers and larger rotors expected to be deployed by 2030 are consistent with the relative importance placed on capacity factor improvements. Achieving lower capital costs while simultaneously increasing turbine size, meanwhile, will require continued design, engineering, and manufacturing advancements.

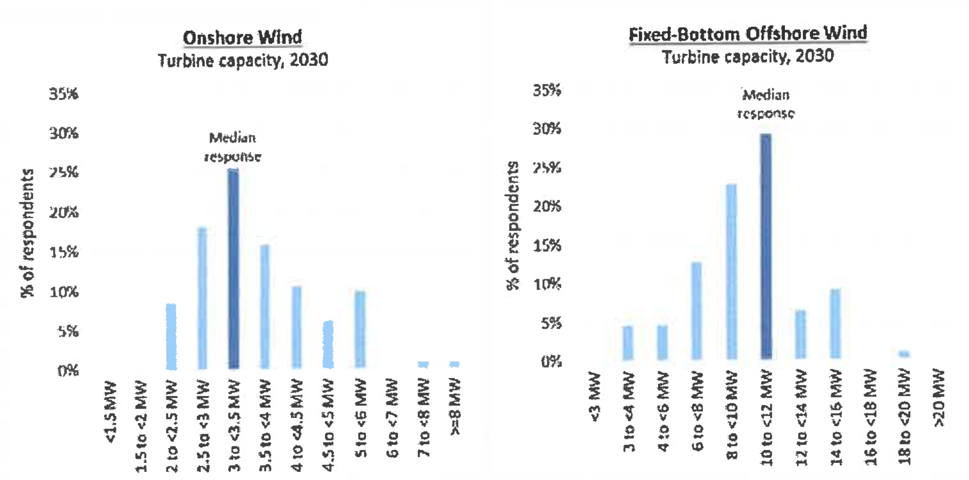
For fixed-bottom offshore wind, reduced upfront costs are seen as the single most-important driver for LCOE improvements to 2030, with capacity factor increases of somewhat lesser significance. Larger average turbine generator capacities will reduce the high (per-MW) cost of substructures, foundations, and installation experienced offshore. As a report by NREL puts it, "Fewer larger sized turbines minimize the balance-of-system requirements (i.e., less substructures and other infrastructure required to achieve the same project size)." A recent report by BVG Associates, meanwhile, highlights the positive impact of turbine generator size, hub height, and rotor length on not only CapEx, but also OpEx and capacity factor; that report cites a possible 18% reduction in LCOE between 2014 and 2030 based on turbine size alone.

Lower energy costs are not the only benefit from bigger turbines.
Recent research shows that machines with low specific power (and taller towers) can boost the value of wind energy in electricity markets, since they have steadier output. Work by and for the U.S. Department of Energy, meanwhile, shows how larger turbines and turbine design advancements might unlock new areas for wind development, both on land and offshore, that would otherwise be deemed unattractive.

Is there room for upside?

The wind industry has a history of under-predicting the growth rates of turbines. Even the experts in our study predict essentially the next step up from current common practice, as their median guess. Are gains beyond that possible? At some size, the cost of a larger turbine will grow faster than the resulting energy output and revenue, making further size increases uneconomic. But will clever engineers continue to find ways of avoiding such a plateau?

The median response from the survey masks the fact that not all experts agree on future turbine size. As shown in Figure 4, some experts anticipate that smaller machines will be more common, while others expect that still-larger turbines will dominate the market.



Range in expert survey opinion on global turbine size in 2030

Those really large turbines will require fundamental technological advancements, and thus a need for public and private R&D. The U.S. Department of Energy is looking into ways to help enable larger turbines, on land and at sea. The EU-funded UpWind and, more recently, INNWIND.EU projects are emphasizing turbines up to 20 MW in size. Floating offshore turbines open a new realm of possibilities, with their own engineering challenges and opportunities. More speculatively, a team of researchers led by University of Virginia (with funding from the U.S. Department of Energy) is studying the potential for turbines with blades large enough to power 50 MW offshore machines; still others are exploring 'high-altitude' wind, essentially flying wind turbines tethered to the ground.

As is often the case with R&D, the original vision may or may not ever come to full fruition. But the scientific advancements will likely bleed-into the commercial wind sector regardless, helping to achieve the potential benefits of turbine scale in reducing costs, enhancing the market value of wind energy, and opening new areas for possible wind development.

The survey was conducted under the auspices of the IEA Wind Technology Collaboration Programme. Berkeley Lab's contributions to this work were funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.

The *Nature Energy* article can be found here. A full report on the survey findings is also available, as are presentation-style slide decks summarizing the results; a pdf version of this blog is also available.

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The World's Largest Wind Turbine Will Smash Previous Records

A planned supersized floating wind turbine with two spinning heads will generate nearly double the amount of energy as the current record-holder

BY YOU XIAOYING EDITED BY ANDREA THOMPSON

Ming Yang's 16-MW OceanX twin turbine arrives at Yangjiang Qingzhou IV Offshore Wind Farm in the ocean off Guangdong Province, China. Ming Yang Smart Energy Group

Renewable Energy

A-4

The world's largest wind turbine—currently being tested off the coast of China—has blades that are more than twice as long as a Boeing 777's wingspan. It can generate 26 megawatts (MW) of energy, more than double the global average for individual turbines. But its record is about to be smashed to smithereens: another offshore wind turbine that is twice as powerful has been announced by Ming Yang Smart Energy, a company based in southern China.

With a capacity of 50 MW, this supersized structure is designed to float on the ocean's surface and can withstand typhoons, according to the company, which plans to start making the turbine later this year and to deploy it next year.

Though Western manufacturers such as Siemens Gamesa are also pushing for bigger and bigger turbines, the trend has been particularly dominant in China after the government stopped subsidizing offshore wind farms in 2022, forcing developers to find ways to save money. Using bigger turbines means that fewer of them will be needed to generate the same amount of power, says Zhu Ronghua, director of Yangjiang Offshore Wind Energy Laboratory, a research institute supported by the provincial government of Guangdong in China. "You can save on transport, construction and installation fees, which account for 70 to 80 percent of the cost of building an offshore wind farm," Zhu says.

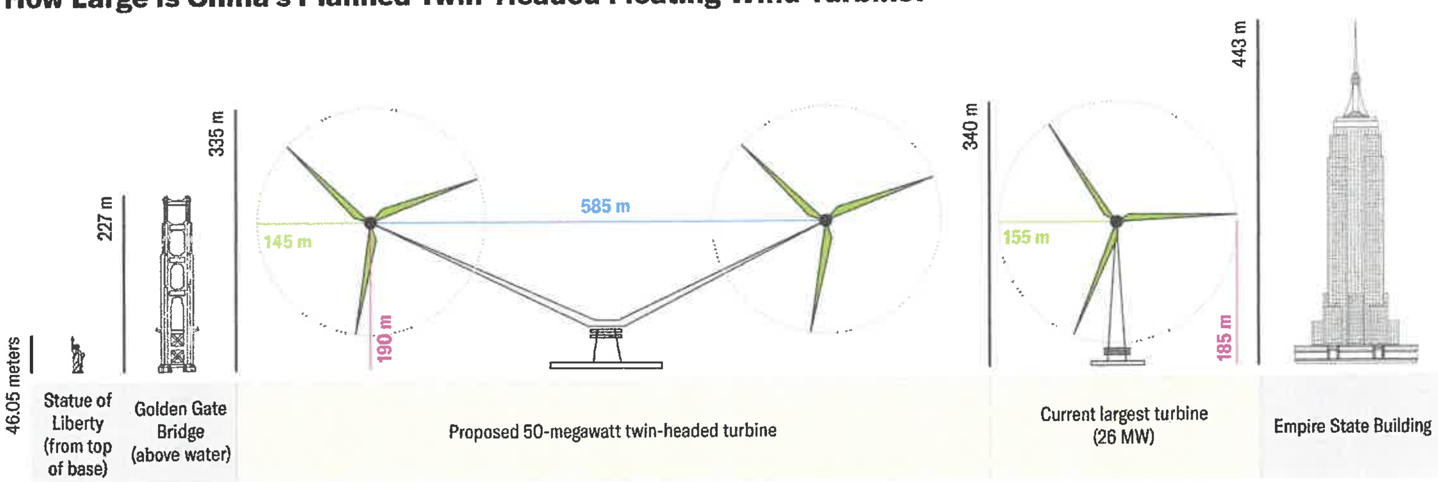
TWIN-HEADED TURBINES

TWIN-HEADED TURBINES

In general, a turbine with a larger capacity is also physically bigger. This is because you need longer blades to catch more wind and generate more electricity per sweep. The current record-holding turbine, made by Dongfang Electric, is so enormous that its tower is as tall as a 63-story skyscraper.

But Ming Yang is taking a different approach: Its megamachine will have not one but two sets of engines and blades, each capable of generating 25 MW of energy. They are supported by a Y-shaped tower on a single platform. Each of its blades is 145 meters long, roughly three times the height of the Statue of Liberty. The design builds on that of the world's first twin-headed turbine, a 16-MW version that is currently operating in the South China Sea, and combines the output of two turbines in one. "If successful [at this scale], this model can be a game changer in the floating wind industry," says Umang Mehrotra, an offshore wind analyst at the Norwegian research firm Rystad Energy.

How Large Is China's Planned Twin-Headed Floating Wind Turbine?



Eve Lu; Sources: Ming Yang Smart Energy presentation at China Wind Power 2025, Beijing, October 2025 (*twin-headed 50-MW turbine*); Dongfang Electric Wind Power (*26-MW turbine*); National Park Service (*Statue of Liberty*); Golden Gate Bridge, Highway and Transportation District (*Golden Gate Bridge*); Empire State Building (*Empire State Building*)

Han Yujia, a researcher of renewable energy at the California-based nonprofit Global Energy Monitor, is most impressed that Ming Yang intends to increase a turbine's capacity by more than 20 MW in one go, far outpacing the industry's average rate of increase of 2–3 MW each year.

Ming Yang says that the 50 MW turbine will have a "strong ability" to counter typhoons but hasn't yet provided more details on how it will do so. The 16-MW model, which is supposed to serve as a prototype, has survived multiple typhoons over the past year, including more than 150-kilometer-per-hour winds from Typhoon Ragasa, says Wang Chao, chief designer for this line of models, known as OceanX. Some of its resilience is because of the fact that it is tethered to the ocean floor at a single point, so it can rotate 360 degrees "like a weather vane" and stay balanced during high winds, Wang says. The feature also means that the turbine can be installed in deeper waters, farther away from the shore, where wind is stronger and more consistent.

But the new model will be significantly bigger, so there could be "a lot of risks," Mehrotra says. And there are potential technical difficulties in ensuring that the two rotors generate power smoothly because they are so close together on a single platform compared with the general spacing specifications of side-by-side turbines, he says. A representative of Ming Yang did not respond to requests for comment from *Scientific American*.

YOU XIAOYING is a freelance journalist based in London. She writes and reports about climate change and the clean energy transition.

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CLEAN ENERGY WIRE

Journalism for the energy transition

25 Sep 2024, 13:28 Sören Amelang (/about-us-clew-team) | Germany

#Renewables (/topics/Renewables) #Wind (/topics/Wind) #Technology (/topics/Technology) #Society (/topics/Society)

Work has begun on the construction of the world's highest wind turbine in the eastern German lignite (/glossary/letter_l#lignite) region Lusatia, reports (https://www.heise.de/news/Grundsteinlegung-fuer-das-hoechste-Windrad-der-Welt-9949700.html) technology website heise online. The foundation stone was laid last week in Schipkau in the state of Brandenburg and operations are scheduled to start next summer. The planned height of the turbine is 364 metres including blades, meaning the windmill will be almost exactly the same height as Berlin's iconic TV tower, reports (https://www.mdr.de/wissen/naturwissenschaften-technik/windkraft-firma-aus-dresden-baut-hoechstes-windrad-der-welt-100.html) regional broadcaster MDR.

The commissioning company Beventum and project developer Gicon (https://www.gicon.de/en) measured high altitude wind speeds with a 300-metre-high measuring tower at the site, according to MDR. The companies said the height will increase wind energy yield by 40 percent, which equates to twice as much electricity yield with the same rotor diameter.

A-5

"At this altitude, the wind not only has higher average speed, but also a wider distribution, which leads to significantly more full-load hours for wind turbines," said Gicon founder Jochen Großmann. He said conditions are comparable to offshore wind (/glossary/letter_o#offshore_wind) turbines, but with onshore operating conditions. "This means that the costs for construction and maintenance are significantly lower, which has a positive effect on profitability," Großmann said. High-altitude wind turbines could also be used to develop so-called low-wind regions, where it has not been possible to utilise wind energy economically to date, he said.

The wind turbine will feature a novel design involving a lattice structure with four legs, reminiscent of (https://youtu.be/y1ou3IW_HcM?feature=shared&t=28) the Eiffel tower in Paris, as well as power poles. The turbine will be attached to a movable inner tower, which will allow it to be lifted to a height of 300 metres – a height out of reach for cranes.

There was no opposition against the project from local residents, who were involved from the outset, Gicon said. The new turbine does not require any additional space, because it will be built between existing wind turbines. "The towers are so high that the rotors do not overlap and take the wind away from each other," Großmann said. Gicon has said in the past (https://www.rbb24.de/wirtschaft/beitrag/2024/04/brandenburg-schikpau-300-meter-windrad-soll-kommen-windmessmast-test-energie.html) that high altitude wind turbines would allow renewable energy production on three levels: Solar panels on the ground, conventional wind turbines, and a layer of high altitude turbines on top.

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Vestas powers up first of its huge flagship offshore wind turbines

European wind industry reaches milestone with 15MW wind turbine commissioned at sea

A-6

Vestas V236-15.0MW wind turbines are installed at the He Dreiht offshore wind farm in the German North Sea.

Photo: Vestas

Steffie Banatvala

Published 26 November 2025, 02:52

Denmark's Vestas has celebrated the commissioning of the first of its flagship 15MW offshore wind turbines at a North Sea wind farm.

The V236 turbine generated the first kilowatt-hour of electricity yesterday at developer EnBW's 960MW He Dreiht wind farm in the German North Sea and fed it into the grid.

As one of Europe's largest turbines, a single turn of the rotor supplies enough electricity for the equivalent of four households for a day, EnBW said.

By comparison, turbines previously installed by the German utility in 2010 only had a rating of 2.3MW.

"The 15MW turbine is a world first in terms of technology, setting new standards in offshore wind power," Nils de Baar, President of Vestas Northern and Central Europe, said.

EnBW He Dreiht offshore wind farm (Photo: EnBW/Rolf Otzipka)

"Its efficiency and performance enable a significant increase in energy yield per turbine."

In total, the project will supply the equivalent of about 1 million homes, making it one of Europe's largest offshore wind projects.

Twenty-seven of the total 64 wind turbines have already been installed, with all the turbines expected to be commissioned by summer 2026.

“Wind energy has the ability to lower power prices, strengthen energy security, and bolster economic prosperity and we are delighted to be using our ground-breaking technology for the first time in collaboration with our partner EnBW,” Nils de Baar added.

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Internal wind farm cabling connecting the turbines and the converter platform, managed by transmission system operator TenneT, was completed in August.

Peter Heydecker, EnBW board member for sustainable generation infrastructure, said: "The first kilowatt-hour produced by our He Dreiht offshore wind farm marks a significant milestone for EnBW.

"Boasting a total output of 960 megawatts, He Dreiht is currently Germany's largest offshore wind farm and a stunning example of how we are shaping the future of sustainable energy.

"EnBW has been planning, building and operating offshore wind farms in Germany and Europe for over 15 years, playing a key role in helping to meet Germany's climate change mitigation targets."

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CLIMATEWIRE

Huge new wind turbines face backlash

By Minho Kim | 10/06/2023 06:27 AM EDT

Taller than the Golden Gate Bridge, new offshore wind turbines are drawing warnings from the federal government and experts over reliability.

When the Interior Department in late August approved construction of a wind farm off the Rhode Island coast, it imposed an unusual restriction on the developer — do not use the most powerful turbines.

The order reflects a critical juncture facing the offshore wind industry, which could provide three times the amount of electricity that the entire U.S. now generates, according to the Department of Energy's National Renewable Energy Laboratory (https://www.nrel.gov/wind/offshore-resource.html).

As the Biden administration boosts offshore wind to help meet its climate targets, developers are trying to make wind power inexpensive by installing increasingly large and powerful turbines aimed at improving efficiency.

But as developers plan for turbines that stand 800 feet — higher than the Golden Gate Bridge towers — federal officials and experts are warning that the models will take years to produce and could increase wind power costs.

"When you build a machine of that size, there are a lot of problems that you have to work out, and those haven't been worked out yet," Walt Musial, a principal engineer at DOE's energy lab, said in an interview.

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A-7

A DOE report by Musial released just after the Rhode Island decision says that turbine manufacturing facilities need improvements costing billions of dollars before they can produce 800-foot models. The upgrades would delay offshore wind projects and increase construction costs, according to DOE's Offshore Wind Market Report for 2023 (https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2023-edition).

An August report by Wood Mackenzie, a global energy consulting firm, called the drive for larger wind turbines an "arms race (https://www.woodmac.com/horizons/cross-currents-charting-a-sustainable-course-for-offshore-wind/)" that could delay construction and set back wind goals worldwide.

"It's a huge risk that we're now seeing for projects," said Finlay Clark, a Wood Mackenzie senior offshore wind analyst and one of the report's authors.

For decades, manufacturers have produced larger, more powerful turbines every few years as developers sought to reduce construction and maintenance costs by using fewer towers per offshore wind farm.

The two U.S. offshore wind farms currently in operation — in Rhode Island and Virginia — have seven turbines combined. All of them generate up to 6 megawatts of power depending on wind strength. One MW can power 400 homes, according to the Biden administration.

At least six planned offshore wind projects, including Atlantic Shores in New Jersey and Empire Wind off Long Island, will use turbines that can generate 14 or 15 MW, according to Vestas and Siemens Gamesa, the European manufacturers building the turbines.

Only a handful of factories outside of China produce 14-MW turbines. Developers of the six wind projects expect the larger turbines to be commercially available in the next year or two.

Equinor, a Norwegian state-owned energy company developing Empire Wind, acknowledged to E&E News that the growing turbine size is "threatening profitability" and said it is working "to find ways of achieving our goals."

"Growing pains will diminish over time," Equinor said.

But developers are ignoring "the risk in going to those larger machines, or whether the supply chains and the vessels and the ports are going to be able to accommodate those machines," Musial said.

"Larger turbines always look better on paper," he added.

Offshore wind is key to renewable energy goals

The Biden administration wants to add 30,000 MW of offshore wind by 2030 that can power 10 million homes. Wind produces 10 percent of U.S. energy, almost all of which comes from onshore wind farms scattered from Texas to Iowa to California. Onshore turbines generate at most 3 MW.

Offshore wind farms could generate far more power because they can use larger turbines and wind is stronger and more consistent at sea.

Offshore wind farms are as reliable as gas-fired power plants and supplement power from solar and onshore wind farms, both of which depend heavily on weather conditions, according to the International Energy Agency (https://www.iea.org/reports/offshore-wind-outlook-2019).

The administration's wind goals focus on installing about2,100 more offshore turbines (https://www.nrel.gov/news/program/2023/road-map-defines-path-to-a-us-offshore-wind-energy-supply-chain.html#:~:text=Achieving%20the%20national%20offshore%20wind,as%20lots%20of%20helping%20hands.) , according to DOE's energy lab.

The turbines would have to generate on average about 14 MW to meet the 30,000-MW goal. The Interior Department limited the new Rhode Island Revolution Wind project to turbines that generate up to 12 MW.

The biggest problem with 14-MW or larger turbines is their unproven reliability, experts say.

Testing sites are not designed to handle the large blades in a 14-MW turbine. And because 14-MW turbines are new products — not upgrades to older turbines — they require extensive testing, Musial of the energy lab said.

A Boston testing site that opened in 2011 can measure the durability of blades up to 300 feet long and is the only blade testing site in North America. But the turbines for the Vineyard Wind project under construction off Massachusetts' coast will use General Electric's 13-MW models with 350-foot blades.

GE was forced to trim its blades to 300 feet to fit the test facility and get certification, according to the Massachusetts Clean Energy Center, a state-owned research group that runs the facility.

But trimming will not work for new turbines with blades reaching nearly 400 feet, which would require an expansion of the testing site, the center said.

Even after turbines are certified, the new designs could run into unforeseen failures in the ocean, where they have no track record of operating, Musial said.

The projects will also face problems with transportation and construction.

The offshore platforms on which wind turbines are assembled and driven into the ocean floor are too small to handle the larger components. So are the barges and tugboats that haul components to the platforms, said Sam Salustro, a vice president at the Business Network for Offshore Wind.

The U.S. needs at least 100 ships to meet the administration's 2030 goal, but only 36 are being built, Salustro said.

More than 20 new platforms are needed to meet international wind goals, but installers have committed to less than half that number, the Wood Mackenzie report says.

Insurers, concerned about reliability, could also slow construction by denying coverage to the larger offshore wind farms for project delays or component failures, according to GCube, an insurance firm specializing in renewable energy projects.

'A monster we created'

The U.S. is unlikely to reach President Joe Biden's offshore wind goal, according to BloombergNEF, which projects 23 gigawatts of new capacity will come online by 2030.

The Biden administration is "using every legally available tool" to advance offshore wind projects, a White House spokesperson said in an email. "Since President Biden signed the Inflation Reduction Act [in August 2022], investments in the U.S. offshore wind industry have increased by $7.7 billion (https://www.whitehouse.gov/briefing-room/statements-releases/2023/07/20/fact-sheet-bidenomics-is-boosting-clean-energy-manufacturing-for-offshore-wind-and-creating-good-paying-american-union-jobs/) — creating thousands of good-paying union jobs across the country in manufacturing, shipbuilding, and construction."

Despite high risk, developers and manufacturers continue to pursue larger turbines. GE and two Chinese manufacturers are developing 1,000-foot, 18-MW turbines.

Many manufacturers fear that if they stop building larger turbines, customers will buy them from other companies, said John Eggers, Vestas' U.S. chief technology officer. Vestas says it won't develop turbines bigger than its 15-MW prototype because transporting larger machines is difficult.

Eggers said manufacturers have fueled the growth in turbine size by producing new, larger models every few years.

"It's a monster we created. It's a monster we have to stop," Eggers said.

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European wind industry reaches milestone with 15MW wind turbine commissioned at sea

A-8

Vestas V236-15.0MW wind turbines are installed at the He Dreiht offshore wind farm in the German North Sea.

Photo: Vestas

Steffie Banatvala

Published 26 November 2025, 02:52

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EnBW He Dreiht offshore wind farm (Photo: EnBW/Rolf Otzipka)

"Its efficiency and performance enable a significant increase in energy yield per turbine."

In total, the project will supply the equivalent of about 1 million homes, making it one of Europe's largest offshore wind projects.

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Review

Examining the trends of 35 years growth of key wind turbine components

Peter Enevoldsen, George Xydis

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Highlights

- Presentation of dataset revealing 35 years of wind turbine development trends, which indicates ever-growing wind turbines.
- Insight to the relationship between developments of core components
- Overview of the consequences of the development throughout 35 years, for on — and offshore wind industry stakeholders.
- A linear forecast of the core specifications of a wind turbine in 2023.

Abstract

A-9

The wind industry has innovated constantly throughout the past decades. Nevertheless, few studies have adequately analyzed the trends and consequences of the ever-growing wind turbines. Understanding the development and relationship of the technical characteristics of wind turbines provides insight into future innovations for multi-megawatt wind turbines. Such knowledge can be useful for industry members or researchers who are determined to design anything from new energy plans to the next wind turbine component. This study draws on an extensive dataset consisting of 35 years of multi-megawatt wind turbine inventions to explain the recent decades' development, which has resulted in a doubling of tower height and rotor diameters as well as eight times greater nameplate capacities. In addition, this study predicts and discusses the future development of wind turbines. The prediction reveals that both onshore and offshore wind turbines will keep growing in size, although offshore wind turbines are forecasted to experience the greatest growth.

Introduction

The world's first multi-megawatt wind turbine started spinning in 1978 in Denmark with a nameplate capacity of 2.0 MW and a rotor diameter of 54 m (Nissen et al., 2009). This wind turbine was one of a kind in a period (1975–1985) where the majority of wind turbines had an installed capacity in the range of 10–110 kW and a rotor diameter in the range of 5–15 m (Nissen et al., 2009). However, since then, the technological development has rendered it possible to develop much larger wind turbines with higher installed capacity, resulting in operating wind turbines with a capacity of 9.5 MW and a rotor diameter of 164 m (www.4coffshore.com, 2017). The development of larger wind turbines is well aligned with the fast-growing wind industry employing more than one million people worldwide (IRENA, 2015), with installations in more than 100 countries (Enevoldsen, Valentine, & Sovacool, 2018) and an installed capacity above 500 GW in 2017 (GWEC, 2017a, GWEC, 2017b). The development of the cumulative wind installations throughout a period of 35 years (1981–2016) has been plotted in Fig. 1.

The graph in Fig. 1 shows the development from 25 MW in 1981 to 539,790 MW in 2017, illustrating the fastest growing renewable energy technology over the past four decades (U.S. Department of Energy, 2015). The increasing development has been supported by favorable energy policies and more focus on the transition to a world powered by renewables. The technological development has furthermore enabled wind turbines to be deployed in various locations (Enevoldsen & Valentine, 2016), which were technologically limited 35 years ago. Naturally, the first offshore wind farm installed in 1992 enabled the spacious ocean as a location for future wind project development, which since has been supported by innovative foundation designs allowing offshore wind turbines to be deployed at deeper seas (Sovacool & Enevoldsen, 2015). The annual development in combined on – and offshore installed wind power capacity (MW) has been plotted in the graph in Fig. 2.

However, despite the rapid development of technologies and installed capacity in the past decades, Grubb and Meyer (1993) already estimated the global gross electricity production from wind power to be 500,000 TWh in 1993. This number is expected to be even greater today, as innovative technologies have enabled new site locations. In 2011, Edenhofer et al. (2011) estimated a potential annual energy production of 840,000 TWh, and in 2005, Archer and Jacobson estimated that harvesting 20% of the potential wind energy would be enough to power the world's energy demand. GWEC (2017a) estimated that wind power installations could reach a cumulative capacity of 2110 GW by 2030, and in their plans for 139 countries, Jacobson et al. (2017) suggested a requirement of 8330 GW of onshore installations and 4690 GW of offshore installations to meet the global energy demands in 2050 in a scenario powered by wind, water, and solar resources. The development of the estimated scenarios is very much caused by the development of the wind turbine technology, which has changed over the past decades.

The trends of wind power technology have been heavily discussed in review papers in the past decades. In Sahin (2004) the average wind turbine was presented with a nameplate capacity of 1500 kW and hub heights of 60–80 m with outlook towards larger wind turbines. In Sahin (2004) concerns were rasied over the increasing wind turbine dimensions and future performance in complex terrains due to excessive loads. A decade later, a study by Islam, Mekhilef, and Saidur (2013) examined the trends of wind power and found that the average wind turbine had a nameplate capacity of 2 MW, yet with expectations of wind turbines exceeding 10 MW in the near future. Islam et al. (2013) furthermore expected vertical axis wind turbines (VAWT) to dominate the wind sector in two to three decades, due to the limited land use and increased power density. However, in their examination of wind energy trends and enabling technologies, Kumar et al. (2016) suggest that VAWT are more applicable for urban purposes. Kumar et al. (2016) defined that borg the rotor diameter and hub height of an average onshore wind turbine is in the range of 50–100 m.

Despite previous studies investigations into wind power trends, few, if any, have adequately explored the development of the vital wind turbine specifications, in order to define the impact and future consequences. Therefore, this research seeks to review and explain the past 35 years of innovative development of multi-megawatt wind turbines in order to predict future wind turbine configurations and explain why wind turbines have been developed the way they have.

Section snippets

Research materials and methods

This research seeks to explore and explain the consequences of 35 years of wind turbine development trends by examining the actual development of the following wind turbine parameters:

- Nameplate capacity ...
- Rotor diameter ...
- Hub height ...
- Rated and cut-in wind speed ...

The parameters have been selected as they represent the physical development of the most visual dominating parts of the wind turbine (rotor and tower) meanwhile introducing the capabilities to produce energy (nameplate capacity and rated and ...

Analyzing the trends of wind power

The primary empirical data source is based on dataset consisting of more than 850 wind turbines commercialized in the period 1981–2017 (June), collected from a range of sources, including the preliminary literature review and majorly from “The Wind Power” (2017). All of the wind turbines have a minimum nameplate capacity of 1 MW, as wind turbines with an installed capacity below 1 MW has been filtered away to avoid household turbines, as well to concentrate on the multi-megawatt market. ...

Discussion

This section introduces the discussion on the wind turbine development throughout the past decades by conceptualizing the impact of this development. As described in the empirical analysis, the technological development has been driven by market forces, yet it remains unclear if the technological development has pushed certain markets to alter their conditions. For instance, it is evident that markets leaning on wind energy, more than other, have tried to develop earlier mechanisms that support ...

Conclusion

This research has examined and analyzed the trends of the main components and capabilities of onshore and offshore wind turbines throughout the past decades at a global scale. The results are an overview of the incremental innovation, including a discussion of the impact and reasons for the engineered development. As expected, the wind turbines and the key components have all grown in size over the past decades, rendering it possible to deploy wind turbines in new locations and generate more ...

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> *Citation Excerpt :*
> ...In addition, a large number of components involved in the power generation process of traditional wind turbines are integrated in the nacelle on top of each individual wind power generator. This brings

inconvenience to installation or maintenance and incurs many costs [11–13]. With the maturity of hydraulic technology and the emergence of its advantages, such as stepless speed regulation, a large power-to-weight ratio and reusable energy [14–16], since 2009 some scholars have successively proposed the concept of hydraulic wind turbines, as shown in Fig. 1....

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Increasing Wind Turbine Tower Heights: Opportunities and Challenges

Eric Lantz,[1] Owen Roberts,[1] Jake Nunemaker,[1] Edgar DeMeo,[2] Katherine Dykes,[1] and George Scott[1]

1 National Renewable Energy Laboratory
2 Renewable Energy Consulting Services, Inc.

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Technical Report
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May 2019

A-10

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List of Abbreviations

1P	rotor rotational frequency
3P	blade passing frequency
BAR	big adaptive rotor
BAU	business as usual
BOS	balance of station
CapEx	capital expenditures
CSM	Cost and Scaling Model
GW	gigawatts
IEC	International Electrotechnical Commission
kN	kilonewton
kNm	kilonewton-meter
kW	kilowatt
LandBOSSE	Land Balance of Station Systems Engineering
LCOE	levelized cost of energy
LDST	large-diameter steel tower
MWh	megawatt-hour
OEM	original equipment manufacturer
O&M	operation and maintenance
R&D	research and development
RNA	rotor nacelle assembly
TowerSE	Tower Systems Engineering
Wind	Wind Integration National Dataset Toolkit
WTT	Wind Tower Technologies

Executive Summary

This report presents the opportunities, challenges, and potential associated with increasing wind turbine tower heights, focusing on land-based wind energy technology. Our principal conclusions are as follows:

- **Wind resource quality improves significantly with height above ground.** Over large portions of the country, our mesoscale resource data indicate an increase in annual average wind speed of 0.5 to 1.0 meters per second (m/s) when moving from 80 to 110 meters (m) and 1.0 to 1.5 m/s when moving from 80 to 160 m.
- **Wind speed differences translate to sizable capacity factor improvements.** Although the observed variance is broad, median capacity factor gains with higher hub heights are estimated at approximately 2 to 4 percentage points when going from 80 to 110 m and an additional 2 to 4 percentage points when going from 110 to 140 m. Between 140 and 160 m, median capacity factor gains are approximately 1 percentage point. Relatively larger gains occur east of the Rocky Mountains, with the greatest gains sprinkled throughout the Heartland, the Midwest, and the Northeast.
- Based on first-order cost estimates informed by current technology, **the most wind-rich regions of the country generally show an economic preference for the lowest considered tower height; higher hub heights (e.g., 110 m and 140 m) are often preferred in more moderate wind speed regions.** This result is consistent with industry experience to date.
- **Higher nameplate and lower specific power turbines (e.g., 150 to 175 watts per square meter) also show a general economic preference for the lowest considered tower height; however, these larger turbines require tower heights of at least 110 m.** Tower heights of 140 m and in some cases 160 m tend to be preferred in more moderate wind speed areas.
- **The highest nameplate capacity turbine we considered (4.5 megawatts) has a relatively greater preference for 140-m hub heights than similar 3-megawatt-class turbines.** This observation is driven by the proportionally lower cost associated with taller towers and tall tower installations in dollars per kilowatt ($/kW) for larger turbines and indicates that turbine scaling (which offers additional cost saving potential) and taller tower deployment is likely to occur in parallel.
- **Future tower innovations could make higher hub heights more attractive.** In a tower cost-bounding scenario, where we apply a fixed $200/kW tower cost for each turbine at all hub heights, we see an economic preference for 160-m tower heights in 70% to 90% of sites, depending on the specific turbine configuration.
- **Reducing the cost of realizing taller towers is critical to capturing the value of higher wind speeds at higher above ground levels** as well as for increasing the viability of wind power in all regions of the country.
- **Additional factors that could impact tower height include blade tip clearance requirements, balance-of-station costs, turbine nameplate capacity, and specific power.** Turbines with higher specific power ratings experience more energy gain for a given change in wind resource. Larger wind turbines tend to have an economic advantage for tall tower applications and offer additional cost saving potential in balance-of-station and turbine-level

economies of scale. Ultimately, wind turbine design reflects an optimization across an array of potential criteria; focusing on tower height alone may result in suboptimal outcomes.

- **When pursuing higher tower heights, a system-level incremental capital cost of less than $500/kW for low specific power turbines and potentially as low as $200/kW, particularly for higher specific power turbine configurations, could support a levelized cost of energy reduction across much of the country, and might also push less-energetic wind resource regions further along the path to economic competitiveness**. Depending on the specific focus regions and turbine configurations under consideration, variance from this general guidance could be merited.
- **To realize taller wind turbine towers, an array of potential concepts remain in play. These concepts rely on various materials spanning rolled tubular steel (currently the most widely used option), concrete, and lattice steel, for space frame designs, as well as hybrid designs that use a combination of concepts**. Although there are clear advantages and disadvantages to each known concept, the future design of tall wind turbine towers remains to be determined. At the same time, our examination suggests that tubular towers can continue to be viable at the higher above-ground heights, particularly with continued advances in control technology that allow for reliable use of soft-soft designs. Tower erection strategies and innovation may also be a determining factor in the viability of future tall tower concepts.

Notable caveats in this analysis include uncertainty in the underlying resource data, which increases at higher above ground levels, coupled with high sensitivity in terms of the analysis results to the assumed wind shear. In addition, our capital expenditure and levelized cost of energy estimates are based on cost characterizations that generally reflect modern state-of-the-art technology and do not consider the potential for future innovations to alter the capital expenditures required to achieve a given tower height. Finally, the tower height economic preference analysis is limited to tower heights of 80 m, 110 m, 140 m, and 160 m; in many cases, real-world economically preferred tower heights will likely fall between these points.

Future research needs elicited from this work include activities that quantify and ultimately reduce the uncertainty of the wind resource data, particularly at higher above ground levels. More robust cost assessments and analysis including more sensitivities as well as evaluation of specific technology opportunities and alternative turbine configurations would also be valuable and further inform the potential for innovative solutions to capture value from taller towers.

Table of Contents

1 Introduction 1
1.1 A Brief History of Wind Power Technology 1
1.2 Analysis Objectives and Organization 3
2 Tower Opportunities and Cost Estimation 4
2.1 Wind Speed Change with Height Above Ground Level 4
2.2 Capacity Factor Change with Height Above Ground Level 6
2.3 Levelized Cost of Energy Estimations 10
2.4 Breakeven Cost Analysis for Turbines with Taller Towers 22
3 Tower Design Options and Related Analysis 27
3.1 Systems Engineering Steel Tower Simulations 27
3.1.1 Tower Optimization Method 27
3.1.2 Tower Optimization Case Study 29
3.1.3 Results 30
3.2 Innovation Opportunities for Additional Alternative Tall Tower Technologies 32
3.2.1 Full-Concrete Field-Cast Towers 32
3.2.2 Hybrid Concrete and Tubular Steel Towers 33
3.2.3 Lattice/Space Frame 34
3.2.4 Comparing and Contrasting Competing Tower Alternatives 35
4 Insights for Tower Design and Innovation 37
4.1 Analysis Results and Insights 37
4.1.1 Wind Resources 37
4.1.2 Capacity Factors 37
4.1.3 Energy Costs 37
4.1.4 Breakeven Costs 38
4.1.5 Tall Tower Options 38
4.2 Analysis Results Discussion 39
4.3 Lessons Learned for Evaluating Tall Tower Opportunities 40
5 Conclusions 42
6 References 43

List of Figures

Figure 1. Difference in mean annual wind speed at 110 m above ground level relative to 80 m, based on the Wind Toolkit 5
Figure 2. Difference in mean annual wind speed at 160 m above ground level relative to 80 m, based on the Wind Toolkit 6
Figure 3. Estimated net capacity factor, all turbines and hub heights 8
Figure 4. Estimated difference in net capacity factor, all turbines and hub heights, relative to the Today turbine at 80 m (percentage points) 9
Figure 5. Estimated difference in net capacity factor, all turbines and hub heights, relative to the lowest hub height available per platform (percentage points) 9
Figure 6. Estimated total installed capital cost by turbine and hub height 13
Figure 7. Estimated LCOE for each Wind Toolkit pixel, assuming the Low-SP 4.5-MW turbine at a 110-m hub height 14
Figure 8. Estimated LCOE for each Wind Toolkit pixel, assuming the Low-SP 4.5-MW turbine at a 160-m hub height 15
Figure 9. Estimated LCOE for each Wind Toolkit pixel; all turbines and all applicable hub heights 16
Figure 10. Estimated LCOE differences for each Wind Toolkit pixel, relative to the Today turbine at 80 m 16
Figure 11. Calculated preferred hub height by turbine configuration, based on estimated performance and costs 18
Figure 12. Calculated economically preferred hub heights for the Today turbine, based on estimated costs and performance 19
Figure 13. Calculated economically preferred hub heights for the BAU turbine, based on estimated costs and performance 19
Figure 14. Calculated economically preferred hub height for the Low-SP 3.25-MW turbine, based on estimated costs and performance 20
Figure 15. Calculated economically preferred hub height for the Low-SP 4.5-MW turbine, based on estimated costs and performance 20
Figure 16. Estimated LCOE differences for each Wind Toolkit pixel, assuming $200/kW tower costs, relative to the Today turbine at 80 m 21
Figure 17. Calculated preferred hub height by turbine configuration, based on estimated performance and costs, assuming $200/kW tower cost 22
Figure 18. Breakeven costs for all turbines and all hub heights 23
Figure 19. Estimated LCOE for the Today turbine at the 80-m hub height 24
Figure 20. Breakeven costs for the BAU turbine at the 110-m hub height 25
Figure 21. Breakeven costs for the BAU turbine at the 140-m hub height 25
Figure 22. Breakeven costs for the Low-SP 4.5-MW turbine at the 110-m hub height 26
Figure 23. Breakeven costs for the Low-SP 4.5-MW turbine at the 140-m hub height 26
Figure 24. Optimization results for soft-stiff tower design cases 30
Figure 25. Optimization results for soft-soft tower design cases 31

List of Tables

Table 1. Turbine Configurations Used To Estimate Capacity Factors at Higher Hub Heights 7
Table 2. Tower Design Variables 28
Table 3. Tower Design Constraints 28
Table 4. Tower Optimization Cases 29
Table 5. IEA Wind Task 37 Land-Based Low Wind Speed Turbine Configuration Data 29
Table A1. Detailed Levelized Cost of Energy Cost Inputs 46
Table A2. Net Capacity Factor Change Statistics, Relative to the Today Turbine at 80 m 47
Table A3. Net Capacity Factor Breakpoints 48
Table A4. Levelized Cost of Energy Summary Statistics ($/megawatt-hour [MWh]) 49
Table A5. Levelized Cost of Energy Breakpoints 50
Table A6. Average State Levelized Cost of Energy ($/MWh) 51
Table A7. Average State Breakeven Cost ($/kW) 54

1 Introduction

Wind power is one of the fastest-growing sources of new electricity generation in the United States. Since the early 2000s, annual investments in new wind capacity have exceeded the billion-dollar threshold, with investments in recent years often more than $10 billion annually. Cumulative installed capacity was estimated at more than 96 gigawatts (GW) at year-end 2018 (American Wind Energy Association [AWEA] 2019) and wind power supplied approximately 6.6% of total electricity generation in 2018 (Energy Information Administration 2019). The recent growth of the wind power industry has been spurred, in part, by innovation and subsequent reductions in costs coupled with state and federal policy support.

Looking ahead, further cost reduction is anticipated to be critical to continued economic competitiveness. This is due, in part, to competitive pressure from low-cost natural gas and solar photovoltaics (Mai et al. 2017; Dykes et al. 2017). Notably, however, with continued cost reduction, economic deployment of wind energy through 2050 could be more than 430 GW and possibly as high as 550 GW, with wind power supplying between 38% and 46% of total electricity generation (Mai et al. 2017). Moreover, the quantity of available wind energy resource is such that the opportunity for capturing thousands of terawatt-hours of low-cost, clean wind energy remains of significant interest.

Key technology attributes enabling cost reductions realized to date include advancements that have resulted in the capture of turbine, balance of station (BOS), and operation and maintenance (O&M) economies of scale as well as increased energy production per turbine and per unit of installed capacity. More specifically, increased energy production has been realized with taller towers that place turbines into higher-quality resource regimes as well as larger rotors that enable more of the wind passing by the turbine to be converted into electricity. Basic science research and development (R&D) coupled with industry innovation has allowed tower height and turbine rotors to grow and increase energy capture while simultaneously eliminating excess material, improving production processes, and maintaining reliability, enabling this increased energy to be achieved at little to no capital cost penalty.

To further drive down costs, wind turbine researchers, designers, and engineers continue to pursue strategies that could use even higher hub heights to be economically attractive. Higher hub heights remain of interest due to the more energetic wind resource that exists at higher above ground levels as well as the need to provide additional clearance for increasingly long blades that maximize energy capture per turbine. In this context, the current analysis seeks to understand and explore the potential opportunity space around tall wind turbine tower technologies. We also demonstrate a new approach to analyzing technology opportunity and potential across a broad geographic area, in this case the contiguous United States. This approach is useful when evaluating wind technology given the significant spatial variability in resource quality and the impact that spatial variability has on optimal technology design.

1.1 A Brief History of Wind Power Technology

In the 1980s, a commercial wind turbine was approximately 100 kilowatts (kW) in nameplate capacity and had a hub height and rotor diameter that were both on the order of 20 meters (m). By the early 1990s, a typical commercial turbine was approximately 300 kW in nameplate capacity and had a hub height and rotor diameter that were both on the order of 30 m. By the early 2000s, machines had achieved a nameplate capacity in excess of 1 megawatt (MW) and a rotor diameter and hub height of approximately 70 m. Most recently, wind turbines installed in the United States in 2018 had a nameplate capacity averaging 2.4 MW, rotor diameters averaging 116 m, and hub heights averaging about 88 m (AWEA 2019). In Germany, where the wind resource is often of lower quality and developable land area is more limited, designers are forced to consider energy production per unit of land area as well as cost per unit of energy among other factors, with optimums favoring larger turbines. The average nameplate capacity for projects commissioned in 2017 in Germany was 2.97 MW; average rotor diameter was 113 m, and average hub height was 128 m (Deutsche WindGuard 2018). In the German context, larger machines and more design constraints (e.g., land area) have resulted in higher wind cost of energy relative to the United States (Hand et al. 2019; Vitina et al. 2015). Nonetheless, these larger turbines have proven preferable for German sites. Although design conditions and optimums in Germany differ from those in the United States and other parts of the world, the German data illustrate that under the right conditions a continued push toward higher hub heights provides value.

Driving trends in turbine configuration, scale, and cost of energy are fundamental economic considerations associated with wind turbine technology and design (Zayas et al. 2015). Historically, increased hub heights have resulted from a general trend of improved wind resource at levels higher above the ground that are less affected and slowed by surface roughness (e.g., trees, buildings) and local topography. At the fundamental level, hub height growth has been constrained by impacts on installation and erection cost, and the incremental cost of the taller tower relative to the additional energy that might be extracted from the improved wind resource quality found at higher above ground levels with the state-of-the-art turbine rotor nacelle assembly (RNA). More recently, hub height growth has also been impacted by transportation and logistics barriers that restrict the sectional tower diameter to fit under highway and railway underpasses. These transport constraints result in relatively inefficient tower designs from a material use and cost perspective, as compared to towers designed solely to meet their fundamental functional design requirements.

In the United States, there has been a partial plateau in tower or hub height scaling (Wiser and Bolinger 2018). The leveling off of tower height is in part a function of the excellent wind resource available in the interior region of the United States and a function of the logistics and transport trends noted earlier—which require substantially greater quantities of steel at higher hub heights to maintain sufficient stiffness while adhering to the transport-dictated sectional diameter constraints. With respect to the former, the world-class wind resource present in the interior region of the United States—even at levels of 80 m above ground level—has allowed projects using modern technology to achieve performance levels that support levelized cost of energy (LCOE) values at or below \$40/megawatt-hour (MWh) to \$45/MWh (excluding the production tax credit). These performance levels have positioned wind to be competitive at 80-m hub heights as a fuel-saving, electricity-generating technology over the past several years, with the federal production tax credit in place.

This is not to suggest that the incentives for continuing to pursue tall wind have diminished, rather that it simply has become more difficult to reap the rewards of turbine scaling as a result of additional constraints that must be addressed as well as the increasingly complex construction requirements of very large turbines. This is particularly true in regions that have very good resources at the heights above ground that are within reach of modern wind industry original equipment manufacturers (OEMs), as well as readily available transport and logistics capabilities. Evidence for the continued pursuit of tall wind in the United States exists in recent turbine offerings from the top-three global wind turbine OEMs: Vestas, GE, and Siemens. Combined, these three OEMs captured more than 90% of the U.S. market (AWEA 2017). In 2016, each of these OEMs began marketing turbines in the 3-MW class, with rotor diameter offerings from approximately 100 m to 140 m, and tower heights from 75 m to 165 m.[1]

1.2 Analysis Objectives and Organization

This report has two primary objectives. First, it seeks to inform the opportunities and potential associated with increasing wind turbine hub heights. It also explores the conditions and locations where taller towers offer the most significant potential to increase wind technology performance and reduce costs. This initial objective is discussed in Section 2. The second objective is to examine the status of tall tower technology as a key subcomponent of wind power advancement. This objective is discussed in Section 3, where we analyze the potential for continued innovation in tubular steel wind turbine towers and explore the status and potential for a select set of alternative tall tower technologies. Key findings and lessons learned are covered in Section 4. A brief summary and final conclusions are found in Section 5. The appendices include more resolved data on estimated LCOE, capacity factor change with height above ground, and breakeven cost.

[1] Recent increases in the turbine scale and hub heights now being offered by OEMs generally are perceived to have been made more feasible by advanced turbine controls that allow the machines to avoid certain portions of the operating envelope that resulted in more conservative design requirements. Looking ahead, the opportunities created by continued evolution of advanced controls deserve continued attention and tracking.

2 Tower Opportunities and Cost Estimation

To begin to understand the potential for higher hub heights as a source of further wind power cost reduction, the authors assessed how taller towers could impact key indicators of wind energy viability across the nation. We begin by examining the change in wind speed that is achieved by increasing hub height from a baseline of 80 m typical of today's commercial installations to 110 m and 160 m across the contiguous United States. Second, we quantify the impact this wind speed change could have on wind power capacity factors by estimating wind energy production for four wind turbine configurations. We conclude this portion of the analysis by estimating LCOE for these four turbine configurations and evaluating which hub height for each configuration tends to have the lowest LCOE, using cost and scaling estimates informed by recent state-of-the-art technology. LCOE and tower height preferences are also estimated for a sensitivity scenario wherein wind turbine tower costs are fixed at levels of $200/kW, even while turbines are able to scale and access hub heights up to 160 m. This additional sensitivity helps to inform the potential LCOE and preferred tower heights that might be achieved if tower R&D and innovations are very successful.

2.1 Wind Speed Change with Height Above Ground Level

As a first step in characterizing the opportunity offered by achieving higher hub heights than the typical 80-m hub height for turbines installed in the United States over the past decade, we utilized wind speed data from the National Renewable Energy Laboratory (NREL) Wind Integration National Dataset (Wind) Toolkit (https://www.nrel.gov/grid/wind-toolkit.html) to compare differences in mean annual wind speeds at each pixel or site within the contiguous United States. The Wind Toolkit is a mesoscale wind-resource data set that was funded by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Wind Energy Technologies Office, and created through the collaborative efforts of NREL and 3TIER.[2] The data set includes meteorological data, including wind speed for more than 1.85 million locations in the contiguous United States for a period of 7 years between 2007 and 2013. Each pixel in the Wind Toolkit represents a 2-km-by-2-km grid cell. The data are generated by meteorological models that have used real-world historical input data to recreate a complete suite of output data to be used in analysis and research. The Wind Toolkit has wind speed data for multiple hub heights. For this analysis, we consider hub heights of 80 m, 110 m, 140 m, and 160 m above ground level, and relied on data from the 2012 calendar year.

A significant caveat to these results that extends throughout the analysis is that the uncertainty in the wind speed data from the Wind Toolkit is not fully understood or characterized, particularly as one moves to higher above ground levels (e.g., 140 m and 160 m). Moreover, the analysis conducted here focuses only on the 2012 weather year. Some variability in the results therefore is likely when considering normal interannual resource variability. Anecdotal evidence from limited site-specific validation suggests that in some locations the uncertainty in the mesoscale data is large (e.g., potentially in excess of 1 meter per second [m/s]). Although the impact of this uncertainty is sizable and important and would undoubtedly impact the precise quantitative outcomes from the analysis, the broad trends and qualitative outcomes from the work are

[2] In the years since the Wind Toolkit was developed, 3TIER has been acquired by Vaisala http://knowledge.vaisala.com/3TIER (accessed March 6, 2019).

generally useful in understanding the opportunity offered by further increases in hub heights for the wind turbines evaluated here.

Figure 1 and Figure 2 illustrate the difference in mean annual wind speed in the Wind Toolkit when comparing 80-m and 110-m hub heights and 80-m and 160-m hub heights, respectively. These data show that nearly all regions of the country observe wind speed increases when moving to 110 m. Minor exceptions in this regard are in small isolated pockets in the Southwest and in California. These "negative" wind-shear locations have relatively rare topographical and meteorological patterns that drive these anomalies. West of the Rocky Mountains, the wind speed increase is largely in the 0- to 0.5-m/s increase category at 110 m. With the exception of the mountainous regions (e.g., along the Appalachian Mountains; the Ouachita Mountains of West Central Arkansas) and Florida, the portion of the country that falls east of the Rocky Mountains primarily sees a wind speed increase of 0.5- to 1.0-m/s when moving from 80 to 110 m.

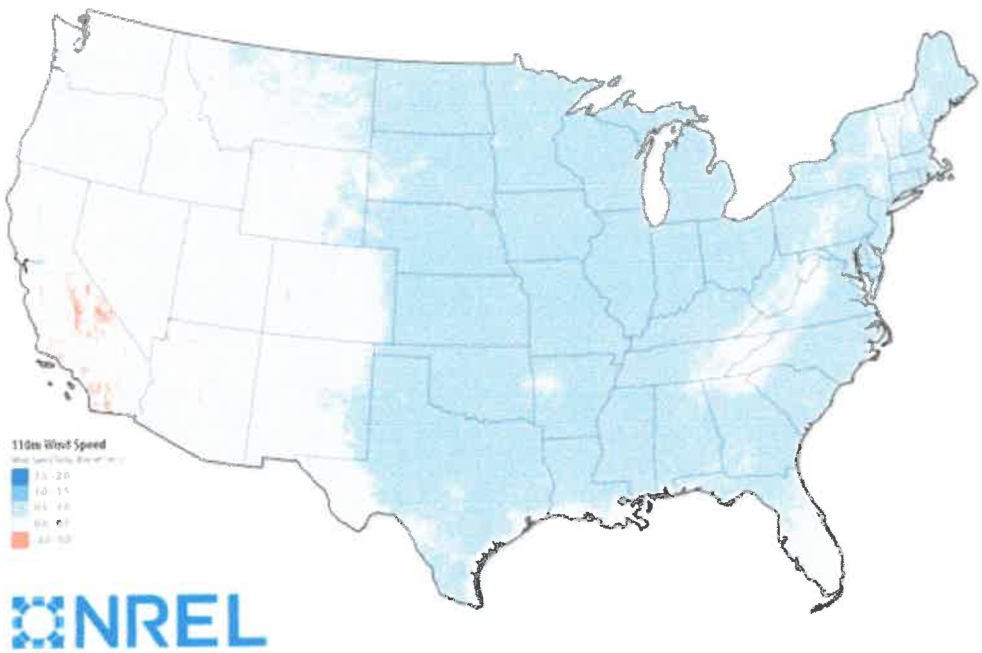

Figure 1. Difference in mean annual wind speed at 110 m above ground level relative to 80 m, based on the Wind Toolkit

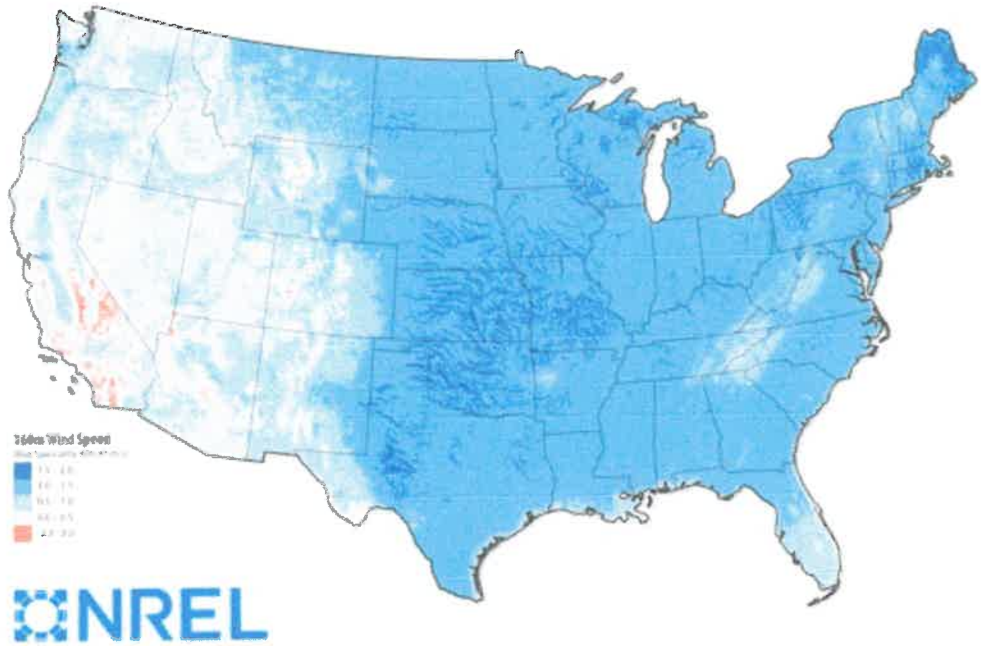

Figure 2. Difference in mean annual wind speed at 160 m above ground level relative to 80 m, based on the Wind Toolkit

When moving from 80 to 160 m, the results are more pronounced and heterogenous. In much of the Interior West between the Rockies and the Sierra Nevada ranges, the improvements are still in the 0- to 0.5-m/s increase category but scattered throughout, and in a loose ring around this region significant portions see increases in wind speed that are in the 0.5- to 1.0-m/s category. Moving east from the Rocky Mountains, when comparing 80 m with 160 m greater increases (1.5–2.0 m/s) can be observed in the lower-lying portions of the central plains, in particular in the river valleys of Oklahoma, Kansas, and Nebraska, as well as along the upper Mississippi River Valley on the borders of Minnesota, Wisconsin, and Iowa. Increases of this magnitude also show up in Southwestern Texas, Missouri, and parts of Arkansas. The remaining portions of the Great Plains generally are in the 1.0- to 1.5-m/s category.

Moving further east, the mountainous regions of Tennessee and surrounding states continue to exhibit a 0–0.5 m/s increase in wind speed. These regions, however, are surrounded by larger areas that observe increases that are more broadly in the 1.0- to 1.5-m/s range. Pennsylvania, New York, and Maine see a broad range of increases, with some areas in the 0.5- to 1.0-m/s category, some in the 1.0- to 1.5-m/s category, and some in the 1.5- to 2.0-m/s category.

In general, these data suggest that the value of achieving higher hub heights—at least according to differences in mean annual wind speed—is widespread but most significant east of the Rocky Mountains. Within that region, the largest increase in wind speeds appear to be in the relatively low-lying areas that fall in otherwise very windy regions (e.g., the river valleys of the Great Plains).

2.2 Capacity Factor Change with Height Above Ground Level

As a second step in understanding the potential value associated with placing wind turbines at higher hub heights, we used hourly wind speed data from the Wind Toolkit coupled with four wind turbine power curves to estimate potential energy generation and capacity factors for these four turbines at multiple hub heights. Net capacity factors were estimated assuming a simple 16.7% losses adjustment, which reflects a combination of array and electrical losses as well as turbine downtime.

The four modeled turbines used to estimate capacity factors were intended to represent state-of-the-art technology available today as well as potential turbines of tomorrow (Table 1). Our "Today," or reference turbine, was calculated from the average nameplate capacity and rotor diameter of turbines installed in the United States in 2017 (Stehly et al. 2018). This composite turbine was 2.3 MW and had a rotor diameter of 113 m, resulting in a specific power of approximately 231 watts (W)/m^2. Our business as usual (BAU) turbine was intended to reflect turbine technology that under BAU or median conditions is expected to be the average turbine installed around the United States by 2030. This turbine was derived from the simple extrapolations of historical trends for turbines installed in the United States and has a nameplate capacity of 3.3 MW and a rotor diameter 156 m, resulting in a specific power of approximately 173 W/m^2.

Two additional turbine concepts reflect potential future turbines in the 3-MW and 4- to 5-MW class, respectively, that are "low specific power," or Low-SP, turbines with specific power of approximately 150 W/m^2. These turbine configurations were selected based on recent trends suggesting continued pursuit by turbine designers and researchers of relatively low specific power wind turbines (Wiser and Bolinger 2018). Given these trends, we sought to understand how turbines with even lower specific power relative to our Today and BAU configurations might compare and contrast, in terms of their ability to extract value from higher hub heights. Including configurations in the 3- to 5-MW range also helps to illuminate potential value from coupled turbine scaling and hub height increase.

Table 1. Turbine Configurations Used To Estimate Capacity Factors at Higher Hub Heights

	Today	BAU	Low-SP 3.25 MW	Low-SP 4.5 MW
Nameplate CapacitTy (MW)	2.32	3.30	3.25	4.50
Rotor Diameter (m)	113	156	166	194
Specific Power (W/m^2)	231	173	150	152

To estimate the capacity factor change associated with each increased hub height, a turbine power curve was calculated for each defined turbine configuration. These power curves were then applied to the 2012 hourly wind speed data for each of the 1.85 million Wind Toolkit sites or "pixels." This process was completed at four hub heights for the Today turbine: 80 m, 110 m, 140 m, and 160 m. Only three hub heights were considered for each of the other turbine configurations: 110 m, 140 m, and 160 m to allow for ground clearance when the turbine blades come closest to the ground. Notably, the Low-SP 4.5-MW turbine with an approximately 95-m blade likely does not have sufficient ground clearance to be commercially deployed at a 110-m hub height. Nevertheless, these data were included in the analysis results to help us understand what the opportunity could be at this hub height. The resulting data were then plotted by capacity factor and frequency to understand the potential capacity factors across the continental United States for each turbine configuration and each hub height.

Spatially, capacity factor trends are closely aligned with the wind speed increases displayed in Section 2.1. Figure 3 illustrates the range and distribution of specific capacity factor improvements for the four modeled turbines at each of the respective hub heights where they were analyzed. Figure 4 illustrates the differences in capacity factor in percentage points for each location in the Wind Toolkit data set for each turbine configuration and hub height, relative to the Today turbine at 80 m. In effect, these data illustrate the potential capacity factor difference relative to current state-of-the-art technology and project norms. Figure 5 is similar to Figure 4 except that in Figure 5 the change in capacity factor is calculated relative to the lowest available hub height for a given turbine platform. In general, increases in hub height shift the resulting capacity factors to higher values. In many cases, as hub height changes, the frequency of certain capacity factors is also changed. For the Today turbine, there is a noticeable shift to the right as one moves from 80 m to 110 m and to 140 m. The increase between 140 and 160 m is more subtle. Similar trends are observed when moving between 140 and 160 m for the BAU and Low-SP turbines.

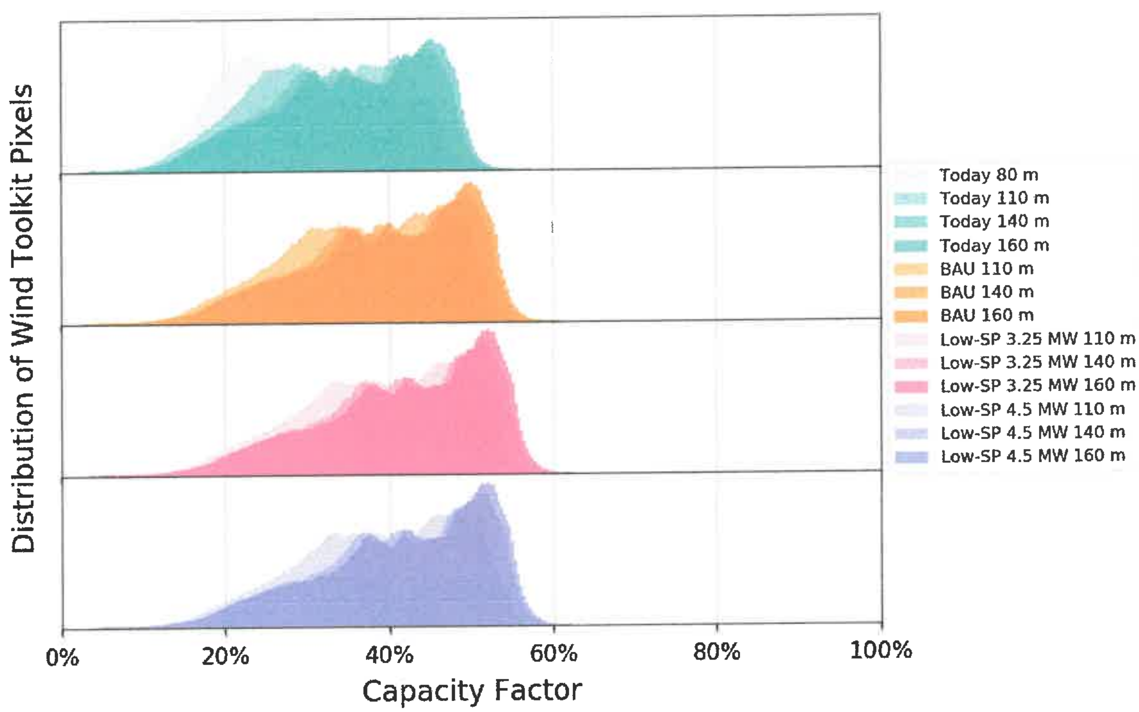

Figure 3. Estimated net capacity factor, all turbines and hub heights

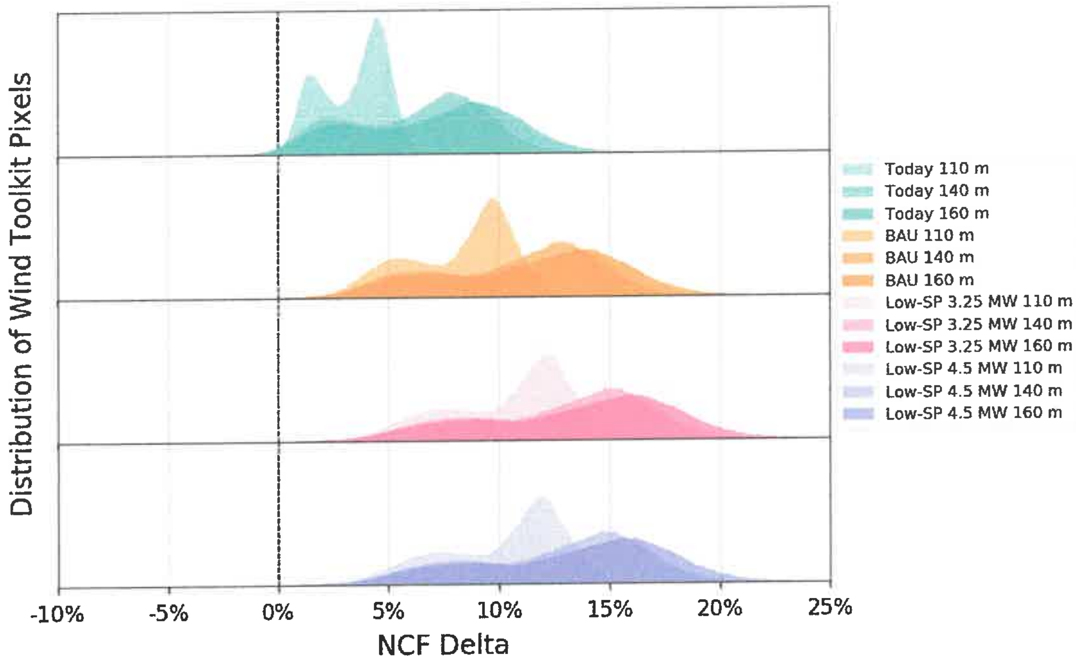

Figure 4. Estimated difference in net capacity factor, all turbines and hub heights, relative to the Today turbine at 80 m (percentage points)

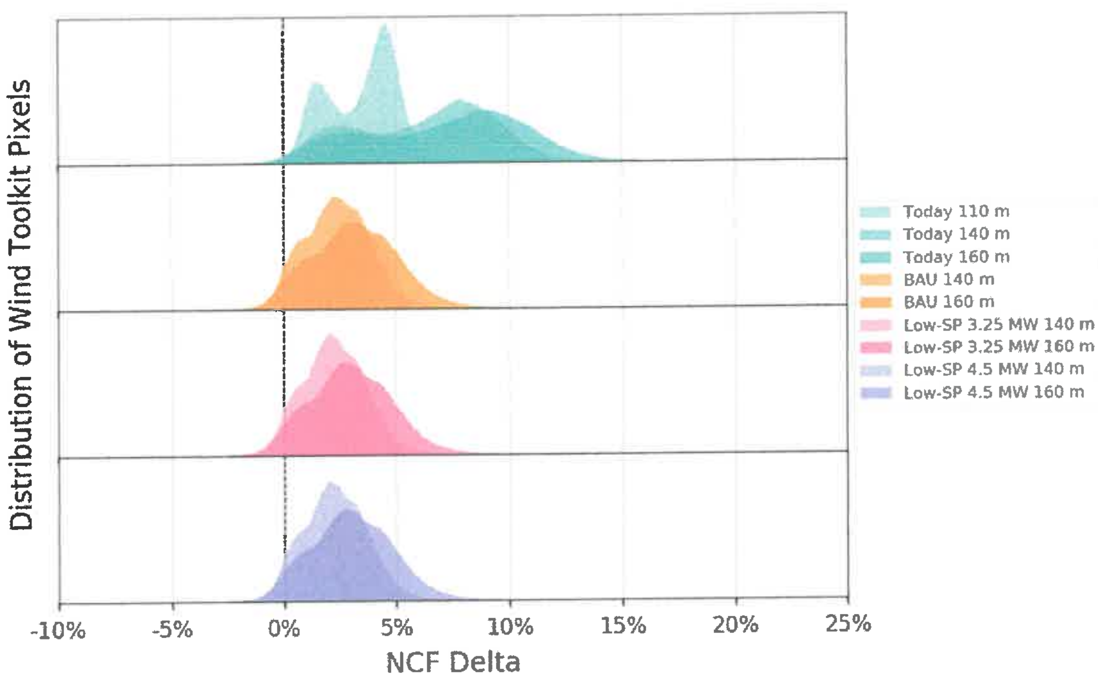

Figure 5. Estimated difference in net capacity factor, all turbines and hub heights, relative to the lowest hub height available per platform (percentage points)

Not surprisingly, the highest capacity factors are observed at 160 m and with the Low-SP turbines. Even at the higher specific power platforms of the Today and BAU turbines, however, the 160-m hub height yields substantial quantities of sites with 40% or greater capacity factors. For the Low-SP turbines, however, a significant number of sites have capacity factors even greater than 50%; approximately 60% of the resource sites for these turbines have a capacity factor greater than 40%.

In terms of capacity factor differences, the BAU turbine configuration has a large number of sites that are approaching a 10% increase in capacity factor relative to the Today turbine at 80 m—even with a move to only 110 m. The Low-SP configurations see a large quantity of resource sites that exceed the 10% improvement level at 110 m relative to the Today turbine at 80 m, and many sites approach a 15% increase at 140 m. Based on the Wind Toolkit data, the benefit of achieving 160-m above-ground-level hub heights is estimated at approximately 1 percentage point in capacity factor, relative to 140 m.

Focusing on the comparison in Figure 5, to the lowest available hub or tower height by platform, it is evident that the higher specific power Today turbine actually sees the largest magnitude of improvement in capacity factor from moving to higher hub heights. Although the lower specific power BAU and Low-SP turbines have higher absolute capacity factors, they also spend more time at full rated power, which limits their ability to increase annual energy production merely by increasing hub height. Of course, one must be cautious not to focus solely on the magnitude of the change as such characterizations can be overstated when comparing against a low value reference or starting point. Although somewhat more obscure, this effect can also be observed in the following LCOE analysis by noting that for a given platform, preferences for taller towers are somewhat lower with lower specific power.

2.3 Levelized Cost of Energy Estimations

Data and analysis presented thus far have focused on the energy production potential associated with realizing higher wind turbine hub heights. Achieving these higher hub heights, however, would—all else being equal—require additional capital cost expenditure because of additional tower material requirements and increased BOS cost increases associated with lifting the nacelle and rotor to these higher above-ground-level heights.[3] It is this trade-off between incremental capital cost expenditure and incremental energy production,[4] coupled with the overall cost of energy for a given site, that ultimately determines the hub heights for commercial wind farms. Here, our analysis begins to shed light on the potential outcomes of this trade-off, as a function of LCOE, for all resource sites in the Wind Toolkit.

Given significant uncertainty in the potential costs of the turbine technology and plants modeled, we do not anticipate our results to be the final word on LCOE or the relative competitiveness of tall wind towers. Instead, this section seeks to establish a method for examining the potential for higher hub heights from a continental perspective with computed LCOE results based on a first-order set of cost assumptions. The results presented should be thought of more as scenarios with the findings contingent on the assumptions associated with the stated scenario. Additional follow-on work to further refine the cost characterizations and LCOE results is strongly

[3] Notably, this latter cost increase could be partially or fully offset by moving to a larger nameplate capacity (e.g., relative to the Today turbine), which for a fixed plant capacity results in fewer turbine lifts and roads and potentially reduced cabling requirements. Analysis to date suggests that indeed balance-of-station (BOS) cost savings associated with achieving higher nameplate capacity turbines could offset a potential BOS cost increase associated with installing nacelles and rotors on hub heights up to 160 m.

[4] In reality, it is the balance between incremental cost and incremental power sales. Where there may be transmission capacity or energy constraints, the timing of any potential energy production increase is also important.

encouraged. Notwithstanding these caveats, the results do provide an indicator of the potential value of achieving higher hub heights across the continental United States.

In addition to the uncertainty in the potential costs of future tall tower technologies and the evaluated tower heights, it is important to note that our cost estimates are primarily scaled from recent vintage wind turbine technology cost and scaling trends. They do not consider the potential for future innovations to impact cost and scaling functions for any turbine subsystem, including towers.

In effect, the analysis represents an LCOE assessment based on extrapolation from recent scaling trends. To the extent that these trends are not indicative of innovation potential for the tower, the results will be biased toward relatively shorter towers. In other words, these results reflect a technology and cost snapshot based on scaling relationships of recent technology; in this sense, they should be somewhat indicative of the calculations and decisions that the development community has made in the very recent past. However, they may be less indicative of the calculations and decisions made in the future, as innovations that improve upon recent technology could have greater preference for tall towers.

To evaluate potential LCOE impacts associated with increased hub heights, we first estimated the installed capital cost for each turbine configuration at each hub height analyzed in Section 2.2. To characterize turbine capital cost, we used the 2015 NREL Cost and Scaling Model (CSM), which is a part of the larger NREL Wind Plant Integrated Systems Design and Engineering Model (WISDEM®) toolset and informs most costing estimates derived from the modeling toolset. The 2015 NREL CSM uses empirically derived—based on industry data points and semistructured interviews—component-level scaling relationships to ascertain the potential change in component costs associated with both higher hub heights and changes in rotor size. Given the vintage of the model and the related empirical data, these relationships are expected to be generally indicative of state-of-the-art technology from the 2012–2014 period.

One update made to the default scaling relationships was in the blade mass scaling exponent. For this analysis, we apply a mass-scaling exponent of 2.2. This is based on more recent (2018) direct input from turbine designers and blade manufacturers, acquired in the parallel and ongoing U.S. Department of Energy "Big Adaptive Rotor" project. Estimated tower costs calculated in the model are believed to be somewhat optimistic relative to historical turbine installations, but anecdotal evidence suggests they may be conservative relative to emerging tall tower solutions under development today. The estimated nacelle and drivetrain costs are believed to be conservative, particularly for larger turbines, given the applied empirical data in the model indicating that larger nameplate turbines may actually be more competitive than suggested here. An additional caveat in this cost characterization is that the 2015 NREL CSM does not consider potential changes in loads associated with these configurations. Changes in mass, and subsequently cost, are calculated based on the empirical scaling functions, not engineering analysis of specific designs or loads. Overall, this approach represents a relatively basic estimation of potential costs but provides an initial starting point for understanding LCOE impacts of these technological changes.

To characterize plant BOS costs, we used the NREL Land Balance of Station Systems Engineering (LandBOSSE) model. This model was developed in calendar year 2018 and, on

December 20, 2018, initially was released to the public as version 1.0. To date, the model has been used and verified internally, and validated by a limited set of industry contacts during development. The LandBOSSE model is a process-based model that allows us to capture potential cost increases associated with lifting the rotor and nacelle to greater above-ground heights, as well as the potential cost savings associated with fewer lifts overall, as a function of increased turbine nameplate capacity.

The model in its current form is relatively comprehensive but has only simplistic collection-system cost algorithms and does not capture site access or transport and logistics costs. Moreover, the modeling approach applied assumes flat terrain. Moving very large cranes capable of lifting components to 160 m is difficult and risky, and moving cranes in complex terrain could require complete disassembly and reassembly for each turbine installation. These additional costs for complex terrain were not captured here. Additionally, we assumed that the nacelle will be split into 80-ton lifts, as some of the world's largest mobile crawler cranes will be required for these lifts. Correspondingly, investigations into alternative erection technologies is suggested for future research. BOS estimates developed here assume 100 turbines in all cases but normalize costs to $/kW for the purposes of calculating total capital expenditures (CapEx). Depending on actual power plant sizes, this approach might overstate potential economies of scale for larger-capacity facilities. Due diligence conducted since these results were developed suggests that the estimated economies of scale embedded in these results are not likely to impact the qualitative results as the captured economies of scale for larger turbines remain significant even when applied to a fixed-capacity plant. Nevertheless, based on these modeling simplifications and limitations, the BOS benefit from larger turbines can be characterized as somewhat optimistic, and future research on BOS cost impacts is encouraged.

Based on the version 1.0 LandBOSSE model and the simplifying assumptions noted earlier, we estimate that the Today turbine would require an approximate 11% increase in BOS cost to move from 80 m to 160 m. The cost would change similarly for the BAU and Low-SP turbines to move from 110 m to 160 m. For the BAU and Low-SP turbines, however, this cost essentially is offset by the reduced number of turbines required to achieve a fixed plant size (e.g., 100 MW). In fact, the estimated cost savings from increased turbine size drives a calculated net savings in BOS cost, at least on a $/kW basis, for the larger turbines, ranging from 10% for the BAU and Low-SP 3.25-MW turbines to nearly 35% for the Low-SP 4.5-MW turbine—even at 160 m—relative to the Today turbine at 80 m.

Estimated total CapEx values based on the first-order cost characterization described earlier are shown in Figure 6, with a more detailed tabular breakdown provided in Appendix A. Based on CapEx alone, these data show the relative competitiveness of the Today turbine at 80 m as well as the relative BOS savings associated with larger turbine nameplate capacities, particularly in moving toward the higher hub heights. These cost estimates are best utilized to provide a context for how the capacity factor benefits associated with higher hub heights might begin to translate into LCOE impacts assuming basic scaling of costs from recent vintage technology.

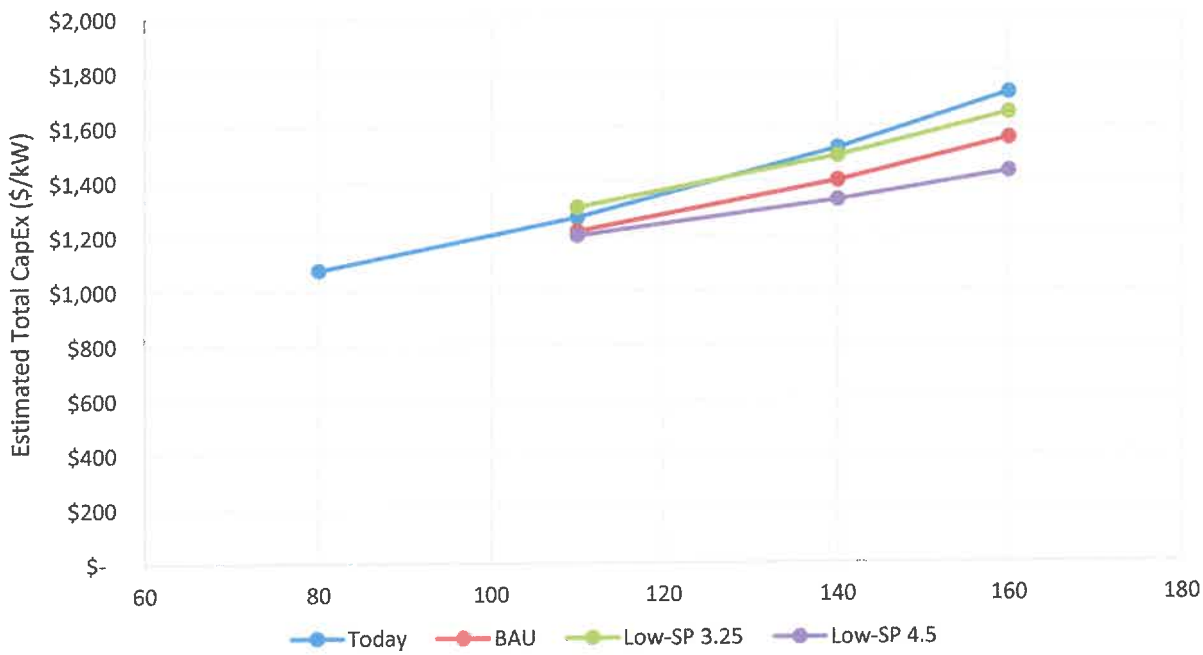

Figure 6. Estimated total installed capital cost by turbine and hub height

The next step in assessing potential LCOE impacts was to estimate the remaining LCOE input variables, specifically operational expenditures (OpEx) and the fixed charged rate, a term that allows us to annualize the total capital cost estimate, considering the cost of capital (i.e., weighted-average cost of capital) as well as the relevant tax treatment, in terms of tax on assumed revenue and allowable depreciation. For these two values, we use an estimated $41/kW for OpEx, as informed by Wiser et al. (forthcoming) and Stehly et al. (2018) and 8% for the real fixed charge rate, commensurate with an implied nominal, after-tax weighted-average cost of capital of approximately 6.4%, and an implied real, after-tax weighted-average cost of capital of approximately 3.9%. Note that OpEx could increase for higher hub heights assuming all else remains equal and no improvements in reliability, as larger component replacements—such as gearboxes, main bearings, and blades—require larger cranes or greater labor costs for up-tower repairs. Additional downtime and lost revenue could also erode the capacity factor benefit estimated here.

The final step in estimating LCOE values was to use these values along with the respective capacity factor data detailed in Section 2.2 to calculate site-specific LCOE for each Wind Toolkit resource pixel or site. The LCOE values were computed for each turbine configuration at each available hub height for all sites. Selected results from the LCOE calculations are illustrated in Figure 7 and Figure 8. Figure 7 shows the calculated LCOE for the Low-SP 4.5-MW turbine at a 110-m hub height. Figure 8 shows the calculated LCOE for the Low-SP 4.5-MW turbine at 160 m. Of course, changes in turbine configuration, estimated energy generation, CapEx, OpEx, and the fixed charge rate all could impact the results.

These results illustrate the potential competitiveness for 110- and 160-m hub heights based on the Low-SP 4.5-MW turbine. Based on the calculations applied here and this specific turbine configuration, much of the interior wind belt plausibly could support unsubsidized LCOE between \$20/MWh and \$35/MWh at 110-m hub heights. Moreover, large swaths of the eastern half of the continental United States could achieve unsubsidized LCOE in the \$35/MWh to \$50/MWh range with nontrivial pockets of potential at lower LCOE values. Results in the Intermountain West and Pacific are more mixed, with large areas falling into virtually all reported cost bins.

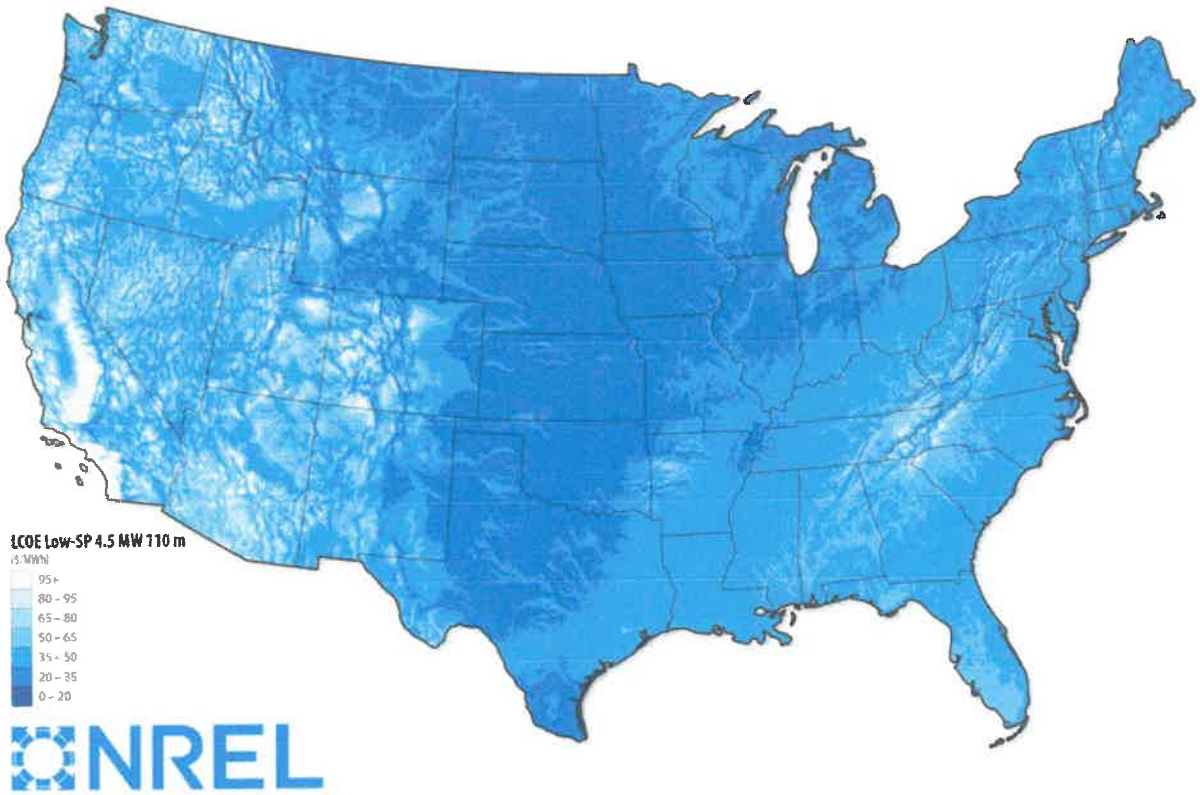

Figure 7. Estimated LCOE for each Wind Toolkit pixel, assuming the Low-SP 4.5-MW turbine at a 110-m hub height

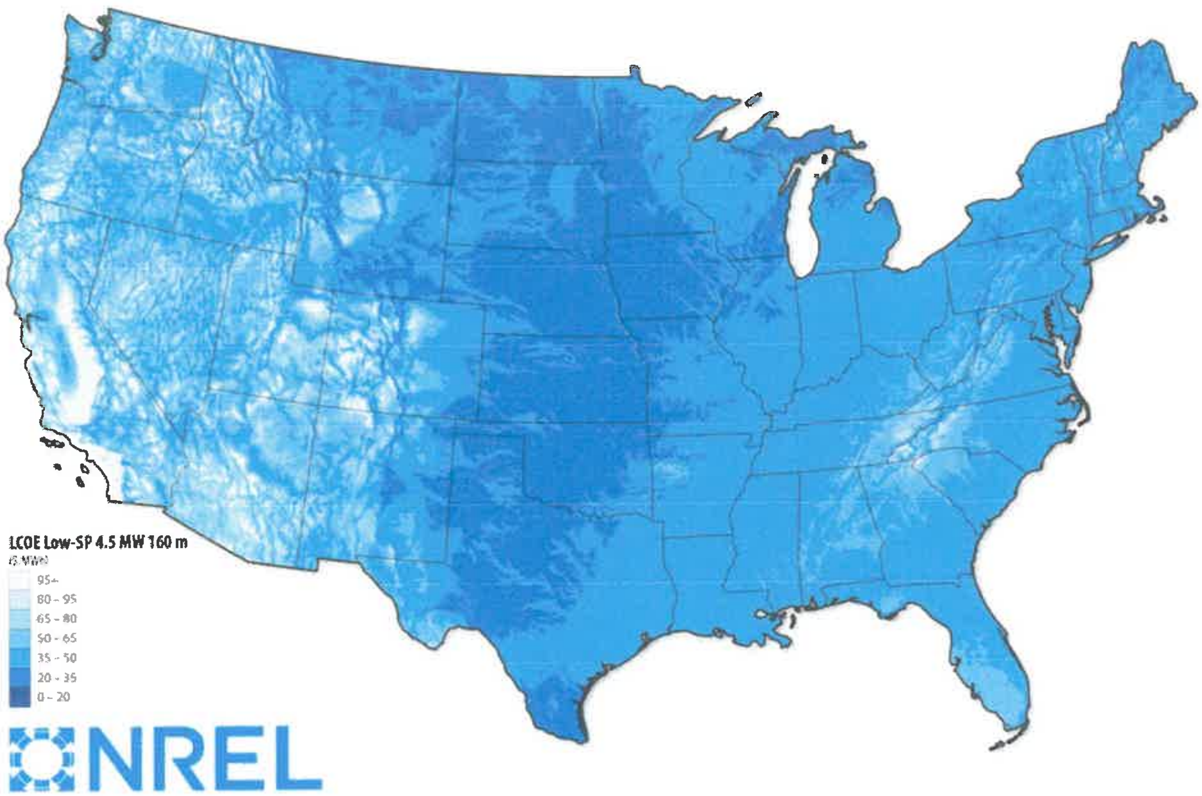

Figure 8. Estimated LCOE for each Wind Toolkit pixel, assuming the Low-SP 4.5-MW turbine at a 160-m hub height

Interestingly, at 160 m, the area of $20/MWh to $35/MWh LCOE is reduced, in the interior region, and the $50/MWh to $65/MWh is also reduced in parts of the east. This outcome is the result of the incremental estimated capital cost to realize 160-m tower heights and indicates somewhat lower competitiveness for the 160-m tower height, under the current estimated costs and performance at 160 m.

To further illustrate the potential impact on LCOE, Figure 9 and Figure 10 detail the distribution of LCOE values by turbine configuration and hub height. Recall that these LCOE values are indicative of recent vintage technology opportunities. Future innovation potential that may increase the relative competitiveness of a given turbine configuration or hub height would alter these results. Additional summary statistics of LCOE results are included in Appendix A.

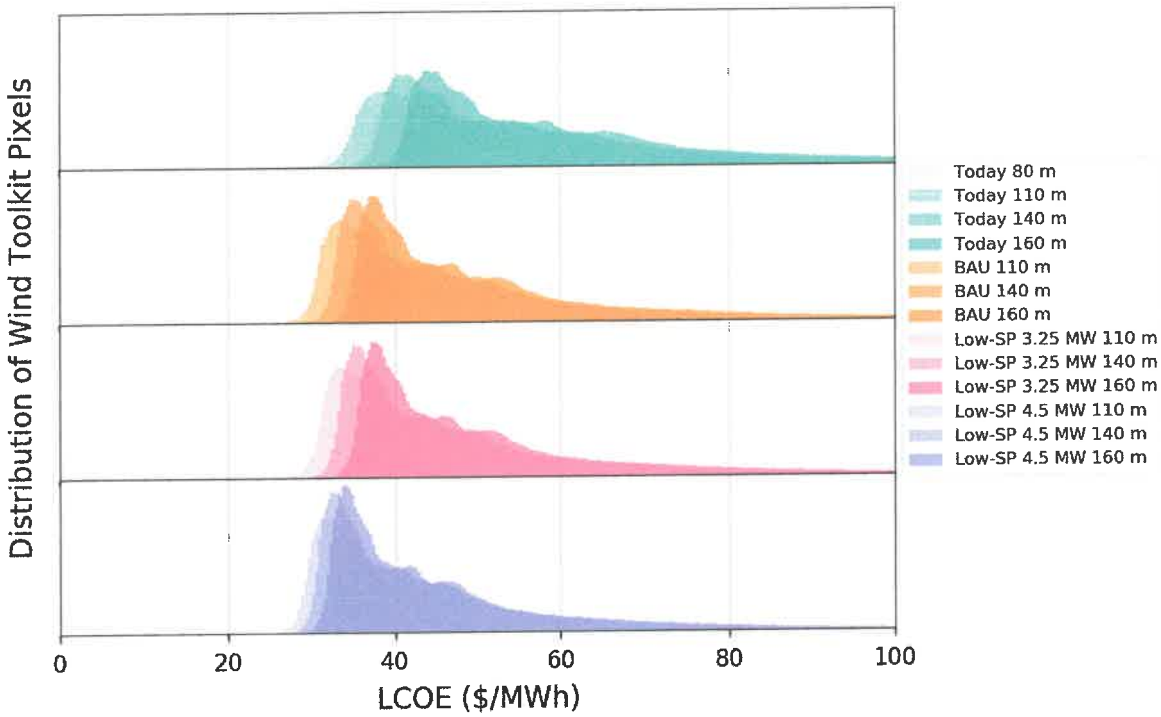

Figure 9. Estimated LCOE for each Wind Toolkit pixel; all turbines and all applicable hub heights

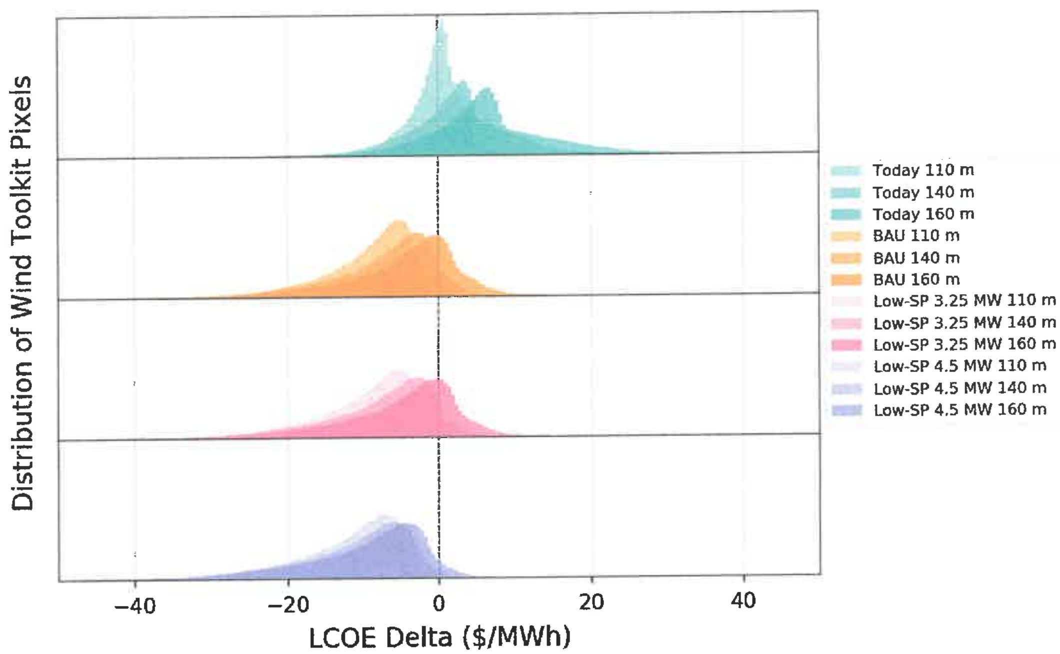

Figure 10. Estimated LCOE differences for each Wind Toolkit pixel, relative to the Today turbine at 80 m

Given cost data that are indicative of recent technology scaling trends, (see also Appendix A), the largest quantity of low LCOE values and the most sizable LCOE reductions appear to be generally associated with the Low-SP 4.5-MW turbine at a 110-m hub height. The 3-MW BAU and Low-SP 3.25-MW turbines, however, also appear to offer nontrivial opportunities to drive down cost at 110 m. The Today turbine LCOE results illustrate why current state-of-the-art commercial technology is most often deployed at a hub height of approximately 80 m.

Real-world results will vary, of course, depending on the actual costs for these turbine platforms, including transport and logistics costs, which may disadvantage larger turbines with larger component sizes, relative to what is shown here. Moreover, these results are indicative of the national trends but may not correspond to subnational or regional economically preferred outcomes. Notwithstanding those caveats, these data suggest that if a single hub height was to be selected for deployments of tall tower technology based on our assumed cost and performance inputs, then 110 m would be preferred. Of course, in real-world commercial applications, developers could select the optimal hub height for a given site based on the available technology.

These conclusions can be further examined by a direct comparison of hub heights for each specific turbine configuration. Figure 11 shows that, for the Today technology, the 80-m hub height is most commonly preferred from an LCOE perspective, applying our current costing assumptions. For the larger turbines, however, the 110-m hub height, which is also the lowest option for these turbines, dominates, with 140 m holding a sizable minority share that varies from approximately 15% to 35% of Wind Toolkit pixels. In these results, preferences for 140 m are typically associated with lower wind speed sites at 80 m that have relatively higher shear. Variability in the share of 140-m sites with the lowest LCOE is a function of the relative benefit that can be gained from a given turbine configuration achieving a higher hub height (i.e., the higher specific power of the BAU turbine means that it is able to extract relatively more benefit from 140 m) and the proportionally lower tower and more limited BOS cost penalty associated with realizing taller towers for larger nameplate capacity machines (i.e., for the Low-SP 4.5 MW).

Notwithstanding the analysis outcomes derived from the current assumptions, the uncertainties in the cost characterization and the magnitude of the differences in the estimated LCOE values suggest that there may not be a clear and dominant winner. More specifically, under our current assumptions, the 110-m height looks attractive but in fact is only economically preferred over the other turbine configurations by a few $/MWh in many cases. Accordingly, if turbine scaling costs vary from recent trends in rotor diameter and specific power or if tower costs come in substantially lower than assumed, then the hub height distribution of future installations could diverge substantially from what is suggested in Figure 11. Moreover, given these differences, investments in tall tower technology that are intended to serve lower wind speed areas could, if successful, easily extend into higher wind speed areas based on the relatively small current advantages of shorter towers on an LCOE basis in those regions.

Finally, the analysis conducted here is somewhat coarse in that it only considers three potential hub heights for the BAU and Low-SP turbines. In reality, commercial developers and OEMs could have the ability to consider additional hub heights that might fall between the three primary focal points of the current analysis with potentially a broader mix of optimal turbine hub heights.

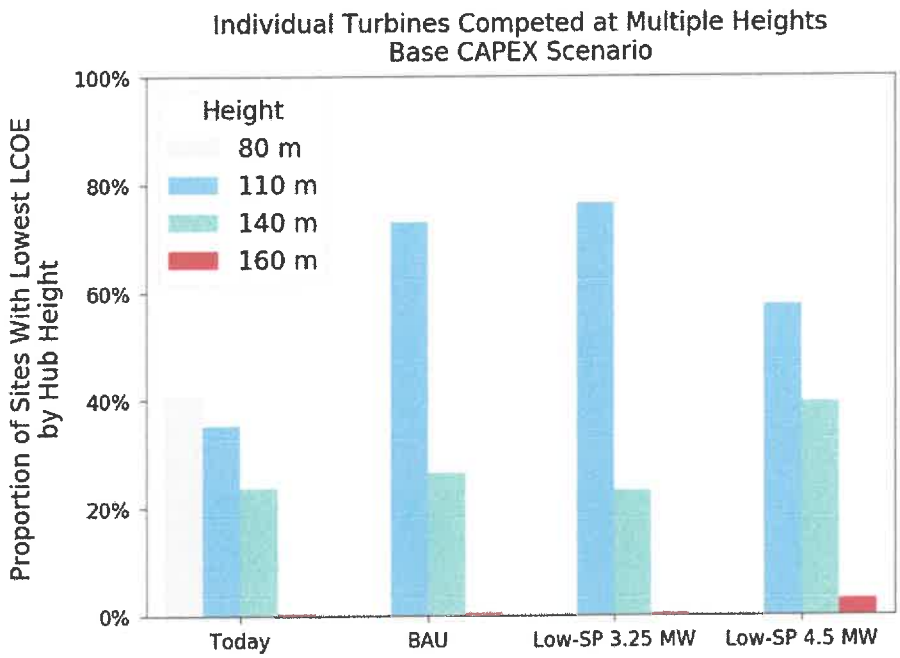

Figure 11. Calculated preferred hub height by turbine configuration, based on estimated performance and costs

Results presented thus far, with their focus on the contiguous United States, do not provide insights into the regions and locations where specific hub heights might prevail. In the same way that the wind speed differences varied geographically, the relative favorability of one hub height (per turbine configuration) or another also varies geographically. Figures 12 through 15 illustrate the economically preferred hub height by location for each of the four turbine configurations evaluated. Although the results presented in the figures are a function of the estimated cost and performance applied here, and therefore are subject to uncertainty, the relative consistency in the trends between turbines is indicative of areas where higher hub height applications will tend to be preferable.

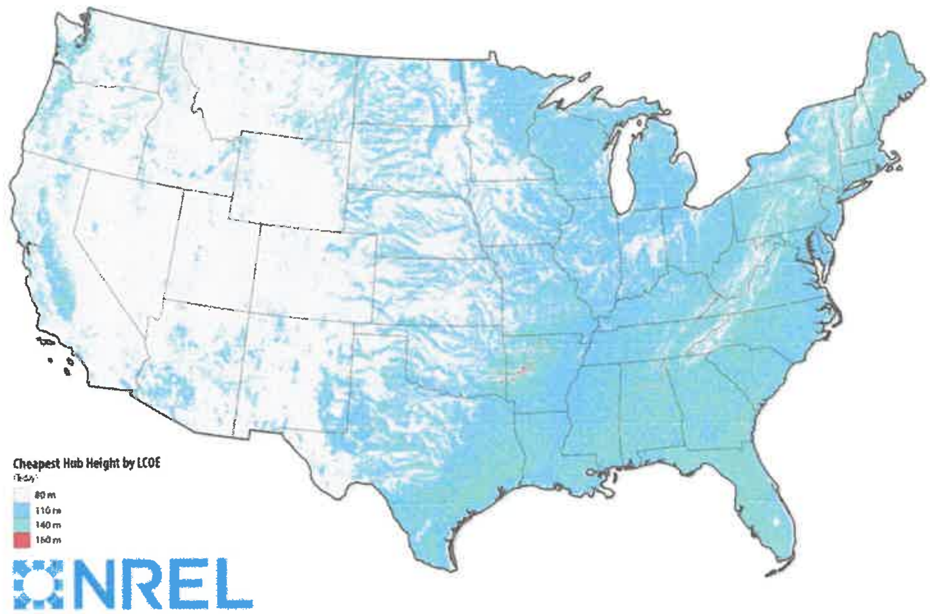

Figure 12. Calculated economically preferred hub heights for the Today turbine, based on estimated costs and performance

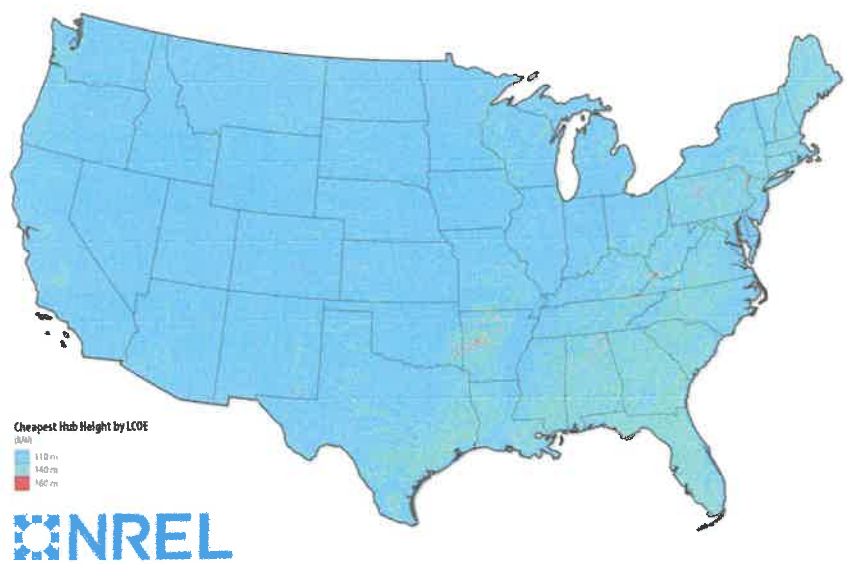

Figure 13. Calculated economically preferred hub heights for the BAU turbine, based on estimated costs and performance

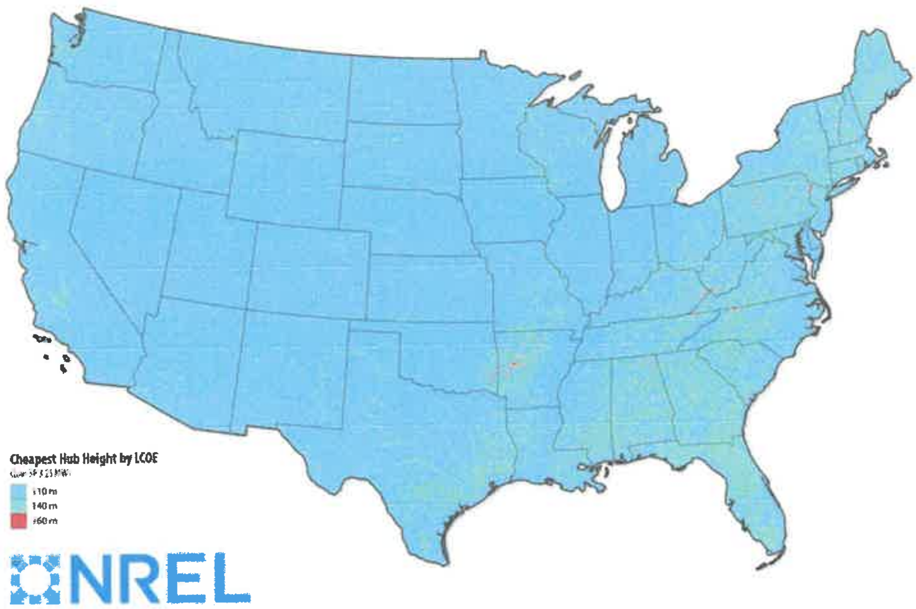

Figure 14. Calculated economically preferred hub height for the Low-SP 3.25-MW turbine, based on estimated costs and performance

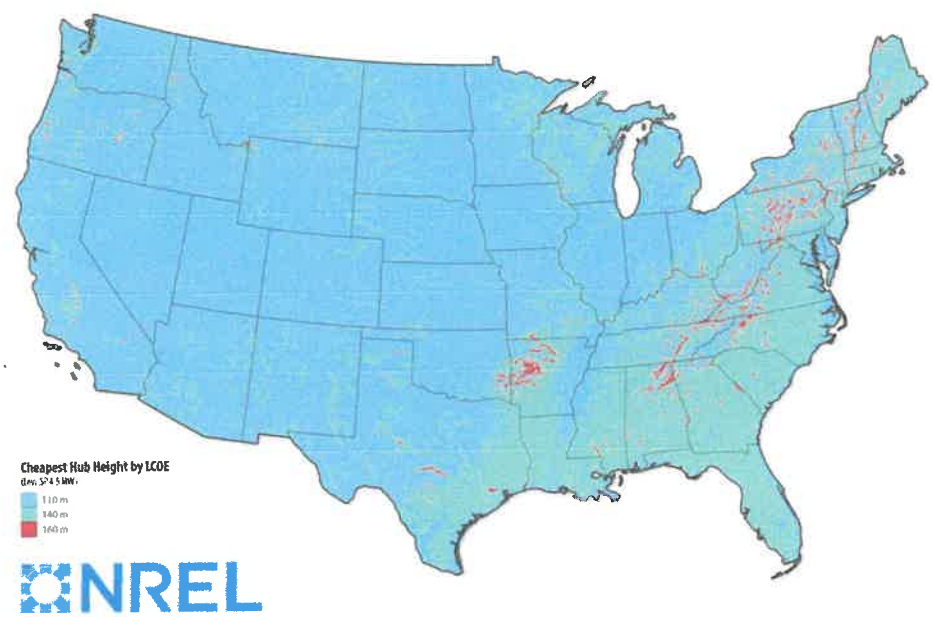

Figure 15. Calculated economically preferred hub height for the Low-SP 4.5-MW turbine, based on estimated costs and performance

The data mapped illustrate that higher hub heights are generally preferred in the east, but the extent of this preference depends on the turbine configuration considered and the estimated costs associated with that turbine. Based on the first-order cost characterization developed for this analysis and the Today turbine, regions experiencing commercial interest today largely fall into those categories where the 80-m and 110-m towers are preferred. This is consistent with the empirical market preferences observed to date. Locations further east suggest more favorable conditions for 140-m towers. Focusing on the BAU turbine and the costs assumed here, the 110-m hub height dominates. Notably, this is the lowest hub height we analyzed for this turbine with an approximately 75-m blade. This suggests that, in many regions of the country, hub heights might be determined simply by requirements for sufficient ground clearance for a given rotor nacelle assembly. Focusing on the Low-SP 3.25-MW turbine, there are only very minor differences from the BAU turbine. Shifting to the Low-SP 4.5-MW turbine, at the assumed costs applied here, results in a modest increase in an area where 140- and 160-m turbines are determined to be economically preferred. Overall, however, the 110-m turbine continues to dominate, especially in the windiest regions of the country.

These results are a direct reflection of the inputs applied and do not account for the potential impact of future tower innovations that might make higher hub heights more attractive. To begin to ascertain the potential impact of tower technology R&D and innovation, we conducted an additional tower cost sensitivity analysis. This sensitivity assumes that tower cost is fixed or static at $200/kW for all turbine configurations and tower heights. This cost is the approximate cost per kilowatt of the Today tower at 80 m. Notably, although this approach fixes cost per kilowatt, it does allow for total tower cost to increase as nameplate capacity increases. This sensitivity scenario enables us to at least partially capture the potential change in competitiveness of the different tower heights, if innovation is able to limit tower cost changes as a function of tower height. The calculated LCOE differences associated with this sensitivity scenario are shown in Figure 16. This plot is an analog to Figure 9, albeit with tower costs fixed at $200/kW for all tower heights. Figure 17 illustrates the economically preferred tower height under these cost assumptions.

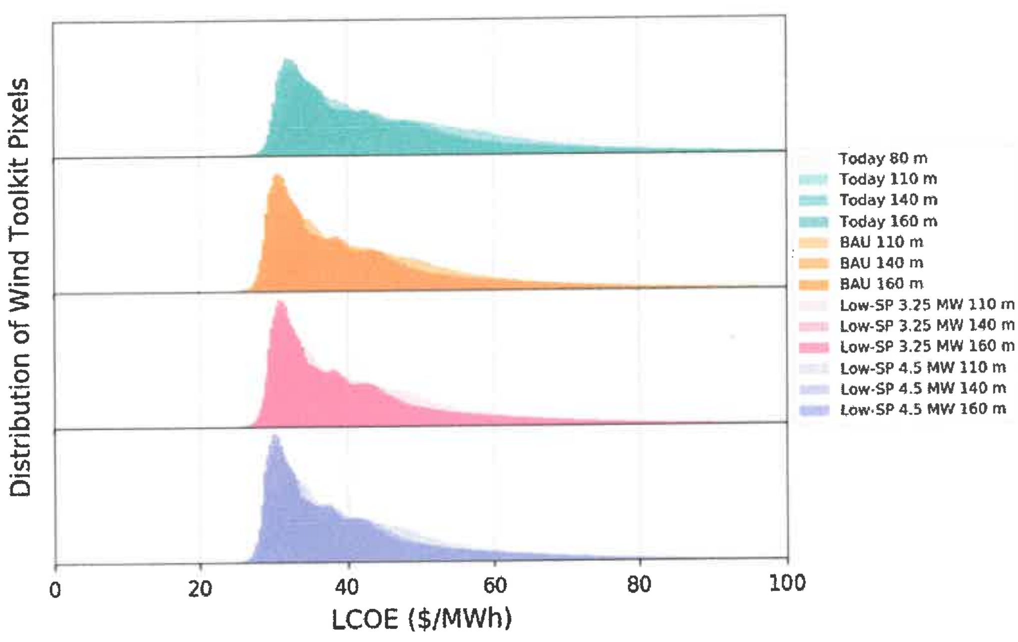

Figure 16. Estimated LCOE differences for each Wind Toolkit pixel, assuming $200/kW tower costs, relative to the Today turbine at 80 m

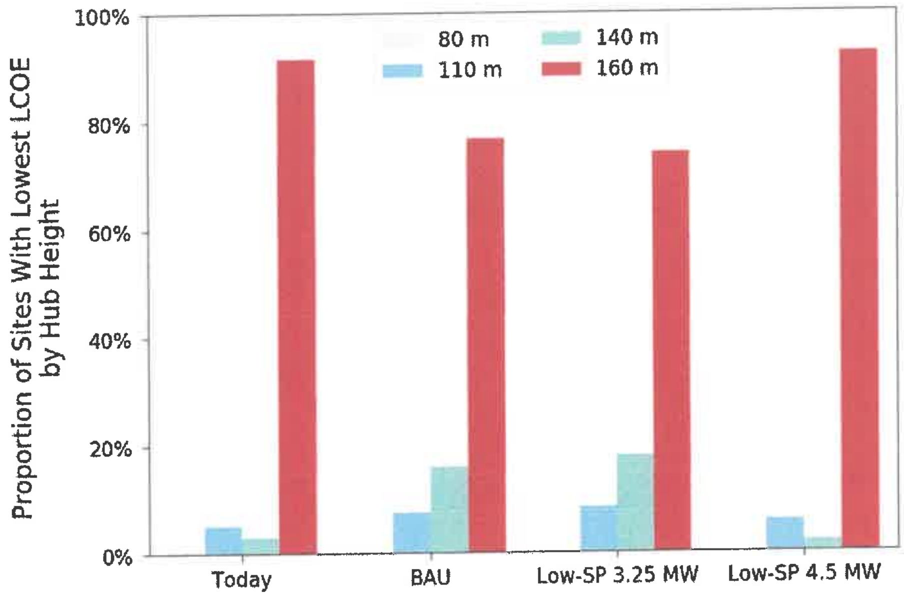

Figure 17. Calculated preferred hub height by turbine configuration, based on estimated performance and costs, assuming $200/kW tower cost

These results illustrate increased competitiveness for tall towers, especially the 160-m tower height and highlight how differences in analysis assumptions and innovation potential could significantly alter preferences and demand for relatively shorter or taller towers. Future analysis would benefit from examination of additional sensitivities and could further parse these results.

2.4 Breakeven Cost Analysis for Turbines with Taller Towers

In addition to the analysis presented thus far, we sought to identify the potential cost targets that must be achieved to justify the application of these technologies at their respective hub heights. To identify these targets, we calculate the incremental price premium or breakeven cost ($/kW) that can be incurred with the improved capacity factors afforded by these technologies and result in an equivalent LCOE as the Today technology at an 80-m hub height. If innovators are able to achieve a total installed capital cost that is at or below the sum of the Today technology capital cost and the breakeven cost, they will be competitive with technology that has recently been installed in the U.S market. In practice, the calculated breakeven cost reflects a potential $/kW cost adder on top of the estimated total CapEx for the Today technology. In regions where the LCOE of the Today technology at 80 m presently is insufficient for wind power to be competitive with other power-generation resources, additional cost reduction beyond the levels associated with the breakeven costs likely would be necessary to drive future wind power deployment.

The concept of the breakeven cost is premised on the idea that a taller turbine might involve more raw material or otherwise be more expensive to install but that the additional energy produced could offset these incremental costs, depending on the magnitude of the energy improvement and the cost premium incurred. It is also possible that innovation could create the conditions under which energy production increases while overall CapEx decreases. In fact, as suggested earlier, this might be necessary for wind power to become viable as an energy-generation resource in some regions. Although anecdotal evidence suggests we may be moving toward this point, we would not necessarily expect increased energy production and lower CapEx to be achieved initially. Increases in energy production per turbine, and reductions in project-level CapEx, however, generally have occurred in concert for much of the last three decades of wind power innovation. Moreover, as a principal benefit of taller turbine innovation is access to turbine- and plant-level economies of scale, it is reasonable to anticipate that these innovations could allow access to better wind resources at higher above ground hub heights while also achieving lower CapEx over time. Numerically, higher values for breakeven costs are generally more advantageous and indicate that there is a relatively greater benefit from moving to taller turbine concepts. As indicated, however, we also must consider that—for sites with relatively low energy production under baseline Today turbine conditions—a high breakeven cost on its own might not justify technology or project investment.

Notwithstanding its limitations, the breakeven cost metric helps to illustrate the costs that innovators must beat to be competitive with state-of-the-art technology available today. In this sense, it is indicative of an innovation cost target that must be achieved simply to be better than the next-best alternative—in this case, the Today technology at an 80-m hub height. The capacity factor change and breakeven cost analysis also begin to inform the potential value of continued tall-turbine technology development in regions that are currently being targeted by wind energy developers, as well as regions that are of less focus to the commercial development community today. The calculated breakeven costs for each of the turbine configurations and hub heights analyzed here are summarized in Figure 18.

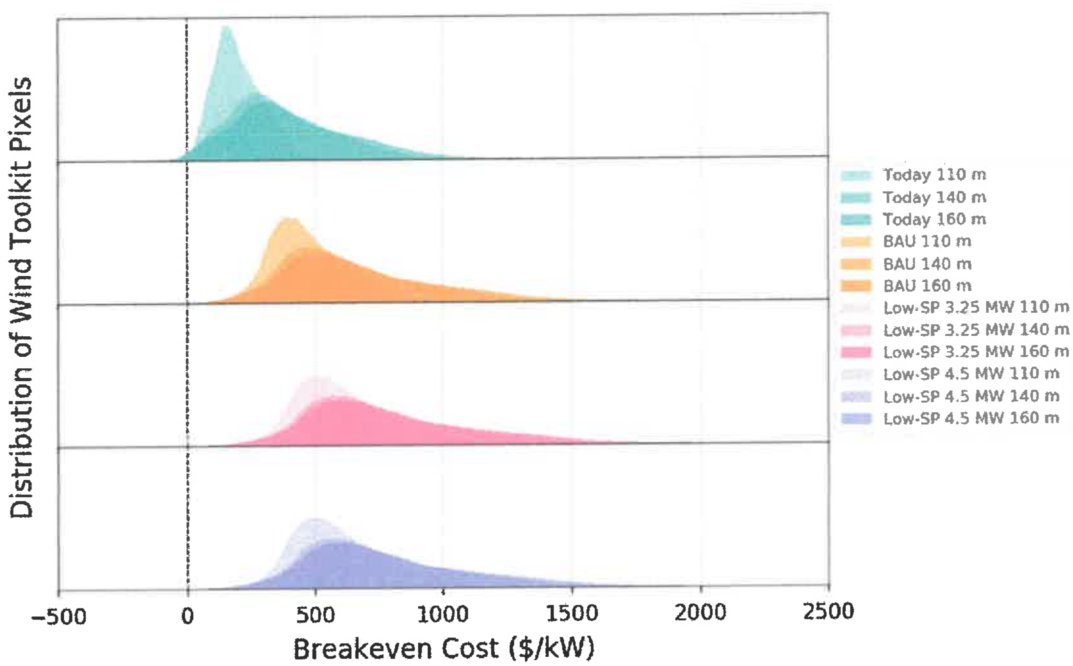

Figure 18. Breakeven costs for all turbines and all hub heights

In addition to the broad distributions in Figure 18, the following maps illustrate the LCOE achieved by the Today turbine (Figure 19)—which constitutes the LCOE from which the breakeven cost is calculated—and show how the estimated breakeven costs (an incremental price premium that would be on top of the estimated capital cost for the Today turbine at 80 m) vary geospatially across the continental United States (Figures 20–23). For these maps, we focus on the BAU and Low-SP 4.5-MW turbine at 110 m and 140 m. A complete summary of average breakeven costs by state is provided in Appendix A.

Collectively, these images illustrate that the distribution of breakeven costs across the country is both broad and sizable. In many locations, the breakeven costs are considerable, suggesting that there is significant opportunity to go to higher hub heights. At the same time, these locations also tend to be where the Today turbine estimated LCOE is quite high and therefore simply achieving the breakeven cost will likely be insufficient to drive economic deployment of new wind power.

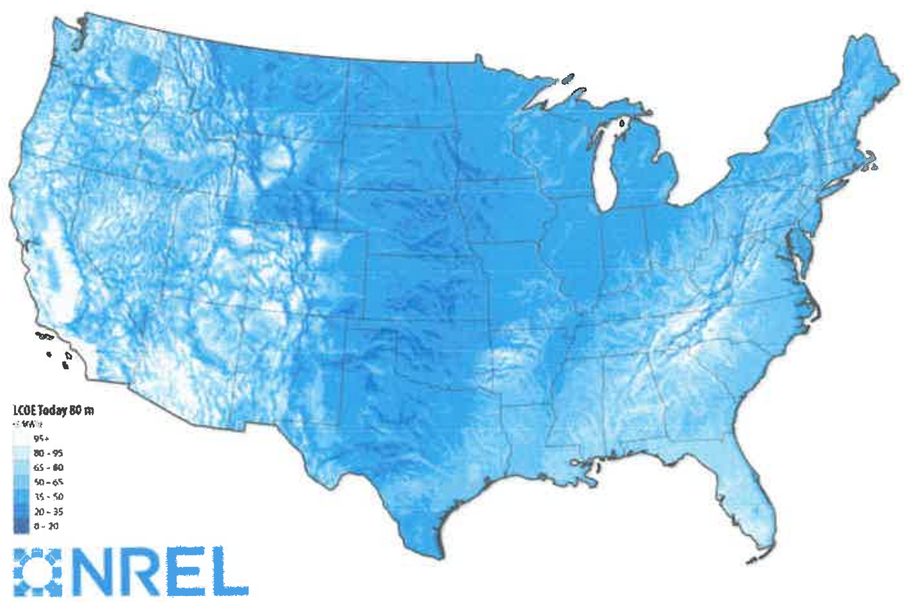

Figure 19. Estimated LCOE for the Today turbine at the 80-m hub height

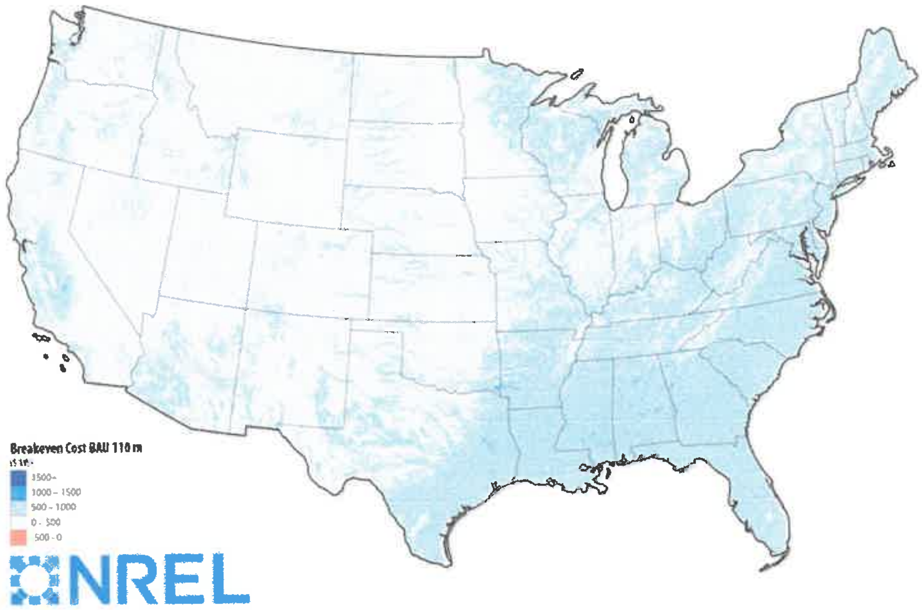

Figure 20. Breakeven costs for the BAU turbine at the 110-m hub height

Note: Breakeven values reported here are the incremental cost premiums that would be added to the CapEx of the Today turbine at 80 m to achieve the same LCOE as the Today turbine at 80 m.

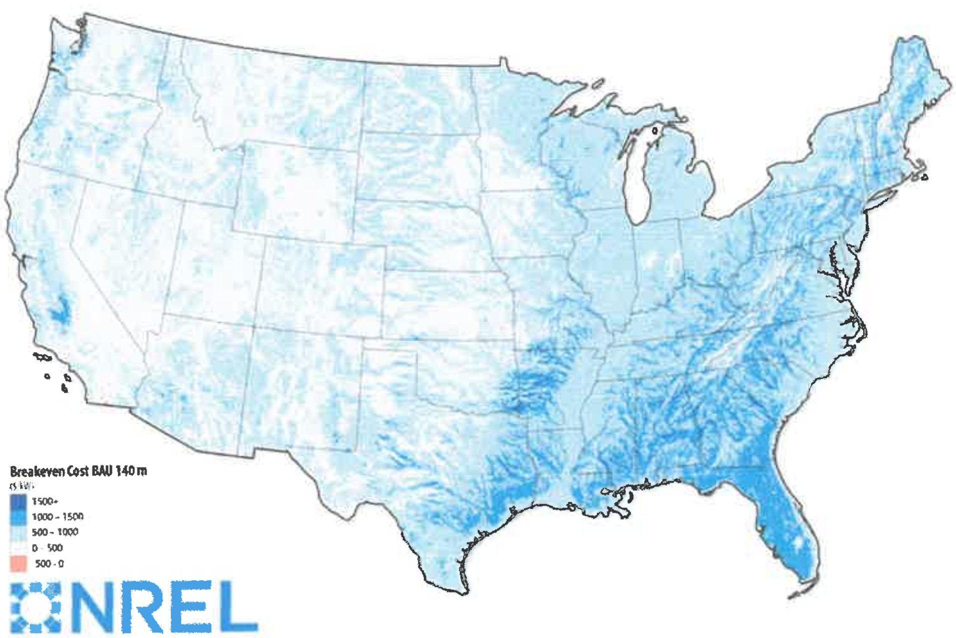

Figure 21. Breakeven costs for the BAU turbine at the 140-m hub height

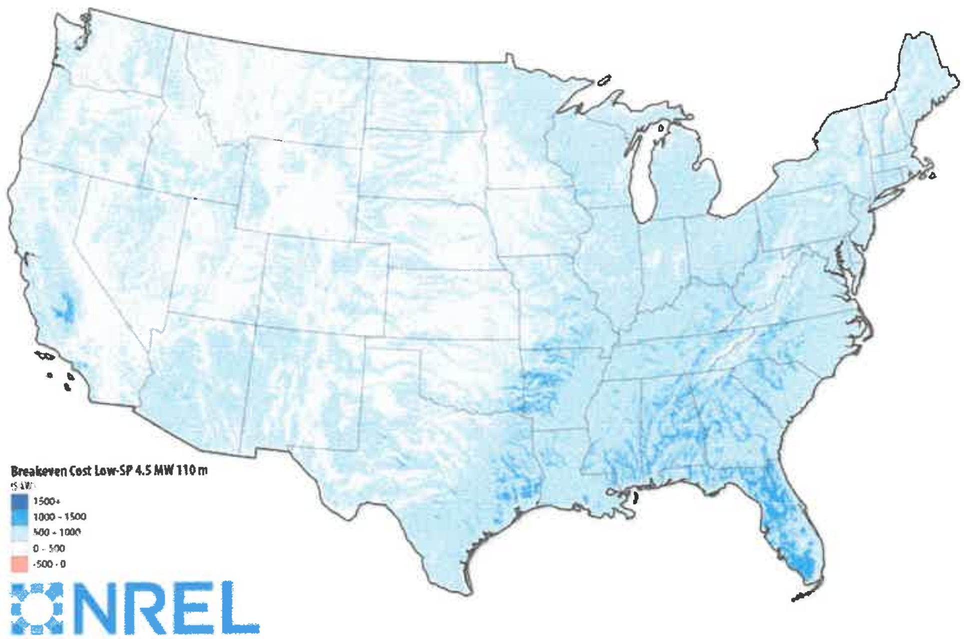

Figure 22. Breakeven costs for the Low-SP 4.5-MW turbine at the 110-m hub height

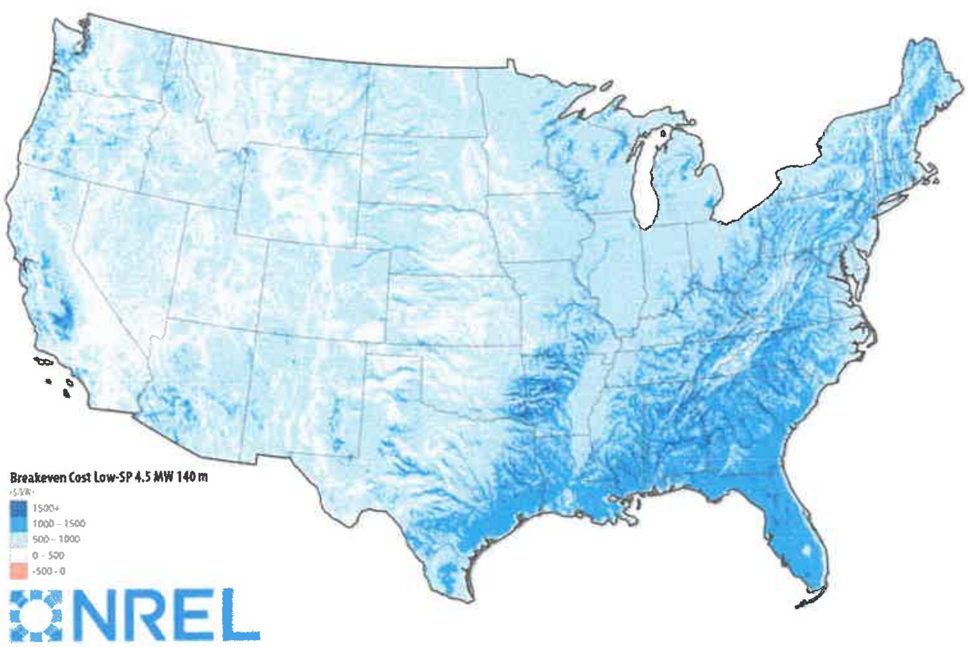

Figure 23. Breakeven costs for the Low-SP 4.5-MW turbine at the 140-m hub height

3 Tower Design Options and Related Analysis

For much of the past two decades, the modern wind industry has been dominated by tubular steel towers also called "cans." Since the mid- to late-2000s, the tubular steel tower has been the industry standard, and tower height trends in the United States largely have plateaued at about 80 m. The dominance of the 80-m tower is, in part, a function of logistics and transport constraints that limit tower-base diameter, and require rapidly increasing quantities of material to get to higher hub heights; and, in part, is a function of the relative cost of energy benefit achieved from realizing higher hub heights. Here, we utilize a systems engineering modeling approach to understand how technology and innovation might impact the future potential of tubular steel tower technology to achieve higher hub heights into the future.

Note: Section 3.1 through Section 3.1.3 is heavily based upon Dykes et al. (2018).

3.1 Systems Engineering Steel Tower Simulations

The designs for land-based wind turbine towers must satisfy a number of criteria, or constraints, to be viable for deployment. The goal for tower design always is to minimize mass, and to reduce material costs, and typically labor costs as well. The tower, however, must be able to support the wind turbine for a large variety of operating conditions and extreme events through the turbine's life. Additionally, the tower needs to be manufacturable and transportable. This last design criterion around transportability has become a challenge as turbine designers push toward higher and higher hub heights. For reasons discussed elsewhere herein, as towers grow larger, the ideal design approach is to increase the diameter at the tower base and keep the wall thickness minimal. For transportation on land, however, tower diameters are limited to approximately 4.3 m dictated by highway and railway overpass heights, which leads to substantial and costly tower designs using conventional technology solutions.

To better understand the potential for steel towers to meet the requisite price points to be viable in the United States, an ideal tall tower modeling analysis was conducted. This effort compares conventional "transportable" tower designs at different hub heights alongside idealized tower designs, with relaxed constraints around transportation and the maximum tower base diameter. In particular, a conventional technology transportable case is compared to a large-diameter steel tower (LDST) design concept with a 6.2-m base diameter as well as an unconstrained base diameter concept potentially accessible through an on-site spiral-welded tower approach. The results compare for each design how tower mass and expected material costs change with increasing hub height, and thus provide insight into the potential of different technical solutions to enable future low-cost tall towers for the wind industry.

3.1.1 Tower Optimization Method

Tower design looks at minimizing mass and cost through manipulation of the diameter and thickness of the tower along its length. The main constraints on the design are associated with the tower strength and stiffness, which are driven by the loads that the tower experiences over its operating lifetime. The loads on the tower stem from aerodynamic, gravitational, and inertial loading from the RNA at the tower top as well as drag loads from the wind impinging directly on the tower, blades, and nacelle. Detailed discussion of the tower design process is provided in "Design of Offshore Wind Turbine Towers" (Damiani 2016).

For this analysis, we use a software tool for Tower Systems Engineering (TowerSE) to optimize the wind turbine tower design to minimize mass by adjusting tower diameter and thicknesses (Ning et al. 2014). TowerSE is a wind turbine tower conceptual design tool that is part of a larger WISDEM toolset (Dykes et al. 2015). The tower-top diameter is fixed so there are two design variables for the diameter—at the base of the tower and at a set point somewhere between the base and top of the tower (which is also a design variable itself). The wall thickness at each of the base, top, and set point are design variables as well (Table 2).

Table 2. Tower Design Variables

Description	Number of Variables
Tower Outer Diameter	2
Tower Wall Thickness	3
Tower Set Point for Tapering	1

The design variables are optimized for minimum tower mass and satisfy constraints caused by key turbine loads (Table 3). We also consider resonance avoidance through a constraint on the tower natural frequencies relative to the RNA frequencies. Depending on the specific case, constraints for manufacturing and transport are applied as well.

Table 3. Tower Design Constraints

Description	Number of Constraints
Utilization against shell and global buckling	68
Utilization against strength	34
Natural frequency lower limit	1
Fatigue damage	1
Diameter-to-thickness ratio (manufacturability)	3
Base diameter (transportability)	1

The methods to calculate the shell buckling, global buckling, fatigue damage, and stresses along the tower for each load case are addressed in prior studies (Ning et al. 2013). The diameter-to-thickness ratio constraint ensures weldability of the tower. The base diameter upper-bound constraint is adjusted depending on the tower design case—4.3 m for conventional technology, 6.2 m for LDST technology, and unconstrained as would be the case for on-site spiral-welded technology.

Finally, the frequency constraint lower bound is adjusted based on the type of tower, present for soft-stiff and absent for soft-soft. The frequency constraint is particularly important to the design because it can often be the binding constraint on a soft-stiff design and push the mass up exponentially as towers grow taller and the natural frequencies move lower (for a fixed diameter and thickness profile). A tower designer must be sure that the tower natural frequencies do not overlap with the rotor rotational frequency (1P) and blade passing frequency (3P for a three-bladed turbine), where excitations can lead to resonance, large amplitude loads, and increased fatigue damage (see Damiani 2016 for detailed discussion). Conventional tower designs historically were soft-stiff and were designed to completely avoid the potential for resonance-induced loading. For modern wind turbine controls, however, it is possible to control loading through resonance conditions and enable the use of soft-soft wind turbine tower designs with very low natural frequencies that are less stiff and require less thickness in towers with smaller diameters. As shown herein, this has significant implications for the small-diameter towers in tall tower applications.

3.1.2 Tower Optimization Case Study

This study examines six different combinations of tower designs for each of six different turbine hub heights for a total of 36 optimization cases (Table 4).

Table 4. Tower Optimization Cases

Tower Configuration	Tower Type	Hub Height
• Conventional (4.3-m base diameter)	• Soft-stiff (constrained to above rated rotor 1P)	• 80 m • 100 m
• LDST (6.2-m base diameter)	• Soft-soft (no frequency constraint)	• 120 m • 140 m
• Spiral-welded (no base diameter constraint)		• 160 m • 180 m

The RNA properties and loads for the study are based on a reference turbine developed by the International Energy Agency (IEA) Wind Task 37 on Wind Energy Systems Engineering (Table 5). The 3.3-MW reference turbine has a rotor diameter of 130 m and a specific power of roughly 240 W/m^2 (IEA 2017). Although not as low in specific power as some machines that are being produced or are expected to be in production soon, it is an International Electrotechnical Commission (IEC) Class 3A turbine design for low wind speed applications and closer to current U.S. land-based wind turbine technology than other available reference turbine designs.

Table 5. IEA Wind Task 37 Land-Based Low Wind Speed Turbine Configuration Data

Wind Turbine Configuration Data	
Lead Developer	Technical University of Munich
Class and Category	IEC Class 3A
Rotor Orientation	Upwind
Number of Blades	3
Control	Variable-speed collective pitch
Drivetrain	Geared machine
Rated Power	~3.3 MW
Rotor Diameter	130 m
Hub Height	110 m

The loads for the turbine were provided by the Technical University of Munich through a comprehensive analysis of the turbine response to various design load cases as defined by IEC design standards for wind turbines (IEC 61400e1 2014). The largest loads for different force and moment components at the tower top were used as input loads to the optimization (including a thrust load of 1,000 kilonewtons (kN) and torsion around the vertical axis of 12,500 kNm). Fatigue loads were applied based on scaling fatigue loads from the NREL 5-MW reference turbine (Jonkman 2009).

3.1.3 Results

Figure 24 shows the results for more traditional soft-stiff tower masses for each of the turbine tower configurations investigated.

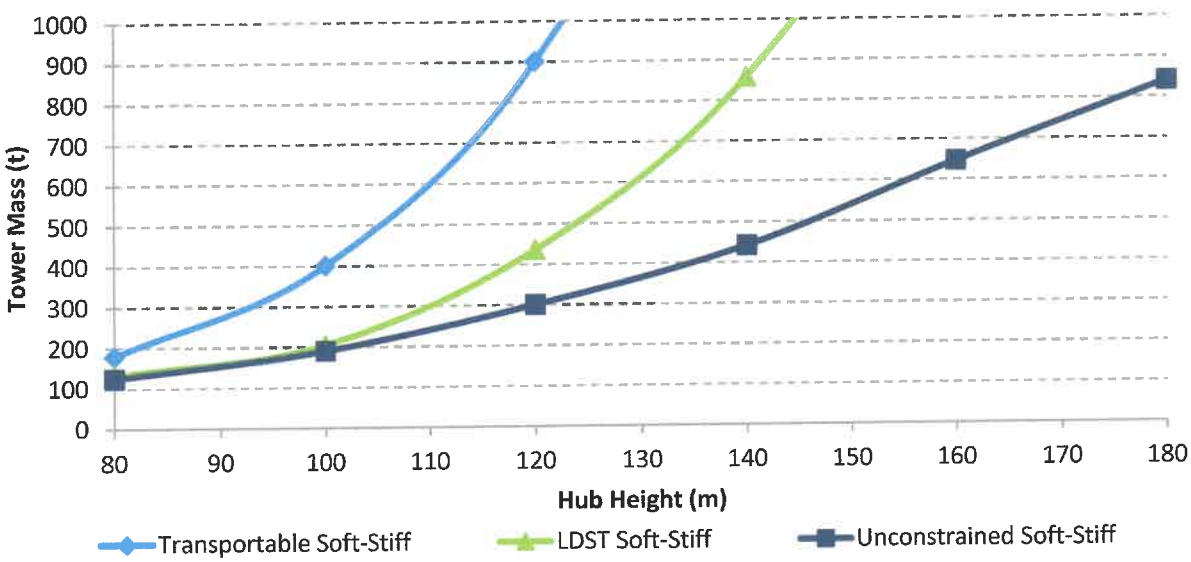

Figure 24. Optimization results for soft-stiff tower design cases

For the transportable towers with a maximum diameter of 4.3 m, the optimizer failed to find a feasible solution for hub heights of 140 m or more. For the heights that were possible to optimize, the weight grows relatively rapidly with tower height. When the constraint on tower base diameter is relaxed, there are benefits in decreasing mass at all heights. Generally, the need to meet the frequency constraint for soft-stiff towers pushes the wall thickness of smaller-based-diameter towers to large values so that the overall mass increases. Notwithstanding these results, it is important to note that tower cost is strongly correlated with mass but is not directly proportional to it, due to the specifics of manufacturing processes.

Figure 25 illustrates the shift in the results when looking not just at traditional soft-stiff towers but also examining soft-soft towers where controls are used to avoid 1P resonance with the rotor.

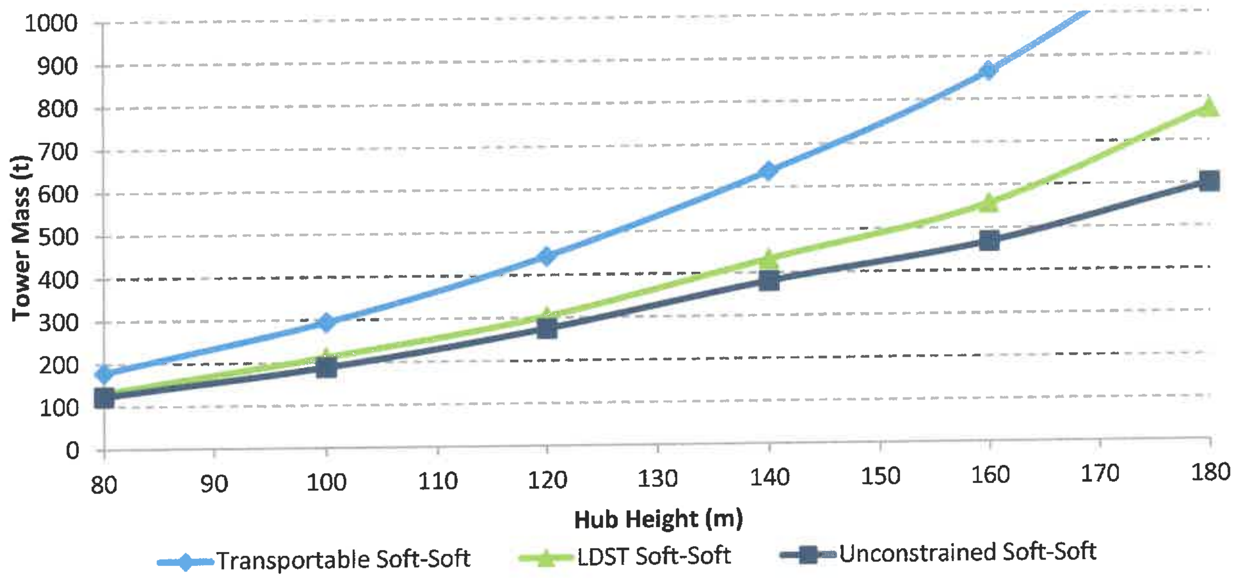

Figure 25. Optimization results for soft-soft tower design cases

Relative to the soft-stiff towers, the mass is reduced in all cases in the soft-soft tower results. The difference is most pronounced in the transportable case with a maximum base diameter of 4.3 m. The optimizer was able to find feasible solutions for all transportable cases, though the 180-m case yielded an optimized mass of 1,200 tons to meet constraints for global buckling. Similarly, the solutions for the LDST and spiral-welded cases all are much lower than before—reduced by as much as 200 tons in the unconstrained case at a 180-m hub height.

Based on data points from actual masses for two transportable towers with hub heights of 120 m and 140 m, we know that these masses can be higher than the transportable tower masses presently available. This likely is due to the fact that the reference turbine design differs from actual technology and the fact that industry has developed more sophisticated control systems to enable not just soft-soft tower designs but also an overall decrease in loads experienced by the tower. The major impact of these advancements will be in reducing fatigue loads, but controls algorithms and load sets for specific turbines are highly valuable intellectual property in the industry. An example of this is Vestas OptiStop and Active Damping technologies that reduce the overall loads experienced by the towers and allow for a more efficient, lower-weight, and reduced-cost tower design (Montanez 2017). These data demonstrate that, although pursuing novel tower technologies holds promise for growing hub heights, innovation around conventional tubular steel tower designs also holds promise and could extend their competitiveness to higher hub heights. At the same time, when the full suite of controls technologies is applied to LDST and unconstrained or spiral-welded technologies, their masses might be decreased even further with further potential to reduce the cost of wind energy for tall tower applications.

3.2 Innovation Opportunities for Additional Alternative Tall Tower Technologies

In spite of the general dominance of tubular steel towers, manufacturers have continued to explore additional alternative tower technologies. The pursuit of alternative tower concepts is justified on various grounds and can result from a desire to hedge against steel-price volatility or from perceived potential for cost reduction. Alternative tower technologies might use lower-cost materials, such as concrete, or could entail more efficient use of steel, such as lattice or space frame designs. Depending on the specifics of a given concept, they also could offer efficiencies in balance of plant and erection. Notably, many alternative tower concepts offer potential solutions to transport challenges and barriers, and in many cases offer opportunities for larger base diameters than the conventional transport limit of 4.3 m. This is of particular interest to OEMs and wind power plant developers operating in the United States, where long transport distances result in nontrivial cost impacts associated with transportation generally. Of course, alternative tower concepts also have challenges that have precluded their broad-based adoption to date, such as much larger labor fraction and on-site labor rates.

One alternative tower design option is on-site manufacturing, which, in principle, should reduce transportation costs and enable taller towers with the trade-off of potentially more labor in the field at the project site. Fundamentally, on-site manufacturing enables the use of commoditized transport and allows the primary production or assembly processes to occur at or near the wind power plant construction site (e.g., avoiding public roads). Currently, a few tower-technology firms—including Wind Tower Technologies (WTT) and Keystone Tower Systems—have conceived and are actively developing on-site manufacturing strategies. Max Bögl is another firm that has commercial offerings of site-cast concrete in mobile factories.

Here, we explore the current status of various alternative tower designs and discuss the design considerations and attributes associated with each of these technologies. Three specific alternative tower concepts are considered: (1) a full-concrete field-cast tower, (2) a hybrid concrete and tubular steel tower, and (3) a lattice or space frame tower. These three alternative tower concepts considered here have all been explored in some depth by wind turbine manufacturers in the past, and all cases have some operational experience in the wind industry. As they were more quantitatively analyzed and discussed, in terms of mass attributes in Section 3.1, we do not reconsider LDST or spiral-welded towers in this section; however, they are also relevant tower options going forward.[5] Notably, this short list of alternatives is not intended to be comprehensive. In particular, it does not consider lower technology readiness level potential solutions such as three-dimensional-printed concrete, which, if successful, could resolve at least some of the challenges with the concrete tower concepts detailed in the following sections.

3.2.1 Full-Concrete Field-Cast Towers

The full-concrete field-cast tower concept has gained interest from the wind industry as a means to circumvent transportation barriers associated with other tall tower technologies. By pouring the tower on-site in the field, overpass clearance barriers are avoided as are other transport hurdles (e.g., weight) associated with moving large concrete sections often utilized in hybrid

[5] Potential challenges associated with these tubular rolled steel variants include significant bolts and on-site assembly costs for the base section of the LDST and the potential needs to set up regional or on-site facilities to manufacturing spiral-welded towers.

concrete and tubular steel concepts. Reliance on concrete as the primary material also offers an opportunity for less sensitivity to steel costs and replaces steel with a lower-cost primary material.

Challenges for full-concrete field-cast concepts include relatively large material quantities, which could erode some of the potential material cost savings associated with lower-cost materials, and a persistent dependence on steel for reinforcing rebar and post-tensioning cables. Additionally, the field-casting and erection process tends to be labor- and time-intensive, increasing labor costs overall and potentially introducing logistics challenges. Moreover, without a self-erecting crane—which has not yet been demonstrated in the field—incremental crane costs could be incurred as the individual sections are cast and ultimately placed on the tower.

In terms of its present status, in the United States, WTT has installed a prototype 115-m hub height (100-m concrete tower, 15-m steel section) tower that utilized concrete annuli that were cast on-site. The WTT tower utilizes a process called "match casting" that provides reduced cycle times during tower installation and less finishing work on the interface of the concrete tower sections. The process involves casting tower sections against one another as they cure; this allows for a precision joint and removes the need for a "wet joint," further decreasing installation cycle time. This process is more widely known as "short line match casting" in civil engineering and the bridge industry and eliminates the need for precision machining of the concrete tower section interface as is typical with factory-cast and highway-transported concrete sections common on hybrid concrete and steel towers.

The WTT technology utilizes concrete that can be produced in the field in most locations in the United States. This approach benefits from having a quarry on or near the wind power plant site. This differs from some hybrid concrete and steel factory-cast sections with compressive strengths of approximately 11,000–13,000 psi. Controlling the quality and strength of these higher-strength mixes can be a challenge in the field. Because the tower segments are assumed to be cast on-site, the moving of the tower segments might only face challenges due to weight and the relatively large diameter. For on-site transport, the additional cost of a specialized trailer, if necessary, and tractor or prime mover are assumed to be limited.

3.2.2 Hybrid Concrete and Tubular Steel Towers

Historically, the hybrid concrete and tubular steel tower is the most common type of tower for hub heights above 120 m. Max Bögl and the turbine OEM Enercon are perhaps the most prominent users of these tower designs, which most frequently have been installed in Germany. Hybrid designs typically use ~90 m of concrete annuli or segmented sections and a 50- to 80-m steel tubular transportable steel tower. Again, an advantage of the concrete construction is that the tower diameter can be optimized (but still considering the transport limits of the concrete sections), which can minimize the material required to construct the concrete portion of the tower.

The cost estimates provided below assume a 90-m concrete tower and a 50-m steel tower. These towers typically use concrete sections that are cast in a factory and utilize high-strength concrete (11,000–13,000 psi). The tower-section mating surfaces are machined parallel and the tower section typically is transported to the site by truck. A transition piece is placed on top of the concrete sections and is used to attach the tubular steel tower section to the concrete base. The transition piece is connected to the base of the steel tubular tower and to steel cables that serve to compress the concrete structure. These cables are post-tensioned after installation of the concrete sections and transition piece, and before the installation of the tubular steel tower segments.

The hybrid concrete-tubular steel tower concept has been pursued explicitly because of its lower sensitivity to fluctuations in steel prices and to avoid transport challenges historically associated with tall steel towers. Hybrid concepts also might provide a viable solution to the geometric constraints within the area covered by the rotor disc. At the same time, transport costs still might be significant because of the need to transport large concrete sections as well as steel sections. Relative to the full-concrete field-cast concept, some labor and material savings could be captured by fabricating the various sections in a centralized manufacturing facility, but this savings potential must be weighed against impacts on transportation costs.

Max Bögl announced the capability of a mobile concrete tower-section manufacturing facility (Max Bögl 2016), which could increase the potential utilization of hybrid concrete towers by reducing the transportation cost and increasing local labor fraction. Relative to a full tubular steel tower, labor and material intensities remain comparatively high. The assembly of the large concrete sections coupled with the joining of the concrete and steel portions of the tower also introduce additional erection-cycle time relative to a tubular steel tower. Notably, as advanced turbine controls have evolved and allowed for alternative steel-tower geometries, LDST-style towers have eroded some of the hybrid concepts market share for tall tower installations in Europe.

3.2.3 Lattice/Space Frame

Lattice towers were used for many years in the wind industry, specifically in the 50- to 400-kW turbine size range from the 1980s to1990s. Lattice towers offer very low material quantities and a complete tower can be moved by a conventional highway legal truck, helping to control transport costs. In the 1990s, these towers fell out of favor for various reasons; however, visual aesthetics and bird interactions are the most commonly cited explanations. The lattice tower concept is sensitive to labor cost because of the large number of individual structural members and fasteners as well as a relatively challenging skin (something often desirable for its favorable aesthetics). Installation time, particularly for the skin, is also sensitive to weather delays. Increased erection-cycle time, due to the increase in number of tower sections and the time needed to install the skin of the tower, compounds the risk of costly weather delays. Despite the move away from lattice towers over the past two decades, designer interest has never been fully eliminated.

This analysis relies on a limited number of data points derived from publicly available sources specific to a GE lattice tower prototype. These data were used as a starting point to define material, labor, and installation estimates. GE acquired the rights to a patented lattice tower design originally from Wind Tower Systems LLC. This design uses a pentagonal base with a varying cross section until roughly the bottom of the rotor plane. The acquired patents included multiple self-erecting designs, including a climbing jib crane to erect the tower, and a lifting apparatus that could be used to install the nacelle and rotor without the need for a large crane. GE installed a 97-m prototype in Tehachapi, California, in 2014 and later installed a 139-m tower. Based on its experience, GE cited issues with the skin installation and torsional stiffness as nontrivial challenges.

Turbine OEM Suzlon is currently offering a 120-m hybrid space frame/tubular steel tower for the Indian market with a total installed capacity of more than 1 GW (Suzlon 2018). This approach might address some of the torsional stiffness issues due to the use of the tubular steel section across the rotor plane, as compared to a full space frame where the lattice structure extends from the yaw ring to the ground. This approach also uses a much smaller rotor diameter (97 m and 111 m versus ~130 m) and a much shorter tubular steel tower section than the typical concrete hybrid towers. After clearing the rotor plane, the Suzlon lattice square cross section grows to ~4.9 m per side or ~6.9 m diagonally (Suzlon 2018).

Nabrawind has demonstrated a 160-m prototype using its Nabralift system, which is a hybrid tubular steel tower within the rotor plane and has a three-leg lattice structure below the rotor. This system uses much larger and fewer members in the lattice structure than used in the GE concept, which reduces labor. This concept also uses much taller segments than many site-cast concrete segments, which reduces cycle times and labor associated with the turbine installation process.

Lattice or other tower approaches with wide footprints also offer the potential use of alternative foundation designs and potentially significant cost reductions in the foundation than a conventional spread foot foundation—which is nearly universally used in the United States. The wider footprint of the lattice towers and potentially spiral-welded towers could allow for large reductions in foundation material, labor, and cost by using individual foundations under each member, or in the case of the spiral-welded tower, use an annular foundation. This could be combined with other foundation approaches, such as rock or soil anchors or small piers, which could result in further reductions in foundation costs. Further cost reductions in BOS could be realized with towers that enable alternative foundation designs. For example, foundation cost fraction is estimated at approximately 15% of total BOS cost for the 4.5-MW Low-SP turbine at 110-, 140-, and 160-m hub heights.

3.2.4 Comparing and Contrasting Competing Tower Alternatives

To begin to understand potential cost differences among tower technologies, we conducted a basic comparison of the relative attributes of the three identified alternatives. Based on this first-order assessment, the lattice tower seems attractive. In particular, its material and transport costs are expected to be quite low. As noted earlier, however, there are significant challenges that need to be overcome for this technology to be achieve widespread commercial utilization. Key weaknesses include substantial and relatively high-risk installation costs—with risks being compounded by potential wind delays during construction and skin installation. Moreover, resolving the torsional structural issues could erode at least some, if not all, of the potential opportunity associated with lattice towers. In this vein, jacket-type offshore wind substructures are a comparable structural strategy to the lattice tower but have yet to substantially displace the use of steel monopole substructures in offshore environments of shallow to moderate depth (Smith et al. 2015; Musial et al. 2017). Although not altogether comparable, this suggests that adequately resolving the potential weaknesses of the lattice tower could result in a significantly reduced opportunity for them relative to what is suggested in this initial first-order assessment.

Focusing on the full-concrete field-cast cost characterization, it appears that there are also nontrivial challenges to achieving cost levels consistent with broad-based deployment. First-order estimates of potential cost are on par with, but not below, what might be achieved with a transportable tubular steel tower of comparable height using current design concepts and manufacturing strategies. Perhaps most challenging from the perspective of fundamentals is that a significant portion of costs is either materials-driven or labor. There certainly is potential to eliminate a large amount of the tower labor cost by having the rebar tied off-site and transported in segments and by improved processes and experience. Self-erecting cranes also could reduce installation and erection costs. It might be more difficult to reduce materials costs.

In the United States, with its relatively large (e.g., 300 mile) transport distances, the factory-cast hybrid concrete and tubular steel tower faces a significant disadvantage. Under these conditions, transport costs are estimated to be significant and potentially prohibitive. Absent these substantial transport costs, it is apparent why the hybrid concept historically has been the tall tower technology of choice. Of course, the magnitude of the transport costs also demonstrate why this approach has lost market share in the tall tower space to the LDST concepts employing advanced controls and "soft-soft" design strategies in recent years. Moreover, material and labor costs for the hybrid concept remain significant even when allowing for substantially shorter transport distances.

4 Insights for Tower Design and Innovation

The previous sections of this report have examined and explored the potential opportunity offered by increased tower height through the lens of wind speed, capacity factor, and LCOE. Additionally, they have explored the potential opportunities afforded by advancements in tubular steel towers, as well as the potential strengths and weaknesses of full-concrete, hybrid, and lattice tower concepts. In this section, we attempt to synthesize the insights generated and posit potential metrics that might be used to characterize the viability of novel tower solutions going forward. Key insights are structured by category and follow the general structure of the report.

4.1 Analysis Results and Insights

4.1.1 Wind Resources

Based on current data in the Wind Toolkit for calendar year 2012, an increase in hub height from 80 to 110 m generally results in wind speed increases of 0 to 0.5 m/s west of the Rockies, and 0.5 to 1.0 m/s east of the Rockies. Additionally, some areas see decreased wind speeds with higher above ground levels, likely owing to unusual topographic features, such as mountainous terrain in California and the Appalachian region. If hub height is increased from 80 to 160 m, portions of the central plains would see wind speed increases of 1.5 to 2.0 m/s. Additionally, some locations in Pennsylvania, New York, and Maine would see increases of 1.0 to 1.5 m/s. These results lead to a general finding that increased hub height is accompanied by increased wind resources. However, there are regional and topographical differences that must be recognized. Moreover, as discussed in Section 2, the quantitative results presented depend in no small part on the accuracy and validity of the Wind Toolkit data. Mesoscale wind resource data, particularly at higher above ground levels, could benefit from further validation and study, in addition to the efforts completed to date.

4.1.2 Capacity Factors

For the Today turbine, capacity factor generally increased when hub height was increased from 80 to 110 m, with the increases clustered at 5 percentage points or less. At 140 m relative to 80 m, capacity factor increases exhibited a range from approximately 0 to 10 percentage points with a relatively flat distribution. For the other three turbines examined and focusing on the comparisons within each turbine platform, median capacity factor increases were approximately 2 to 3 percentage points when moving from 110 to 140 m and approximately 1 percentage point when moving from 140 to 160 m. Generalizing these results indicates that increasing hub heights to 110 and 140 m drives sizable gains across turbine platforms with seemingly diminishing returns above 140 m. These findings exhibit the same regional and topographical variations observed with the wind resource data. These results are highly dependent on the accuracy of the wind resource data, particularly at the higher above ground levels, and also vary depending on the specific turbine configuration applied. While diminishing returns with higher above ground heights is at least partially intuitive, the uncertainty in the underlying resource data makes it difficult to ascertain the robustness of the observed trends.

4.1.3 Energy Costs

Of the four turbines examined, the Low-SP 4.5-MW turbine exhibited the lowest LCOE values. At a 110-m hub height, unsubsidized LCOE for this machine ranged from \$25/MWh to \$35/MWh throughout much of the nation's interior wind belt. In the eastern half of the nation, LCOE ranged from $35/MWh to $50/MWh. Throughout the Pacific and Intermountain West regions, results were mixed. With hub height increased to 160 m, there was less support for $25/MWh to $35/MWh LCOE in the interior wind belt, whereas in some eastern regions LCOE was reduced relative to the 110-m case. This correlates with experience within the wind industry: commercial wind developers' interest in taller towers is emerging in the eastern states, but as yet there is no corresponding drive in the interior wind belt.

Changes in LCOE relative to the estimated LCOE for the Today turbine at 80 m were also estimated for all four turbines at each Wind Toolkit site (more than 1.85 million nationwide), yielding broad distributions reflecting the wide range of wind resources throughout the nation. For the Low-SP 4.5-MW turbine, the changes in LCOE range from slightly positive to reductions of as much as $30/MWh, with a broad peak clustered around $5/MWh to $10/MWh. In contrast, LCOE values for the Today turbine at the higher hub heights tend to be greater as hub height is increased. Results for the other two machines are similar to those for the 4.5-MW machine but are less pronounced.

Economically preferred tower heights were determined for each of the four turbines at each Wind Toolkit site. The preferred height—selected from the options of 80 m, 110 m, 140 m, and 160 m—yielded the lowest LCOE at that site. Of course, not all of these sites would offer an LCOE low enough to be commercially viable. Many would, however, so the results of this exercise provide an indication of preferred tower heights based on recent technology cost and scaling trends. For today's turbine, 80 m is preferred for more than half of the sites—again consistent with commercial experience in the interior region—but substantial opportunities exist at 110 m and 140 m as well. For the three larger turbines, 110 m is preferred for more than 60% of all sites, with significant opportunities at 140 m as well. The 160-m height was preferred only by the Low-SP 4.5-MW turbine, and at only about 2% of sites.

4.1.4 Breakeven Costs

For a 110-m hub height, the analysis found breakeven costs for today's turbine of well under $500/kW for many locations. For the Low-SP 4.5-MW turbine, breakeven costs were clustered around $500/kW, tailing off to about $1,500/kW. At the 140-m hub height, breakeven costs exhibited a wide distribution with a broad peak. For the Today turbine, breakeven costs were clustered around approximately $250/kW, tailing off to about $1,000/kW.

These results provide turbine designers with a rough indication of the cost budget allowable in pursuing economical taller turbines. Of course, beating the breakeven cost could be accomplished with whatever means are available to designers, manufacturers, and installers. These could include changes in design or other machine features, reduced blade costs or a reduced blade mass scaling exponent, advances in tower design or manufacturing, advanced turbine controls, erection economies or other BOS advances, other unforeseen improvements, or combinations of several of these methods.

4.1.5 Tall Tower Options

In pursuing higher hub heights at affordable costs, tower cost is a major factor. We examined prospects for tubular steel towers and several other options under consideration. Three tubular steel options were analyzed: transportable tower, with a 4.3-m base diameter; LDST, with a 6.2-m base diameter; and an unconstrained base diameter tower, which might be fabricated on-site with spiral-welding techniques. We considered hub heights from 80 to 180 m and examined both soft-stiff and soft-soft designs.

In the soft-stiff case, the transportable tower becomes uneconomical rapidly as its height is increased. At 80 m, its weight is estimated at 180 tons. At 120 m, its weight has increased to 900 tons. Beyond 120 m, it was determined to be economically impractical. For the LDST case, the 80-m weight is estimated at 130 tons, reflecting the reduced steel thickness allowed by the larger base diameter. At 140 m, its weight has increased to 850 tons. For the unconstrained case, the 140-m tower weight is 440 tons (or about half of the 140-m LDST weight). Clearly, the unconstrained option offers a huge advantage with respect to weight; however, on-site production presents its own nontrivial challenges.

For the soft-soft cases examined, significant weight reductions are estimated relative to soft-stiff options. The transportable tower weight at 140 m is 440 tons, less than half the weight of the soft-stiff tower at 120 m. Even at 160 m, its weight of 860 tons is less than that of the 120-m soft-stiff tower. The other two tower options also show comparable reductions. In the unconstrained case, the 160-m tower, at 470 tons, is only slightly heavier than the 140-m soft-stiff tower (440 tons).

It is clear from these results that soft-soft tower designs offer a substantial weight—and thus likely cost—advantage. Even the transportable option that is able to clear today's highway transport constraints becomes feasible at 140 m. The major challenge for soft-soft designs is management of 1P resonances through advanced controls, damping, or some other means. Wind turbine OEMs appear to be making significant progress along these lines, as evidenced by commercial tower weights that are somewhat less than the weights estimated in our analysis.

In addition to steel towers, we also examined prospects and costs for several other tower options, including full-concrete field-cast, hybrid concrete and tubular steel tower, and lattice or space frame. These could offer advantages in transport, erection, and BOS costs, and might allow for larger base diameters, but all are accompanied by much greater labor costs than those of transportable towers. Potential advantages and risks were assessed for each of these options. For installations in the United States, none of these options shows a clear advantage over tubular steel towers. Of the three, the lattice-based approaches seem to offer the greatest potential, based on low material and transport costs. However, there are sizable risks associated with on-site labor requirements, wind conditions during installation, and torsional loads. With the full-concrete field-cast approach, reducing costs below tubular steel presents a major challenge. With the hybrid-concrete approach, large concrete sections are cast in a factory and then transported over long distances. With transportation costs approaching nearly half of total installed tower cost, the prospects for this option appear limited, unless there are logistics or other innovations that can greatly reduce transportation requirements and costs.

4.2 Analysis Results Discussion

Overall, this analysis leads to three primary conclusions. First, there is sufficient additional wind resource in the United States at higher above ground levels to warrant the pursuit of technology enabling higher hub heights. Second, tall tower technologies with the greatest potential appear to be tubular steel based on soft-soft design criteria; these towers have gained relative prominence in the industry over the past several years. Third, hub heights of 110 m to 140 m have the potential to offer some LCOE advantages relative to today's typical turbines, with optimal hub heights potentially varying from these discrete points were a more continuous set of solutions available. Based on the initial first-order cost estimates applied here, LCOE reductions between \$5/MWh and \$10/MWh, and in some cases even larger, are plausible. Tall tower technologies and solutions could be even more attractive if they are able to incorporate innovation potential not captured here that enhances their economics relative to recent scaling trends.

Given the substantial uncertainties embedded in our cost assumptions and the relative optimism toward higher hub heights and larger machines, however, these findings need to be verified and validated with more resolved and comprehensive cost estimates before they can be deemed robust. More specifically, changes in turbine or BOS CapEx could alter the observed outcomes.

Additionally, our analysis indicates somewhat diminishing returns from hub height increases to 140 m and subsequently to 160 m. Moreover, potential returns from achieving 140 m or 160 m are in locations where estimated LCOEs are relatively high, suggesting that simply making an economic case for a higher hub height in these locations might not be sufficient to support wind deployment in these regions. These results suggest that potential future drivers of higher wind turbine hub heights could be governed by factors beyond the observed improvement in wind resource alone. Alternative drivers could include increased land constraints (as has been observed in Germany), with more limited locations to install wind turbines and therefore a need to maximize the energy generation per turbine. Another alternative driver could be a desire to further increase rotor size and therefore increase hub height to provide sufficient ground clearance.

4.3 Lessons Learned for Evaluating Tall Tower Opportunities

This analysis shows that wind resource quality improves in most locations with higher above ground levels, up to at least 160 m. The analysis, however, also shows that the relative value of achieving higher hub heights is not absolute and varies significantly by location. Moreover, the locations where the value is potentially greatest from achieving higher hub heights tend to be places where the wind energy resource is less robust; therefore, economically achieving a higher hub height alone might not be sufficient to make wind power economic in those locations.

Given this context, evaluating the viability of a given tall tower opportunity is both complex and difficult to generalize. Based on our insights from this work, we suggest focusing on LCOE, total CapEx, and breakeven cost as the means of evaluating relative usefulness of a proposed tall tower approach. Consideration of a particular set of site conditions is also important given the variability in value as a function of geospatial variables. Further, tower cost itself is important but can be misleading. Some tower solutions could actually increase tower cost and still result in a lower CapEx if they enable an elegant installation solution that further minimizes BOS cost. Moreover, if computed on a dollars-per-kilowatt (\$/kW) basis, a solution requires holding the turbine's nameplate capacity constant to avoid manipulating one particular component cost (e.g., tower) simply by increasing or decreasing nameplate capacity; tower scaling and generator scaling are not directly proportional.

The LCOE and total CapEx (or breakeven costs) are of particular importance given the interplay between turbine and plant subsystems, as well as the potential for hub height to impact BOS and operational expenditures. Notably, the most critical innovation enabling soft-soft towers is the turbine controls, which now enable the machine to avoid operating conditions that were key design constraints in prior eras. Similarly, going forward, alternative erection techniques that reduce BOS costs could be as critical to realizing the value of higher hub heights as is developing novel tower solutions.

If focusing on a singular metric for evaluating the potential afforded by any given tall tower solution, we propose a focus on breakeven cost—computed at the system or total CapEx level. The value of the metric should also consider the LCOE that might be required to support economic deployment of wind energy in a given region. Based on the analysis conducted here, a system-level breakeven cost of less than \$500/kW for relatively lower specific power turbines and potentially as low as \$200/kW, particularly for higher specific power turbines, could be sufficient to support an LCOE reduction across much of the country, and also would push less-energetic wind resource regions further along the path to competitiveness. Stated from a developer's perspective, if a prospective taller-tower solution (110 m or higher) can be realized at an additional cost of about \$200/kW (relative to the same turbine on an 80-m tower), that solution is likely to offer wide applicability across the nation. The same would be true at \$500/kW, but to a lesser extent. Depending on the specific focus areas, turbine configuration, and relevant site conditions, and especially if pushing toward higher hub heights (e.g., 140 m, 160 m), divergence of higher breakeven costs from this general guidance could be merited.

5 Conclusions

We find the question of optimal wind turbine tower height to be a rich and complex area of research, particularly when considering the problem at the continental scale. The system nature of wind technology and the variability in key input variables across time and space—not least of which is the wind resource—add dimensions to the analysis that require consideration of a great number of potential trade-offs as well as the possibility for multiple equally optimal solutions. Moreover, we have observed that our results are sensitive to changes in key assumptions (e.g., total CapEx and wind shear) that are highly uncertain but, at the same time, the magnitude of the difference in outcomes is not always significant.

Notwithstanding the complexity of the tasks and the array of potential outcomes, our analysis suggests that there are sizable gains to be had by realizing tall tower technologies. At the same time, there may also be diminishing returns to higher hub heights, and locations where the value of higher hub heights is greatest tend to be the areas where wind energy presently is relatively high cost. Based on our current cost assumptions derived from recent vintage technology scaling functions, it is the case across much of the continental United States that the lowest available hub height (e.g., 80 m, 110 m) often provides the lowest-cost solution. At the same time, taller towers may be critical to increasing the opportunity for wind power across the nation and could become increasingly attractive as innovations drive down the costs required to achieve higher hub heights. Continued tower growth could also be a result of a combination of factors, including land constraints that result in stronger consideration for maximizing energy production per turbine and the need to provide sufficient ground clearance as a function of continued rotor growth.

Future work efforts in this domain are anticipated to benefit from research that quantifies and ultimately reduces the uncertainty of the wind resource data, particularly at higher above ground levels. In addition, more focus on cost estimates including sensitivities, analyzing specific technology opportunities, and analyzing alternative turbine configurations could provide more robust perspectives and insights into the potential for innovative solutions to capture additional value from taller towers.

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Appendix A. Supplemental Input and Results Data

Table A1. Detailed Levelized Cost of Energy Cost Inputs

	Today	Low Specific Power (SP) 4.5	Business as Usual (BAU)	Low-SP 3.25 MW
Nameplate Capacity (megawatts [MW])	2.32	4.50	3.30	3.25
Rotor Diameter (meters [m])	113	194	156	166
Specific Power (watts (W)/m^2)	231	152	173	150
Hub Height 80 m, Tower Cost ($/kilowatt [kW])	$198	—	—	—
Hub Height 110 m, Tower Cost ($/kW)	$378	$195	$266	$270
Hub Height 140 m, Tower Cost ($/kW)	$616	$318	$433	$440
Hub Height 160 m, Tower Cost ($/kW)	$808	$416	$568	$577
Turbine Rotor Nacelle Assembly ($/kW), Blade Exp = 2.2	$562	$802	$695	$779
Balance of Station (BOS) ($/kW), Hub Height 80 m	$317	—	—	—
BOS ($/kW), Hub Height 110 m	$330	$206	$258	$258
BOS ($/kW), Hub Height 140 m	$343	$212	$274	$274
BOS ($/kW), Hub Height 160 m	$352	$215	$292	$292
Capital Expenditures (CapEx) ($/kW), blade Exp = 2.2, 80 m	$1,077	—	—	—
CapEx ($/kW), blade Exp = 2.2, 110 m	$1,270	$1,203	$1,218	$1,306
CapEx ($/kW), blade Exp = 2.2, 140 m	$1,521	$1,331	$1,402	$1,492
CapEx ($/kW), blade Exp = 2.2, 160 m	$1,722	$1,433	$1,555	$1,648
CapEx ($/kW), blade Exp = 2.2, 80 m, $200/kW tower	$1,077	—	—	—
CapEx ($/kW), blade Exp = 2.2, 110 m, $200/kW tower	$1,092	$1,208	$1,153	$1,237
CapEx ($/kW), blade Exp = 2.2, 140 m, $200/kW tower	$1,105	$1,213	$1,168	$1,252
CapEx ($/kW), blade Exp = 2.2, 160 m, $200/kW tower	$1,114	$1,217	$1,187	$1,271

Table A2. Net Capacity Factor Change Statistics, Relative to the Today Turbine at 80 m

(Percentage Points)

Turbine Configuration	Median	25th Percentile	75th Percentile
Today 110 m	3.8	2.1	4.7
Today 140 m	6.67	3.6	8.5
Today 160 m	7.5	4.1	9.7
Business as usual (BAU) 110 m	8.8	6.2	10.0
BAU 140 m	11.3	7.6	13.4
BAU 160 m	12.1	8.1	14.4
Low-SP 3.25 MW, 110 m	11.1	8.2	12.5
Low-SP 3.25 MW, 140 m	13.4	9.5	15.6
Low-SP 3.25 MW, 160 m	14.2	10.0	16.7
Low-SP 4.5 MW, 110 m	10.9	8.0	12.2
Low-SP 4.5 MW, 140 m	13.2	9.3	15.4
Low-SP 4.5 MW, 160 m	13.9	9.8	16.4

Table A3. Net Capacity Factor Breakpoints

(Percentage of pixels with an increase greater than 5, 10, and 15 percentage points as listed in the column head of the table, relative to the Today turbine at 80 m)

Turbine Configuration	5	10	15
Today 110 m	15.3%	0.0%	0.0%
Today 140 m	65.0%	8.4%	0.0%
Today 160 m	69.6%	21.6%	0.3%
BAU 110 m	86.5%	25.0%	0.0%
BAU 140 m	90.9%	61.1%	8.8%
BAU 160 m	91.7%	65.3%	19.4%
Low-SP 3.25 MW, 110 m	95.8%	62.4%	0.9%
Low-SP 3.25 MW, 140 m	96.6%	72.6%	32.7%
Low-SP 3.25 MW, 160 m	96.6%	75.0%	42.3%
Low-SP 4.5 MW, 110 m	95.3%	60.5%	0.6%
Low-SP 4.5 MW, 140 m	96.2%	71.6%	29.8%
Low-SP 4.5 MW, 160 m	96.3%	74.0%	40.1%

Table A4. Levelized Cost of Energy Summary Statistics ($/megawatt-hour [MWh])

Turbine Configuration	Median	25th Percentile	75th Percentile
Today 80 m	$51	$41	$66
Today 110 m	$51	$41	$64
Today 140 m	$52	$44	$66
Today 160 m	$56	$47	$71
BAU 110 m	$42	$35	$53
BAU 140 m	$43	$37	$54
BAU 160 m	$46	$39	$57
Low-SP 3.25 MW, 110 m	$42	$35	$52
Low-SP 3.25 MW, 140 m	$43	$37	$53
Low-SP 3.25 MW, 160 m	$45	$39	$56
Low-SP 4.5 MW, 110 m	$40	$34	$49
Low-SP 4.5 MW, 140 m	$40	$34	$49
Low-SP 4.5 MW, 160 m	$41	$35	$51

Table A5. Levelized Cost of Energy Breakpoints

(Percentage of pixels with an LCOE less than the dollar values listed in the column head of the table)

Turbine Configuration	$30/MWh	$40/MWh	$50/MWh
Today 80 m	0.4%	20.9%	47.8%
Today 110 m	0.1%	20.0%	48.8%
Today 140 m	0.0%	9.3%	44.5%
Today 160 m	0.0%	0.8%	36.4%
BAU 110 m	1.3%	43.0%	69.0%
BAU 140 m	0.1%	39.4%	66.9%
BAU 160 m	0.0%	30.0%	61.2%
Low-SP 3.25 MW, 110 m	1.0%	44.3%	71.1%
Low-SP 3.25 MW, 140 m	0.1%	40.0%	68.6%
Low-SP 3.25 MW, 160 m	0.0%	30.2%	62.5%
Low-SP 4.5 MW, 110 m	5.4%	50.9%	76.2%
Low-SP 4.5 MW, 140 m	1.2%	50.6%	76.3%
Low-SP 4.5 MW, 160 m	0.2%	46.3%	73.6%

Table A6. Average State Levelized Cost of Energy ($/MWh)

State	Today 80 m	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Lo SP M 11
AL	$72	$66	$64	$67	$54	$52	$54	$52	$51	$53	$5
AR	$57	$53	$53	$55	$44	$43	$45	$43	$43	$45	$4
AZ	$81	$83	$90	$97	$68	$72	$77	$66	$70	$75	$6
CA	$105	$108	$118	$129	$88	$95	$102	$86	$93	$99	$8
CO	$63	$65	$71	$77	$55	$58	$62	$54	$58	$61	$5
CT	$55	$52	$51	$54	$43	$42	$44	$42	$42	$43	$4
DC	$68	$63	$61	$64	$52	$50	$52	$51	$49	$51	$4
DE	$49	$47	$49	$52	$39	$41	$43	$39	$40	$42	$3
FL	$74	$68	$67	$71	$54	$53	$55	$52	$52	$54	$4
GA	$70	$65	$63	$67	$52	$51	$53	$51	$50	$52	$4
IA	$39	$39	$41	$44	$33	$35	$37	$34	$35	$37	$3
ID	$66	$68	$74	$80	$57	$60	$64	$56	$59	$63	$5
IL	$44	$43	$45	$48	$37	$38	$40	$36	$38	$40	$3
IN	$46	$45	$48	$51	$38	$40	$42	$38	$40	$42	$3
KS	$38	$38	$40	$44	$33	$35	$37	$33	$35	$37	$3
KY	$59	$56	$56	$60	$47	$47	$49	$46	$46	$49	$4
LA	$61	$57	$57	$61	$46	$47	$49	$45	$46	$48	$4
MA	$52	$50	$50	$52	$41	$41	$43	$41	$41	$43	$3
MD	$55	$53	$54	$57	$44	$44	$47	$43	$44	$46	$4
ME	$51	$49	$49	$51	$41	$40	$42	$40	$40	$42	$3
MI	$45	$43	$45	$48	$37	$38	$40	$36	$37	$40	$3

State	Today 80 m	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Lo SP M 11
MN	$42	$41	$43	$46	$35	$37	$39	$35	$37	$39	$
MO	$45	$43	$45	$48	$37	$38	$40	$37	$38	$40	$
MS	$62	$57	$57	$60	$47	$47	$49	$46	$46	$48	$
MT	$48	$49	$52	$56	$42	$44	$47	$42	$44	$47	$
NC	$66	$62	$63	$66	$51	$51	$53	$50	$50	$53	$
ND	$39	$40	$42	$45	$34	$35	$38	$34	$36	$38	$
NE	$38	$39	$41	$44	$33	$35	$37	$33	$35	$37	$
NH	$57	$55	$56	$58	$46	$46	$48	$45	$45	$47	$
NJ	$55	$52	$52	$55	$43	$43	$45	$42	$42	$44	$
NM	$59	$60	$65	$69	$50	$53	$56	$50	$52	$55	$
NV	$66	$69	$77	$83	$58	$63	$67	$58	$62	$66	$
NY	$52	$51	$51	$54	$42	$42	$44	$42	$42	$44	$
OH	$52	$50	$51	$54	$42	$42	$45	$41	$42	$44	$
OK	$40	$40	$42	$45	$34	$35	$38	$34	$36	$38	$
OR	$65	$67	$72	$77	$56	$59	$63	$56	$58	$62	$
PA	$57	$55	$54	$57	$45	$45	$46	$44	$44	$46	$
RI	$47	$45	$46	$49	$38	$38	$40	$37	$38	$40	$
SC	$69	$64	$64	$67	$52	$52	$54	$51	$51	$53	$
SD	$40	$41	$43	$46	$35	$37	$39	$35	$37	$39	$
TN	$65	$62	$62	$65	$51	$51	$53	$50	$50	$52	$
TX	$47	$46	$47	$50	$38	$39	$41	$38	$39	$41	$
UT	$69	$72	$79	$86	$61	$66	$70	$60	$65	$69	$

State	Today 80 m	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Lo SP M 11
VA	$66	$63	$63	$66	$52	$51	$54	$51	$51	$53	$4
VT	$55	$54	$55	$58	$45	$45	$47	$44	$44	$46	$4
WA	$64	$66	$71	$77	$56	$59	$63	$55	$58	$62	$5
WI	$46	$45	$46	$49	$38	$38	$40	$37	$38	$40	$3
WV	$66	$63	$63	$67	$52	$52	$54	$51	$52	$54	$4
WY	$50	$52	$56	$60	$44	$47	$50	$44	$46	$49	$4

Table A7. Average State Breakeven Cost ($/kW)

State	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Low-S 4.5 M 110 r
AL	$412	$793	$917	$849	$1,208	$1,325	$1,059	$1,406	$1,520	$1,03
AR	$352	$667	$772	$726	$1,017	$1,116	$902	$1,182	$1,277	$883
AZ	$166	$266	$302	$532	$628	$662	$713	$806	$838	$694
CA	$146	$221	$245	$470	$537	$558	$631	$694	$713	$614
CO	$151	$254	$290	$446	$540	$573	$587	$677	$708	$572
CT	$332	$669	$790	$715	$1,038	$1,149	$898	$1,210	$1,316	$879
DC	$373	$771	$919	$773	$1,165	$1,309	$967	$1,353	$1,494	$946
DE	$285	$504	$571	$628	$818	$878	$788	$965	$1,021	$771
FL	$394	$736	$848	$893	$1,220	$1,327	$1,138	$1,455	$1,558	$1,11
GA	$399	$758	$876	$839	$1,184	$1,297	$1,054	$1,388	$1,499	$1,03
IA	$228	$393	$440	$481	$617	$657	$594	$718	$756	$583
ID	$150	$253	$291	$462	$560	$596	$612	$708	$743	$596
IL	$262	$455	$512	$560	$723	$774	$695	$847	$895	$681
IN	$254	$442	$497	$561	$725	$774	$704	$857	$903	$689
KS	$208	$352	$392	$450	$567	$601	$559	$665	$697	$548
KY	$315	$587	$672	$665	$917	$997	$833	$1,075	$1,151	$815
LA	$366	$662	$755	$789	$1,059	$1,144	$991	$1,246	$1,329	$969
MA	$307	$603	$708	$662	$938	$1,033	$829	$1,092	$1,183	$811
MD	$294	$549	$634	$645	$880	$959	$811	$1,036	$1,112	$794
ME	$306	$616	$726	$658	$948	$1,048	$822	$1,100	$1,195	$805
MI	$274	$502	$573	$588	$784	$845	$731	$913	$969	$716
MN	$245	$434	$491	$531	$690	$739	$660	$806	$852	$646

State	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Low-S 4.5 M 110
MO	$285	$509	$575	$583	$775	$833	$719	$897	$953	$705
MS	$378	$694	$793	$779	$1,070	$1,162	$969	$1,247	$1,336	$949
MT	$158	$286	$330	$415	$531	$572	$534	$645	$684	$522
NC	$331	$625	$725	$716	$994	$1,089	$901	$1,170	$1,263	$881
ND	$216	$381	$430	$485	$623	$665	$606	$733	$772	$593
NE	$207	$360	$406	$460	$588	$626	$574	$690	$726	$562
NH	$262	$534	$638	$599	$865	$964	$759	$1,019	$1,115	$742
NJ	$326	$629	$732	$702	$984	$1,078	$882	$1,151	$1,241	$863
NM	$174	$304	$351	$491	$615	$659	$644	$764	$806	$628
NV	$116	$178	$201	$414	$472	$494	$558	$614	$635	$542
NY	$268	$526	$619	$603	$847	$933	$761	$996	$1,078	$745
OH	$293	$534	$607	$631	$849	$914	$790	$996	$1,058	$773
OK	$239	$423	$478	$500	$654	$701	$618	$758	$802	$605
OR	$158	$281	$326	$458	$577	$620	$604	$719	$761	$588
PA	$304	$617	$733	$667	$969	$1,078	$840	$1,134	$1,239	$821
RI	$299	$568	$658	$649	$894	$976	$814	$1,046	$1,123	$797
SC	$381	$718	$829	$806	$1,125	$1,231	$1,012	$1,322	$1,424	$990
SD	$204	$363	$413	$464	$601	$643	$582	$708	$748	$569
TN	$319	$606	$702	$689	$961	$1,052	$867	$1,130	$1,218	$849
TX	$273	$499	$572	$611	$807	$869	$766	$947	$1,004	$750
UT	$122	$194	$220	$405	$471	$496	$540	$604	$627	$526
VA	$310	$595	$697	$684	$960	$1,057	$865	$1,134	$1,229	$846
VT	$246	$494	$592	$586	$831	$925	$749	$990	$1,080	$731

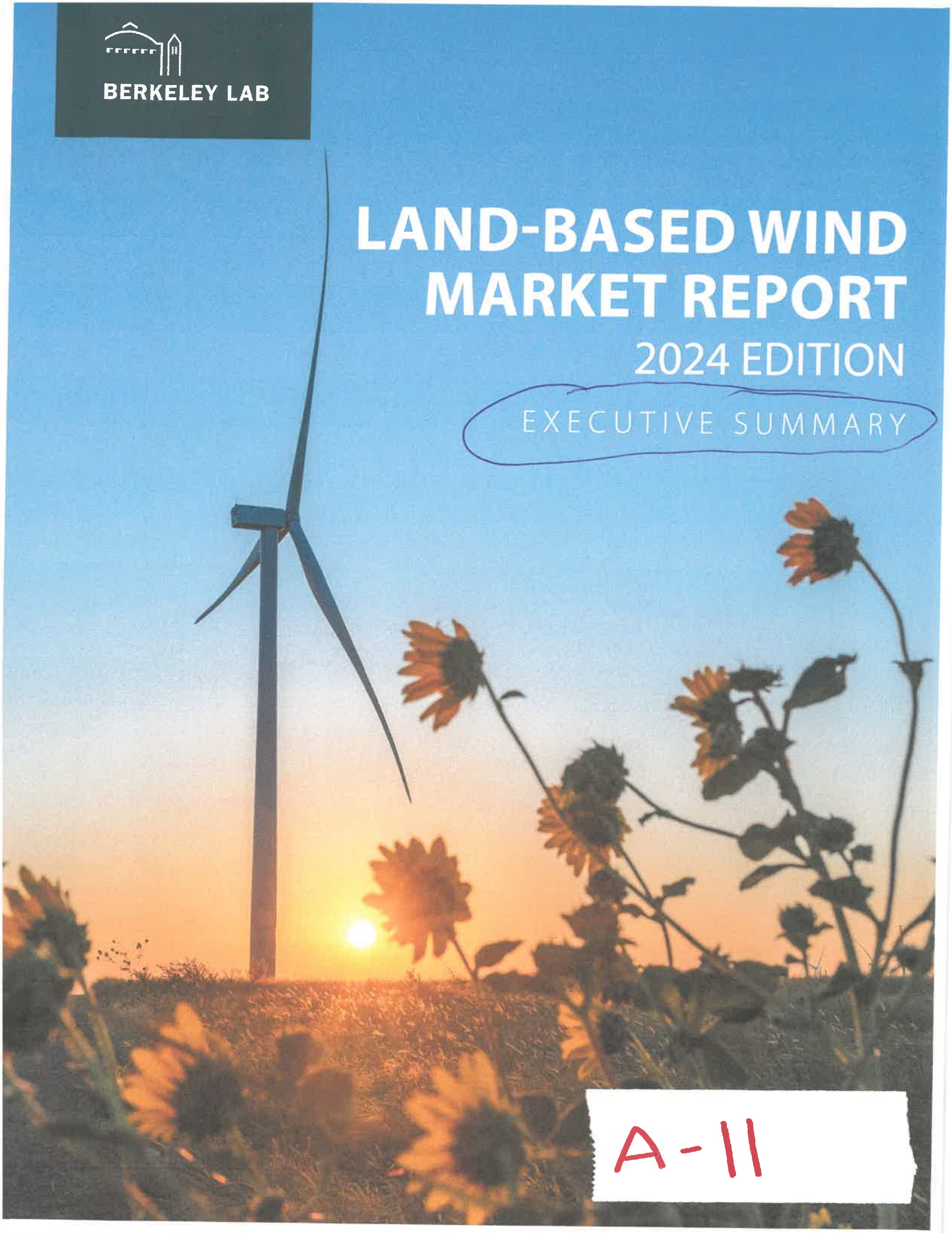
State	Today 110 m	Today 140 m	Today 160 m	BAU 110 m	BAU 140 m	BAU 160 m	Low-SP 3.25 MW 110 m	Low-SP 3.25 MW 140 m	Low-SP 3.25 MW 160 m	Low-S 4.5 M 110 r
WA	$159	$278	$320	$447	$558	$597	$585	$692	$728	$57
WI	$296	$543	$619	$618	$833	$899	$766	$965	$1,027	$75
WV	$295	$575	$673	$652	$920	$1,012	$824	$1,085	$1,173	$80
WY	$140	$248	$287	$395	$496	$532	$515	$612	$646	$50

BERKELEY LAB

LAND-BASED WIND MARKET REPORT

2024 EDITION

EXECUTIVE SUMMARY



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Preparation and Authorship

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Executive Summary

Wind power additions in the United States totaled 6.5 gigawatts (GW) of capacity in 2023.[1] Wind power growth has historically been supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as numerous state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. Nonetheless, 2023 was a slow year in terms of new wind deployment, the lowest since 2014. Elevated interest rates played a role in slowing deployment, as did interconnection and siting challenges.

Passage of the Inflation Reduction Act (IRA) promises new market dynamics for wind power deployment and supply chain investments in the years ahead. IRA contains a long-term extension of the PTC at full value (assuming that wage and apprenticeship standards are met) along with opportunities for wind plants to earn two 10 percent bonus credits that add to the PTC for meeting domestic content requirements and for being in energy communities. IRA also includes new production-based and investment-based tax credits to support the build-out of domestic clean energy manufacturing and supply chains. Though it is too early to see the full impacts of IRA in historical data, IRA has increased analyst forecasts for future wind power capacity additions and has motivated many wind industry supply-chain announcements.

Key findings from this year's *Land-Based Wind Market Report*—which primarily focuses on land-based, utility-scale wind—are summarized below. Note that the sections on "Installation Trends," "Industry Trends," and "Future Outlook" often contain combined data inclusive of both offshore and land-based wind. Other sections exclusively focus on land-based wind.

Installation Trends

- **The U.S. added 6.5 GW of wind power capacity in 2023, totaling $10.8 billion of investment.** The newly installed projects in 2023 were all land-based; no offshore projects were commissioned in 2023. Development was concentrated in the Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP).[2] Cumulative wind capacity grew to 150 GW. In addition, 0.6 GW of existing wind plants were partially repowered in 2023, mostly by upgrading rotors (blades) and nacelle components like gearboxes and generators.
- **Wind power's contribution to total U.S. electric-power capacity additions in 2023 fell to 12%, the lowest level since 2013.** Wind power constituted 12% of all generation and storage capacity additions in 2023, behind solar (52%), natural gas (21%), and storage (13%). Over the last decade, wind represented 26% of total capacity additions, and a larger fraction of new capacity in SPP (86%), MISO (46%), ERCOT (44%), and the non-ISO West (29%).
- **Globally, the United States again ranked a distant second in annual wind capacity and remained well behind the market leaders in wind energy penetration**. Global wind additions reached a record 117 GW in 2023, yielding a cumulative 1,021 GW. The United States remained the second-leading market in terms of annual and cumulative capacity, well behind China. Many countries have achieved high wind electricity shares, with wind supplying 57% of Denmark's total electricity generation in 2023 and more than 20% in ten other countries. In the United States, wind supplied 10% of total generation.

[1] Note that this report seeks to align with American Clean Power (ACP) for annual wind capacity additions and project-level specifics, where possible. Differences in reporting exist between ACP and the Energy Information Administration.
[2] The nine regions most used in this report are the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO), and the non-ISO West and Southeast.

- **Texas once again installed the most wind capacity of any state in 2023 (1,323 MW), followed by Illinois (928 MW); twelve states exceeded 20% wind energy penetration.** Texas also remained the leader on a cumulative capacity basis, with more than 41 GW. Notably, the wind capacity installed in Iowa supplied 59% of all in-state electricity generation in 2023; twelve states achieved wind penetration levels of 20% or higher. Within independent system operators (ISOs) and other regions, wind electricity shares (expressed as a percentage of electricity demand) were 37.1% in SPP, 24.1% in ERCOT, 13.6% in MISO, 12.5% in the non-ISO West, and 8.5% in California Independent System Operator (CAISO), with lower shares in PJM Interconnection (PJM), ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and the non-ISO Southeast.
- **Hybrid wind plants that pair wind with storage and other resources saw growth in 2023, with three new projects completed.** There were 46 hybrid wind power plants in operation at the end of 2023, representing 4.1 GW of wind and 1.1 GW of co-located generation or storage assets. The most common wind hybrid project combines wind and storage technology, where 3 GW of wind has been paired with 0.5 GW of battery storage. While the average storage duration of these projects is 1.1 hours, more-recent projects have longer storage durations, suggesting a movement towards energy shifting, rather than ancillary service, applications. In contrast to wind hybrids, solar hybrids continue to expand rapidly with 62 new PV+storage projects coming online in 2023.
- **A record-high 366 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace**. At the end of 2023, there were 366 GW of wind seeking transmission interconnection, including 120 GW of offshore wind and 49 GW of hybrid projects (in the latter case, mostly wind paired with storage). The non-ISO West, NYISO, CAISO, and PJM had the greatest quantity of wind in their queues at the end of 2023. In 2023, 107 GW of wind capacity entered interconnection queues, 11% of which was for offshore wind plants. Storage and solar interconnection requests have increased rapidly in recent years, often pairing solar with storage. Overall, wind represented 14% of all active capacity in the queues at the end of 2023, compared to 42% for solar, 40% for storage, and 3% for natural gas.

Industry Trends

- **Four turbine manufacturers, led by GE Vernova, supplied all the U.S. utility-scale wind power capacity installed in 2023.** In 2023, GE Vernova captured 58% of the market for turbine installations, followed by Vestas with 30%, Nordex with 9%, and Siemens-Gamesa Renewable Energy (SGRE) with 4%.[3]
- **The Inflation Reduction Act has created renewed optimism about supply-chain expansion.** The number of land-based wind turbine towers and nacelles (which sit on top of the tower and house the gearbox and generator) that can manufactured domestically has held steady or increased over the last several years. At the end of 2023, domestic capacity was nearly 15 GW per year for nacelle assembly and over 12 GW per year for tower manufacturing. Domestic blade manufacturing capability, on the other hand, declined precipitously after 2020, but with a slight rebound in 2023 to over 4 GW per year. The Inflation Reduction Act holds promise for fueling supply-chain expansion in the years ahead: fifteen new, re-opened, or expanded manufacturing facilities have been announced since IRA to serve the land-based wind market, with more than 3,200 expected new jobs. As for turbine manufacturer profitability, there were signs of a turnaround in 2023, with improved profitability (or reduced losses) for Vestas, GE Vernova, and Nordex.
- **The U.S. wind industry continues to depend on imports, though these have fallen to their lowest level in a decade.** Wind-related imports decreased to $1.7 billion in 2023 from $2.3 billion in 2022, mirroring the decrease in annual wind capacity additions. Almost 70% of all wind-specific imports that

[3] Numerical values presented here and elsewhere may not add to 100%, due to rounding.

are tracked through trade codes came from Mexico, Germany, Spain, and India, with the remaining imports mostly from Canada and various countries in Europe and Asia.

- **Independent power producers own most wind assets built in 2023, extending historical trends.** Independent power producers (IPPs) own 90% of the new wind capacity installed in the United States in 2023, with the remaining assets (10%) owned by investor-owned utilities.
- **Non-utility buyers entered more contracts to purchase wind than did utilities in 2023.** Direct retail purchasers of wind—including corporate offtakers—buy electricity from at least 48% of the new wind capacity installed in 2023. This exceeds the share purchased by electric utilities, who either own or buy electricity from wind projects that, in total, represent 29% of the new capacity installed in 2023. Merchant/quasi-merchant projects and power marketers make up at least another 9% and 3%, respectively, while the remainder (11%) is presently undisclosed.

Technology Trends

- **Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term.** To optimize project cost and performance, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed land-based wind turbines in the United States in 2023 was 3.4 MW, up 5% from the previous year and 375% since 1998–1999. The average rotor diameter of newly installed turbines was 133.8 meters, a 2% increase over 2022 and 178% over 1998–1999, while the average hub height was 103.4 meters, up 5% from 2022 and 83% since 1998–1999.
- **Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has moderated in recent years.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average "specific power" [4] (in W/m^2), from 393 W/m^2 among projects installed in 1998–1999 to 237 W/m^2 among projects installed in 2023—though specific power has modestly increased over the last four years. Turbines with low specific power ratings were originally designed for lower wind speed sites.
- **Wind turbines were deployed in lower wind-speed sites in 2023 than in recent years.** Wind turbines installed in 2023 were located in sites with an average estimated long-term wind speed of 7.9 meters per second at a height of 100 meters above the ground—the lowest site-average wind speed since 2012. Federal Aviation Administration (FAA) and industry data on projects that are either under construction or in development suggest that the sites likely to be built out over the next few years will, on average, have consistent or lower average wind speeds. Increasing hub heights will help to partially offset this trend, however, enabling turbines to access higher wind speeds than otherwise possible with shorter towers.
- **Low-specific-power turbines are deployed on a widespread basis throughout the country; taller towers are seeing increased use in a wider variety of sites.** Low specific power turbines continue to be deployed at both lower and higher wind speed sites and across all regions. The tallest towers (i.e., those above 110 meters) are found in greater relative frequency in the Midwest and Northeastern regions.
- **Wind projects planned for the near future are poised to continue the trend of ever-taller turbines.** The average "tip height" (from ground to blade tip extended directly overhead) among projects that came online in 2023 is 170 meters. FAA data suggest that future land-based projects will deploy even taller turbines. Among "proposed" turbines in the permitting process, the average tip height reaches 206 meters.
- **In 2023, seven wind projects were partially repowered, all of which now feature significantly larger rotors and lower specific power ratings.** Partially repowered projects in 2023 totaled 630 MW prior to repowering (640 MW after), a substantial decrease from the 1.7 GW of projects partially repowered in

[4] A wind turbine's specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

2022. Of the changes made to the turbines, larger rotors dominated, reducing specific power from 325 to 213 W/m^2. The primary motivations for partial repowering have been to re-qualify for the PTC, while at the same time increasing energy production and extending the useful life of the projects.

Performance Trends

- **The average capacity factor in 2023 was 33.5% on a fleet-wide basis and 38.2% among wind plants built in 2022.** The 38.2% capacity factor for land-based projects was higher than for projects built in 2021 but consistent with averages for projects built over the last decade. Cumulative, fleet-wide performance has tended to increase over time, growing from under 27% in 1999 to 36% in 2022. However, 2023 was a low wind year nationally, driving down fleet-wide capacity factors in 2023 to 33.5%.
- **State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country.** Based on projects built from 2017 to 2022, average capacity factors in 2023 were highest in central states and lower closer to the coasts. Not surprisingly, the relative state and regional capacity factors are roughly consistent with the relative quality of the wind resource in each region.
- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term**. The decline in specific power over the last two decades has been a major contributor to higher capacity factors but has been offset in part by a tendency toward building projects at sites with lower annual average wind speeds. As a result, average capacity factors have been relatively stable among projects built over the last ten years.
- **Wind power curtailment in 2023 varied by region, averaging 4.6% across seven ISOs**. Across all ISOs, wind energy curtailment in 2023 stood at 4.6%, a decline from 2022 but higher than a decade ago. This average masks variation across regions (and projects): SPP (8.3%), ERCOT (4.2%), NYISO (3.3%), and MISO (3.2%) experienced the highest rates of wind curtailment in 2023, while the other three ISOs were each at less than 2%.
- **2023 was a low wind resource year across most of the country.** The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation impacts project performance from year to year. In 2023, the national wind index stood at 0.95, its lowest level since 2005, as most regions experienced a below-average wind year.
- **Wind project capacity factors decline as projects age.** Capacity factor data suggest performance decline with project age. The decline is present in both older and newer projects in the sample. By year 20, the median wind project has a capacity factor that is roughly 70% that of year 2.

Cost Trends

- **Wind turbine prices modestly declined in 2023, averaging roughly $1,000/kW.** Wind turbine prices for land-based projects declined by more than 50% between 2008 and 2020. Supply-chain pressures and elevated commodity prices led to increased turbine prices from 2020 to 2022—trends that began to moderate in 2023, with prices flat or somewhat lower than in 2022. Data indicates that average pricing over the last year ranges from $900/kW to $1,100/kW.[5]
- **Despite recent fluctuations in turbine prices, average reported installed project costs have held surprisingly steady since 2018**. The average installed costs of land-based wind projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of that decade before peaking in 2009–2010.

[5] All cost figures presented in the report are denominated in real 2023 dollars.

Project-level costs have since declined back to levels seen in the early 2000s—and, since 2018, have largely held steady at ~$1,700/MW on a capacity-weighted average basis.

- **Recent installed costs differ by region, with SPP and ERCOT featuring the lowest costs.** The lowest-cost projects installed in 2022 and 2023 have been in SPP (averaging $1,320/kW) and ERCOT (averaging $1370/kW). Higher average costs are observed in MISO, the non-ISO West, and PJM.
- **Installed costs (per megawatt) generally decline with project size, and are lowest for projects over 200 MW.** Installed project costs exhibit economies of scale, with an especially apparent drop in average costs for the largest (> 200 MW) projects in the sample.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data, projects installed over the last decade and a half have, on average, incurred lower operations and maintenance (O&M) costs than the oldest projects in the data sample.

Power Sales Price and Levelized Cost Trends

- **Wind power purchase agreement prices have drifted higher since about 2018, with a recent range from below $20/MWh to more than $40/MWh.** The combination of declining capital and operating costs and improved performance drove land-based wind PPA prices to all-time lows through 2018, but prices have since increased—in part due to supply-chain and other inflationary pressures. Though our sample size in the last few years has been small, pricing in 2021 and 2022 appears to have averaged around $25/MWh in the Central and West regions of the country, with higher prices in the East (~$45/MWh).
- **LevelTen Energy's PPA price indices confirm rising PPA prices and regional variation.** In contrast to the PPAs summarized above, which principally involve utility purchasers, the company LevelTen Energy provides an index of PPA offers made to large, end-use customers. These data also show that prices have risen over the last couple of years and vary by ISO. Among regions reporting data, CAISO features the highest pricing (~$65/MWh in the fourth quarter of 2023 once converted to levelized 2023-dollar terms); the lowest prices are found in SPP and ERCOT (~$35/MWh in 2023 dollars).
- **Among a sample of projects built in 2023, the (unsubsidized) average levelized cost of wind energy is estimated to be $49/MWh.** Trends in the levelized cost of energy (LCOE) of land-based wind projects follow PPA trends, at least over the long term. Wind's LCOE decreased from 1998 to 2005, rose through 2008-2011, declined through 2018, but has then held steady or increased—to $49/MWh among a sample 2023 projects. The rise in LCOE in 2023 is due, in part, to a higher cost of capital and to a decrease in average capacity factors. As more data become available, the average LCOE among recent wind plants could be revised.
- **Levelized costs vary by region, with the lowest costs in SPP and ERCOT**. The lowest average LCOEs for projects built in 2022 and 2023 are found in SPP ($37/MWh on average) and ERCOT ($42/MWh), with PJM, MISO, and the non-ISO West averaging around $47–49/MWh.

Cost and Value Comparisons

- **Despite relatively low PPA prices, wind faces competition from solar and gas.** The once-wide gap between land-based wind and solar PPA prices has narrowed, as solar prices have fallen more rapidly over the last decade. With the support of federal tax incentives, both wind and solar PPA prices are on par with or below the projected cost of burning natural gas in gas-fired combined cycle units.
- **The grid-system market value of wind declined in 2023 across all regions and was often lower than recent wind PPA prices.** Average land-based wind PPA prices tended to well exceed the wholesale market value of wind from 2008 to 2012. With continued declines in PPA prices, however, those prices connected with the market value of wind in 2013 and have remained in competitive territory in subsequent years. With the increase in natural gas and electricity prices, 2022 wind market values rose to

levels last seen in 2014 in several regions and were higher than recent PPA prices in many locations. However, those high market values for wind were temporary, with 2023 seeing a steep decline in natural gas prices and wind's market value across all ISO regions.

- **The grid-system market value of wind in 2023 varied strongly by project location, from an average of \$13/MWh in SPP to \$60/MWh in CAISO.** Regionally, wind market value in 2023 was highest in CAISO (\$60/MWh) and ISO-NE (\$36/MWh). PJM (\$25/MWh), NYISO (\$23/MWh), and ERCOT (\$23/MWh) were the next highest markets. The average market value of wind was the lowest in SPP (\$13/MWh) and MISO (\$17/MWh). The market value across all wind projects located in ISOs spanned \$7/MWh to \$52/MWh in 2023 (10^{th}–90^{th} percentile range). Within a region, transmission congestion can noticeably reduce the grid value of wind plants.

- **The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment.** The regions with the highest wind penetrations (SPP at 37%, ERCOT at 24%, and MISO at 14%) have generally experienced the largest reduction in wind's value relative to average wholesale prices. In 2023, wind's value was roughly 40%, 40%, 50%, and 60%, lower than average wholesale prices in NYISO, MISO, ERCOT, and SPP, respectively; but was only roughly 10% lower in ISO-NE and CAISO and 20% lower in PJM. These value reductions were primarily caused by a combination of transmission congestion and hourly wind generation that was negatively correlated with wholesale prices. Curtailment had only a minimal impact.

- **The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind.** Wind reduces emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide, providing public health and climate benefits. Nationally and considering nearly all wind plants, these health and climate benefits can be quantified in monetary terms, averaging \$162 per MWh of wind in 2023. Combined, the national average climate, health, and grid-system value of wind (\$183/MWh) sums to more than three times the average LCOE of plants built in 2023.

Future Outlook

- **Energy analysts project growing wind deployment, spurred by incentives in the Inflation Reduction Act.** Expected total capacity additions, inclusive of land-based and offshore wind, range from 7.3 GW to 9.9 GW in 2024. Expected additions then increase, supported by expanded incentives in the Inflation Reduction Act as well as anticipated growth in offshore wind. In 2028, expected total additions range from 14.5 GW to 24.8GW. The majority of the expected additions over this 5-year period and in 2028 come from land-based wind, with offshore wind averaging 11% of the total. Despite this anticipated growth, headwinds remain: inflation, higher interest rates, limited transmission infrastructure, interconnection costs and timeframes, siting and permitting challenges, and competition from solar may dampen growth.

- **Longer term, the prospects for wind energy will be influenced by the Inflation Reduction Act and by the sector's ability to continue to improve its economic position.** The prospects for wind energy in the longer term will be influenced by the implementation of the Inflation Reduction Act, which not only provides extensions and expansions of deployment-oriented tax credits but also new incentives for the buildout of domestic supply chains. Also influencing deployment will be the sector's ability to continue to improve its economic position even in the face of challenging competition from other generation resources, such as solar and natural gas. Growing electricity loads may further motivate additional wind power deployment. Finally, changing macroeconomic conditions, corporate demand for clean energy, and state-level policies will also continue to impact wind power deployment, as will the buildout of transmission infrastructure, resolution of siting, permitting and interconnection constraints, and the future uncertain cost of natural gas.

Land-Based Wind Market Report: 2024 Edition

EXECUTIVE SUMMARY

August 2024

Cover details: Sunrise at King Plains Wind Farm in Garber, Oklahoma. *Photo by Bryan Bechtold, NREL*

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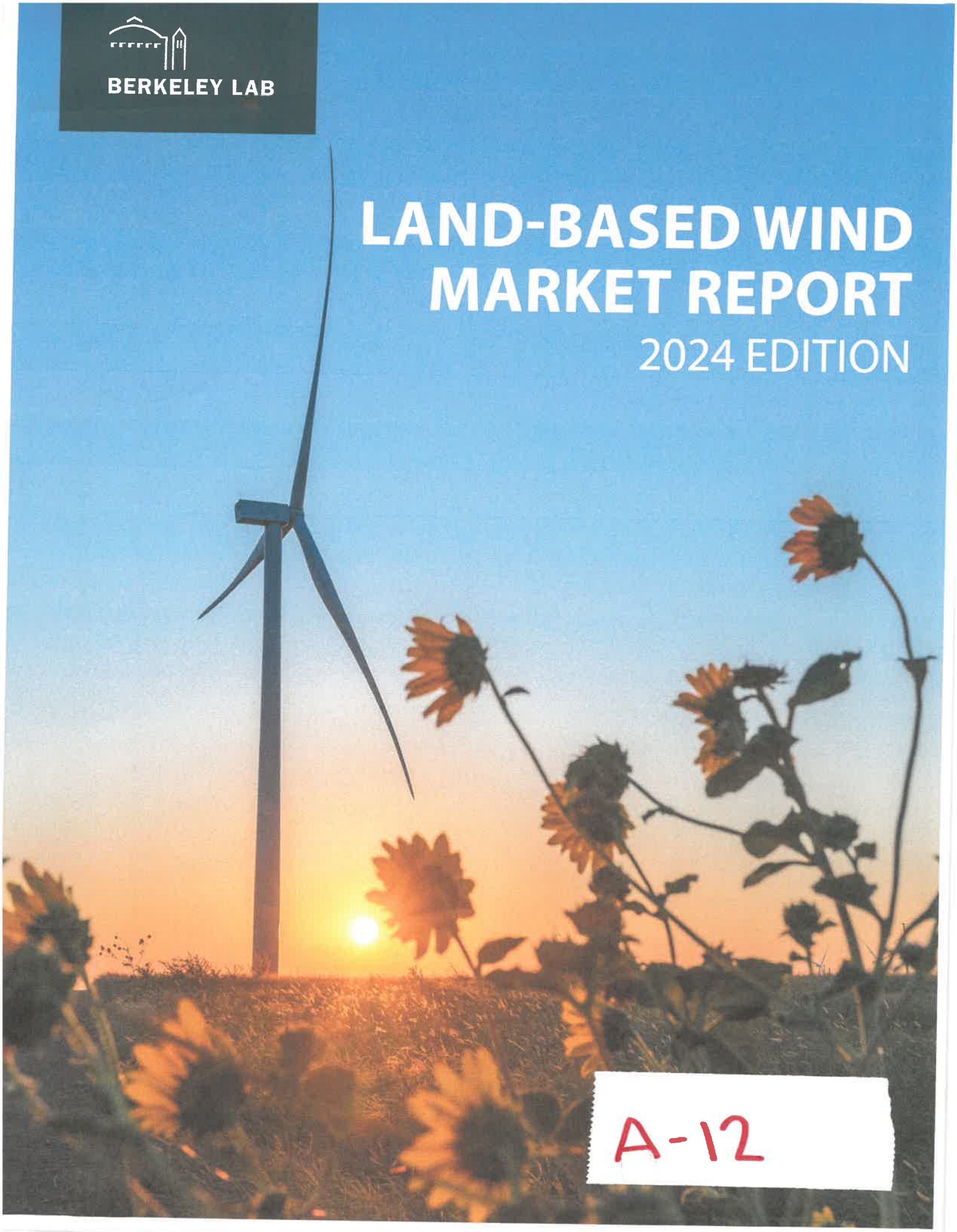
LAND-BASED WIND MARKET REPORT

2024 EDITION



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Preparation and Authorship

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List of Acronyms

ACP	American Clean Power Association
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COD	commercial operation date
CCA	community choice aggregator
CREZ	competitive renewable energy zones
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
HTS	Harmonized Tariff Schedule
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
m^2	square meter
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PJM	PJM Interconnection

POU	Publicly-owned utility
PPA	power purchase agreement
PTC	production tax credit
PV	photovoltaics
REC	renewable energy certificate
RPS	renewables portfolio standard
RTO	regional transmission organization
SGRE	Siemens Gamesa Renewable Energy
SPP	Southwest Power Pool
W	watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

Wind power additions in the United States totaled 6.5 gigawatts (GW) of capacity in 2023.[1] Wind power growth has historically been supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as numerous state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. Nonetheless, 2023 was a slow year in terms of new wind deployment, the lowest since 2014. Elevated interest rates played a role in slowing deployment, as did interconnection and siting challenges.

Passage of the Inflation Reduction Act (IRA) promises new market dynamics for wind power deployment and supply chain investments in the years ahead. IRA contains a long-term extension of the PTC at full value (assuming that wage and apprenticeship standards are met) along with opportunities for wind plants to earn two 10 percent bonus credits that add to the PTC for meeting domestic content requirements and for being in energy communities. IRA also includes new production-based and investment-based tax credits to support the build-out of domestic clean energy manufacturing and supply chains. Though it is too early to see the full impacts of IRA in historical data, IRA has increased analyst forecasts for future wind power capacity additions and has motivated many wind industry supply-chain announcements.

Key findings from this year's *Land-Based Wind Market Report*—which primarily focuses on land-based, utility-scale wind—are summarized below. Note that the sections on "Installation Trends," "Industry Trends," and "Future Outlook" often contain combined data inclusive of both offshore and land-based wind. Other sections exclusively focus on land-based wind.

Installation Trends

- **The U.S. added 6.5 GW of wind power capacity in 2023, totaling $10.8 billion of investment.** The newly installed projects in 2023 were all land-based; no offshore projects were commissioned in 2023. Development was concentrated in the Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP).[2] Cumulative wind capacity grew to 150 GW. In addition, 0.6 GW of existing wind plants were partially repowered in 2023, mostly by upgrading rotors (blades) and nacelle components like gearboxes and generators.
- **Wind power's contribution to total U.S. electric-power capacity additions in 2023 fell to 12%, the lowest level since 2013.** Wind power constituted 12% of all generation and storage capacity additions in 2023, behind solar (52%), natural gas (21%), and storage (13%). Over the last decade, wind represented 26% of total capacity additions, and a larger fraction of new capacity in SPP (86%), MISO (46%), ERCOT (44%), and the non-ISO West (29%).
- **Globally, the United States again ranked a distant second in annual wind capacity and remained well behind the market leaders in wind energy penetration**. Global wind additions reached a record 117 GW in 2023, yielding a cumulative 1,021 GW. The United States remained the second-leading market in terms of annual and cumulative capacity, well behind China. Many countries have achieved high wind electricity shares, with wind supplying 57% of Denmark's total electricity generation in 2023 and more than 20% in ten other countries. In the United States, wind supplied 10% of total generation.
- **Texas once again installed the most wind capacity of any state in 2023 (1,323 MW), followed by Illinois (928 MW); twelve states exceeded 20% wind energy penetration.** Texas also remained the

[1] Note that this report seeks to align with American Clean Power (ACP) for annual wind capacity additions and project-level specifics, where possible. Differences in reporting exist between ACP and the Energy Information Administration.
[2] The nine regions most used in this report are the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO), and the non-ISO West and Southeast.

leader on a cumulative capacity basis, with more than 41 GW. Notably, the wind capacity installed in Iowa supplied 59% of all in-state electricity generation in 2023; twelve states achieved wind penetration levels of 20% or higher. Within independent system operators (ISOs) and other regions, wind electricity shares (expressed as a percentage of electricity demand) were 37.1% in SPP, 24.1% in ERCOT, 13.6% in MISO, 12.5% in the non-ISO West, and 8.5% in California Independent System Operator (CAISO), with lower shares in PJM Interconnection (PJM), ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and the non-ISO Southeast.

- **Hybrid wind plants that pair wind with storage and other resources saw growth in 2023, with three new projects completed.** There were 46 hybrid wind power plants in operation at the end of 2023, representing 4.1 GW of wind and 1.1 GW of co-located generation or storage assets. The most common wind hybrid project combines wind and storage technology, where 3 GW of wind has been paired with 0.5 GW of battery storage. While the average storage duration of these projects is 1.1 hours, more-recent projects have longer storage durations, suggesting a movement towards energy shifting, rather than ancillary service, applications. In contrast to wind hybrids, solar hybrids continue to expand rapidly with 62 new PV+storage projects coming online in 2023.
- **A record-high 366 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace.** At the end of 2023, there were 366 GW of wind seeking transmission interconnection, including 120 GW of offshore wind and 49 GW of hybrid projects (in the latter case, mostly wind paired with storage). The non-ISO West, NYISO, CAISO, and PJM had the greatest quantity of wind in their queues at the end of 2023. In 2023, 107 GW of wind capacity entered interconnection queues, 11% of which was for offshore wind plants. Storage and solar interconnection requests have increased rapidly in recent years, often pairing solar with storage. Overall, wind represented 14% of all active capacity in the queues at the end of 2023, compared to 42% for solar, 40% for storage, and 3% for natural gas.

Industry Trends

- **Four turbine manufacturers, led by GE Vernova, supplied all the U.S. utility-scale wind power capacity installed in 2023.** In 2023, GE Vernova captured 58% of the market for turbine installations, followed by Vestas with 30%, Nordex with 9%, and Siemens-Gamesa Renewable Energy (SGRE) with 4%.[3]
- **The Inflation Reduction Act has created renewed optimism about supply-chain expansion.** The number of land-based wind turbine towers and nacelles (which sit on top of the tower and house the gearbox and generator) that can manufactured domestically has held steady or increased over the last several years. At the end of 2023, domestic capacity was nearly 15 GW per year for nacelle assembly and over 12 GW per year for tower manufacturing. Domestic blade manufacturing capability, on the other hand, declined precipitously after 2020, but with a slight rebound in 2023 to over 4 GW per year. The Inflation Reduction Act holds promise for fueling supply-chain expansion in the years ahead: fifteen new, re-opened, or expanded manufacturing facilities have been announced since IRA to serve the land-based wind market, with more than 3,200 expected new jobs. As for turbine manufacturer profitability, there were signs of a turnaround in 2023, with improved profitability (or reduced losses) for Vestas, GE Vernova, and Nordex.
- **The U.S. wind industry continues to depend on imports, though these have fallen to their lowest level in a decade.** Wind-related imports decreased to $1.7 billion in 2023 from $2.3 billion in 2022, mirroring the decrease in annual wind capacity additions. Almost 70% of all wind-specific imports that are tracked through trade codes came from Mexico, Germany, Spain, and India, with the remaining imports mostly from Canada and various countries in Europe and Asia.

[3] Numerical values presented here and elsewhere may not add to 100%, due to rounding.

- **Independent power producers own most wind assets built in 2023, extending historical trends.** Independent power producers (IPPs) own 90% of the new wind capacity installed in the United States in 2023, with the remaining assets (10%) owned by investor-owned utilities.
- **Non-utility buyers entered more contracts to purchase wind than did utilities in 2023.** Direct retail purchasers of wind—including corporate offtakers—buy electricity from at least 48% of the new wind capacity installed in 2023. This exceeds the share purchased by electric utilities, who either own or buy electricity from wind projects that, in total, represent 29% of the new capacity installed in 2023. Merchant/quasi-merchant projects and power marketers make up at least another 9% and 3%, respectively, while the remainder (11%) is presently undisclosed.

Technology Trends

- **Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term.** To optimize project cost and performance, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed land-based wind turbines in the United States in 2023 was 3.4 MW, up 5% from the previous year and 375% since 1998–1999. The average rotor diameter of newly installed turbines was 133.8 meters, a 2% increase over 2022 and 178% over 1998–1999, while the average hub height was 103.4 meters, up 5% from 2022 and 83% since 1998–1999.
- **Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has moderated in recent years.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average "specific power" [4] (in W/m^2), from 393 W/m^2 among projects installed in 1998–1999 to 237 W/m^2 among projects installed in 2023—though specific power has modestly increased over the last four years. Turbines with low specific power ratings were originally designed for lower wind speed sites.
- **Wind turbines were deployed in lower wind-speed sites in 2023 than in recent years.** Wind turbines installed in 2023 were located in sites with an average estimated long-term wind speed of 7.9 meters per second at a height of 100 meters above the ground—the lowest site-average wind speed since 2012. Federal Aviation Administration (FAA) and industry data on projects that are either under construction or in development suggest that the sites likely to be built out over the next few years will, on average, have consistent or lower average wind speeds. Increasing hub heights will help to partially offset this trend, however, enabling turbines to access higher wind speeds than otherwise possible with shorter towers.
- **Low-specific-power turbines are deployed on a widespread basis throughout the country; taller towers are seeing increased use in a wider variety of sites.** Low specific power turbines continue to be deployed at both lower and higher wind speed sites and across all regions. The tallest towers (i.e., those above 110 meters) are found in greater relative frequency in the Midwest and Northeastern regions.
- **Wind projects planned for the near future are poised to continue the trend of ever-taller turbines.** The average "tip height" (from ground to blade tip extended directly overhead) among projects that came online in 2023 is 170 meters. FAA data suggest that future land-based projects will deploy even taller turbines. Among "proposed" turbines in the permitting process, the average tip height reaches 206 meters.
- **In 2023, seven wind projects were partially repowered, all of which now feature significantly larger rotors and lower specific power ratings.** Partially repowered projects in 2023 totaled 630 MW prior to repowering (640 MW after), a substantial decrease from the 1.7 GW of projects partially repowered in 2022. Of the changes made to the turbines, larger rotors dominated, reducing specific power from 325 to

[4] A wind turbine's specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

213 W/m^2. The primary motivations for partial repowering have been to re-qualify for the PTC, while at the same time increasing energy production and extending the useful life of the projects.

Performance Trends

- **The average capacity factor in 2023 was 33.5% on a fleet-wide basis and 38.2% among wind plants built in 2022.** The 38.2% capacity factor for land-based projects was higher than for projects built in 2021 but consistent with averages for projects built over the last decade. Cumulative, fleet-wide performance has tended to increase over time, growing from under 27% in 1999 to 36% in 2022. However, 2023 was a low wind year nationally, driving down fleet-wide capacity factors in 2023 to 33.5%.
- **State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country.** Based on projects built from 2017 to 2022, average capacity factors in 2023 were highest in central states and lower closer to the coasts. Not surprisingly, the relative state and regional capacity factors are roughly consistent with the relative quality of the wind resource in each region.
- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term**. The decline in specific power over the last two decades has been a major contributor to higher capacity factors but has been offset in part by a tendency toward building projects at sites with lower annual average wind speeds. As a result, average capacity factors have been relatively stable among projects built over the last ten years.
- **Wind power curtailment in 2023 varied by region, averaging 4.6% across seven ISOs**. Across all ISOs, wind energy curtailment in 2023 stood at 4.6%, a decline from 2022 but higher than a decade ago. This average masks variation across regions (and projects): SPP (8.3%), ERCOT (4.2%), NYISO (3.3%), and MISO (3.2%) experienced the highest rates of wind curtailment in 2023, while the other three ISOs were each at less than 2%.
- **2023 was a low wind resource year across most of the country.** The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation impacts project performance from year to year. In 2023, the national wind index stood at 0.95, its lowest level since 2005, as most regions experienced a below-average wind year.
- **Wind project capacity factors decline as projects age.** Capacity factor data suggest performance decline with project age. The decline is present in both older and newer projects in the sample. By year 20, the median wind project has a capacity factor that is roughly 70% that of year 2.

Cost Trends

- **Wind turbine prices modestly declined in 2023, averaging roughly $1,000/kW.** Wind turbine prices for land-based projects declined by more than 50% between 2008 and 2020. Supply-chain pressures and elevated commodity prices led to increased turbine prices from 2020 to 2022—trends that began to moderate in 2023, with prices flat or somewhat lower than in 2022. Data indicates that average pricing over the last year ranges from $900/kW to $1,100/kW.[5]
- **Despite recent fluctuations in turbine prices, average reported installed project costs have held surprisingly steady since 2018**. The average installed costs of land-based wind projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of that decade before peaking in 2009–2010.

[5] All cost figures presented in the report are denominated in real 2023 dollars.

Project-level costs have since declined back to levels seen in the early 2000s—and, since 2018, have largely held steady at ~$1,700/MW on a capacity-weighted average basis.

- **Recent installed costs differ by region, with SPP and ERCOT featuring the lowest costs.** The lowest-cost projects installed in 2022 and 2023 have been in SPP (averaging $1,320/kW) and ERCOT (averaging $1370/kW). Higher average costs are observed in MISO, the non-ISO West, and PJM.
- **Installed costs (per megawatt) generally decline with project size, and are lowest for projects over 200 MW.** Installed project costs exhibit economies of scale, with an especially apparent drop in average costs for the largest (> 200 MW) projects in the sample.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data, projects installed over the last decade and a half have, on average, incurred lower operations and maintenance (O&M) costs than the oldest projects in the data sample.

Power Sales Price and Levelized Cost Trends

- **Wind power purchase agreement prices have drifted higher since about 2018, with a recent range from below $20/MWh to more than $40/MWh.** The combination of declining capital and operating costs and improved performance drove land-based wind PPA prices to all-time lows through 2018, but prices have since increased—in part due to supply-chain and other inflationary pressures. Though our sample size in the last few years has been small, pricing in 2021 and 2022 appears to have averaged around $25/MWh in the Central and West regions of the country, with higher prices in the East (~$45/MWh).
- **LevelTen Energy's PPA price indices confirm rising PPA prices and regional variation.** In contrast to the PPAs summarized above, which principally involve utility purchasers, the company LevelTen Energy provides an index of PPA offers made to large, end-use customers. These data also show that prices have risen over the last couple of years and vary by ISO. Among regions reporting data, CAISO features the highest pricing (~$65/MWh in the fourth quarter of 2023 once converted to levelized 2023-dollar terms); the lowest prices are found in SPP and ERCOT (~$35/MWh in 2023 dollars).
- **Among a sample of projects built in 2023, the (unsubsidized) average levelized cost of wind energy is estimated to be $49/MWh.** Trends in the levelized cost of energy (LCOE) of land-based wind projects follow PPA trends, at least over the long term. Wind's LCOE decreased from 1998 to 2005, rose through 2008-2011, declined through 2018, but has then held steady or increased—to $49/MWh among a sample 2023 projects. The rise in LCOE in 2023 is due, in part, to a higher cost of capital and to a decrease in average capacity factors. As more data become available, the average LCOE among recent wind plants could be revised.
- **Levelized costs vary by region, with the lowest costs in SPP and ERCOT.** The lowest average LCOEs for projects built in 2022 and 2023 are found in SPP ($37/MWh on average) and ERCOT ($42/MWh), with PJM, MISO, and the non-ISO West averaging around $47–49/MWh.

Cost and Value Comparisons

- **Despite relatively low PPA prices, wind faces competition from solar and gas.** The once-wide gap between land-based wind and solar PPA prices has narrowed, as solar prices have fallen more rapidly over the last decade. With the support of federal tax incentives, both wind and solar PPA prices are on par with or below the projected cost of burning natural gas in gas-fired combined cycle units.
- **The grid-system market value of wind declined in 2023 across all regions and was often lower than recent wind PPA prices.** Average land-based wind PPA prices tended to well exceed the wholesale market value of wind from 2008 to 2012. With continued declines in PPA prices, however, those prices connected with the market value of wind in 2013 and have remained in competitive territory in subsequent years. With the increase in natural gas and electricity prices, 2022 wind market values rose to

levels last seen in 2014 in several regions and were higher than recent PPA prices in many locations. However, those high market values for wind were temporary, with 2023 seeing a steep decline in natural gas prices and wind's market value across all ISO regions.

- **The grid-system market value of wind in 2023 varied strongly by project location, from an average of \$13/MWh in SPP to \$60/MWh in CAISO.** Regionally, wind market value in 2023 was highest in CAISO (\$60/MWh) and ISO-NE (\$36/MWh). PJM (\$25/MWh), NYISO (\$23/MWh), and ERCOT (\$23/MWh) were the next highest markets. The average market value of wind was the lowest in SPP (\$13/MWh) and MISO (\$17/MWh). The market value across all wind projects located in ISOs spanned \$7/MWh to \$52/MWh in 2023 (10^{th}–90^{th} percentile range). Within a region, transmission congestion can noticeably reduce the grid value of wind plants.

- **The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment.** The regions with the highest wind penetrations (SPP at 37%, ERCOT at 24%, and MISO at 14%) have generally experienced the largest reduction in wind's value relative to average wholesale prices. In 2023, wind's value was roughly 40%, 40%, 50%, and 60%, lower than average wholesale prices in NYISO, MISO, ERCOT, and SPP, respectively; but was only roughly 10% lower in ISO-NE and CAISO and 20% lower in PJM. These value reductions were primarily caused by a combination of transmission congestion and hourly wind generation that was negatively correlated with wholesale prices. Curtailment had only a minimal impact.

- **The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind.** Wind reduces emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide, providing public health and climate benefits. Nationally and considering nearly all wind plants, these health and climate benefits can be quantified in monetary terms, averaging \$162 per MWh of wind in 2023. Combined, the national average climate, health, and grid-system value of wind (\$183/MWh) sums to more than three times the average LCOE of plants built in 2023.

Future Outlook

- **Energy analysts project growing wind deployment, spurred by incentives in the Inflation Reduction Act.** Expected total capacity additions, inclusive of land-based and offshore wind, range from 7.3 GW to 9.9 GW in 2024. Expected additions then increase, supported by expanded incentives in the Inflation Reduction Act as well as anticipated growth in offshore wind. In 2028, expected total additions range from 14.5 GW to 24.8GW. The majority of the expected additions over this 5-year period and in 2028 come from land-based wind, with offshore wind averaging 11% of the total. Despite this anticipated growth, headwinds remain: inflation, higher interest rates, limited transmission infrastructure, interconnection costs and timeframes, siting and permitting challenges, and competition from solar may dampen growth.

- **Longer term, the prospects for wind energy will be influenced by the Inflation Reduction Act and by the sector's ability to continue to improve its economic position.** The prospects for wind energy in the longer term will be influenced by the implementation of the Inflation Reduction Act, which not only provides extensions and expansions of deployment-oriented tax credits but also new incentives for the buildout of domestic supply chains. Also influencing deployment will be the sector's ability to continue to improve its economic position even in the face of challenging competition from other generation resources, such as solar and natural gas. Growing electricity loads may further motivate additional wind power deployment. Finally, changing macroeconomic conditions, corporate demand for clean energy, and state-level policies will also continue to impact wind power deployment, as will the buildout of transmission infrastructure, resolution of siting, permitting and interconnection constraints, and the future uncertain cost of natural gas.

Table of Contents

Executive Summary vi
1 Introduction 1
2 Installation Trends 4
3 Industry Trends 16
4 Technology Trends 25
5 Performance Trends 34
6 Cost Trends 41
7 Power Sales Price and Levelized Cost Trends 47
8 Cost and Value Comparisons 54
9 Future Outlook 65
References 67
Appendix: Sources of Data Presented in this Report 69

List of Figures

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 100 meters.......2
Figure 2. Annual and cumulative growth in U.S. wind power capacity 4
Figure 3. Relative contribution of generation types and storage to U.S. annual capacity additions....5
Figure 4. Generation and storage capacity additions by region over last ten years..............................6
Figure 5. Wind electricity share in subset of top global wind markets..7
Figure 6. Location of wind power development in the United States...8
Figure 7. Wind (left panel) and combined wind & solar (right panel) generation as a proportion of demand by region 10
Figure 8. Location and capacity of hybrid wind plants in the United States 11
Figure 9. Design characteristics of hybrid power plants operating in the United States, for a subset of configurations 11
Figure 10. Generation capacity in interconnection queues from 2014 to 2023, by resource type .. 12
Figure 11. Wind power capacity in interconnection queues at end of 2023, by region 13
Figure 12. Generation capacity in interconnection queues, including hybrid power plants 14
Figure 13. Hybrid wind power plants in interconnection queues at the end of 2022......................... 15
Figure 14. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2023 16
Figure 15. Location of turbine and component manufacturing facilities.. 17
Figure 16. Domestic wind manufacturing capability vs. U.S. wind power capacity installations 18
Figure 17. Turbine OEM global profitability.. 19
Figure 18. Imports of wind-related equipment that can be tracked with trade codes 20
Figure 19. Summary map of tracked wind-specific imports in 2023: top-10 countries of origin and states of entry.. 21
Figure 20. Wind equipment imports over time, by country: percent of total tracked wind-specific imports.. 21
Figure 20. Origins of U.S. imports of selected wind turbine equipment in 2023................................ 22
Figure 21. Cumulative and 2023 wind power capacity categorized by owner type 23
Figure 22. Cumulative and 2023 wind power capacity categorized by power offtake arrangement24
Figure 23. Average turbine nameplate capacity, hub height, and rotor diameter for land-based wind projects 25
Figure 24. Trends in turbine nameplate capacity, hub height, and rotor diameter............................. 26
Figure 25. Trends in wind turbine specific power 27

Figure 26. Wind resource quality by year of installation at 100 meters and at turbine hub height . 28

Figure 27: Location of low specific power turbine installations: all U.S. wind plants 29

Figure 28: Location of tall tower turbine installations: all U.S. wind plants 30

Figure 29. Total turbine heights proposed in FAA applications, by development status 31

Figure 30. Total turbine heights proposed in FAA applications, by location 31

Figure 31. Annual amount of partially repowered wind power capacity and number of turbines..... 32

Figure 32. Change in average physical specifications of all turbines that were partially repowered in 2023 33

Figure 33. Calendar year 2023 capacity factors by commercial operation date 35

Figure 34. Average wind capacity factor in calendar year 2022 by state 35

Figure 35. 2023 capacity factors and various drivers by commercial operation date 36

Figure 36. Calendar year 2023 capacity factors by wind resource quality and specific power: 2014–2022 projects 37

Figure 37. Wind curtailment and penetration rates by ISO 38

Figure 38. Inter-annual variability in the wind resource by region and nationally 39

Figure 39. Changes in project-level capacity factors as projects age 40

Figure 40. Reported wind turbine transaction prices over time.. 41

Figure 41. Installed wind power project costs over time 42

Figure 42. Installed cost of 2022 and 2023 wind power projects by region 43

Figure 43. Installed wind power project costs by project size: 2022 and 2023 projects.................... 44

Figure 44. Average O&M costs for available data years from 2000 to 2023, by commercial operation date 45

Figure 45. Median annual O&M costs by project age and commercial operation date 46

Figure 46. Levelized wind PPA prices by PPA execution date and region (full sample)...................... 48

Figure 47. Generation-weighted average levelized wind PPA prices by PPA execution date and region 49

Figure 48. LevelTen Energy wind PPA price index by quarter of offer 50

Figure 49. Estimated levelized cost of wind energy by commercial operation date............................ 51

Figure 50. Estimated levelized cost of wind energy, by region 52

Figure 51. Levelized wind and solar PPA prices and levelized gas price projections.......................... 54

Figure 52. Wind PPA prices and natural gas fuel cost projections by calendar year over time......... 55

Figure 53. Regional wholesale market value of wind and average levelized long-term wind PPA

prices over time 57
Figure 54. Regional wholesale market value of wind in 2023, by region 58
Figure 55. Project-level wholesale market value of wind in 2023 59
Figure 56. Trends in wind value factor as wind penetrations increase 60
Figure 57. Impact of transmission congestion, output profile, and curtailment on wind energy market value in 2023 61
Figure 58. Marginal health and climate benefits from all wind generation by region in 2023 62
Figure 59. Marginal health, climate, and grid-value benefits from new wind plants versus LCOE in 2023 63
Figure 60. Wind power capacity additions: historical installations and projected growth 65

List of Tables

Table 1. International Rankings of Total Wind Power Capacity 6
Table 2. U.S. Wind Power Rankings: The Top 20 States 9
Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis. 70

1 Introduction

Wind power additions in the United States totaled 6.5 gigawatts (GW) of capacity in 2023. Wind power growth has historically been supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as numerous state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind additions, yielding low-priced wind energy for utility, corporate, and other power purchasers. Nonetheless, 2023 was a slow year in terms of new wind deployment, the lowest since 2014. Elevated interest rates played a role in slowing deployment, as did interconnection and siting challenges.

Passage of the Inflation Reduction Act (IRA) promises new market dynamics for wind power deployment and supply chain investments in the years ahead (U.S. DOE 2023). IRA contains a long-term extension of the PTC at full value (assuming that wage and apprenticeship standards are met) along with opportunities for wind plants to earn two 10 percent bonus credits that add to the PTC for meeting domestic content requirements and for being located in energy communities.[6] IRA also includes new production-based and investment-based tax credits to support the build-out of domestic clean energy manufacturing and supply chains. Though it is too early to see the full impacts of IRA in historical data, IRA has increased analyst forecasts for future wind power capacity additions and motivated many wind industry supply-chain announcements.

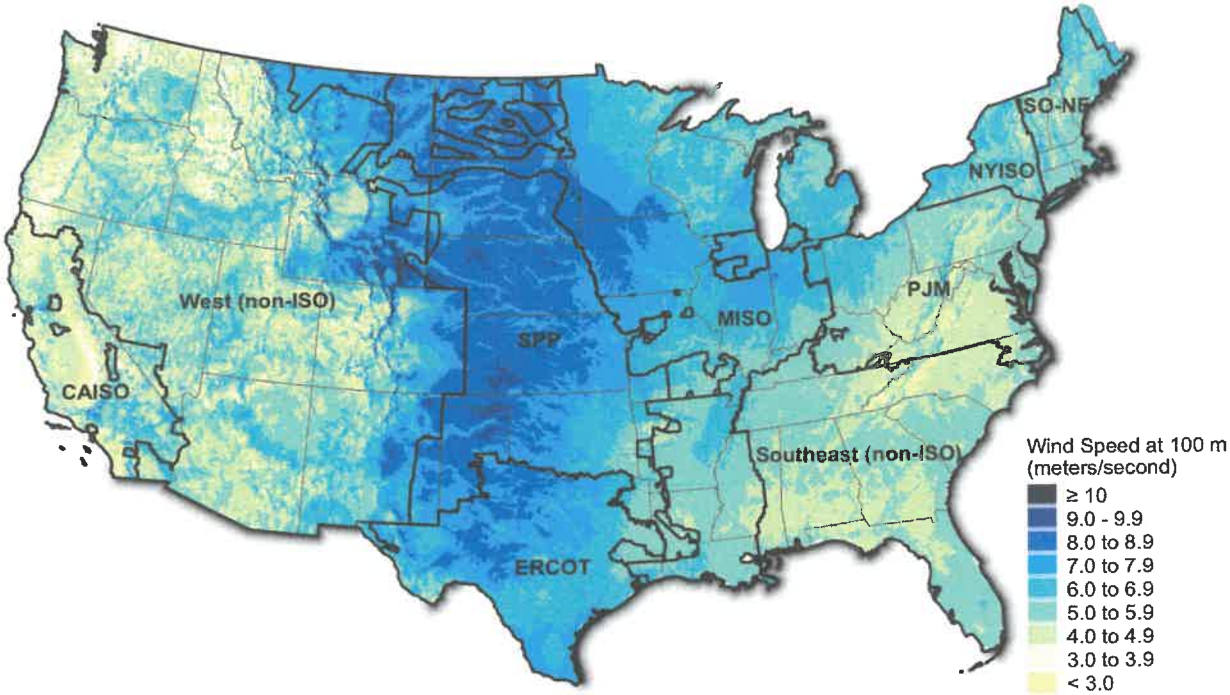
This annual report—now in its eighteenth year—provides an overview of trends in the U.S. wind power market, with a particular focus on land-based wind in the year 2023.

- Chapter 2 begins with an overview of installation-related trends: U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual U.S. states; hybrid projects that couple wind with storage and other sources of generation; and the quantity of proposed wind power capacity in interconnection queues.
- Chapter 3 covers an array of wind industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into the United States; and trends among wind power project owners and power purchasers.
- Chapter 4 summarizes wind turbine technology trends: turbine capacity, hub height, rotor diameter, and specific power, as well as changes in site-average wind speed and recent repowering activity.
- Chapter 5 discusses wind plant performance, focusing on capacity factor trends and drivers over time and regionally but also including data on curtailment, performance degradation as projects age, and inter-annual wind resource variability.
- Chapter 6 highlights wind energy cost drivers and trends, including data on wind turbine prices, installed project costs, and operations and maintenance (O&M) expenses.
- Chapter 7 reviews the prices paid for wind power through power purchase agreements (PPAs) and calculates the levelized cost of wind energy based on the input parameters from earlier chapters.
- Chapter 8 compares the price of wind energy to the value of wind generation in wholesale energy markets, forecasts of future natural gas prices, and solar PPA prices. It also contrasts the levelized cost of wind energy to its societal value—defined narrowly here to include the grid-system value of wind along with its health and climate benefits.

[6] For more on energy communities, see: https://energycommunities.gov/energy-community-tax-credit-bonus/. For additional details on the domestic content bonus and other tax provisions, see: https://www.irs.gov/inflation-reduction-act-of-2022.

- Chapter 9 concludes with a preview of possible near-term market developments based on the findings of other analysts.

Many of these trends vary by state or region, depending in part on the strength of the local wind resource. To that end, Figure 1 superimposes the boundaries of nine regions, seven of which align with organized wholesale power markets (i.e., independent system operators),[7] on a map of average annual U.S. wind speed at 100 meters above the ground. These nine regions are referenced on many occasions throughout this report.



Sources: AWS Truepower, National Renewable Energy Laboratory (NREL)

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 100 meters

This edition of the annual report updates data presented in previous editions while highlighting recent trends and new developments. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[8] The U.S. wind power sector is multifaceted, and includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on *distributed wind power*, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S. Department of Energy (DOE) and authored by Pacific Northwest National Laboratory—the Distributed Wind Market Report.

In Chapters 2, 3, and 9 of this report—where it is sometimes difficult to separate offshore and land-based wind—this report often covers land-based and offshore wind, in combination. Other chapters exclusively focus on land-based wind. A companion study funded by DOE and authored by the National

[7] The seven independent system operators (ISOs) include the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO).

[8] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match the American Clean Power Association's historical methodology. In years prior to 2011, different cut-offs are used to better match ACP's reported capacity numbers and to ensure that older utility-scale projects in California are not excluded from the sample.

Renewable Energy Laboratory, which focuses exclusively on *offshore wind power* is also available—the Offshore Wind Market Report.

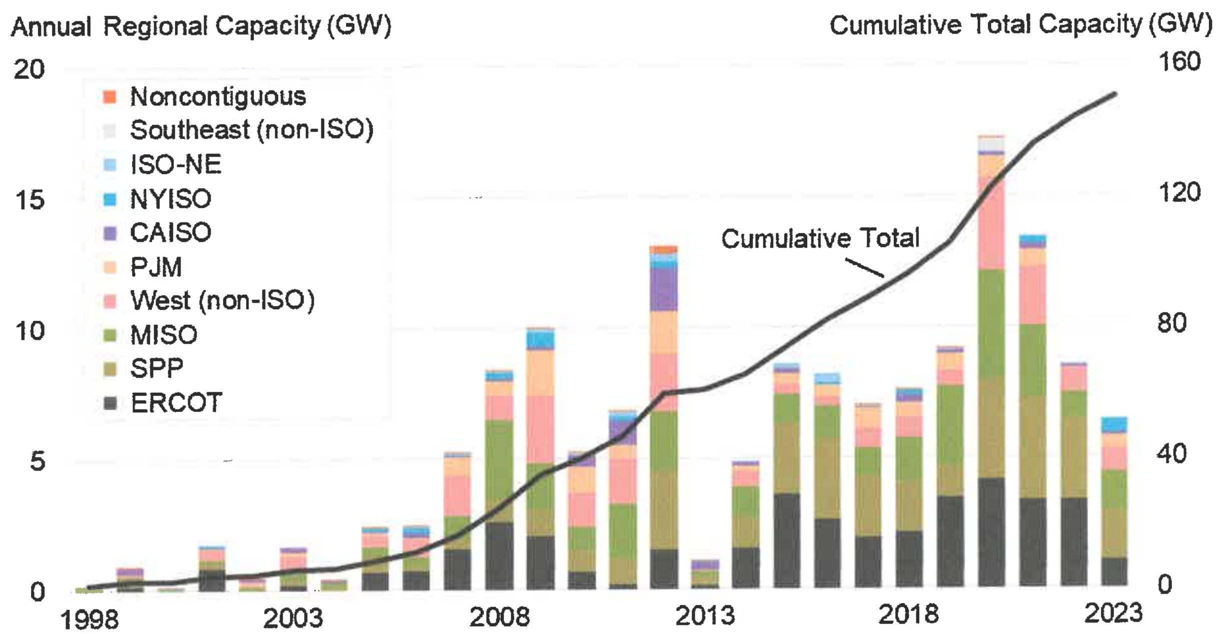
Much of the data included in this report were compiled by DOE's Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Clean Power Association (ACP—along with its predecessor, the American Wind Energy Association). The Appendix provides a summary of the many data sources. In some cases, the data shown represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. Emphasis should therefore be placed on overall trends, rather than on individual data points. Finally, each section of this report primarily focuses on historical and recent data. With some limited exceptions—including the last section of the report—the report does not seek to forecast wind energy trends.

2 Installation Trends

The U.S. added 6.5 GW of wind power capacity in 2023, totaling $10.8 billion of investment

U.S. wind capacity additions totaled 6.5 GW in 2023, bringing cumulative wind capacity to 150 GW at the end of the year (Figure 2).[9] This growth represented $10.8 billion of investment in new wind power plants.[10,11] A full 70% of the new wind capacity installed in 2023 is located in SPP (30%), MISO (23%) and ERCOT (17%), with the remainder mostly in the non-ISO West (14%), NYISO (9%), and PJM (8%). All of the newly installed capacity in 2023 came from land-based wind. Of the 150 GW of total installed wind capacity at the end of 2023, 42 MW is from offshore wind projects located in Rhode Island and Virginia.

In addition, 0.6 GW of existing wind plants were "partially repowered" in 2023.[12] Partial repowering, in which major components of turbines are replaced (most often resulting in increased rotor diameters and upgrades to major nacelle components), provides access to favorable tax incentives, increases energy production with more-advanced technology, and extends project life. See Chapter 4 for more details on partial repowering.



Source: ACP

Figure 2. Annual and cumulative growth in U.S. wind power capacity

These figures depict a slow year in terms of new wind deployment—a steep decline from the high in 2020 and the lowest since 2014. This downward trend was driven in part by the step-down in the federal production tax credit prior to the passage of IRA, and echoed similar boom/bust cycles associated with previous PTC

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[9] These capacity figures include both land-based and offshore wind. When reporting annual capacity additions, this report focuses on *gross* additions, and does not consider partial repowering. The *net* increase in capacity each year can be lower, reflecting turbine decommissioning, or higher, reflecting partial repowering that increases turbine capacity. Full repowering, on the other hand, is considered a new project and so is included in annual additions. Cumulative capacity ('Total' in Figure 2) includes both decommissioning and repowering.

[10] All cost and price data are reported in real 2023 dollars.

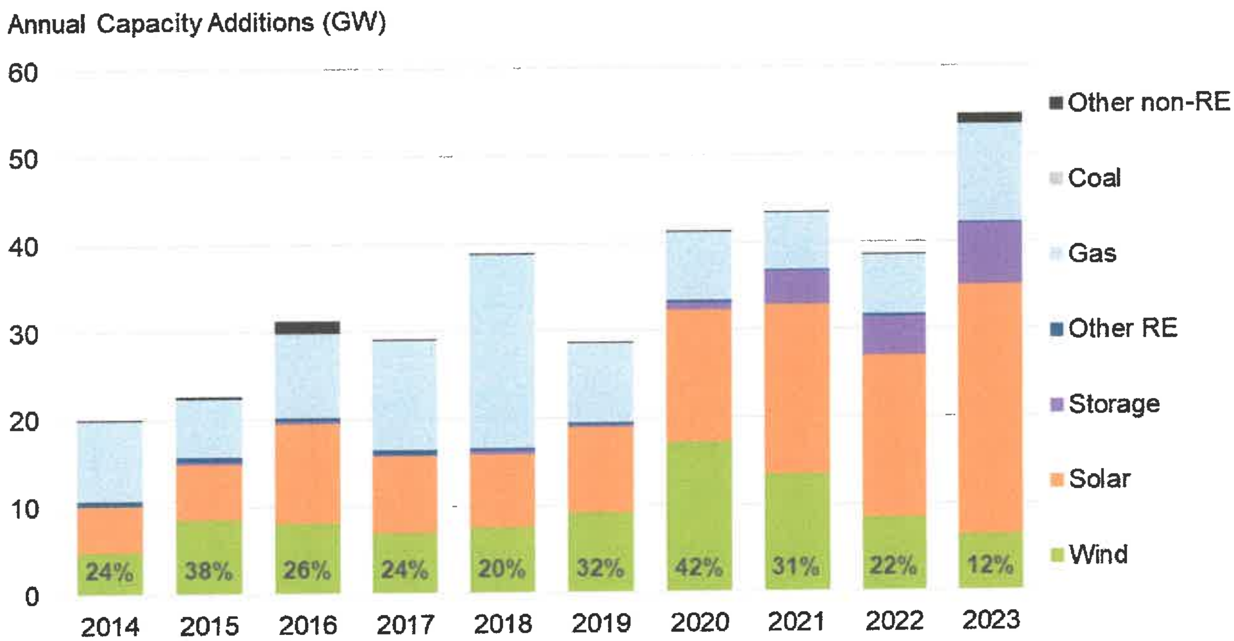
[11] This investment figure is based on an extrapolation of the average project-level capital costs reported later in this report and does not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

[12] Any change in capacity from partial repowering is included in the cumulative data but not the annual data reported in Figure 2.

expiration dates that can be seen in Figure 2 in 2002, 2010, and 2013. The industry also contended with continued headwinds in 2023: high interest rates, interconnection backlogs, limited transmission infrastructure, siting and permitting challenges, and competition with solar. Pushing in the other direction was the continued availability of the PTC, state renewables portfolio standards (RPS), and corporate demand for renewable energy. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind additions, yielding low-priced wind energy for utility, corporate, and other power purchasers even as higher wind turbine prices and interest rates have pushed recent project costs higher.

Wind power's contribution to total U.S. electric-power capacity additions in 2023 fell to 12%, the lowest level since 2013

In 2023, wind power constituted 12% of all U.S. generation and storage capacity additions, behind solar (52%), natural gas (21%), and storage (13%)—the lowest percentage share since 2013 (Figure 3).[13]

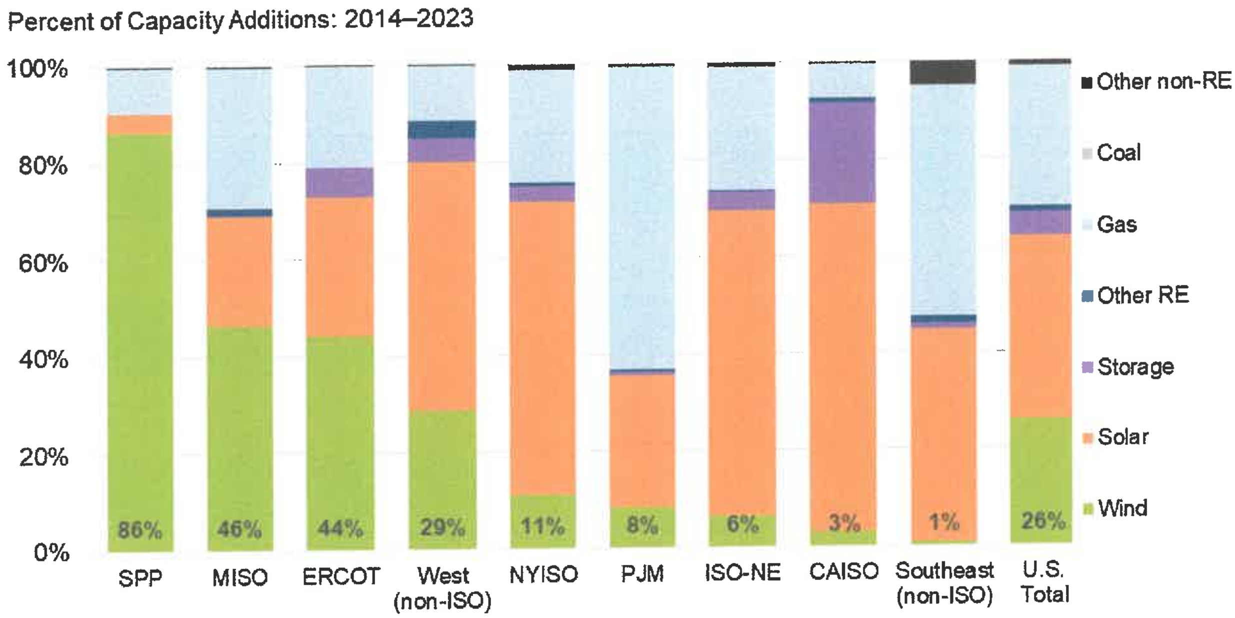


Sources: EIA, ACP

Figure 3. Relative contribution of generation types and storage to U.S. annual capacity additions

Over the last decade, wind power represented 26% of total U.S. generation and storage capacity additions, and an even larger fraction of new capacity in SPP (86%), MISO (46%), ERCOT (44%), and the non-ISO West (29%) (Figure 4; see Figure 1 for regional definitions). Wind power's contribution to capacity growth over the last decade is smaller in NYISO (11%), PJM (8%), ISO-NE (6%), CAISO (3%), and the Southeast (1%).

13 Data presented here are based on gross capacity additions, not considering retirements or partial repowering. For solar, both utility-scale and distributed applications are included. Data include only the 50 U.S. states, not U.S. territories.



**U.S. Total also includes AK and HI, in addition to the regions listed*

Sources: EIA, ACP

Figure 4. Generation and storage capacity additions by region over last ten years

Globally, the United States again ranked a distant second in annual wind capacity and remained well behind the market leaders in wind energy penetration

Global wind additions achieved a record 117 GW in 2023 (including both land-based and offshore wind). With its 6.5 GW representing 5% of new global installed capacity, the United States continued to maintain its second-place position, well behind China (Table 1). Cumulative global wind capacity reached 1,021 GW (crossing the Terawatt mark) (GWEC 2024),[14] with the United States accounting for 15%.

Table 1. International Rankings of Total Wind Power Capacity

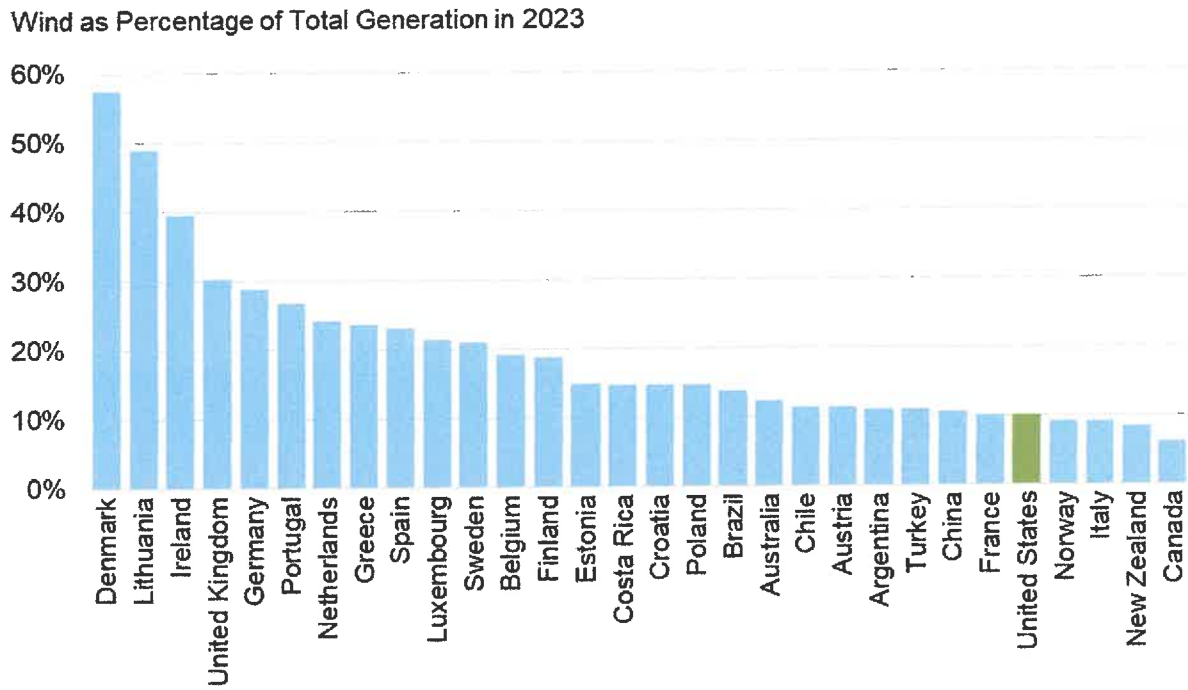
Annual Capacity (2023, GW)	
China	75.7
United States	6.5
Brazil	4.8
Germany	3.8
India	2.8
Netherlands	2.5
Sweden	2.0
France	1.8
Canada	1.7
United Kingdom	1.4
Rest of World	13.8
TOTAL	117

Cumulative Capacity (end of 2023, GW)	
China	441
United States	150
Germany	69
India	45
Spain	31
Brazil	30
United Kingdom	30
France	23
Canada	17
Sweden	16
Rest of World	168
TOTAL	1,021

Sources: GWEC (2024); ACP for U.S.

14 Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2024) but are updated, where necessary, with the U.S. data presented here.

Many countries have achieved higher wind-electricity market shares (i.e., wind generation as a percentage of total generation) than the United States. Figure 5 presents data on a subset of countries. The wind electricity share was highest in Denmark, at 57%, and was over 20% in ten other countries. In the United States, wind supplied about 10% of total electricity generation in 2023.



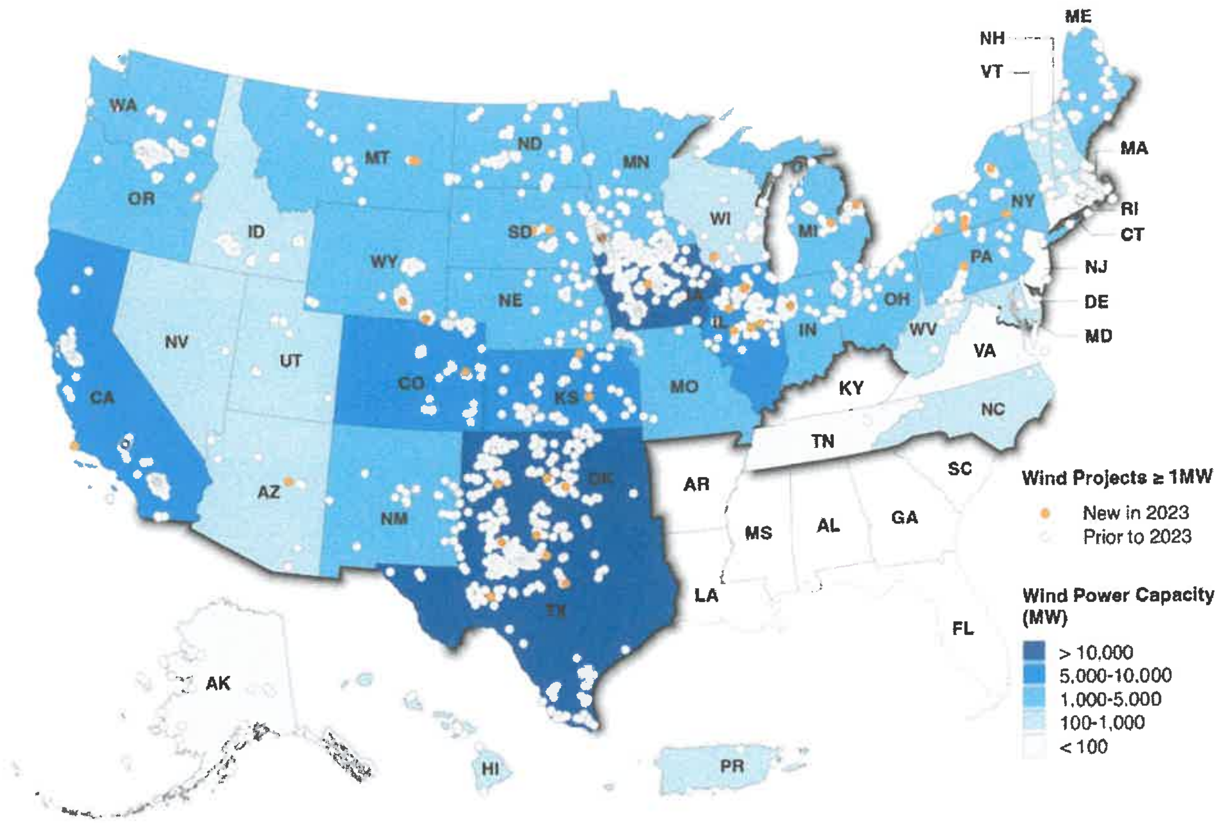
Source: IEA Monthly Electricity Statistics

Figure 5. Wind electricity share in subset of top global wind markets

Texas once again installed the most wind capacity of any state in 2023 (1,323 MW), followed by Illinois (928 MW); twelve states exceeded 20% wind energy penetration

New utility-scale wind turbines were installed in 17 states in 2023. Texas once again installed the most capacity of any state, adding 1,323 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity added in 2023—included Illinois (928 MW), Kansas (843 MW), and New York (557 MW).

On a cumulative basis, Texas remained the clear leader, with more than 41 GW installed at the end of 2023—more than three times as much as the next-highest state (Iowa). Texas has more wind capacity than all but four countries (Table 1). States distantly following Texas in cumulative capacity include Iowa (>13 GW), Oklahoma (>12 GW), Kansas (>9 GW), and Illinois (~8 GW). Twenty-three states had more than 1 GW of wind capacity at the end of 2023, with seven above 5 GW. A total of 43 states host utility-scale turbines.



Sources: ACP, Berkeley Lab

Figure 6. Location of wind power development in the United States

Some states have reached high wind electricity shares. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2023 divided by total in-state electricity generation and by in-state electricity sales in 2023. Electric transmission networks enable most states to both import and export power in real time, and states do so in varying amounts. Denominating in-state wind generation as both a proportion of in-state generation and as a proportion of in-state sales is relevant, but both should be viewed with some caution given varying amounts of imports and exports.

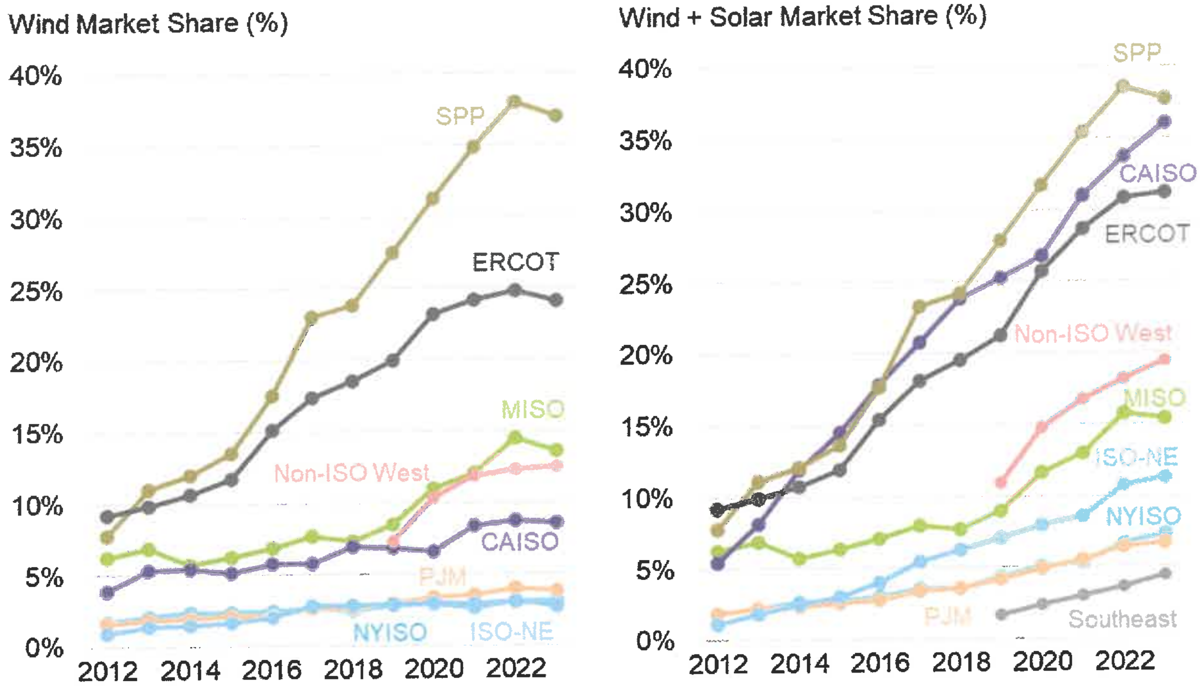
As a fraction of in-state generation, Iowa leads the list, with 59% of electricity generated in the state coming from wind, followed by South Dakota, Kansas, Oklahoma, and New Mexico. As a fraction of in-state sales, Iowa once again leads, with 76% of the electricity sold in the state being met by wind, followed by South Dakota and Kansas. Twelve states achieved wind penetration levels of 20% or higher when expressed as a percentage of generation (thirteen exceed 20% as a percentage of sales).

Table 2. U.S. Wind Power Rankings: The Top 20 States

Installed Capacity (MW)				2023 Wind Generation as a Percentage of:			
Annual (2023)		Cumulative (end of 2023)		In-State Generation		In-State Sales	
Texas	1,323	Texas	41,594	Iowa	59.2%	Iowa	76.4%
Illinois	928	Iowa	13,007	South Dakota	55.3%	South Dakota	69.7%
Kansas	843	Oklahoma	12,624	Kansas	46.2%	Kansas	66.3%
New York	557	Kansas	9,078	Oklahoma	41.9%	North Dakota	54.8%
Oklahoma	402	Illinois	7,968	New Mexico	38.0%	Wyoming	52.8%
South Dakota	399	California	6,195	North Dakota	36.0%	Oklahoma	51.9%
Michigan	337	Colorado	5,394	Nebraska	29.7%	New Mexico	51.3%
Montana	311	Minnesota	4,859	Colorado	27.2%	Nebraska	35.7%
Arizona	239	New Mexico	4,327	Minnesota	25.3%	Colorado	29.5%
Iowa	224	North Dakota	4,302	Texas	22.0%	Montana	28.4%
Indiana	202	Oregon	4,055	Wyoming	20.6%	Texas	24.6%
Colorado	200	Indiana	3,658	Maine	20.5%	Maine	22.1%
Wyoming	134	South Dakota	3,618	Montana	17.6%	Minnesota	21.8%
Minnesota	100	Michigan	3,568	Idaho	14.8%	Oregon	16.9%
California	95	Nebraska	3,519	Vermont	14.6%	Illinois	16.1%
Wisconsin	92	Washington	3,407	Oregon	14.6%	Idaho	9.9%
Pennsylvania	88	Wyoming	3,286	Illinois	12.3%	Washington	9.1%
		New York	2,749	Indiana	10.4%	Indiana	8.9%
		Missouri	2,435	Missouri	10.0%	Missouri	8.7%
		Montana	1,737	Washington	7.5%	Michigan	8.6%
Rest of U.S.	*0*	*Rest of U.S.*	*9,112*	*Rest of U.S.*	*1.7%*	*Rest of U.S.*	*1.5%*
Total	6,474	Total	150,492	Total	10.0%	Total	11.0%

Note: Based on 2023 wind and total generation and retail sales by state from EIA's Electric Power Monthly (2024a).
Sources: ACP, EIA

Given the ability to trade power across state boundaries, wind electricity shares within multi-state regions—for example, based on independent system operators (ISOs)—are also relevant. In 2023, wind-electricity market shares (expressed as a percentage of customer load inclusive of behind-the-meter solar generation) were 37% in SPP, 24.1% in ERCOT, 13.6% in MISO, 12.5% in the non-ISO West, and 8.5% in CAISO, with lower shares in other regions (Figure 7). As also shown in the figure, combined solar and wind shares exceed these levels, especially in CAISO, ISO-NE, ERCOT, and the non-ISO West.



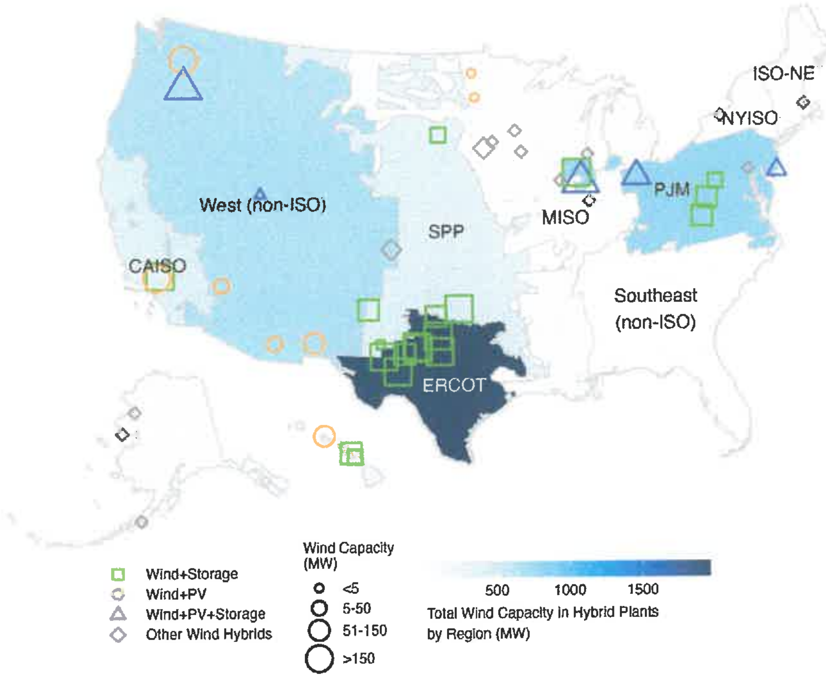
Sources: EIA, Hitachi, MISO, CAISO, SPP, NYISO, PJM, ISO-NE, ERCOT, Berkeley Lab

Figure 7. Wind (left panel) and combined wind & solar (right panel) generation as a proportion of demand by region

Hybrid wind plants that pair wind with storage and other resources saw growth in 2023, with three new projects completed

There were 46 hybrid wind power plants in operation at the end of 2023, representing 4.1 GW of wind and 1.1 GW of co-located assets (storage, PV, or fossil-fueled generators). Some of these represent full hybrids where, for example, wind and storage are co-located and the design, configuration, and operation of the constituent technologies are fully integrated. In other cases, plants are co-located, sharing a point of interconnection, but are designed, configured, and operated more independently (e.g., hybrids that pair wind and gas plants).

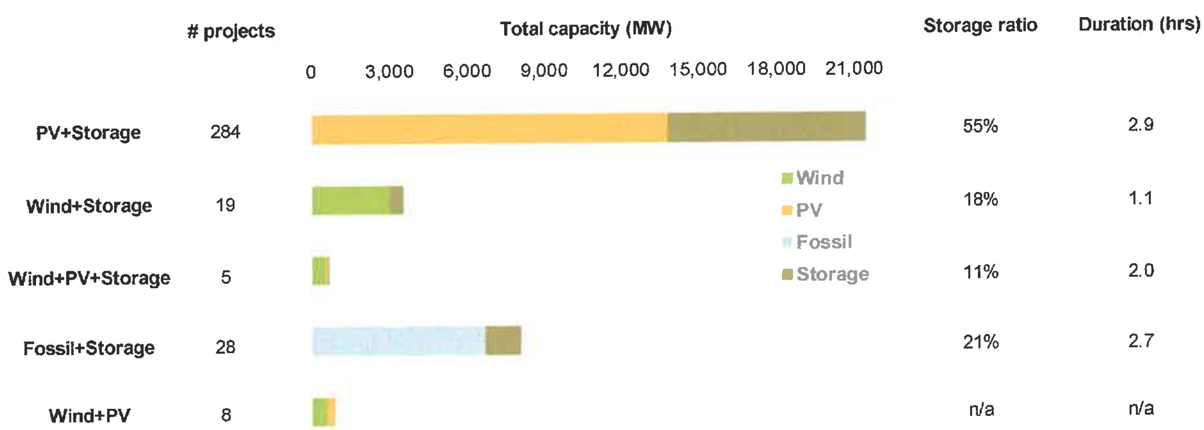
The most common type of wind hybrid project combines wind and storage technology, where 3 GW of wind has been paired with 0.5 GW of battery storage across 19 plants. All three new projects in 2023 combined these two technologies. Other combinations include wind and PV; wind, PV, and storage; wind and gas; and more (Figure 8). The ERCOT region hosts the largest amount of wind capacity in hybrid plants (2 GW), followed by PJM (0.8 GW) and the non-ISO West (0.6 GW). All three new wind hybrids in 2023 were added within ERCOT's footprint. Wind capacity tends to be larger for wind+storage hybrids than for other hybrid configurations.



Sources: EIA-860 2023 Early Release, Berkeley Lab

Figure 8. Location and capacity of hybrid wind plants in the United States

Figure 9 displays design characteristics for a subset of the more-common hybrid plant configurations, including those that do not incorporate wind. Wind+storage hybrids have a 18% storage-to-generator ratio with an average storage duration of just 1.1 hours. More recent projects have longer storage durations, suggesting a movement towards energy shifting, rather than solely ancillary service, applications. Fossil+storage hybrids have similar storage-to-generator ratios (21%) but longer battery durations (2.7 hours). PV+storage hybrids have significantly higher average storage-to-generator ratios (55%) and battery durations (2.9 hours).



Notes: Not included in the figure are many other hybrid projects with other configurations. Storage ratio defined as total storage capacity divided by total generator capacity for a given project type.

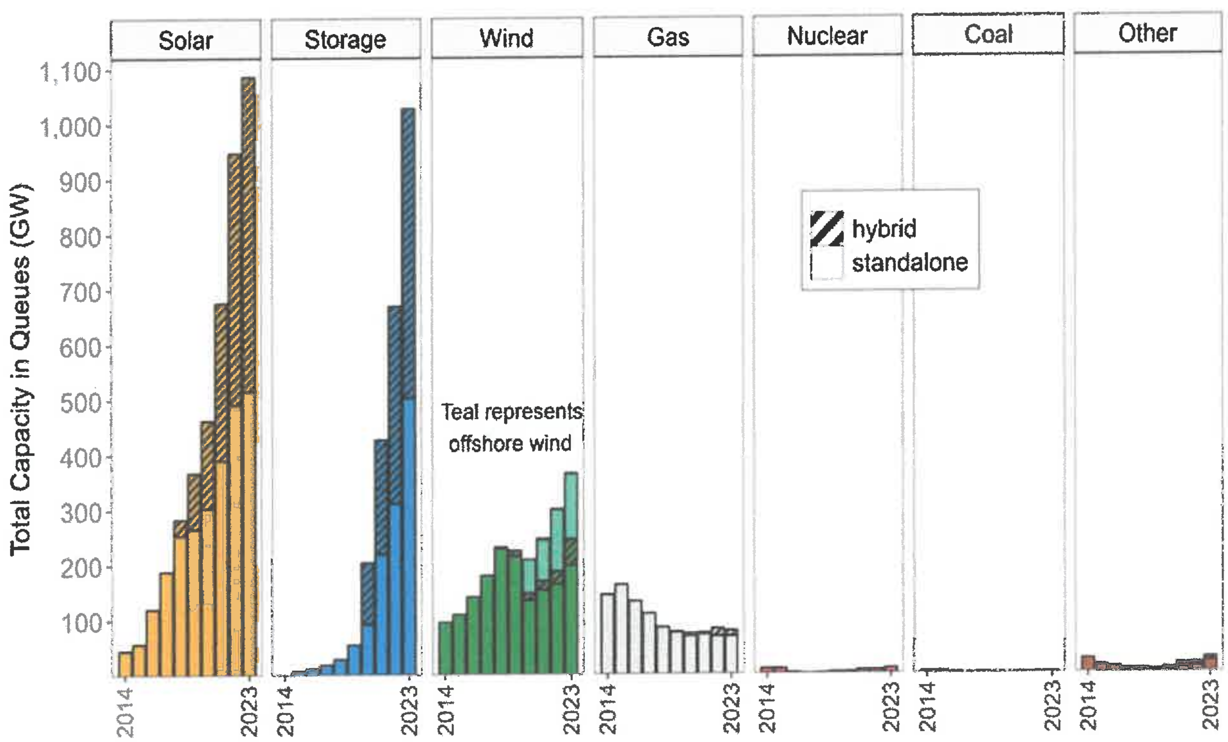
Sources: EIA-860 2023 Early Release, Berkeley Lab

Figure 9. Design characteristics of hybrid power plants operating in the United States, for a subset of configurations

The trend to co-locate wind with other assets has progressed at a slow but steady pace since 2006. The year 2023 saw the largest increase in wind hybrid development so far, with three news plants comprising 1.1 GW of co-located wind capacity. However, commercial interest in solar hybrids has expanded much more rapidly, with 62 new PV+storage projects, comprising 5.3 GW of co-located solar capacity, coming online in 2023.

A record-high 366 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace

One testament to the amount of developer and purchaser interest in wind energy is the amount of wind power capacity working its way through the major transmission interconnection queues across the country. Figure 10 provides this information over the last ten years for wind power and other resources aggregated across more than 50 different interconnection queues administered by ISOs and utilities.[15] These data should be interpreted with caution as placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built. Recent analysis found an overall average completion rate of 20% for projects of all types proposed from 2000 to 2018 (Rand et al. 2024). Some projects are exploratory in nature, and duplicate projects also complicate interpretation.



Notes: Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data; storage capacity in hybrids was not estimated for years prior to 2020; offshore wind was not separately identified prior to 2020.

Source: Berkeley Lab review of interconnection queues

Figure 10. Generation capacity in interconnection queues from 2014 to 2023, by resource type

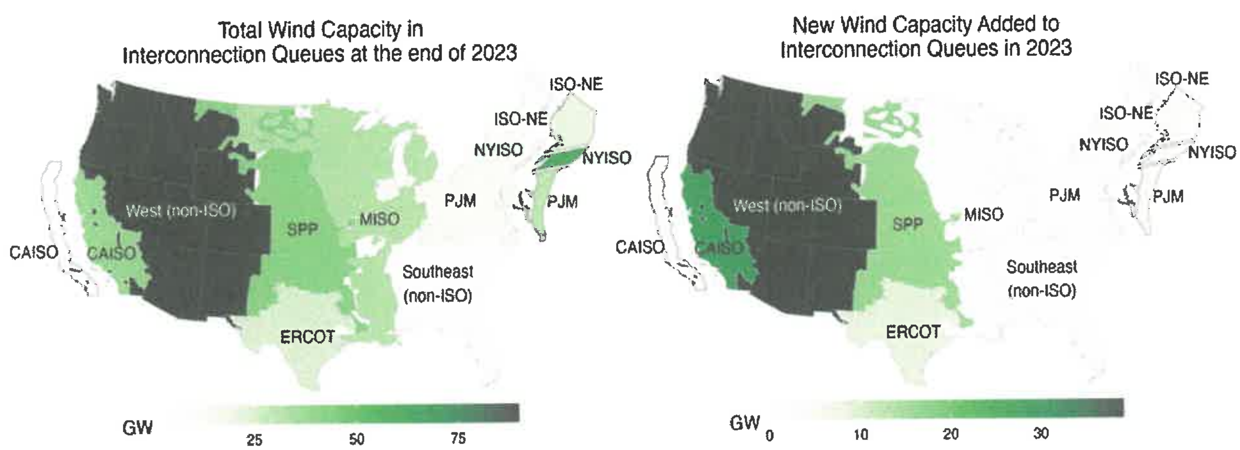
Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides an indication of developer interest. At the end of 2023, there were 366 GW of wind capacity in the queues reviewed for this report—a marked increase from the 300 GW in the queues the previous year and supported by continued growth in offshore wind in the queues. In 2023, 107 GW of new wind capacity entered

15 The queues surveyed include PJM, MISO, NYISO, ISO-NE, CAISO, ERCOT, SPP, Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and many other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here currently host approximately 95% of the total U.S. installed generation and storage capacity. The figures in this section only include projects that were active in the queues at the times specified but that had not yet been built; suspended projects are not included.

the queues, 26 GW of which were in hybrid configurations and 12 GW of which were for offshore wind. Solar additions to interconnection queues far outpaced wind in 2023, with 312 GW added. Storage additions to the queues have increased much more rapidly than wind in recent years as well, both for standalone plants and hybridized with solar or wind. Overall, wind represented 14% of all active capacity in the queues at the end of 2023, compared to 42% for solar, 40% for storage, and 3% for natural gas. The combined capacity of wind and solar now active in the queues (1,452 GW) exceeds the total installed U.S. electric generating capacity in 2023. Concerningly, the subset of proposed plants that work their way through the interconnection process and come online are taking longer to do so: the median wind project reaching commercial operation in 2023 submitted an interconnection request more than 5 years prior, compared to a 3-year duration for projects that came online from 2005 to 2010 (Rand et al. 2024).[16]

The total wind capacity in the interconnection queues is spread across the United States, as shown in Figure 11 (left image), with the largest amounts in the non-ISO West (25%), NYISO, (19%), CAISO (12%), and PJM (12%). Smaller amounts are found in SPP (11%), MISO (9%), ERCOT (6%), ISO-NE (6%), and the non-ISO Southeast (1%). Nearly one third (120 GW) of active wind capacity in the queues has requested to come online by the end of 2026, and 15% (55 GW) of wind capacity has a fully executed interconnection agreement.

Focusing just on wind additions to the queues in 2023 (Figure 11, right image), the non-ISO West and CAISO experienced especially large additions (>30 GW each). Across all queues, 33% (120 GW) of all wind capacity in the queues at the end of 2023 was offshore, and 11% (12 GW) of the wind added to queues in 2023 was offshore. New offshore wind capacity was added to four ISOs in 2023 (NYISO, PJM, ISO-NE, and CAISO).



Note: Offshore areas reflect the amount of offshore wind in the interconnection queues of each region.

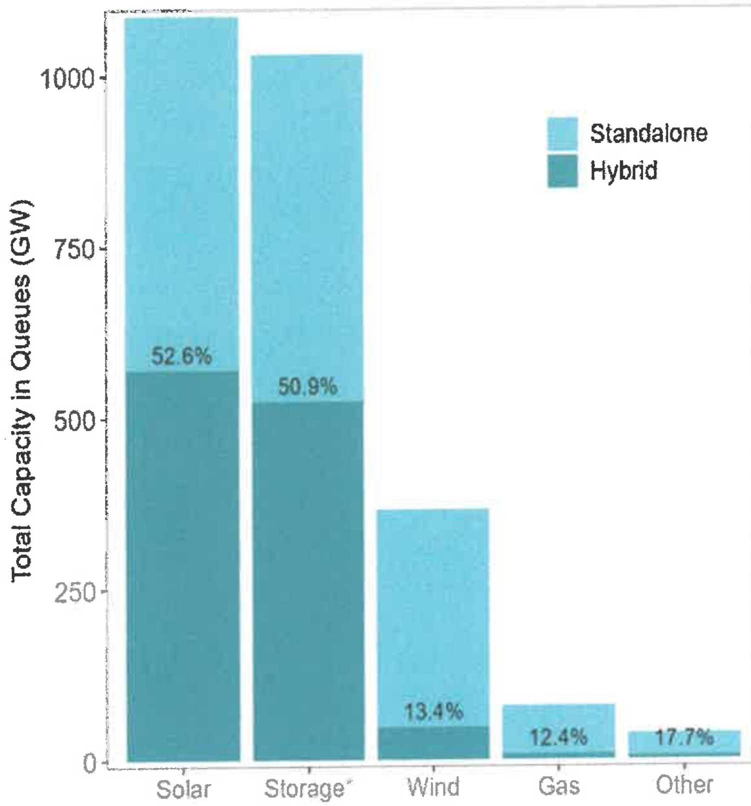
Source: Berkeley Lab review of interconnection queues

Figure 11. Wind power capacity in interconnection queues at end of 2023, by region

As shown in Figure 12, 53% of the solar capacity in interconnection queues at the end of 2023 has been proposed as hybrid plants, whereas only 13% of the wind capacity is paired with storage or another generation resource. In part this is due to policy design—until the passage of the Inflation Reduction Act, the investment tax credit for solar could be used for paired storage, whereas the production tax credit regularly used by wind

[16] The U.S. Department of Energy is engaging with interconnection stakeholders via the Interconnection Innovation e-Xchange (i2X). The i2X program recently released a Transmission Interconnection Roadmap, which included 35 solutions to improve interconnection. For more, see: https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange

plants had no such storage allowance. Of the 49 GW of proposed wind capacity in hybrid configurations, the majority (35 GW) is paired with storage, with the rest primarily paired with both solar and storage (13 GW).



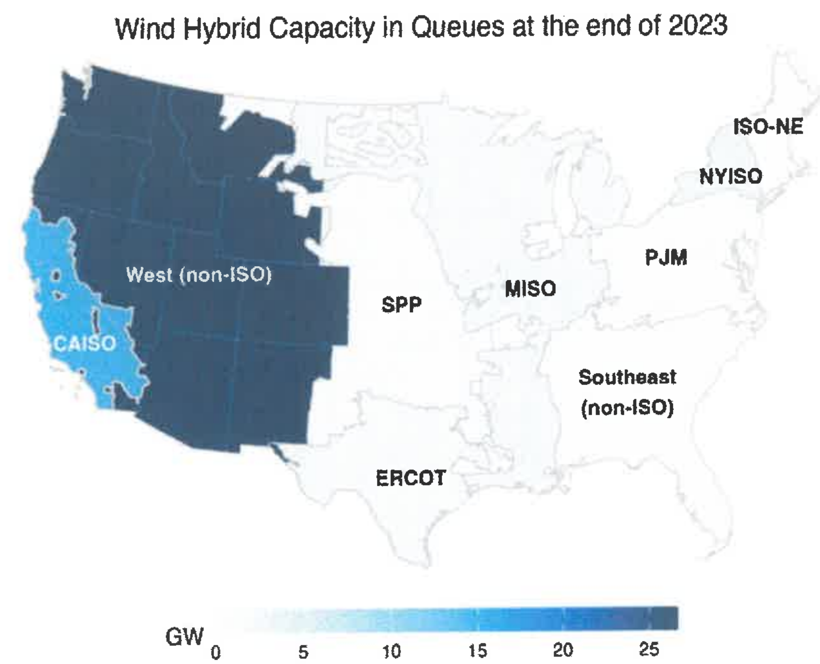
Note: Each bar reflects the listed resource type. A solar+storage hybrid will have its solar capacity in the 'solar' column and its storage capacity in the 'storage' column

*Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data.

Source: Berkeley Lab review of interconnection queues

Figure 12. Generation capacity in interconnection queues, including hybrid power plants

As shown in Figure 13, commercial interest in wind hybrid plants is highest in California and the West (non-ISO). In fact, 34% of the wind in CAISO's queues is proposed as a hybrid, as is 30% of the wind in the West.



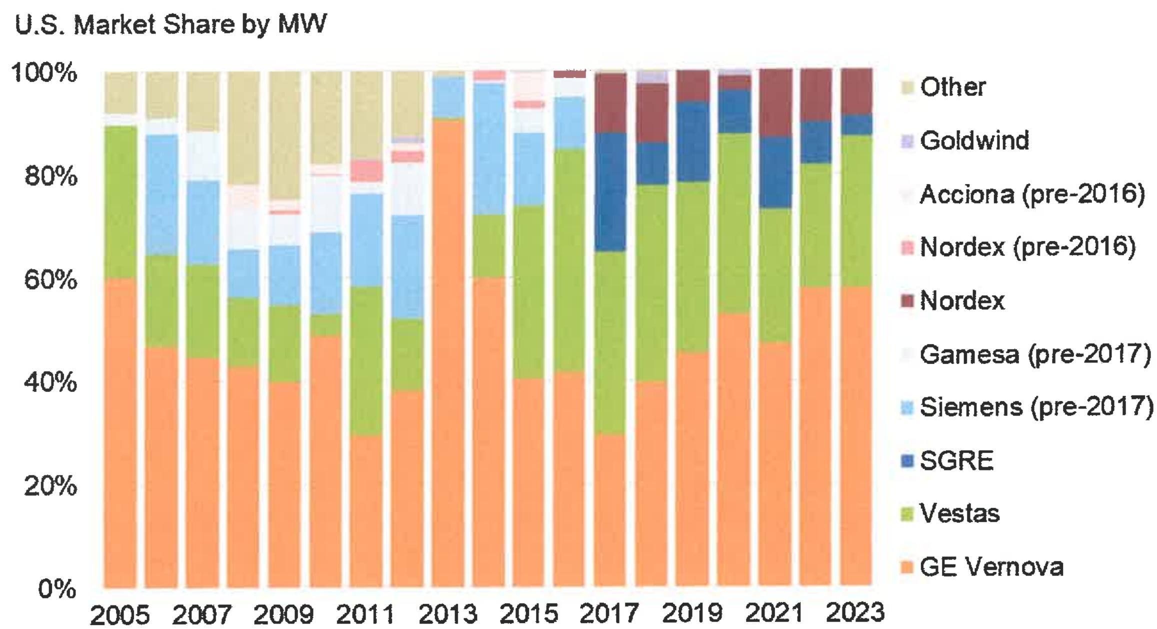
Source: Berkeley Lab review of interconnection queues

Figure 13. Hybrid wind power plants in interconnection queues at the end of 2022

3 Industry Trends

Four turbine manufacturers, led by GE Vernova, supplied all the U.S. utility-scale wind power capacity installed in 2023

Of the 6.5 GW of wind installed in the United States in 2023, GE Vernova supplied 58%, followed by Vestas (30%), Nordex (9%), and Siemens Gamesa Renewable Energy (SGRE, 4%).[17] GE Vernova and Vestas have dominated the U.S. market for some time, with SGRE and Nordex vying for third (Figure 14).



Source: ACP

Figure 14. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2023

The Inflation Reduction Act has created renewed optimism about supply-chain expansion

Figure 15 identifies the many wind turbine component manufacturing, assembly, and other supply chain facilities operating in the United States at the end of 2023. Three of the four major turbine OEMs that serve the U.S. wind industry—GE Vernova, Vestas, and SGRE—are represented within this total, each having one or more operating manufacturing facility. Figure 15 also highlights the geographic breadth of the supply chain.

Also included in the figure are fifteen operating or planned new, re-opened, or expanded facilities intended to serve the land-based wind industry, all announced since passage of the Inflation Reduction Act.[18] IRA contains, for the first time, production-based tax credits for domestic manufacturing of key wind turbine components, including nacelles, blades, and towers (U.S. DOE 2023). It also extends the PTC for wind power deployment, inclusive of a new 10% bonus on top of the full-value PTC for wind projects that meet domestic content requirements (a separate 10% bonus is available for projects located in energy communities).

The fifteen announced domestic manufacturing facilities include:

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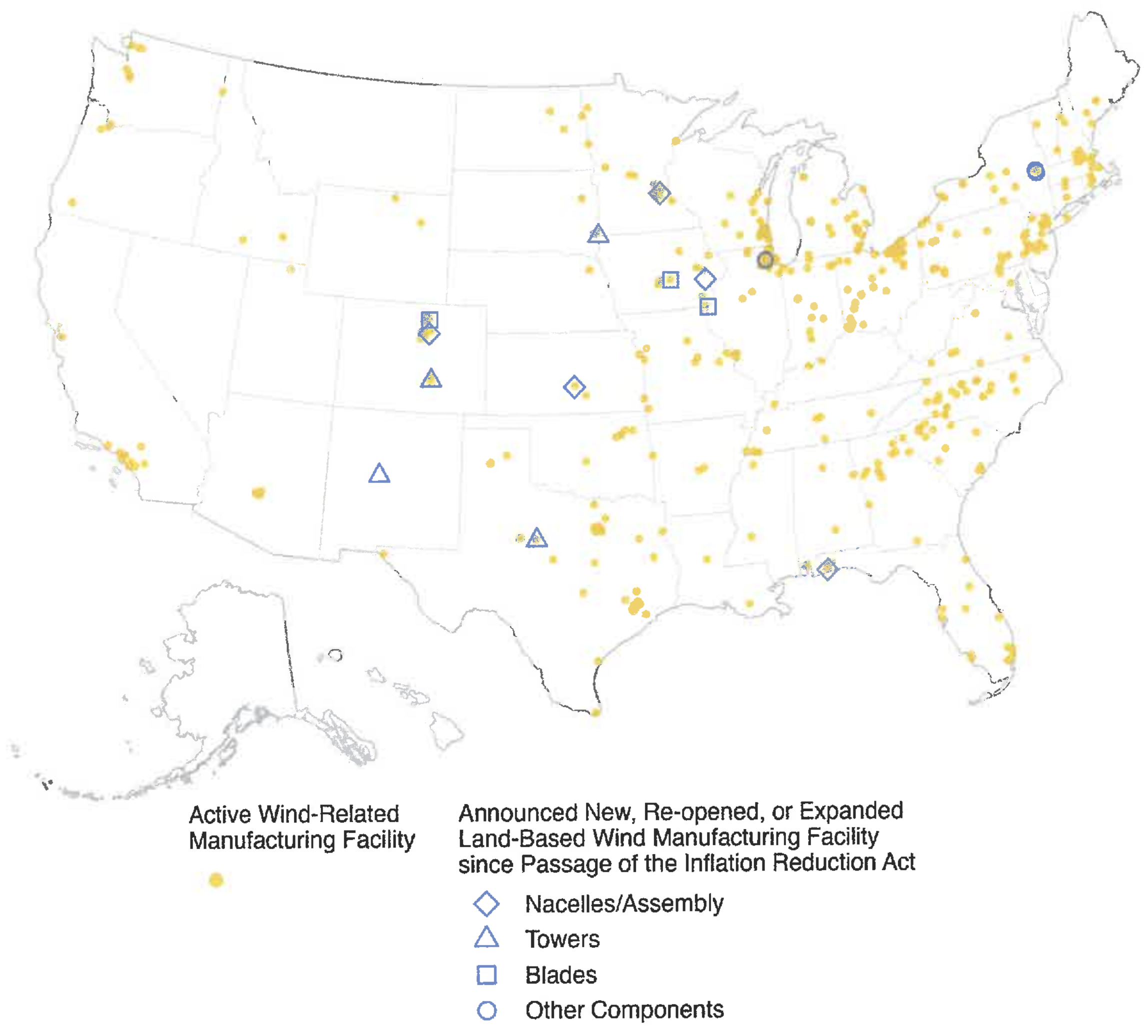
17 Market share is reported in MW terms and is based on project installations in the year in question.
18 See: https://www.energy.gov/invest

- Tower facilities in New Mexico (Arcosa), Colorado (CS Wind), South Dakota (Marmen), and Texas (Broadwind)
- Blade facilities in Iowa (TPI Composites and SGRE) and Colorado (Vestas)
- Component manufacturing in Illinois (Flender) and New York (GE Vernova and Jupiter Bach)
- Nacelle and turbine component assembly in Florida (GE Vernova), Kansas (SGRE), Colorado (Vestas), Iowa (Nordex), and Minnesota (WEG)

In total, these announced new facilities and expansions anticipate more than 3,200 new jobs.



Source: U.S. Department of Energy, ACP

Figure 15. Location of turbine and component manufacturing facilities

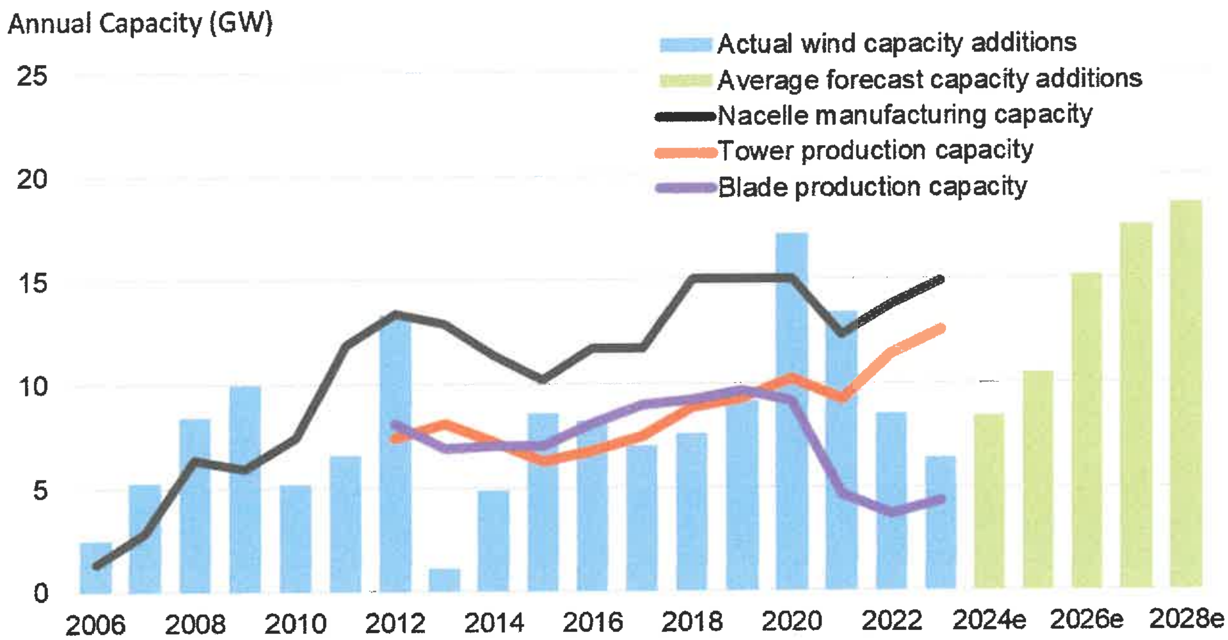
Domestic turbine nacelle assembly[19] capability is defined here as the maximum capacity of nacelles that can be assembled annually at U.S. plants operating at full utilization. This value grew from less than 1.5 GW in

[19] Nacelle assembly is defined as the process of combining the multitude of components included in a turbine nacelle, such as the gearbox and generator, to produce a complete turbine nacelle unit.

2006 to more than 13 GW in 2012, fell to roughly 10 GW in 2015, and then rose to 15 GW in 2018 and has held largely steady at that level since (Figure 16).

From 2012 through 2020, domestic blade and tower manufacturing capability was largely stable or growing, in each case increasing from around 7 to 8 GW/year in 2012 to around 10 GW/year in 2020. In the case of towers, domestic capability continued to increase, reaching over 12 GW in 2023. Domestic blade manufacturing, on the other hand, plummeted in 2021—a decline that continued into 2022 but with a slight rebound in 2023. Competition from foreign suppliers, growing blade lengths that require retooling of manufacturing equipment, and uncertain (pre-IRA) future deployment prospects for land-based wind in the United States combined to weaken domestic wind manufacturing capabilities. The impact of IRA on these trends, inclusive of the newly announced facilities listed earlier, will be seen in the years ahead.

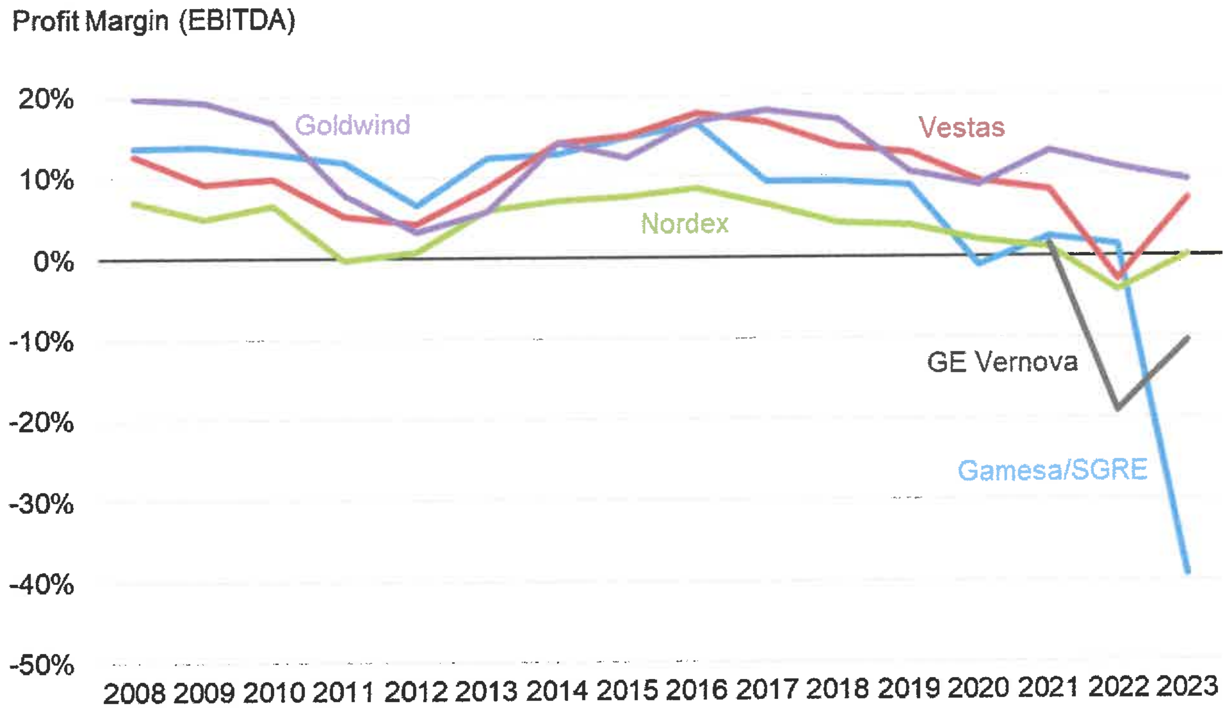
Figure 16 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future new installations (see Chapter 9, "Future Outlook"). It demonstrates that domestic manufacturing capability for towers and nacelle assembly remains reasonably well balanced with near-term projected wind additions in the United States, but that blade manufacturing capability has fallen well below near-term wind additions as international suppliers outcompete domestic ones.



Sources: ACP, independent analyst projections, Berkeley Lab

Figure 16. Domestic wind manufacturing capability vs. U.S. wind power capacity installations

Fierce competition, supply chain limitations and, in some cases, technical failures have challenged OEM profitability in recent years. However, there were modest signs of a turnaround in 2023, with improved profitability (or reduced losses) for Vestas, GE Vernova, and Nordex (Figure 17).



Note: EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

Sources: OEM annual reports and financial statements

Figure 17. Turbine OEM global profitability

The U.S. wind industry continues to depend on imports, though these have fallen to their lowest level in a decade

Despite the breadth of the domestic wind industry supply chain, the U.S. wind sector remains reliant on imports, as demonstrated by data on wind equipment trade from the U.S. Department of Commerce.[20] Imports of wind-related equipment that can be tracked through trade codes have fallen from a recent high of $5.5 billion in 2020 to $1.7 billion in 2023—a low not seen since 2013. Import numbers in recent years have largely mirrored annual capacity additions, with import value per gigawatt ($/GW) holding stable since 2021.

Figure 18 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. The figure shows imports of wind-powered generating sets and parts, including nacelles (i.e., nacelles with blades, nacelles without blades, and, in some cases, other turbine components internal to the nacelle) as well as imports of other select turbine components shipped separately from the generating sets and nacelles.[21] The turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (as well as generator parts), and blades and hubs.[22]

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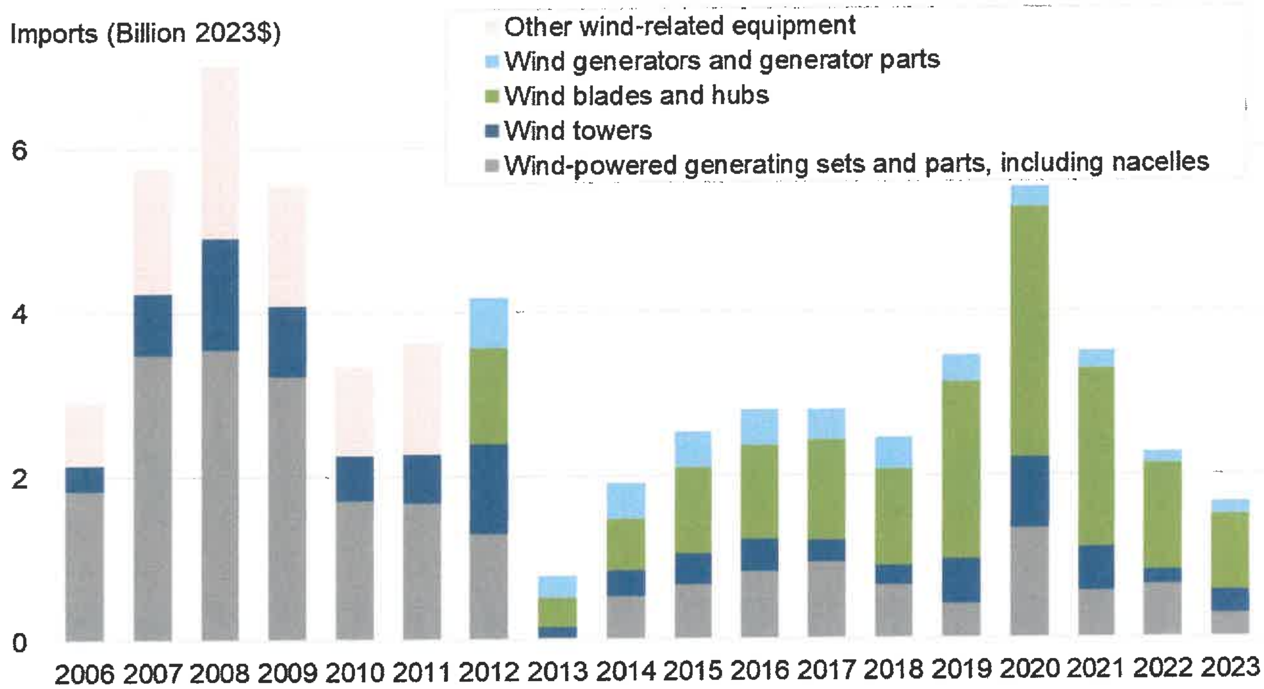
20 See the Appendix for further details on data sources and methods used in this section, including the specific trade codes considered.

21 Wind turbine components such as blades, towers, and generators are included in the data on wind-powered generating sets and nacelles if shipped in the same transaction. Otherwise, these component imports are reported separately.

22 Though all the import estimates in the figure since 2020 are specific to wind equipment, import trends should be viewed with caution because the underlying data from earlier years are based on trade categories that are not all exclusive to wind. Some of these earlier-year estimates therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. Note also that the trade code for towers is not exclusive to wind but is believed to be dominated by wind since 2011—we assume that 100% of imports from this trade category, since 2011, represent wind equipment.

As shown, blade and hub imports exceed other tracked imports in total dollar volume, representing 56% of the value of tracked imports in 2023—a figure that has remained reasonably stable for five years.



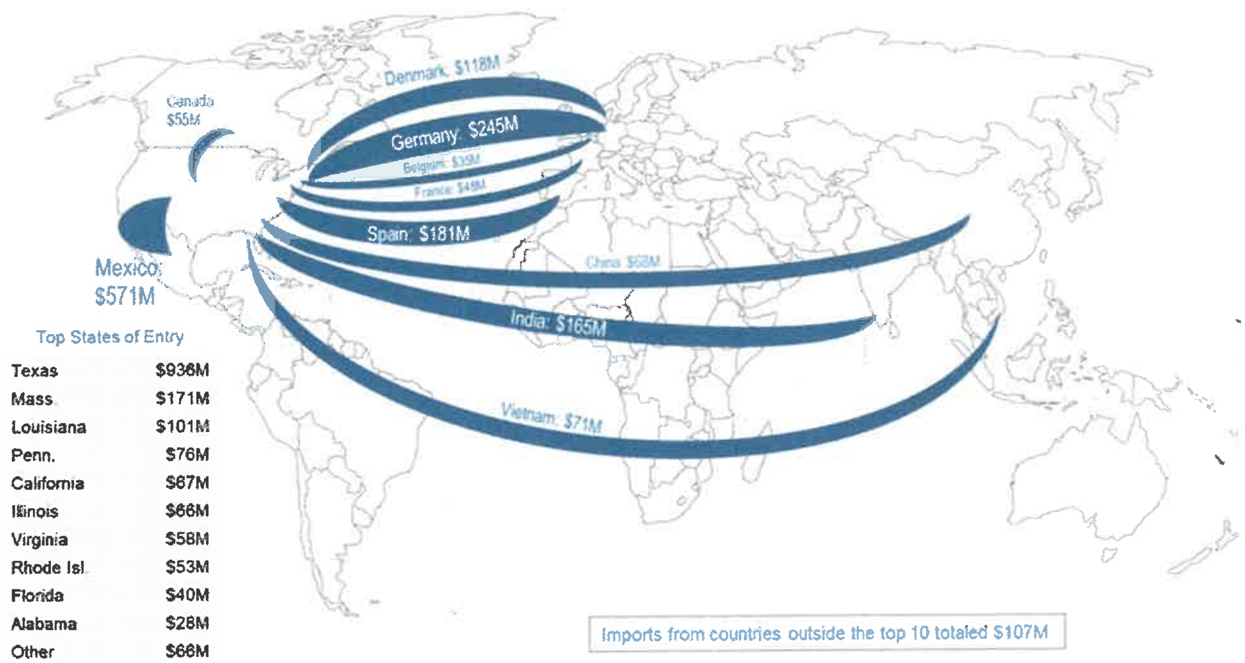
Note: Wind-related trade codes and definitions are not consistent over the full time period.

Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 18. Imports of wind-related equipment that can be tracked with trade codes

Interpreting time trends in these data is challenging given changes in annual wind additions from year to year, time lags between equipment import and installation, and fluctuations in wind turbine and equipment pricing. Also, because imports of component parts occur in additional, broad trade categories different from those included in Figure 18, the data presented here understate the aggregate amount of wind equipment imports. Nonetheless, the estimated imports of tracked wind-related equipment into the United States increased from 2006 to 2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then plummeting in 2013 with the simultaneous drop in U.S. wind installations. From 2014 through 2023, imports of wind-related turbine equipment followed U.S. wind installation trends, bouncing back from the low of 2013 and then with a marked decline from 2020 through 2023.

Figure 19 shows the total value of tracked wind-specific imports in 2023, by country of origin, as well as states of entry. Major countries from which the United States imported wind equipment in 2023 include Mexico, Germany, Spain, and India, which together account for nearly $1.2 billion in wind-specific exports to the United States in 2023. Texas remained the dominant entry point in 2023, with nearly $0.9 billion of wind-specific equipment flowing through it last year, followed distantly by Massachusetts, Louisiana, Pennsylvania, and California.



Note: Line widths are proportional to import amount by country. Figure does not intend to depict the destination of these imports, by state.
Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 19. Summary map of tracked wind-specific imports in 2023: top-10 countries of origin and states of entry

Figure 20 depicts trends in wind equipment imports over time for five leading countries, presented as a percentage of total tracked wind-specific imports. As shown, tracked wind equipment imports from China have declined in recent years, whereas imports from India and Mexico have increased.

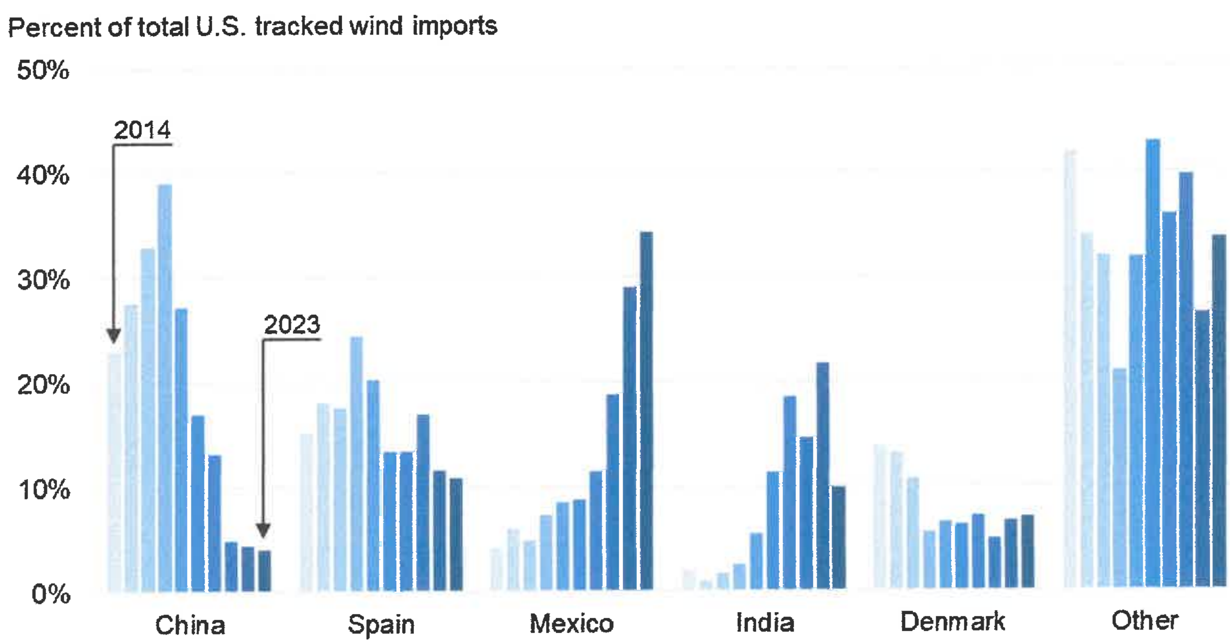
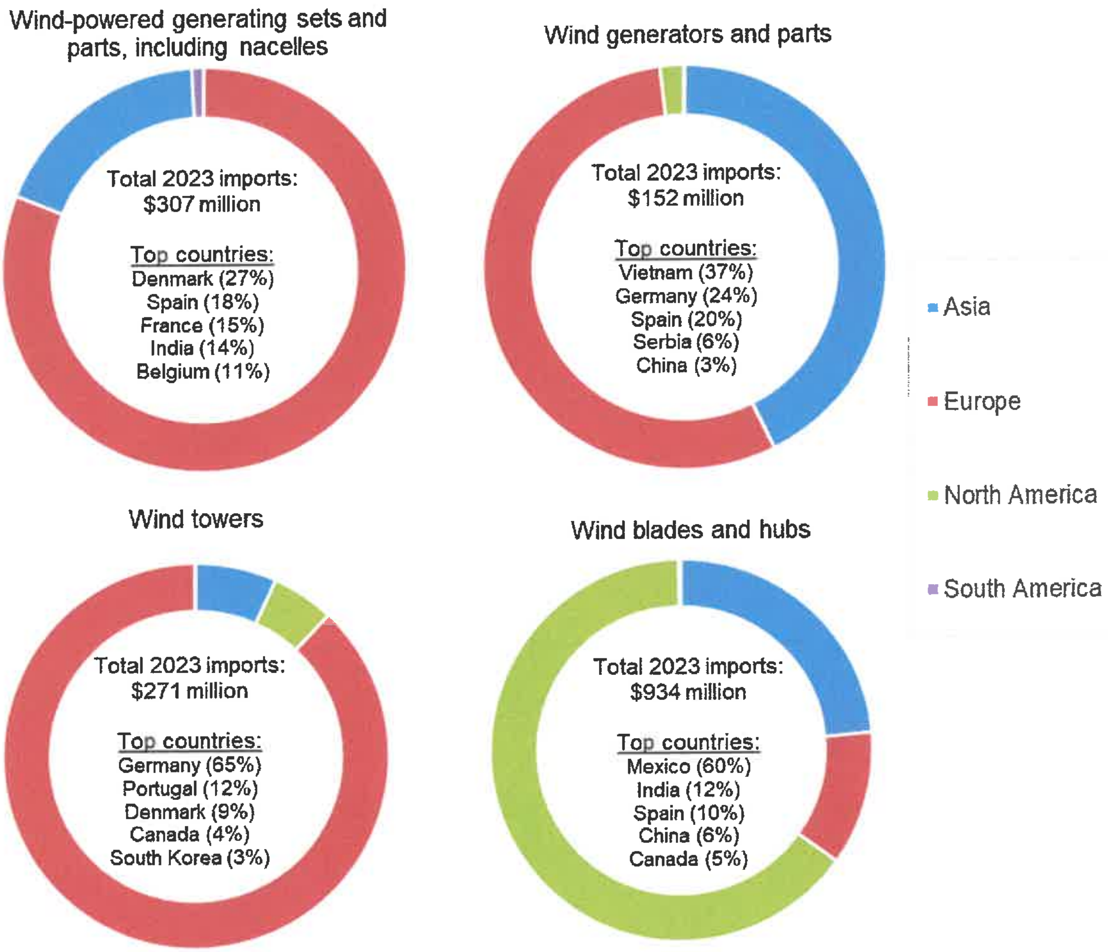


Figure 20. Wind equipment imports over time, by country: percent of total tracked wind-specific imports

Looking behind these data in further detail for 2023, Denmark, followed by Spain, France, India, and Belgium, were the primary source countries for wind-powered generating sets and parts, including nacelles (Figure 21). Tower imports came from a mix of countries near and far—Germany accounted for 65% of tower imports, with a majority of the remaining coming from Portugal, Denmark, Canada, and South Korea. For blades and hubs, Mexico accounted for 60% of the imports, with India, Spain, China, and Canada being the next largest source countries in 2023. Finally, about 81% of wind-related generators and generator parts in 2023 came from Vietnam, Germany, and Spain, with a majority of the remaining imports coming from Serbia and China.

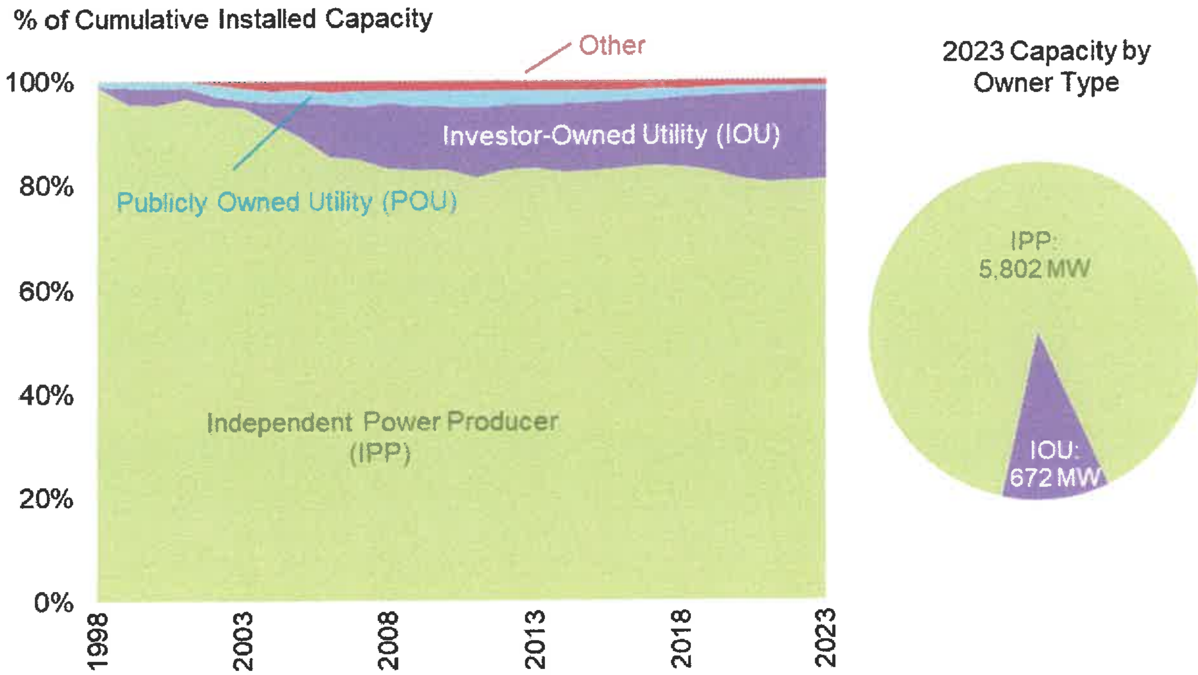


Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 21. Origins of U.S. imports of selected wind turbine equipment in 2023

Independent power producers own most wind assets built in 2023, extending historical trends

Independent power producers (IPPs) own 5,802 MW or 90% of the new wind capacity installed in the United States in 2023 (Figure 22, right pie chart). Investor-owned utilities (IOUs) own the remaining 672 MW (10%). Of the cumulative installed wind power capacity at the end of 2023 (Figure 22, left chart), IPPs own 81% and utilities own 18% (17% IOU and 1% publicly-owned utility, or POU), with the remaining 1% falling into the "other" category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers, etc.).[23] Additional details on ownership can be found in ACP (2024).



Source: Berkeley Lab estimates based on ACP

Figure 22. Cumulative and 2023 wind power capacity categorized by owner type

Non-utility buyers entered more contracts to purchase wind than did utilities in 2023

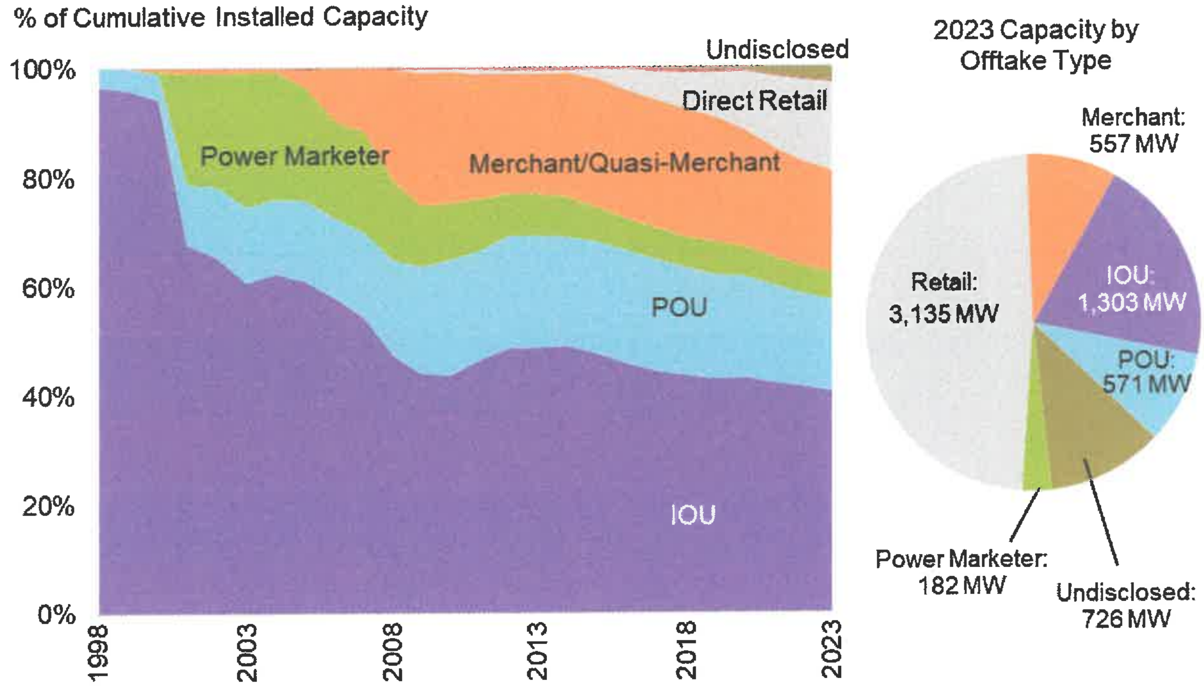
Whereas the prior section analyzes wind plant ownership, this section focuses on who uses or buys the wind generation from those plants. Electric utilities either own or buy the electricity from wind projects that, in total, represent 29% of the new capacity installed in 2023 (with the 29% split between 20% IOU and 9% POU—Figure 23, right pie chart). On a cumulative basis, utilities own or buy power from 57% of all wind power capacity installed in the United States (with the 57% split between 40% IOU and 17% POU, with the POU category including community choice aggregators (CCAs)).

Continuing a trend from previous years, direct retail purchasers of wind power represent a growing share of the market for wind offtake. Specifically, a diverse set of corporate and non-corporate offtakers supported at least 48% of the new wind power capacity installed in the United States in 2023 (and 16% of cumulative wind power capacity). Such purchasers span a wide range of organizations, from technology companies, retailers, finance, and telecommunication firms to governments and universities. Merchant/quasi-merchant projects accounted for at least 9% of all new 2023 capacity and 19% of cumulative capacity.[24] Finally, power marketers—defined here to include commercial intermediaries that purchase power under contract and then

[23] Many of the "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project. Note that any changes to ownership or offtake beyond the commercial operation data are not tracked in this or the following section.

[24] Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracts and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period), rather than being locked in through a long-term PPA.

resell that power to others[25]—bought at least the remaining 3% of new 2023 wind capacity and 5% of cumulative capacity. We qualify the level of support from these non-utility offtakers as "at least" because it is likely that much of the 0.7 GW of 2023 capacity that has not yet disclosed an offtaker is being sold to corporate buyers, power marketers, or into merchant arrangements, rather than to utilities. Additional details on wind purchasers can be found in ACP (2024).



Source: Berkeley Lab estimates based on ACP

Figure 23. Cumulative and 2023 wind power capacity categorized by power offtake arrangement

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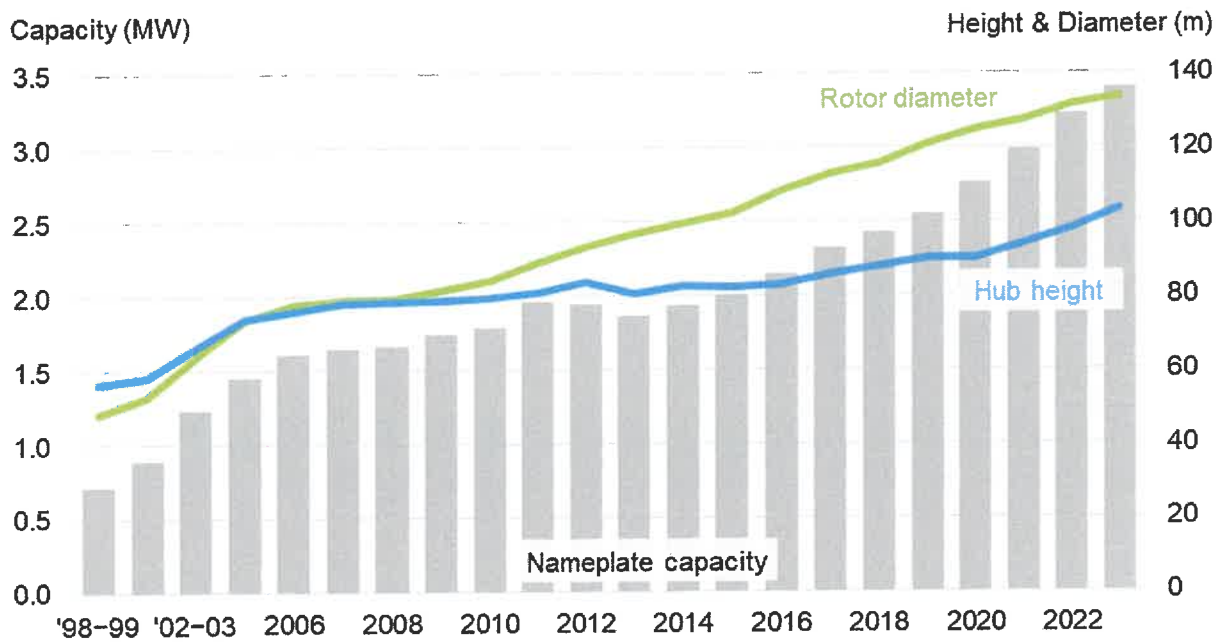
25 These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.

4 Technology Trends

Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term

The average nameplate capacity of newly installed land-based wind turbines in the United States in 2023 was 3.4 MW, 5% larger than in 2022 and up 375% since 1998–1999 (Figure 24).[26] The average hub height of turbines installed in 2023 was 103.4 meters, 5% larger than in 2022 and up 83% since 1998–1999. The average rotor diameter in 2023 was 133.8 meters, 2% larger than in 2022 and up 178% since 1998–1999. These trends, in turn, impact the project-level capacity factors highlighted later in this report.

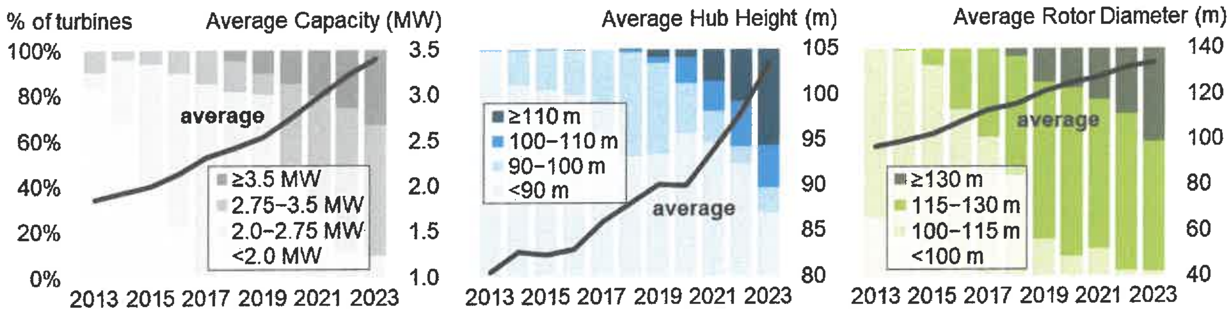


Sources: ACP, Berkeley Lab

Figure 24. Average turbine nameplate capacity, hub height, and rotor diameter for land-based wind projects

Figure 25 presents these same trends since 2013, but with additional detail on the relative distribution of turbines with different capacities, hub heights, and rotor diameters. For example, 2023 saw an increase in the proportion of turbines installed in size category of 3.5 MW or larger. The percentage of turbines with hub heights equal to or larger than 110 meters increased in 2023, to 42%—up from 23% in 2022 and just 4% in 2020. Finally, the steady progression toward larger rotors continued. In 2013, no turbines employed rotors that were 115 meters in diameter or larger, while 98% of newly installed turbines featured such rotors in 2023 (and 41% of those were at least 130 meters).

[26] Figure 24 and several of the other figures and tables included in this report combine data into both one- and two-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; although not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects. Though 2013 was a slow year for wind additions, it is shown separately here despite the small sample size.



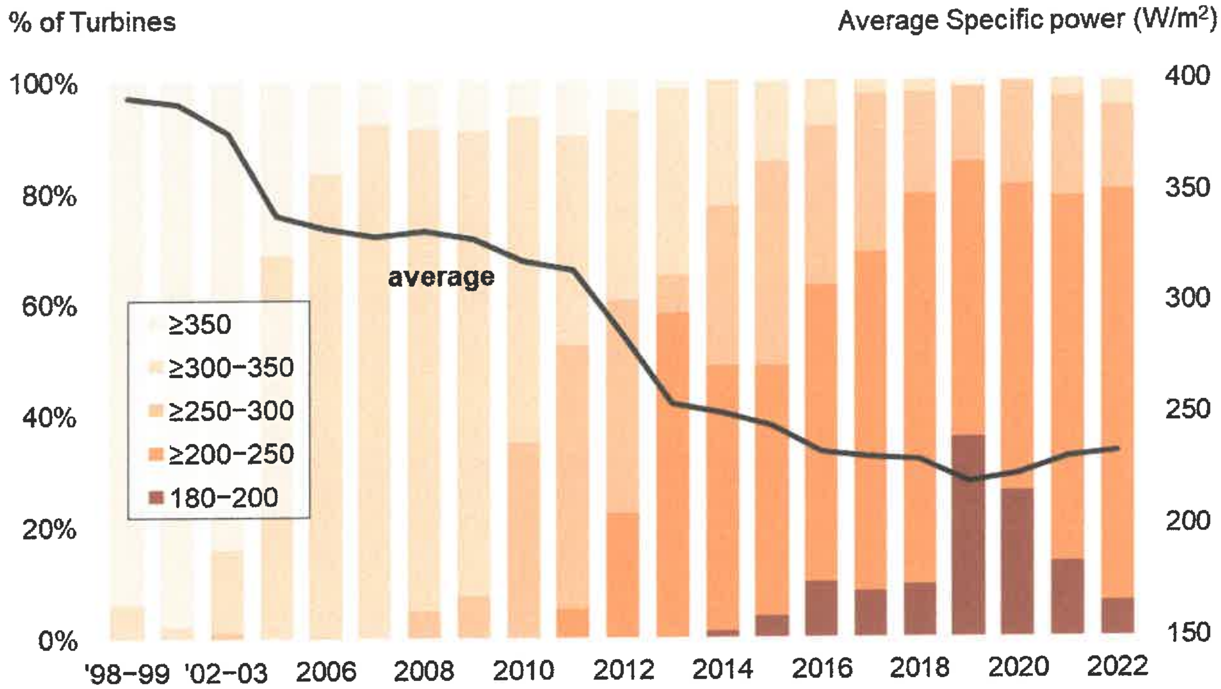
Sources: ACP, Berkeley Lab

Figure 25. Trends in turbine nameplate capacity, hub height, and rotor diameter

Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has moderated in recent years

As wind turbine blade length has increased over time, the amount of area the blades cover when spinning, known as the rotor swept area (in m^2), has grown. Rotor swept area has tended to grow faster than the increase in average nameplate capacity of land-based wind turbines over time. This has resulted in a decline in the average "specific power" among the U.S. turbine fleet, which is calculated by dividing the nameplate capacity (in watts [W]) by the rotor swept area (m^2). This value declined from 393 W/m^2 among projects installed in 1998–1999 to 237 W/m^2 among projects installed in 2023. However, as shown in Figure 26, the long-term decline in specific power has reversed in recent years, with specific power rising slightly since the low point in 2019 as turbines with a specific power in the range of 180–200 W/m^2 have become less popular or available as wind turbine capacities have increased significantly over this timeframe.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites, intended to maximize energy capture in areas where large-rotor machines would not be placed under excessive physical stress due to high or turbulent winds. As suggested in Figure 26 and as detailed later, however, such turbines are in widespread use in the United States—even in sites with high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.



Sources: ACP, Berkeley Lab

Figure 26. Trends in wind turbine specific power

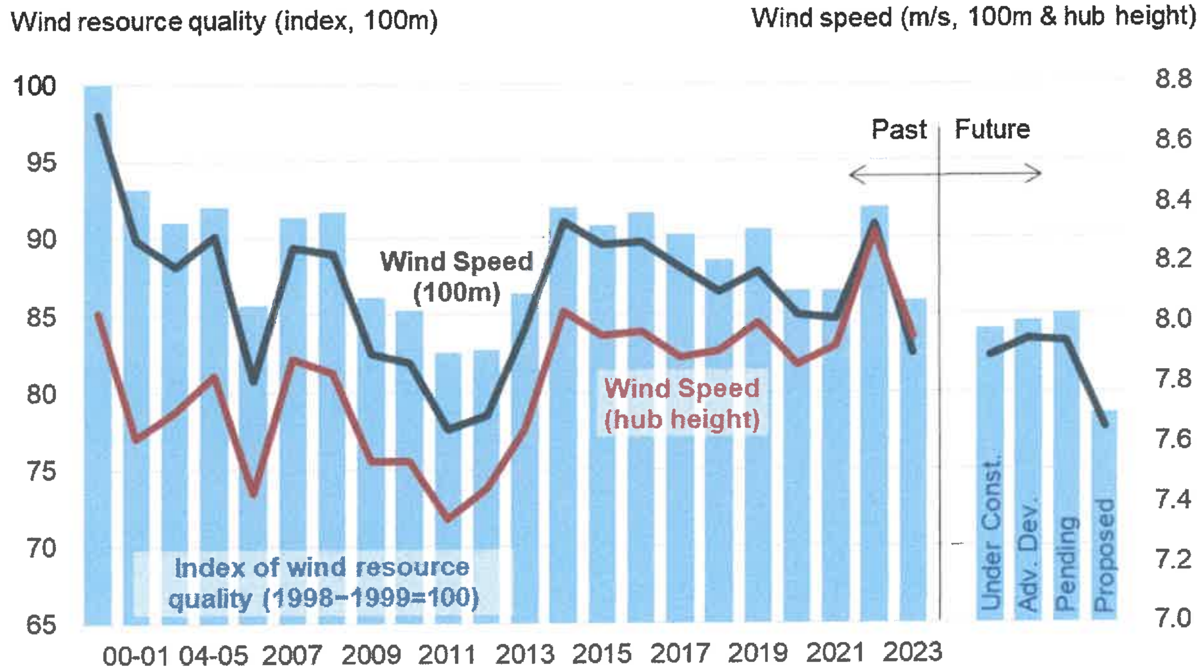
Wind turbines were deployed in lower wind-speed sites in 2023 than in recent years

Wind projects located in windier areas will tend to have higher performance than projects installed in less windy sites. Figure 27 shows the long-term average wind resource at wind project sites, by commercial operation date. The figure depicts the site-average wind speed (in meters per second, on the right axis) both at 100 meters and at the hub heights for projects installed in each year. Wind resource quality at 100 meters (blue bars) is measured on the left axis and is related to wind speed and other parameters; it represents an estimate of the gross capacity factor for each turbine location, indexed to the 1998–1999 installations.[27] Regardless of the specific metric used, the figure illustrates trends in where wind projects are sited over time.

Wind projects that came online in 2023 are located—on average—at sites with an estimated long-term average 100-meter wind speed of 7.9 meters per second (m/s). Given that the average hub height among 2023 wind plants was just above 100 meters, that average wind speed largely holds at hub height as well. Measured at 100 meters, this is the lowest site-average wind speed since 2012. Measured at average hub height, on the other hand, the wind speed is much more consistent with turbines installed over the last decade. The different trends at 100 meters (shown by the blue line) and at hub height (shown by the red line) illustrate the value of increasingly taller towers in boosting realized average wind speeds at hub height. Federal Aviation Administration (FAA) and industry data on projects that are "under construction," in "advanced development," "pending," or "proposed" suggest that projects will be built in less windy sites in the years ahead; whether

[27] The wind resource quality index is based on site estimates of gross capacity factor at 100 meters, with values indexed to projects built in 1998–1999; this quality index controls for site elevation and wind speed distributions but assumes a common turbine power curve and no losses. Further details are found in the Appendix. A benefit of this wind resource quality index is that changes in the index value will better approximate expected changes in actual wind project performance than will changes in average annual wind speed.

these hold when controlling for hub height will depend on future trends in tower height.[28] Trends in the wind resource quality index are broadly similar to average wind speed estimates at 100 meters.



Sources: ACP, Berkeley Lab, AWS Truepower, FAA Obstacle Evaluation / Airport Airspace Analysis files

Figure 27. Wind resource quality by year of installation at 100 meters and at turbine hub height

Several factors could have driven the observed long-term trends in average site quality and wind speeds. First, the availability of low-wind-speed turbines that feature lower specific power has enabled the economic build-out of lower-wind-speed sites; the same is true with taller towers. Second, transmission constraints (or other siting constraints, or even just regionally differentiated wholesale electricity prices) may have, over time, increasingly focused developer attention on those projects in their pipeline that have access to transmission (or higher-priced markets, or readily available sites without long permitting times), even if located in somewhat lower wind resource areas. These factors may partially explain why average resource quality and wind speeds dropped from the late 1990s to 2012 and again tended to decline from 2014 through 2023 (with 2022 being an outlier year). The build-out of new transmission (for example, the completion of major transmission additions in West Texas in 2013), however, may at times have offered the chance to install new projects in more energetic sites. Other forms of federal and/or state policy could also play a role. For example, wind projects built in the four-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Many projects availed themselves of this incentive and, because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers also seized this limited opportunity to build out the less-energetic sites in their development pipelines. State policies can also sometimes motivate in-state or in-region wind development in lower wind resource regimes.

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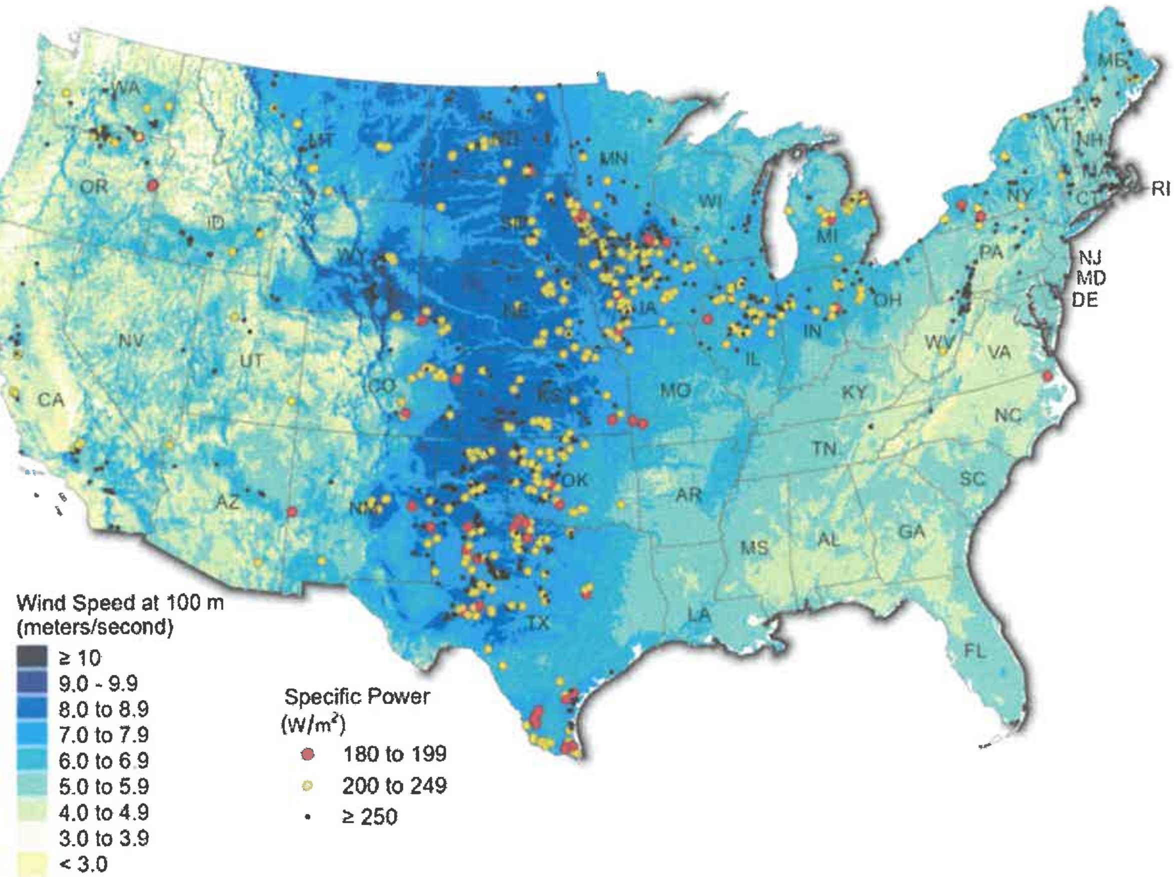
[28] "Under construction" turbines are part of a project where construction has begun, but the project has not yet been commissioned. Turbines in "advanced development" have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership, indicating a high likelihood that they will be built. "Pending" turbines are those that have received a "No Hazard" determination by the FAA and are not set to expire for another 18 months, while "proposed" turbines have not yet received any determination. Pending and proposed turbines may not all ultimately be built. However, analysis of past data suggests that FAA pending and proposed turbines offer a reasonable proxy for turbines built in subsequent years.

Low-specific-power turbines are deployed on a widespread basis throughout the country; taller towers are seeing increased use in a wider variety of sites

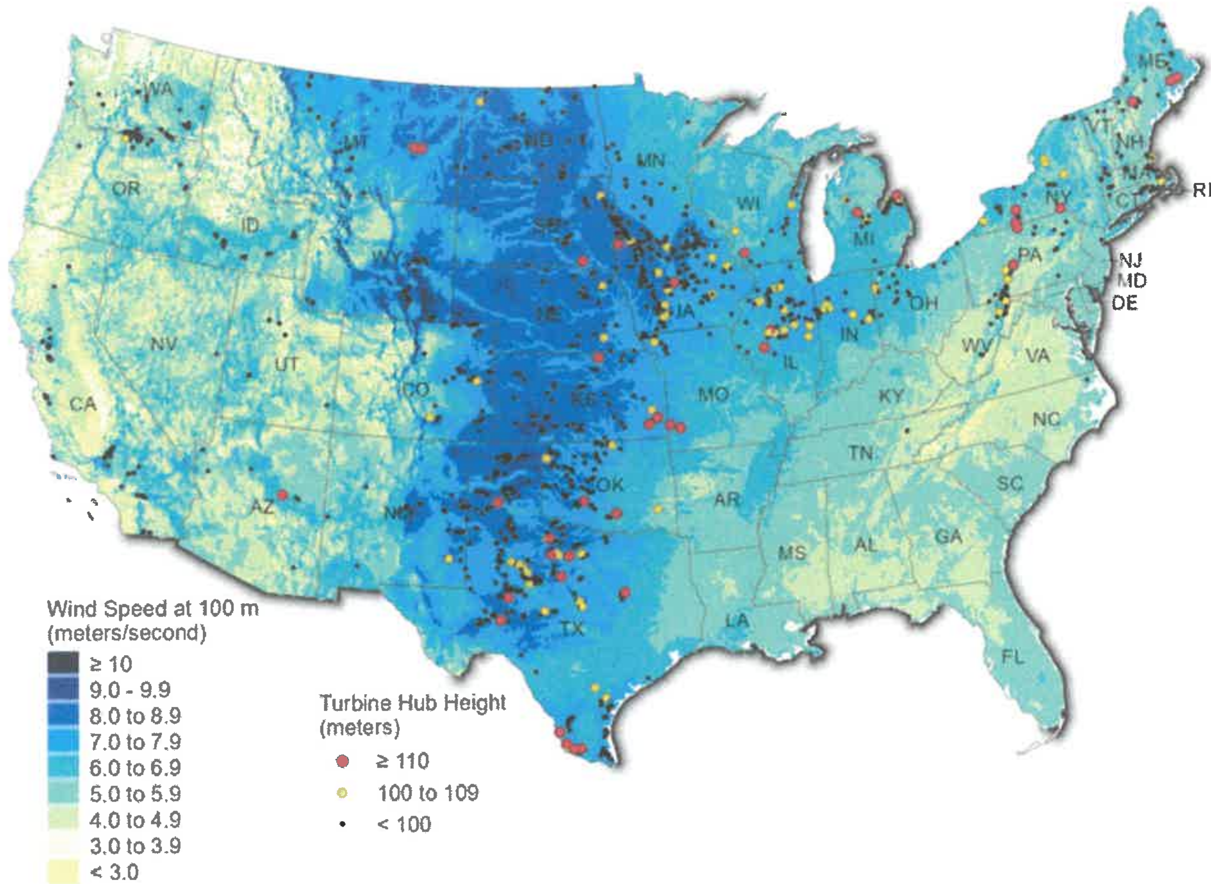
With the recent dominance of lower-specific-power turbines (defined here as turbines with specific power < 250 W/m^2), it comes as no surprise that such turbines have established a strong foothold across the nation and over a wide range of wind speeds (see Figure 28, which shows all U.S. wind projects).



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

Figure 28: Location of low specific power turbine installations: all U.S. wind plants

Likewise, taller towers are being deployed across a wide array of sites (Figure 29). The tallest towers (>110m) have found use in the Midwest and Northeast, two regions known to have higher-than-average wind shear (i.e., greater increases in wind speed with height), which makes taller towers more economical.



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

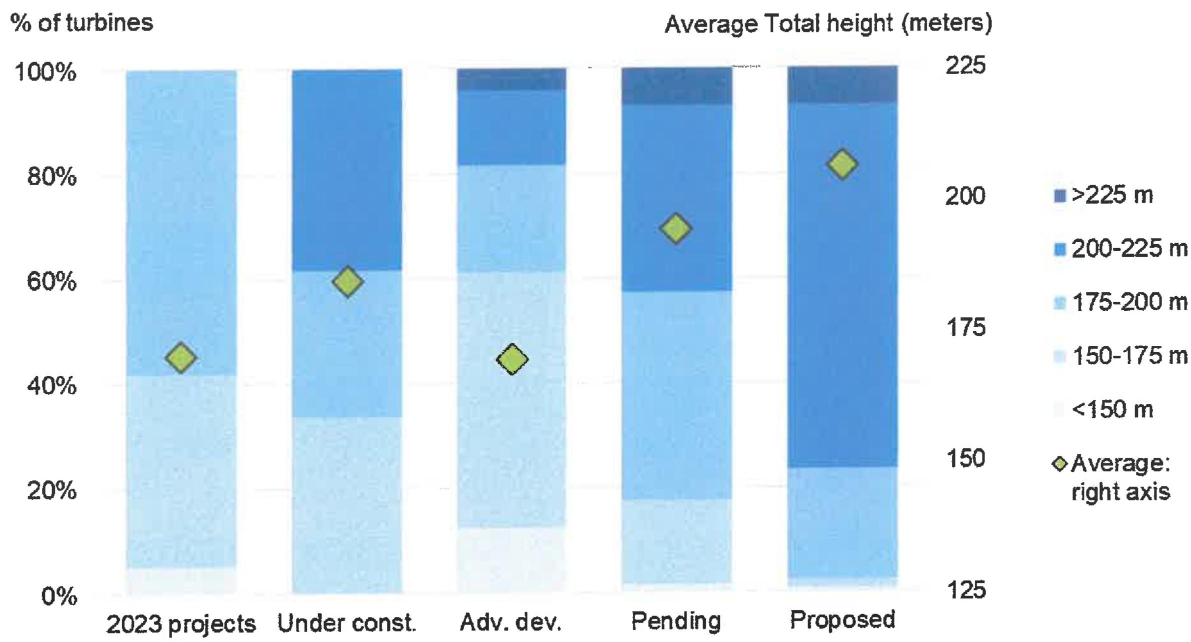
Figure 29: Location of tall tower turbine installations: all U.S. wind plants

Wind projects planned for the near future are poised to continue the trend of ever-taller turbines

FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications for land-based projects are reported in Figure 30. Note that these data represent total turbine height or "tip height"—not hub height—and include the combined effect of both the tower and half the rotor diameter. Figure 30 shows the average FAA tip height, along with the distribution, for 2023 installations as well as turbines under construction, in advanced development, pending, and proposed.[29]

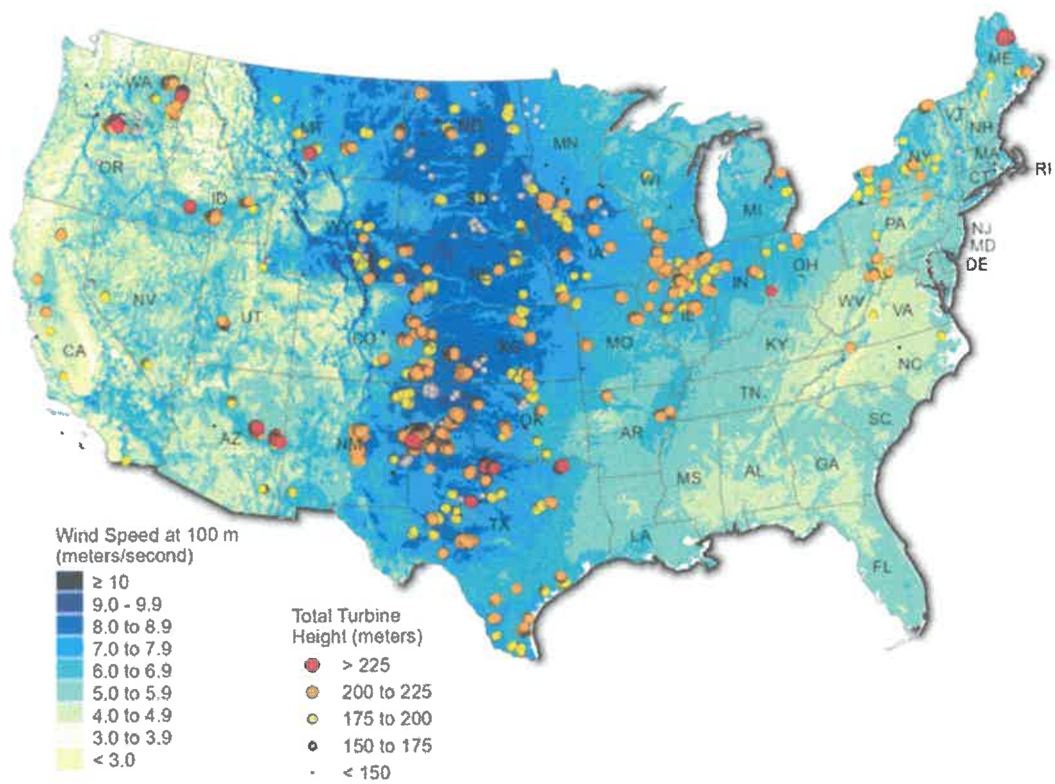
Average tip heights for projects that came online in 2023 are 170 meters, up from 164 meters for 2022 projects, and seem destined to climb higher in the next few years, reaching an average of 206 meters among the "proposed" turbines. The tallest turbines in the permitting process are over 225 meters. Turbines of at least 200 meters appear likely to be installed in nearly every region of the United States (Figure 31).

[29] Turbine heights reported in FAA permit applications represent the maximum height and can differ from what is installed. Historically, however, the FAA permit datasets have strongly conformed to subsequent actual installations on average.



Sources: ACP, FAA files, Berkeley Lab

Figure 30. Total turbine heights proposed in FAA applications, by development status



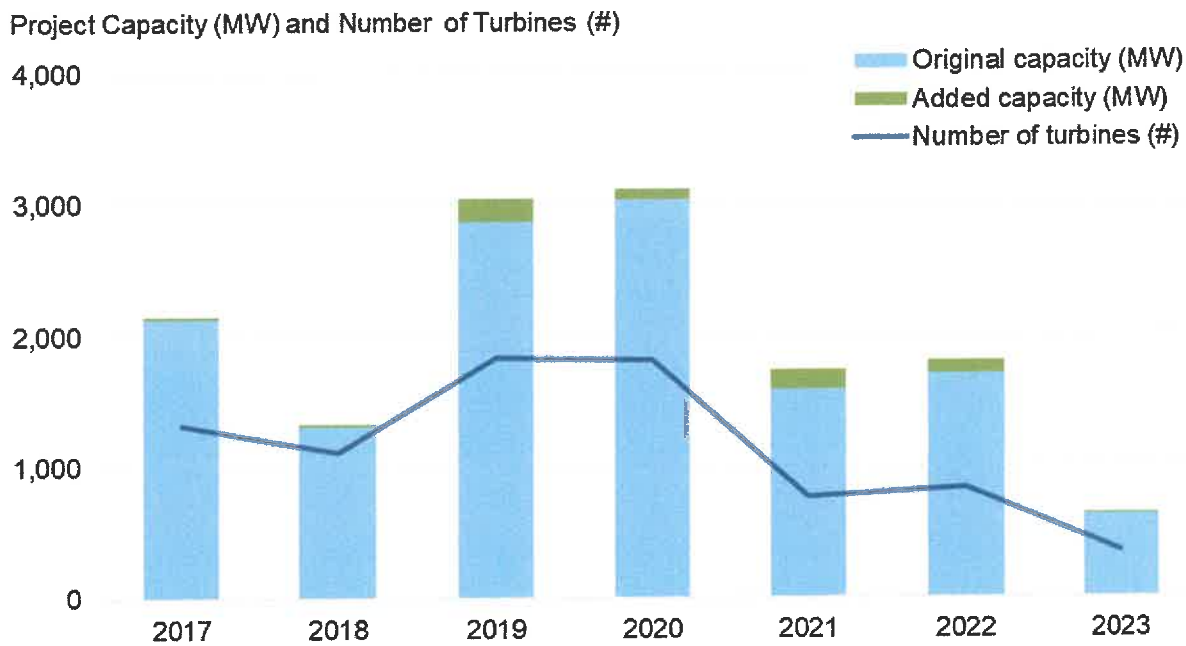
Note: Figure includes FAA data on under-construction, advanced development, pending, and proposed turbines

Sources: FAA Obstacle Evaluation / Airport Airspace Analysis files, AWS Truepower, ACP, Berkeley Lab

Figure 31. Total turbine heights proposed in FAA applications, by location

In 2023, seven wind projects were partially repowered, all of which now feature significantly larger rotors and lower specific power ratings

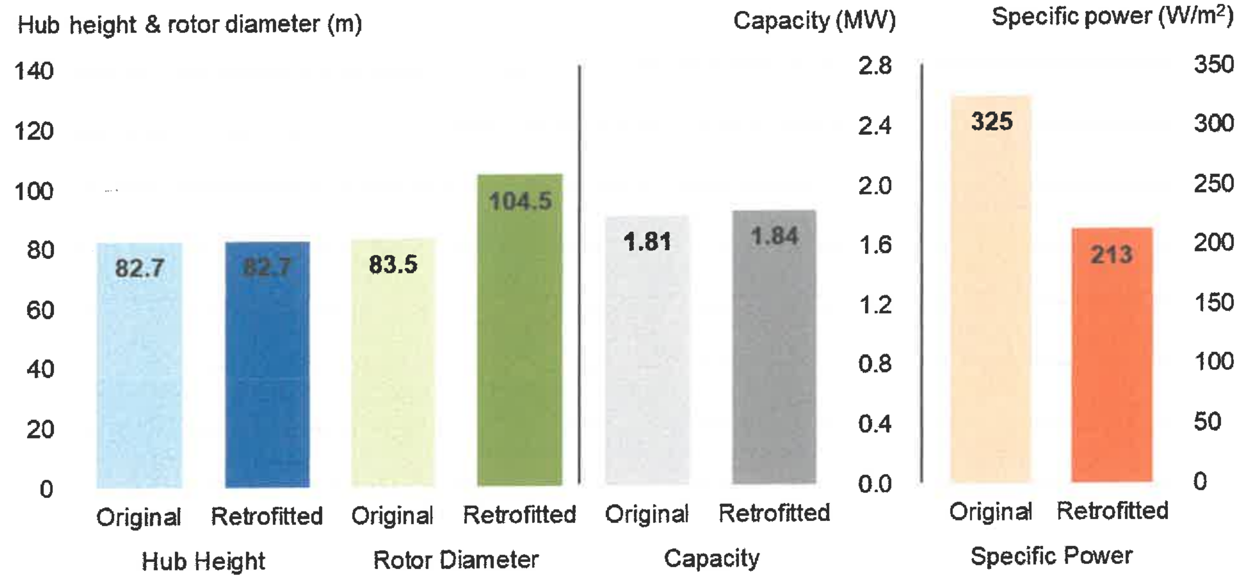
The trend of partial wind project repowering continued in 2023, albeit at a slower pace than in prior years, and involved replacing major components of turbines with more-advanced technology to increase energy production, extend project life, and access tax incentives. In 2023, 7 projects were partially repowered, involving 348 turbines that totaled 630 MW prior to repowering. Retrofitted turbines ranged in age from 11 to 15 years old; the median was 13 years. The 630 MW of retrofitted turbines in 2023 is a substantial decrease from the 1.6-1.7 GW/year retrofitted in 2021-2022 and the 3 GW/year retrofitted in 2019-2020 (Figure 32).



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 32. Annual amount of partially repowered wind power capacity and number of turbines

The most common retrofit in 2023 was the replacement of shorter with longer blades, but slight changes in turbine nameplate capacity were also common. Overall, the average turbine nameplate capacity of the retrofitted projects increased modestly (the final repowered capacity of these plants is 640 MW), but rotor diameters strongly increased (Figure 33). None of the turbines retrofitted in 2023 saw a change in hub height. With the relatively small change in capacity but the larger change in rotor diameter, these retrofits drove a significant decrease in average specific power, from 325 to 213 W/m^2.



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 33. Change in average physical specifications of all turbines that were partially repowered in 2023

5 Performance Trends

The average capacity factor in 2023 was 33.5% on a fleet-wide basis and 38.2% among wind plants built in 2022

Following the previous discussion of technology trends, this chapter presents data from a compilation of land-based project-level capacity factors.[30] The full data sample consists of 1,079 land-based wind projects built between 1998 and 2022 and totaling 125 GW. Excluded from this assessment are older projects installed prior to 1998. Projects built in 2023 are also excluded, as full-year performance data are not yet available for those projects. Projects that are repowered or partially repowered in a specific year are given a new commercial operation date, and data for that year are not reported given that such projects would have been at least partly offline during a portion of the year. Unless otherwise noted, all capacity factors in this chapter are reported on an as-observed and unadjusted basis (i.e., after any losses from curtailment, less-than-full availability, wake effects, ice or soil on blades, etc.). When looking at performance degradation over time, however, adjustments are made for inter-annual variability in the wind resource (as described in the Appendix).

To start, Figure 34 shows both individual project and average capacity factors in 2023, broken out by commercial operation date.[31] From left to right, Figure 34 shows an increase in weighted-average 2023 capacity factors when moving from projects installed in the 1998–1999 period to those installed in 2006. Subsequent project vintages through 2012 show no improvement in average capacity factors recorded in 2023. This pattern of stagnation is broken by projects installed in 2013–2022; average capacity factors for projects built in this later period are reasonably consistent and considerably higher than for projects built earlier.

The average 2023 capacity factor among projects built in 2022 was 38.2%: higher than for projects built in 2021 but reasonably consistent with averages for projects built over the last decade.[32] Cumulative, fleet-wide performance (shown only for 2023 in the figure) has tended to increase over time, growing from under 27% in 1999 to 36.1% in 2022. However, as demonstrated later, 2023 was a low wind year nationally, driving down fleet-wide capacity factors, to 33.5%. These overall trends are impacted by several additional factors that are also explored later, including project location and the quality of the wind resource at each site; turbine scaling and design; and performance degradation over time.

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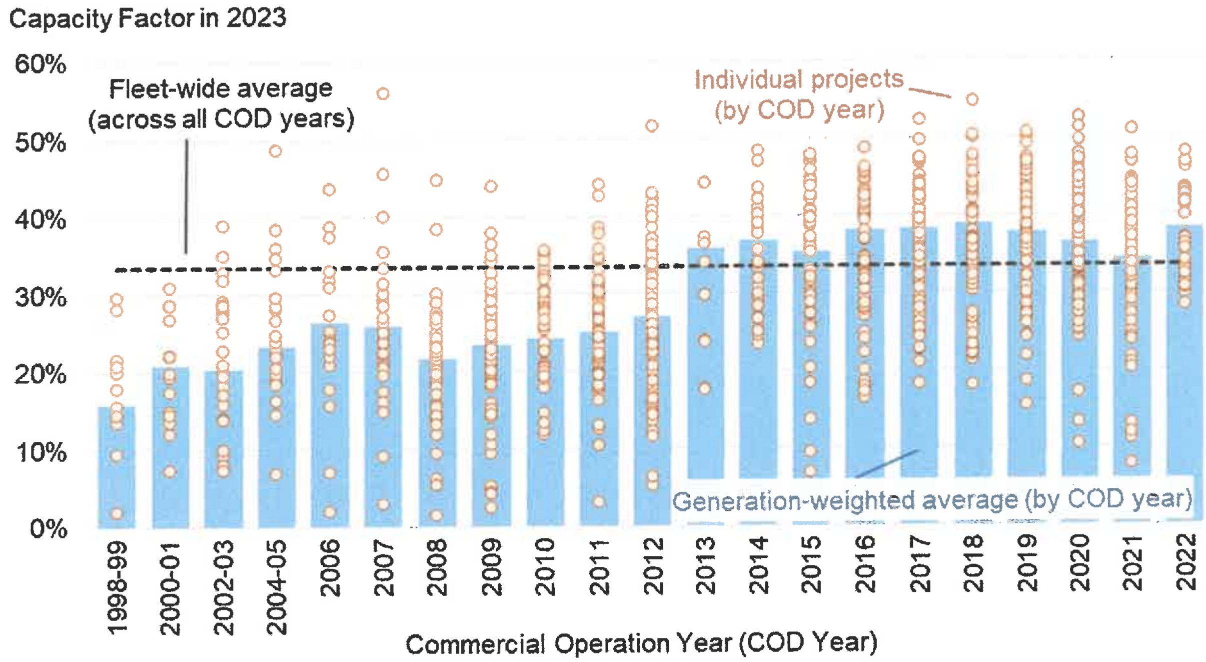
30 Capacity factor is a measure of the actual energy generated by a project over a given timeframe (typically annually) relative to the maximum possible amount of energy that could have been generated over that same timeframe if the project had been operating at full capacity the entire time.

31 Focusing on capacity factors in a single year, 2023, controls (at least loosely) for factors that can impact performance from one year to the next but that are unrelated to technology change, for example, the degree of wind power curtailment or inter-annual variability in the strength of the wind resource. But it also means that the *absolute* capacity factors shown in Figure 34 may not be representative over longer terms if 2023 was not a representative year in terms of curtailment or the strength of the wind resource (as noted later, 2023 was a below-average wind year overall).

32 The 2023 capacity factor of projects that were built in 2022 may be biased low, due to possible first-year "teething" issues, as projects may take a few months to achieve normal, steady-state production after first achieving commercial operations.

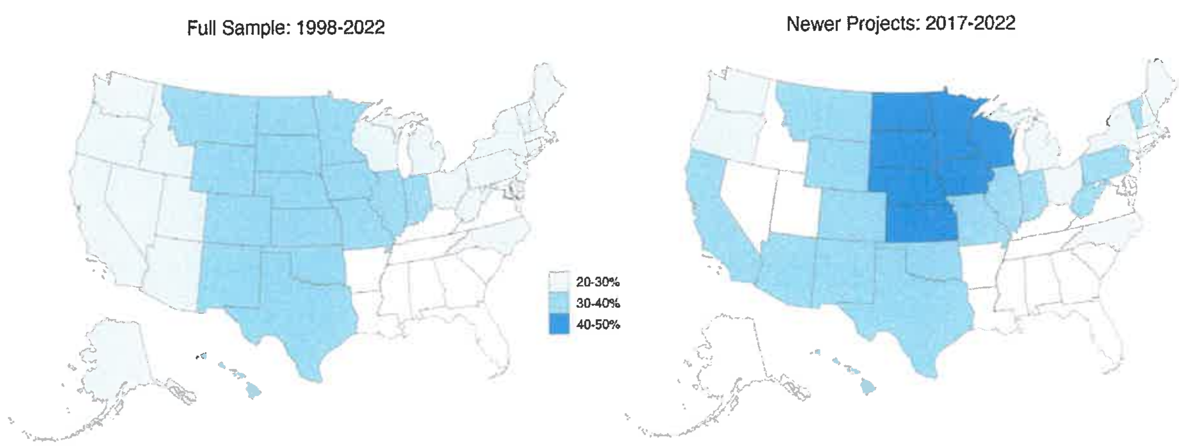


Sources: EIA, FERC, Berkeley Lab

Figure 34. Calendar year 2023 capacity factors by commercial operation date

State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country

The project-level spread in capacity factors shown in Figure 34 is enormous, with capacity factors in 2023 ranging from less than 5% to over 50%. Some of the spread—for projects built in 2022 and earlier—is attributable to regional variations in average wind resource quality. Figure 35 shows average state-level capacity factors in 2023 for the full sample of projects built from 1998 through 2022 (left) and a subset of newer projects built from 2017 through 2022 (right). Among the full sample, the overall range runs from 19%–39%, with higher capacity factors in the interior of the country. Consistent with Figure 34, the newer projects demonstrate higher state-average capacity factors than those among the full sample.



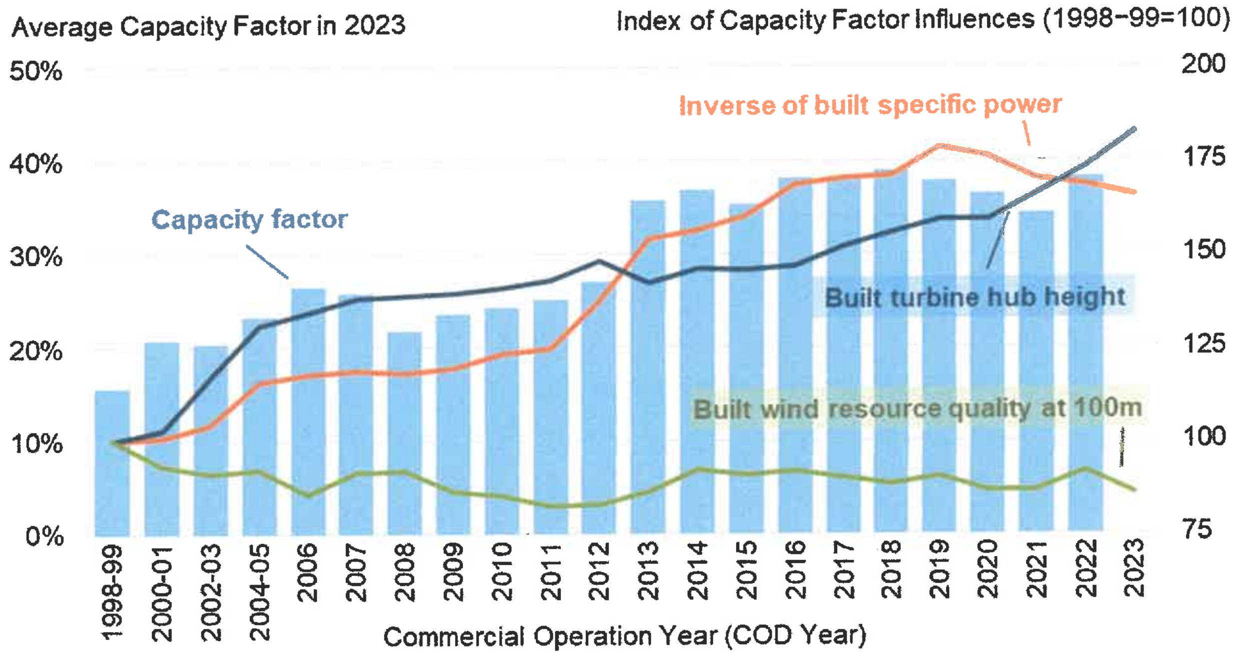
Note: States shaded in white have no projects in full sample (left) or in newer sample (right)

Sources: EIA, FERC, Berkeley Lab

Figure 35. Average wind capacity factor in calendar year 2022 by state

Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term

The trends in average capacity factor by commercial operation date seen in Figure 34 can largely be explained by several underlying influences described in Chapter 4 and shown again in Figure 36. First, as documented in Chapter 4, there has been a long-term trend toward lower specific power and higher hub heights. These two drivers are shown again in Figure 36 in index form, relative to projects built in 1998–1999 (with specific power shown in the inverse, to correlate with capacity factor movements). All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of turbine capacity. Meanwhile, increasing turbine hub heights helps the rotor access higher wind speeds. Second, counterbalancing these drivers has been the tendency to build new wind projects in areas that feature lower average wind speeds, especially among projects installed from 2009 through 2012 as shown by the wind resource quality index in Figure 36. This trend reversed course in 2013 and 2014, but then drifted lower once again through 2021 before increasing in 2022 (these wind resource trends are easier to see in Figure 27, where the y-axis scale is less expansive). Finally, as shown later, two other drivers include project age (given the possible degradation in performance among older projects) and variations in curtailment over the past few years. (Curtailment is baked into the capacity factors shown throughout this chapter.)



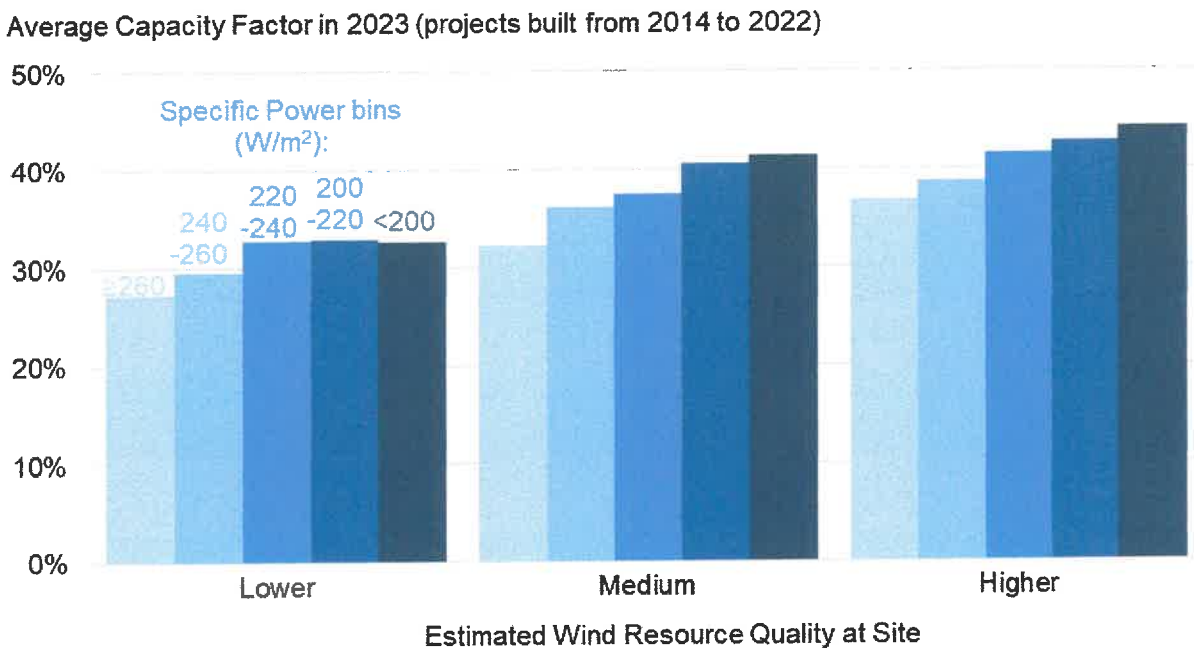
Note: To have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

Sources: EIA, FERC, Berkeley Lab

Figure 36. 2023 capacity factors and various drivers by commercial operation date

In Figure 36, the significant improvement in average 2023 capacity factors from among those projects built in 1998–1999 to those built in 2004–2005 is driven by both an increase in hub height and a decline in specific power, despite a shift toward somewhat lower-quality wind resource sites. The stagnation in average capacity factors that subsequently persists through 2011-vintage projects reflects less-rapid changes in hub height and specific power, coupled with a general decline in wind resource quality at built sites. The sharp increase in average capacity factors among projects built from 2013 to 2018 is driven by a steep reduction in average specific power over that entire period, coupled with a marked improvement in the quality of wind resource sites in the first few years and an increase in average hub height in the last few years of that period. Projects built from 2019 to 2021 had lower average capacity factors in 2023, driven by a turnaround in the specific power trend and a continuing move towards lower-quality wind resource sites. Projects built in 2022, on the other hand, are in especially windy areas and have higher hub heights, driving up average 2023 capacity factors. Looking ahead, projects with commercial operation dates in 2023 could record lower capacity factors on average than those built in 2022, considering the lower-quality wind resource sites in which they are located and despite strong increases in average hub height.

To help disentangle the primary and sometimes competing influences of turbine design evolution and wind resource quality on capacity factor, Figure 37 controls for each. Across the x-axis, projects built from 2014 to 2022 are grouped into four distinct categories, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As would be expected, projects sited in higher wind speed areas generally realized higher capacity factors in 2023 than those in lower wind speed areas, regardless of specific power. Likewise, projects that fall into a lower specific power range typically realized higher capacity factors in 2023 than those in a higher specific power range.[33]



Note: The Appendix provides details on how the wind resource quality at each individual project site is estimated.
Sources: EIA, FERC, Berkeley Lab

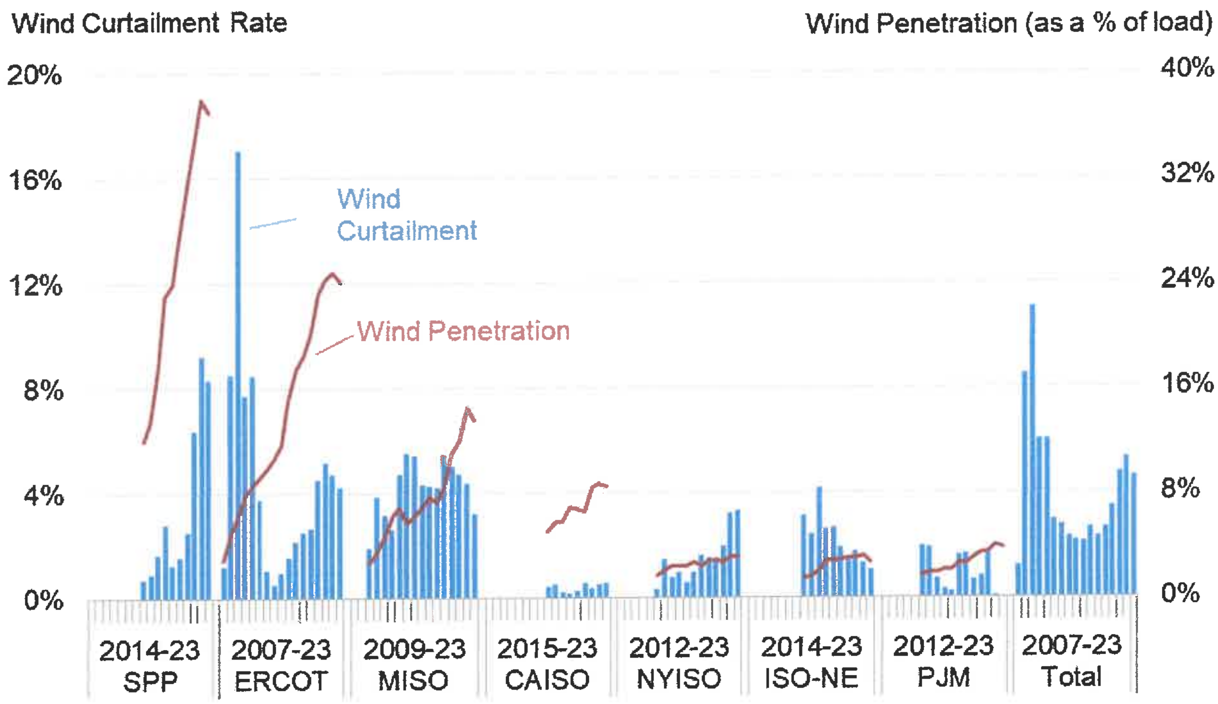
Figure 37. Calendar year 2023 capacity factors by wind resource quality and specific power: 2014–2022 projects

Wind power curtailment in 2023 varied by region, averaging 4.6% across seven ISOs

Curtailment of wind project output results from transmission inadequacy and other forms of grid and generator inflexibility in concert with wind over-supply. For example, over-generation can occur when wind generation is high but transmission capacity is insufficient to move generation to other load centers, or thermal generators cannot feasibly ramp down any further or quickly enough. This can push local wholesale power prices negative, thereby potentially triggering wind curtailment, especially among projects not earning the PTC.

[33] Note that some of the bins shown in the figure have relatively small samples, which likely explains any cases where trends are not as one might expect.

Curtailment is generally expected to increase as wind energy's market share grows, and—as shown in Figure 38—that has certainly been the case in some regions. In SPP, curtailment rose from just 0.7% in 2014 to 8.3% in 2023, at the same time as the percentage of electricity from wind expanded from 12% to 37% of load. This correlation between market share and curtailment does not always hold, though. Particularly in areas where curtailment has been acute in the past, steps taken to address the issue have often borne fruit. For example, Figure 38 shows that just 0.5% of potential wind energy generation within ERCOT was curtailed in 2014, down sharply from 17% in 2009. This decline in ERCOT curtailment corresponded to a significant build-out of new transmission serving West Texas, most of which was completed by the end of 2013. Since 2014, however, wind's market share has increased in ERCOT, and so too has wind curtailment, which has hovered around 4% to 5% for the past four years.



Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

Figure 38. Wind curtailment and penetration rates by ISO

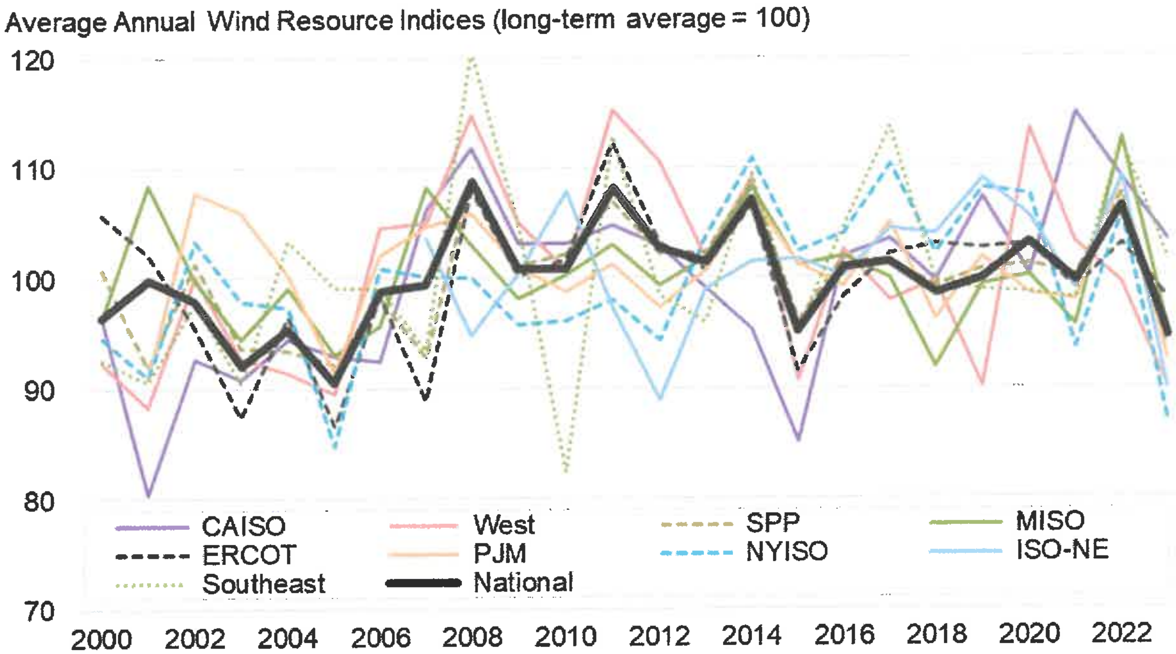
Curtailment rates in the other five ISO/RTO regions are lower: in 2023, 3.3% in NYISO, 3.2% in MISO, 1.1% in ISO-NE, 0.6% in CAISO, and at least 0.1% in PJM (the PJM data shown here likely reflect only a portion of overall wind curtailment, which the RTO does not regularly report). The overall wind power curtailment rate in 2023 across all seven regions was 4.6%, slight a decline from 2022 but higher than a decade ago.

2023 was a low wind resource year across most of the country

The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. Figure 39 shows national and regional indices of the historical inter-annual variability in the wind resource among the U.S. fleet over time.[34] Though inter-annual variation has, at

[34] These indices estimate changes in the strength of the average region- or fleet-wide wind resource from year to year (see the Appendix for more details). Note that these indices of inter-annual variability differ from the AWS Truepower wind resource quality data presented elsewhere, in that the former show variability from year to year across the entire region or fleet, while the latter focus on the multi-year long-term average wind resource at specific wind project sites.

times, reached +/-20% at the regional level (i.e., 0.8 and 1.2 in the graphic), geographical averaging has enabled nationwide variation to remain within +/-10%. In 2023, the national wind index stood at 0.95, its lowest level since 2005, as most regions experienced a below-average wind year. As a consequence, and as noted earlier, fleet-wide average wind project capacity factors dropped from 36.1% in 2022 to 33.5% in 2023.



Note: The "Southeast" result is based on a limited sample of one to four plants, depending on the year.

Sources: ERA, Berkeley Lab; methodology behind the index of inter-annual variability is explained in the Appendix

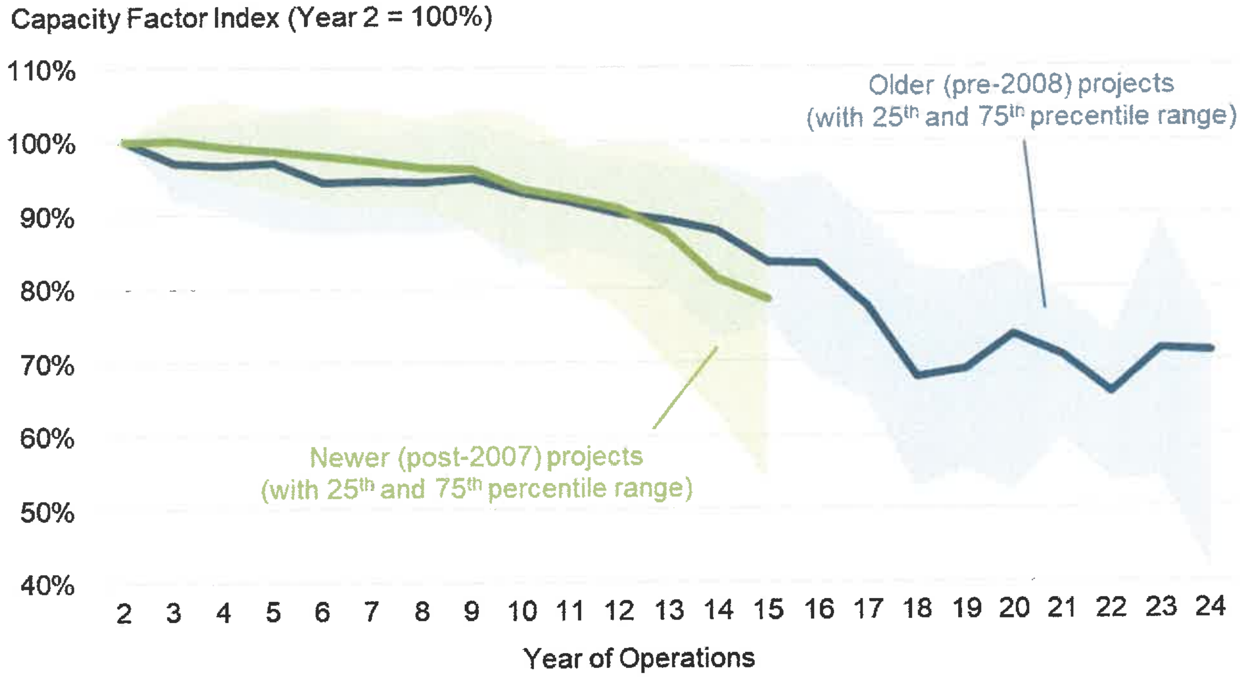
Figure 39. Inter-annual variability in the wind resource by region and nationally

Wind project capacity factors decline as projects age

A final variable that influences the variation in project-level capacity factors in 2023 is project age. If wind turbine (and project) performance tends to degrade over time, then older projects may have performed worse in 2023 than more recent projects simply due to their relative age.

Figure 40 explores this question by graphing median (and 25th to 75th percentile ranges) "weather-normalized" (i.e., correcting for inter-annual variability in the strength of the wind resource) capacity factors over time. Here, time is defined as the number of full calendar years after each individual project's commercial operation date, and each project's capacity factor is indexed to 100% in year two to focus solely on changes in capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base to reflect the initial production ramp-up period commonly experienced by wind projects as their operators work through and resolve initial "teething" issues during the first year of operations.

Figure 40 suggests that performance decline is present, as indexed capacity factors decline with project age. As well, that decline is present in both older and newer projects in the sample. By year 20, the median wind project has a capacity factor that is roughly 70% that of year 2. Hamilton et al. (2020) explores these performance trends in more depth. Note that the wind project sample for Figure 40 excludes from later-year performance projects that have been partially repowered (e.g., refurbished with longer blades); the performance of such projects typically improves post-refurbishment, but we assign a new commercial operation date for such projects upon repowering.



Sources: EIA, FERC, Berkeley Lab

Figure 40. Changes in project-level capacity factors as projects age

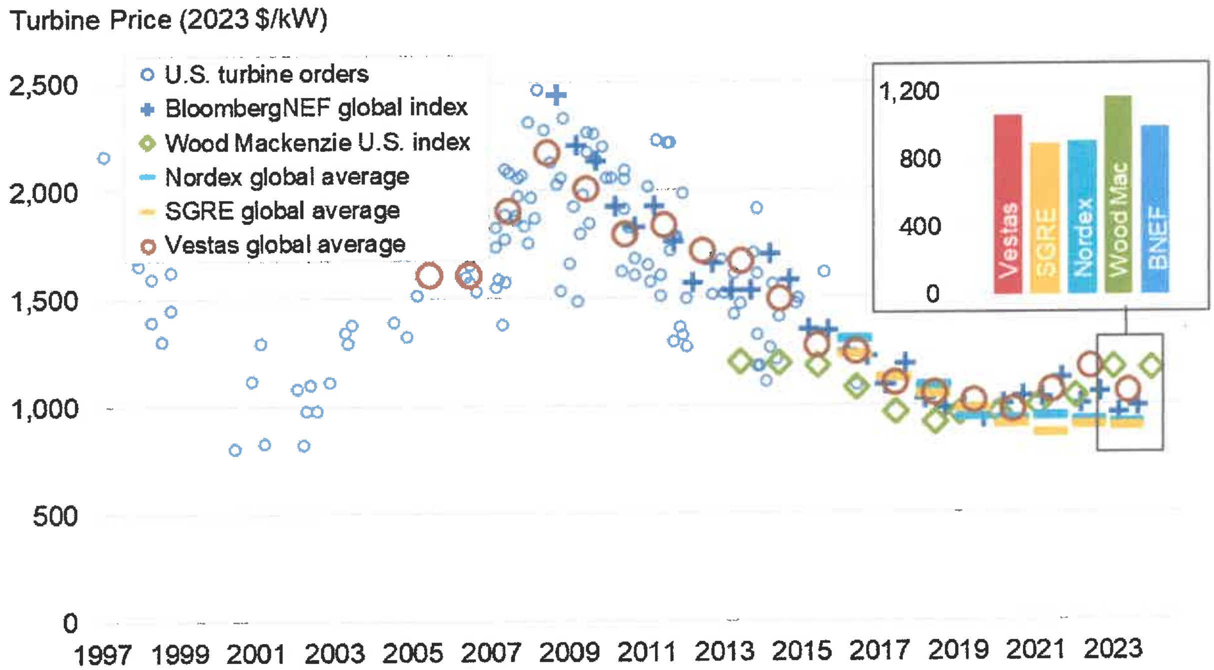
Taken together, Figure 34 through Figure 40 suggest that, to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of parameters. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.

6 Cost Trends

Wind turbine prices modestly declined in 2023, averaging roughly $1,000/kW

Wind turbine prices (in $/kW) for land-based wind projects have dropped since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. However, with supply chain pressures and elevated materials prices, turbine prices increased from 2020 through 2022 before moderating in 2023.

Figure 41 depicts wind turbine transaction prices from a variety of sources: (1) Vestas, SGRE, and Nordex, on those companies' global average turbine pricing, as reported in corporate financial reports; (2) BloombergNEF (2023a) and Wood Mackenzie (2024a), on those companies' turbine price indices by contract signing date; and (3) 121 U.S. wind turbine transactions announced from 1997 through 2016, as previously collected by Berkeley Lab. Wind turbine transactions can differ in the services included (e.g., whether towers are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery. These differences drive some of the observed intra-year variability in transaction prices. Most of the prices and transactions reported in the figure are inclusive of towers and delivery to the site. Only turbines destined for land-based (not offshore) wind sites are included.



Sources: Berkeley Lab, annual financial reports, forecast providers

Figure 41. Reported wind turbine transaction prices over time

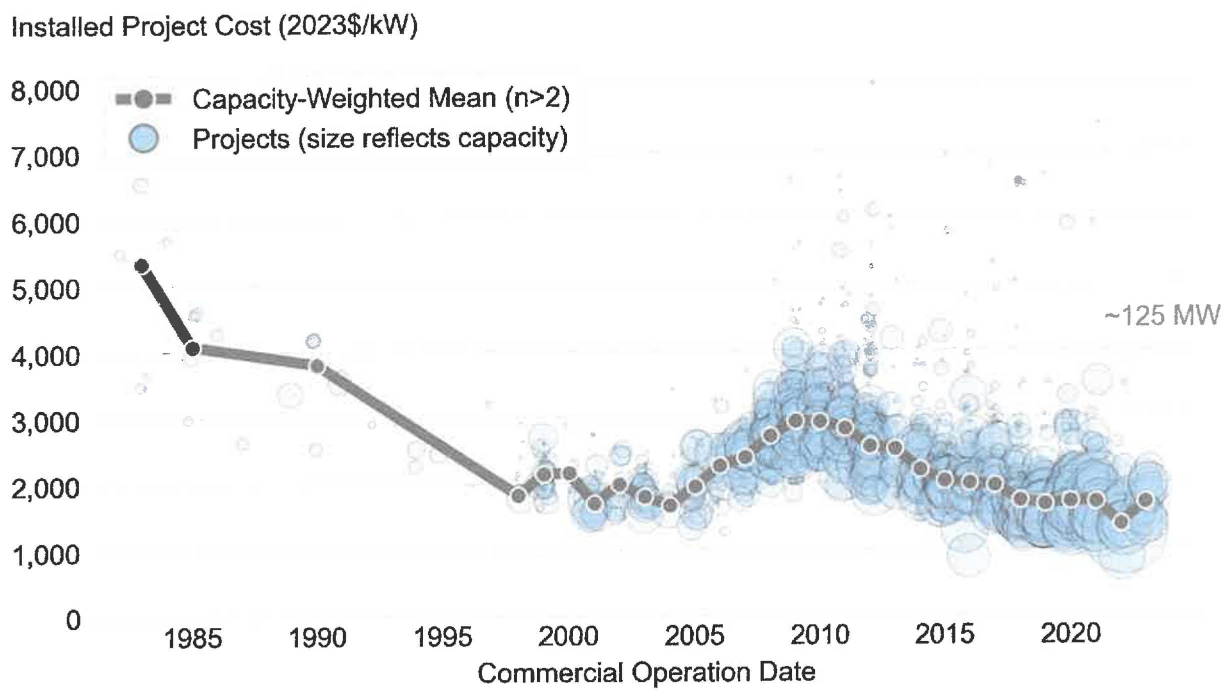
After hitting an initial low of roughly $1,000/kW, on average, from 2000 to 2002, wind turbine prices more than doubled, rising to an average of over $2,000/kW in 2008. This increase in turbine prices was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability; and increased costs for turbine warranty provisions (Moné et al. 2017).

Wind turbine prices have declined by more than 50% since 2008, in part reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as significant cost-cutting measures on the part of turbine and component suppliers. Supply-chain pressures and elevated commodity prices led to increased turbine prices from 2020 to 2022—trends that began to moderate in 2023, with prices flat or somewhat lower than in 2022. Data indicate average pricing in the range of $900/kW to $1,100/kW over the last year.

Despite recent fluctuations in turbine prices, average reported installed project costs have held surprisingly steady since 2018

Berkeley Lab also compiles available data on the total installed cost of land-based wind projects in the United States, including data on 19 projects completed in 2023 and totaling 2.9 GW—45% of the wind power capacity installed in that year. In aggregate, the dataset includes 1,260 completed, land-based wind power projects in the continental United States installed from the early 1980s through the end of 2023. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.

As shown in Figure 42, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of that decade before peaking in 2009–2010. Project-level costs have since declined back to levels seen in the early 2000s—and, since 2018, have largely held steady at ~$1,700/MW on a capacity-weighted average basis. (The outlier year shown in the figure, 2022, reflects a limited cost sample dominated by a small number of low-cost projects).



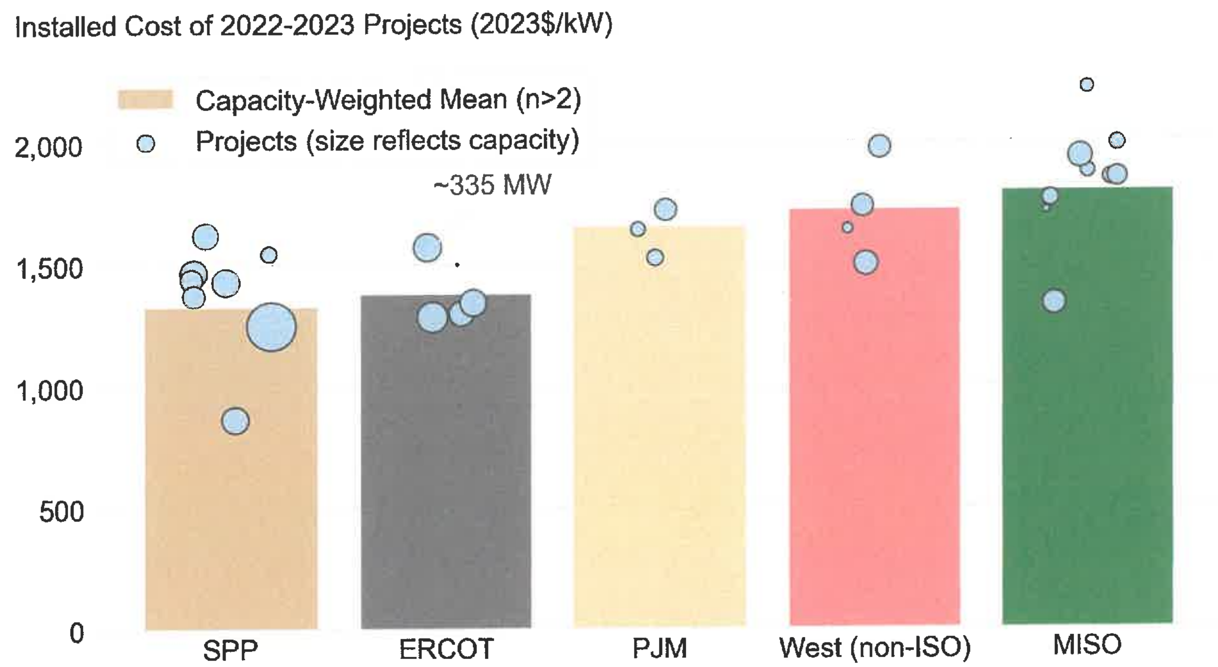
Note: Smallest bubble size reflects smallest wind project (< 1 MW), whereas largest bubble size reflects largest wind project (> 1,000 MW)
Sources: Berkeley Lab, EIA (some data points suppressed to protect confidentiality)

Figure 42. Installed wind power project costs over time

Recent installed costs differ by region, with SPP and ERCOT featuring the lowest costs

Regional differences in average project costs are also apparent and may occur due to variations in labor costs, development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in average project size and the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources, or taller towers in areas with higher wind shear).

Because sample size for both 2022 and 2023 is limited, Figure 43 combines data from both years. (Even after combining years, some regions do not have enough data to warrant inclusion.) As shown, the lowest-cost projects in recent years have been in SPP (averaging $1,320/kW) and ERCOT (averaging $1,370/kW). Higher average costs are observed in MISO, the non-ISO West, and PJM.

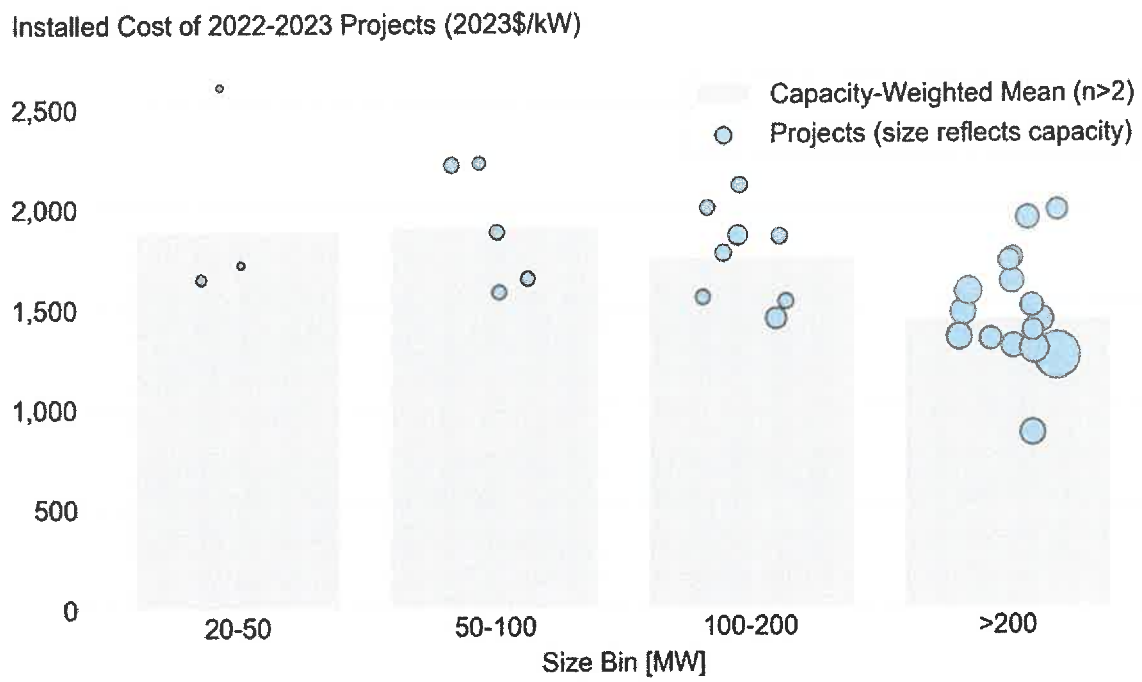


Notes: Other regions lack adequate data for inclusion; bubbles reflect projects that range from roughly 2 MW to 1,000 MW
Source: Berkeley Lab

Figure 43. Installed cost of 2022 and 2023 wind power projects by region

Installed costs (per megawatt) generally decline with project size, and are lowest for projects over 200 MW

Installed project costs exhibit economies of scale. Among a sample of projects installed in 2022 and 2023 (Figure 44), economies of scale are evident when moving from smaller projects to larger projects. There is an especially apparent drop in average costs for the largest projects in the sample.



Note: Bubbles reflect projects that range from roughly 2 MW to 1,000 MW

Source: Berkeley Lab

Figure 44. Installed wind power project costs by project size: 2022 and 2023 projects

Operations and maintenance costs varied by project age and commercial operations date

Operations and maintenance (O&M) costs are a key component of the overall cost of land-based wind energy and can vary among projects. Unfortunately, publicly available data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the changes in wind turbine technology that have occurred over time (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 211 installed, land-based wind power projects, totaling 25,566 MW and with commercial operation dates of 1982 through 2022.[35] These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects and so may not be broadly representative. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M data are available for just a subset of years of project operations. Although not all data sources clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the wind project, as well as rent.[36] Other ongoing expenses, including general and administrative expenses, taxes, property insurance,

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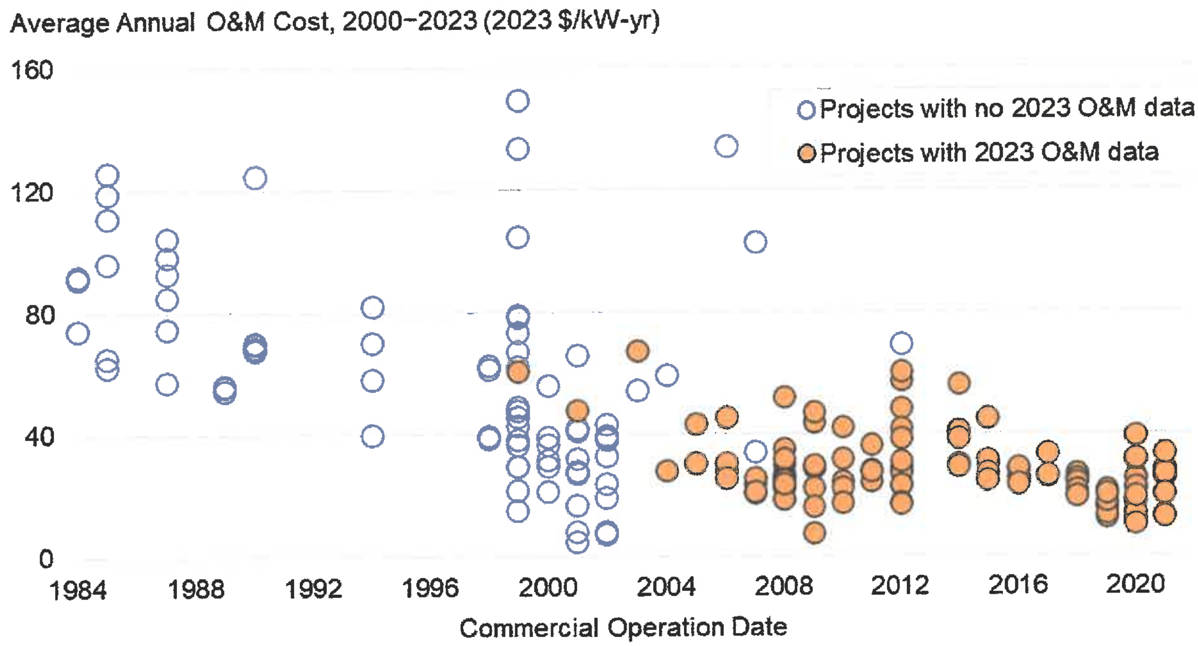
[35] For projects installed in multiple phases, the commercial operation date of the largest phase is used. For repowered projects, the date at which repowering was completed is used. No data for projects installed in 2023 are included, as such projects would not have a full year of O&M data available by the end of 2023.

[36] Most of the recent data derive from FERC Form 1, which uses the Uniform System of Accounts to define what should be reported under "operating expenses"—namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. Though not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under "electric plant" accounts rather than maintenance accounts.

depreciation, and workers' compensation insurance are generally not included. As such, Figure 45 and Figure 46 are not representative of *total* operating expenses for wind power projects.

Figure 45 shows O&M costs by commercial operation date. Here, each project's O&M costs are depicted as average annual O&M costs from 2000 through 2023, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2022, only 2023 data are available, and that is what is shown. Many other projects only have data for a subset of years, so each data point in the chart may represent a different averaging period within the overall 2000–2023 period. The chart shows the 120 projects, totaling 21,318 MW, for which 2023 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

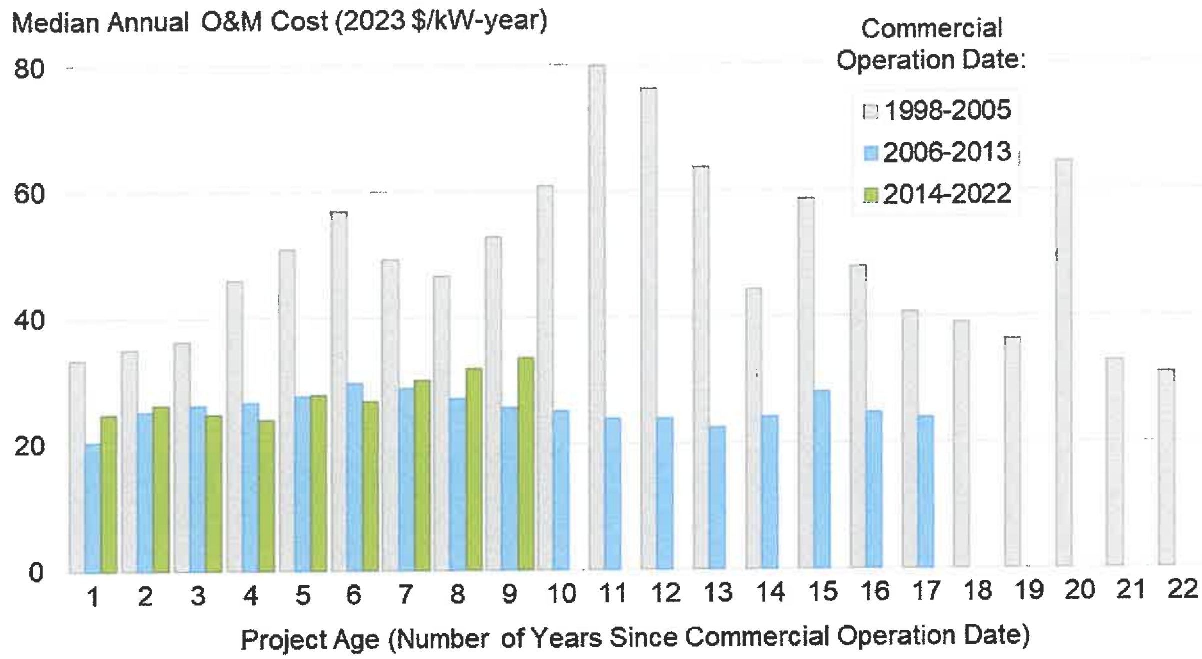


Source: Berkeley Lab; some data points suppressed to protect confidentiality

Figure 45. Average O&M costs for available data years from 2000 to 2023, by commercial operation date

The data demonstrate that O&M costs are far from uniform across projects. Figure 45 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2023 O&M costs for the 24 projects in the sample constructed in the 1980s equal $80/kW-year, dropping to $66/kW-year for the 37 projects installed in the 1990s, to $30/kW-year for the 65 projects installed in the 2000s, $27/kW-year for the 59 projects installed in the 2010s, and $20/kW-year for the 26 projects installed since 2020. This decline may be due to at least two factors: (1) O&M costs may tend to increase as turbines age and component failures become more common; and (2) projects installed more recently, with larger and more mature turbines and more sophisticated O&M practices, may experience lower overall O&M costs.

Limitations in the underlying data do not permit the influence of these two factors to be clearly distinguished. Nonetheless, to help illustrate key trends, Figure 46 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Though sample size is limited, the data show a general upward trend in project-level O&M costs as projects age, at least for two of the three age cohorts and through the first decade of project life. Figure 46 also shows that projects installed over the last 17 years have had, in general, lower O&M costs than those installed in the earlier years of 1998–2005, at least for the first 17 years of operation.



Source: Berkeley Lab; medians shown only for groups of two or more projects, and only projects >5 MW are included

Figure 46. Median annual O&M costs by project age and commercial operation date

As indicated previously, these data include only a subset of total operating expenses. A U.S. wind industry survey of total operating costs suggests that the costs reported in Figure 45 and Figure 46 may constitute less than half of total operating costs—other ongoing expenses include property taxes, insurance, asset management, and more (Wiser et al. 2019).

7 Power Sales Price and Levelized Cost Trends

Wind power purchase agreement prices have drifted higher since about 2018, with a recent range from below $20/MWh to more than $40/MWh

Earlier chapters documented trends in capacity factors, installed project costs, and O&M costs for land-based wind projects—all of which are determinants of the wind power purchase agreement (PPA) prices and levelized cost of energy (LCOE) estimates presented in this chapter.

Berkeley Lab collects data on wind PPA prices, resulting in a dataset that includes 560 PPAs totaling more than 58 GW from land-based wind projects that have either been built or are planned for installation later in 2024 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs; a later text box highlights REC prices), and most of them have a utility as the counterparty.[37] Except where noted, PPA prices are expressed on a levelized basis over the full term of each contract and are reported in real 2023 dollars.[38] Whenever individual PPA prices are averaged together, the average is generation-weighted. Whenever they are broken out by time, the date on (or year in) which the PPA was executed is used. Because PPA prices are reduced by the receipt of state and federal incentives and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. Accordingly, at the end of this chapter, the data presented earlier in this report are leveraged to estimate project-level and average wind LCOE for a large sample of U.S. wind projects.

Figure 47 plots contract-specific levelized wind PPA prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region. As a result of the low average project costs and high average capacity factors shown earlier in this report, ERCOT and SPP tend to be the lowest-priced regions. Of note, PPA prices have not smoothly declined over time. Instead, prices declined through 2003, then rose though 2009 with the increased turbine and installed costs presented earlier as well as with general price increases during this period in the power and natural gas markets. Following that rise was a steep reduction and, more recently, stabilization and then an increase in PPA prices—partly due to supply chain pressures, including higher material prices and transportation costs. These same supply chain and inflationary pressures may have led to some renegotiations of previously agreed-upon PPA prices among plants not yet built.

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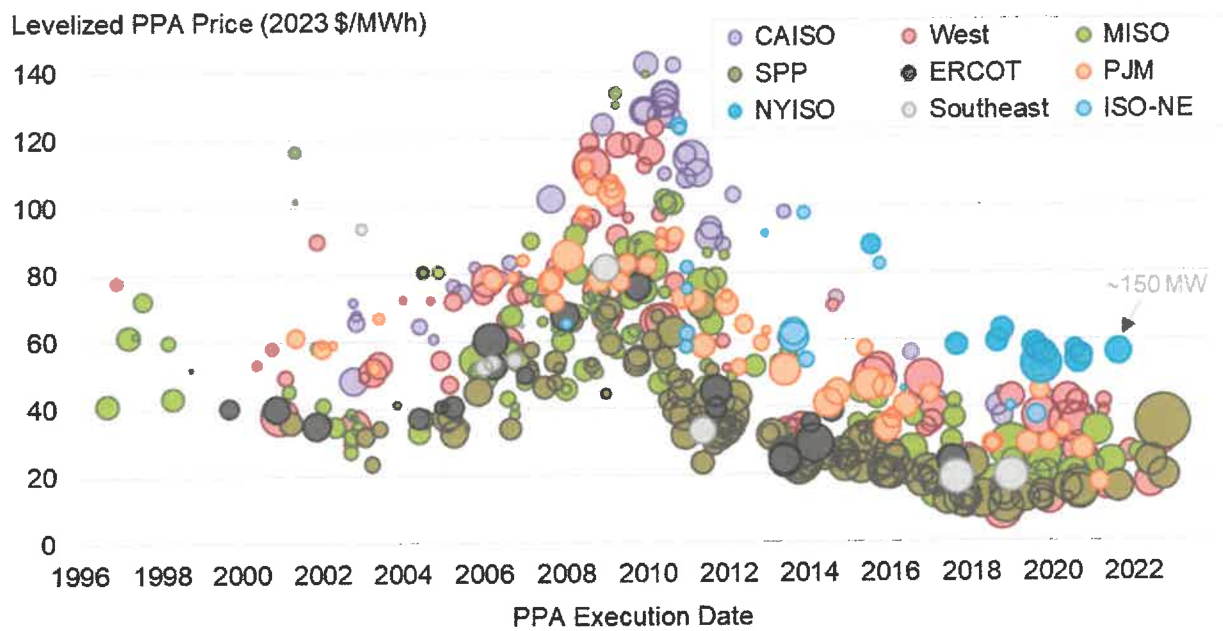
37 Though some PPAs with corporate offtakers are included in the sample, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters a "contract for differences" with the corporate offtaker around an agreed-upon strike price. Because the strike price is not linked to the sale of electricity, it is rarely disclosed (at least through traditional sources, like regulatory filings). Data from LevelTen Energy presented later in this chapter, however, sheds more light on trends in corporate PPA prices.

38 Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables these PPA prices to be presented on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 35 years, with 20 years being the most common. Prices are levelized using a 4% real discount rate.

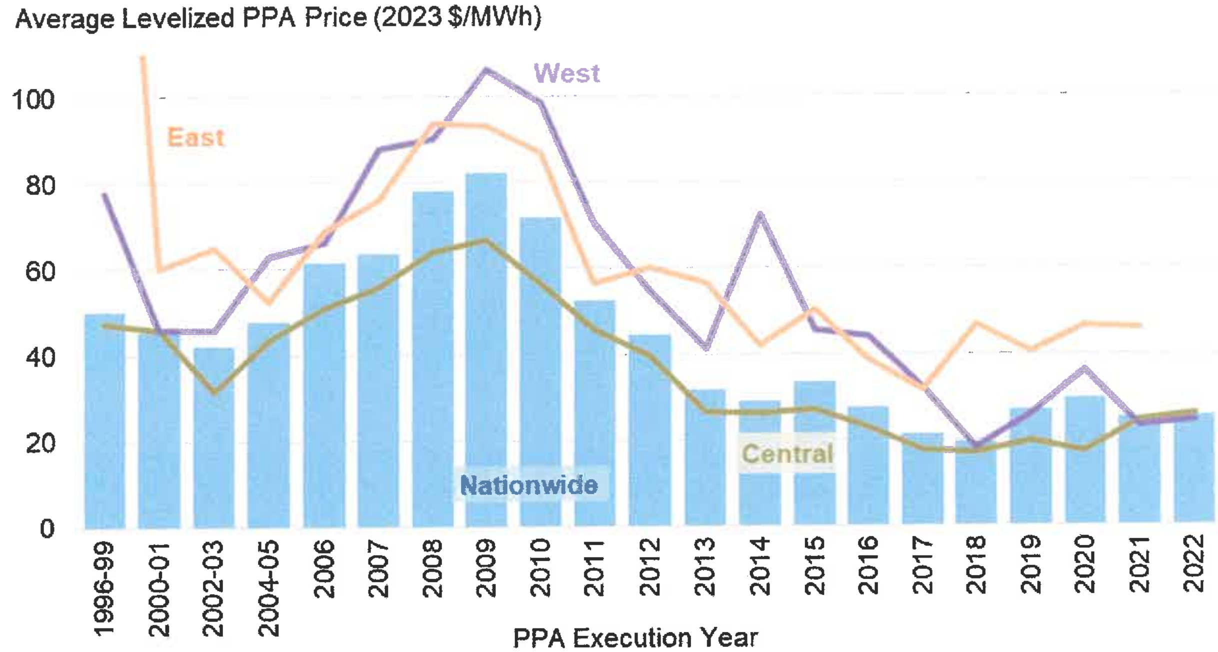


Note: Smallest bubble sizes reflect smallest-volume PPAs (<5 MW), whereas largest reflect largest-volume PPAs (>500 MW)

Source: Berkeley Lab, FERC

Figure 47. Levelized wind PPA prices by PPA execution date and region (full sample)

Figure 48 provides a smoother look at the time trend nationwide and regionally by averaging the wide range in individual levelized PPA prices shown in Figure 47, and consolidating the regional breakdown into just three categories: West, Central, and East. After topping out at over $80/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample dropped to $20/MWh for PPAs executed in 2018. Since then, prices have increased. Though our sample size in the last few years has been small, pricing in 2021 and 2022 appears to have averaged around $25/MWh in the Central and West regions of the country, with higher average prices in the East (~$45/MWh).



Note: West = CAISO, West (non-ISO); Central = MISO, SPP, ERCOT; East = PJM, NYISO, ISO-NE, Southeast (non-ISO)

Source: Berkeley Lab, FERC

Figure 48. Generation-weighted average levelized wind PPA prices by PPA execution date and region

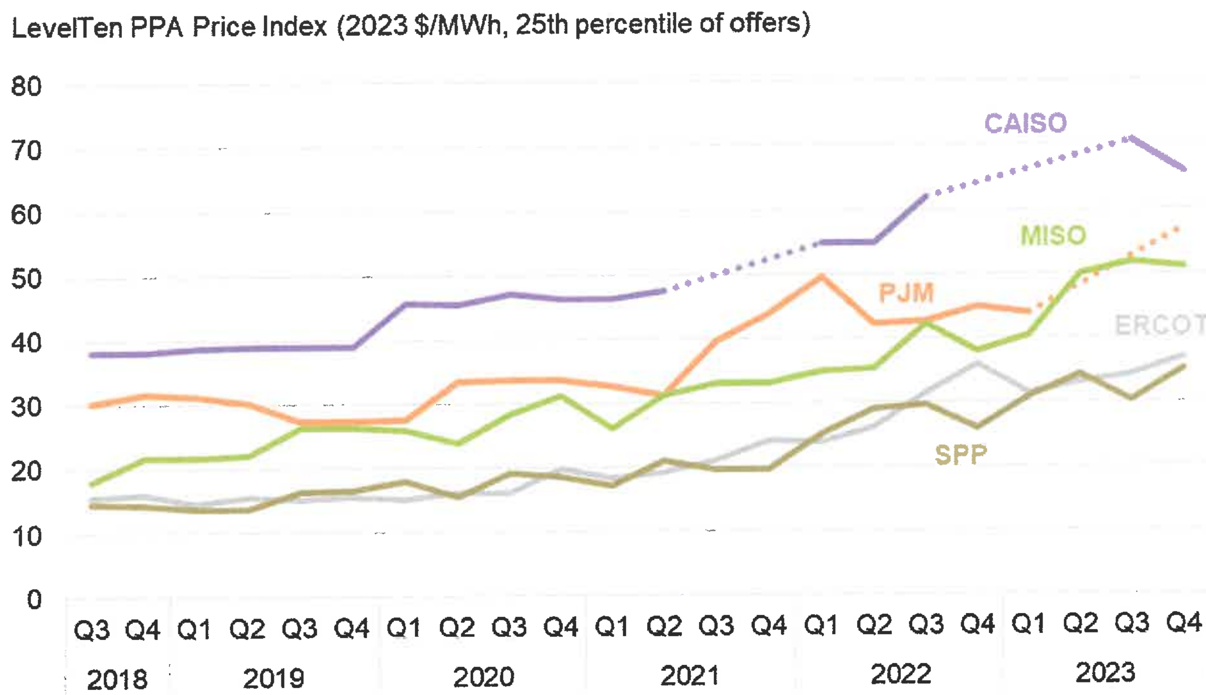
LevelTen Energy's PPA price indices confirm rising PPA prices and regional variation

In contrast to the PPAs summarized above, which principally involve utility purchasers, LevelTen Energy (2024) provides an index of land-based wind PPA offers made to large, end-use customers.

Each quarter, the LevelTen Energy PPA Price Index reports the prices that wind and solar developers have offered for PPAs available on the LevelTen Marketplace. Contract terms tend to range from 10 to15 years, reflective of the shorter terms typically pursued by end-use customers that purchase wind energy relative to the utility PPAs summarized earlier. Price data are aggregated and reported in nominal dollars on a 'P25' basis, referring to the most competitive 25th percentile of offer prices.[39]

As shown in Figure 49, prices have risen over the last couple years, and vary by ISO; here, LevelTen data are converted to real, levelized 2023$ to enhance comparability with data presented elsewhere in this report. Among regions reporting data, CAISO features the highest wind PPA pricing (~$65/MWh in the fourth quarter of 2023 when converted to levelized real dollar terms), whereas the lowest prices are in SPP and ERCOT (~$35/MWh in the fourth quarter of 2024). In real dollar terms, LevelTen's reported price trends since 2018 are broadly similar to those described in the prior section but show continued price increases in 2023.

[39] Note that these are PPA offers, not signed PPAs. Reporting the most competitive offers likely better reflects those offers that result in signed PPAs than the average or median offer.



Note: Dashed lines represent interpolations between data points where intermediate data are missing.

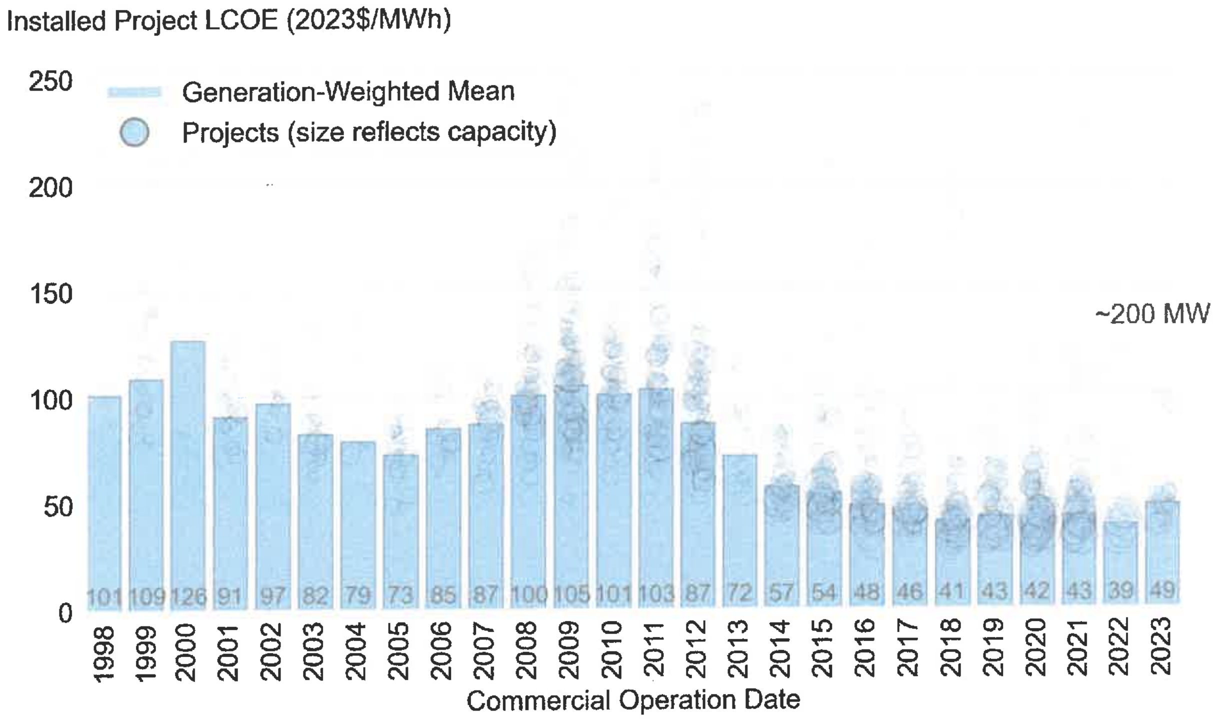
Source: LevelTen Energy

Figure 49. LevelTen Energy wind PPA price index by quarter of offer

Among a sample of projects built in 2023, the (unsubsidized) average levelized cost of wind energy is estimated to be $49/MWh

In a competitive market, long-term PPA prices can be thought of as reflecting the LCOE reduced by the value of any incentives received (e.g., the PTC). Hence, as a first-order approximation, LCOE can be estimated simply by adding the levelized value of incentives received to the levelized PPA prices. LCOE can also be estimated more directly from its components, and Berkeley Lab has data on both the installed cost and capacity factor of 129 GW of land-based wind projects installed from 1998 through 2023, representing 85% of all capacity built over that period. Here, those data are used, in conjunction with estimates of operational costs, financing costs, project life and other factors, to estimate LCOE in real 2023 dollars (see the Appendix for details on the data and calculations). One benefit of this "bottom up" approach to estimating LCOE is that it relies on a large sample of project-level installed cost and performance data, covering more projects than the PPA sample.

Figure 50 depicts the resulting average LCOE values over time on a national basis. As shown, average wind LCOE declined from over $100/MWh in 1998–2000 to $73/MWh in 2005, before rising to around $100/MWh in 2008-2011. Subsequently, average LCOE declined rapidly through 2018, to $41/MWh, but has since held steady or increased—to $49/MWh among a sample of 19 projects that started operation in 2023. The rise in LCOE in 2023 is due, in part, to a higher cost of capital (particularly cost of debt) and to a decrease in average capacity factors (the 2023 LCOE sample has a greater share of projects in the Great Lakes region and fewer projects in the wind-rich Interior region). As more data become available over time, the estimated average LCOE for 2022- and 2023-vintage plants could change.[40]



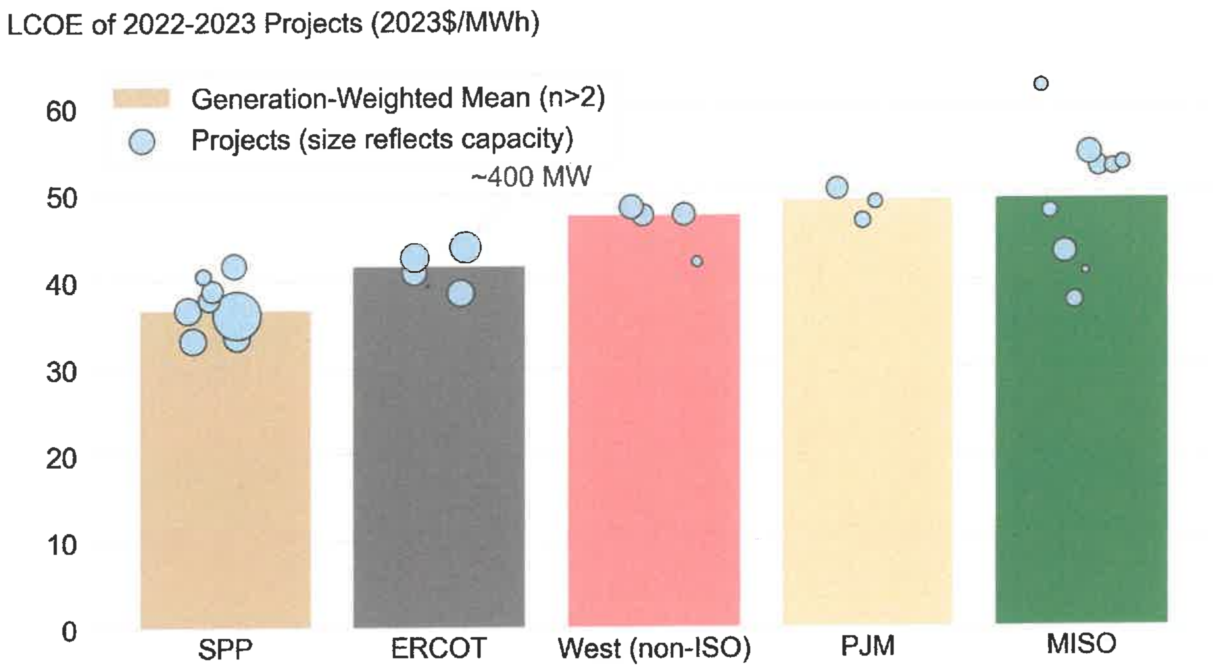
Note: Smallest bubble size reflects smallest wind project (< 1 MW), whereas largest bubble size reflects largest wind project (> 1,000 MW)
Source: Berkeley Lab

Figure 50. Estimated levelized cost of wind energy by commercial operation date

Levelized costs vary by region, with the lowest costs in SPP and ERCOT

Because of the small sample among 2022 and 2023 plants, Figure 51 combines both years (and even then, only has enough data to show five of the nine regions). The lowest average LCOEs for projects built in 2022 and 2023—only considering regions with at least three plants in the sample—are found in SPP ($37MWh) and ERCOT ($42/MWh), with PJM, MISO, and the non-ISO West averaging $47–49/MWh.

[40] Note that, each year, additional data become available that result in revisions to earlier-year data. This can include additional or superior installed cost data, updated capacity factors, changes in the assumed cost of capital, inflation, and more. See the appendix for additional details on the assumptions used in this year's report.



Notes: Some individual outliers may be excluded; Other regions lack adequate data for inclusion; Bubbles reflect projects that range from roughly 2 MW to 1,000 MW

Source: Berkeley Lab

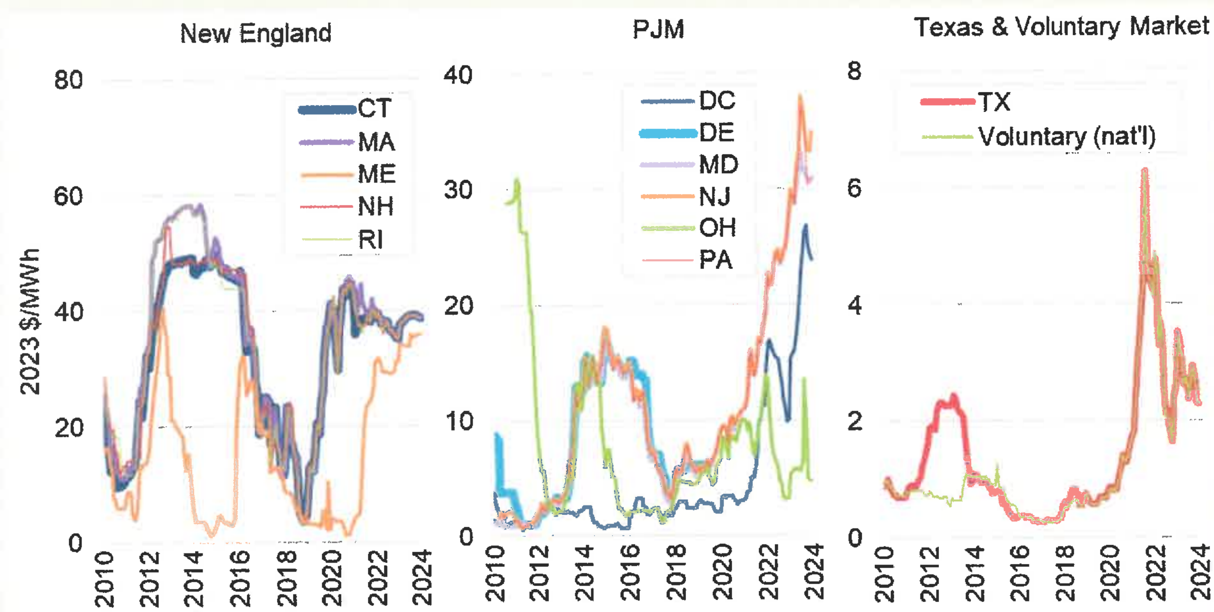
Figure 51. Estimated levelized cost of wind energy, by region

Renewable Energy Certificate (REC) Prices

Wind power sales prices presented in this report reflect bundled sales of both electricity and RECs. Projects that sell RECs separately from electricity, thereby generating two sources of revenue, are excluded. REC markets are fragmented, but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis. Mandatory RPS programs exist in 29 states and Washington, D.C. In recent years, roughly one-third of these states have increased their RPS targets, in many cases to levels ranging from 50% to 100% of retail electricity sales. Voluntary markets for renewable energy have also grown.

The figure below presents indicative data of spot-market REC prices in both compliance and voluntary markets. Spot REC prices have varied, both over time and across states, though prices across states within common regional power markets (New England and PJM) are linked to varying degrees (consequently, several of the lines in the figure overlap).

Data in many compliance markets are at or nearing the alternative compliance payment (ACP) rates, indicating tight or tightening supplies of RPS-eligible resources. Across all of the New England states other than Maine, REC prices held steady over the course of 2023 at just under $40/MWh, the ACP rate for the Class I RPS tier in Massachusetts and Connecticut, the two largest markets in the region. In PJM, REC prices in most states continued their steep upward trajectory from the past several years. Within the premium markets of Maryland, New Jersey and Pennsylvania, prices moved largely in tandem, ending the year at $30/MWh in Maryland (the state's ACP rate) and at roughly $35/MWh in New Jersey and Pennsylvania, an all-time high for both states, though still below their respective ACP rates. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas, which track each other closely and are well below REC prices in most compliance markets, hovered around $3/MWh throughout the year.



Notes: Data for compliance markets focus on "Class I" or "Tier I" RPS requirements; these are the requirements for more-preferred resource types or vintages and are therefore the markets in which wind would typically participate. Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded. REC prices trade at similar levels in a number of markets such that some of the lines in the above graphic overlap.

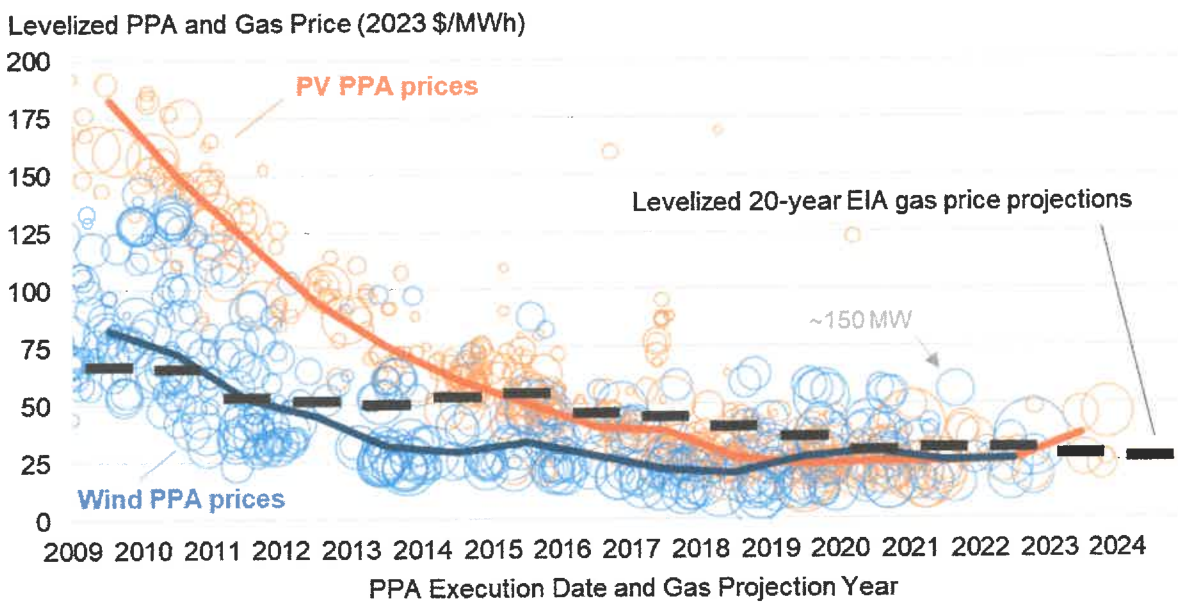
Source: Marex Spectron

8 Cost and Value Comparisons

Despite relatively low PPA prices, wind faces competition from solar and gas

Figure 52 plots land-based wind PPA prices against utility-scale solar PPA prices since 2009 (the blue and gold lines show the generation-weighted average wind and solar PPA prices in each year, respectively). Although the gap between wind and solar PPA prices was quite wide a decade ago, that gap has narrowed, as solar prices fell more rapidly than wind prices.[41]

The figure also shows that wind PPA prices—and, more recently, utility-scale solar PPA prices—have, in many cases, been competitive with the projected fuel costs of gas-fired combined cycle generators. Specifically, the black dash markers show the 20-year levelized fuel costs—converted from natural gas to power terms at an assumed heat rate of 7.5 million British Thermal Units (MMBtu) per MWh—from then-current EIA projections of natural gas prices delivered to electricity generators.[42] Supported by federal tax incentives, the average levelized wind and solar PPA prices within this contract sample have, for many years now, been at or below the projected levelized cost of burning natural gas in existing gas-fired units.



Note: Smallest bubble sizes reflect smallest-volume PPAs (<5 MW), whereas largest reflect largest-volume PPAs (>500 MW)

Sources: Berkeley Lab, FERC, EIA

Figure 52. Levelized wind and solar PPA prices and levelized gas price projections

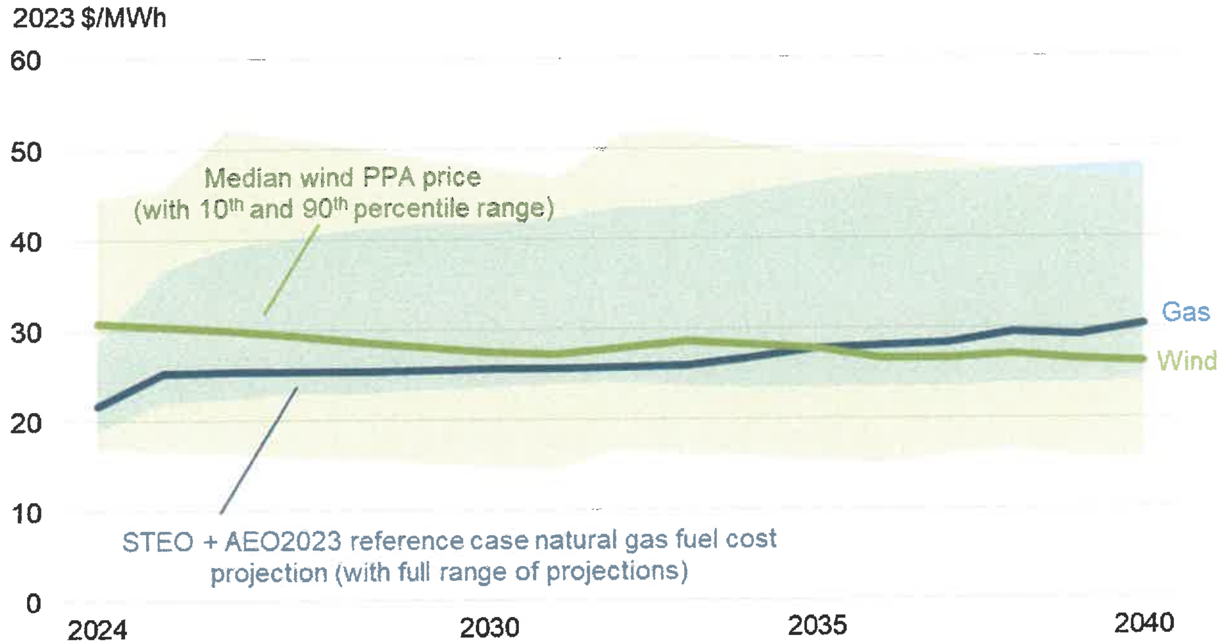
Rather than levelizing the wind PPA prices and gas price projections, Figure 53 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown) from PPAs executed in 2020–2022 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[43] As shown, the 10th-90th percentile range of wind prices is quite wide, due in part to the relatively small sample of contracts signed over

[41] The solar PPA prices are sourced from Berkeley Lab's "Utility-Scale Solar" data series.

[42] For example, the black dash marker in 2009 shows the 20-year levelized gas price projection from Annual Energy Outlook 2009, while the black dash in 2023 shows the same from Annual Energy Outlook 2023 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh).

[43] The fuel cost projections come from the EIA's *Short-Term Energy Outlook* (June 2024) and *Annual Energy Outlook 2023* publications. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. Fuel prices are converted from $/MMBtu into $/MWh based on heat rates implied by the modeling output.

this period. The median wind PPA price hovers around $30/MWh through 2040, and over most of that period falls squarely within the range of fuel cost projections.



Sources: Berkeley Lab, FERC, EIA

Figure 53. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 53 also hints at the long-term value that wind power might provide as a "hedge" against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could be lower or higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the duration of the forecast increases.

The grid-system market value of wind declined in 2023 across all regions and was often lower than recent wind PPA prices

In many regions of the country, wind projects participate in organized wholesale electricity markets. In some cases, wind projects directly bid into those markets, and earn the prevailing market price. In other cases—especially when a PPA is in place—the wind purchaser will schedule the wind energy into the market, paying the wind project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price. PPAs between wind generators and commercial customers are often a hybrid of these two models.

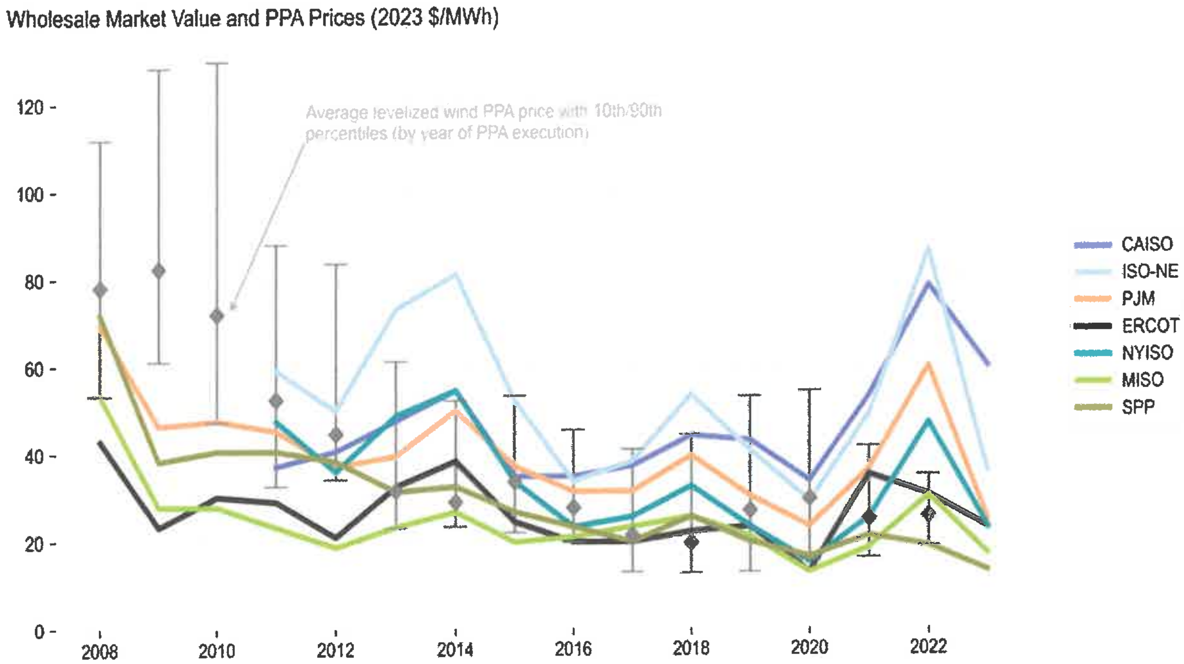
In all these cases, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, sales into wholesale markets create revenue for the plant equal to its market value. In the case of wind projects sold under a PPA, on the other hand, the pre-negotiated PPA price establishes plant revenue. Even in this latter case, however, the revenue that would have been earned by the sale of wind in the wholesale market still reflects the underlying market value of that wind—but in this instance, for the purchaser, in the form of an avoided cost. This is because wholesale electricity prices reflect the timing of when energy is cheap or expensive and embed the cost of transmission congestion and losses. A purchaser could, in theory, obtain power from the wholesale market instead of from a wind project. A wind project's estimated revenue participating in the wholesale market therefore reflects costs avoided by the purchaser of wind under a PPA.

This (potential) revenue—or value—can be segmented into "energy" market value and, where capacity markets or requirements exist, "capacity" value. Wholesale energy prices vary over time and by location. They are strongly influenced by the cost of natural gas. Because wind power deployment is sometimes concentrated in areas with limited transmission capacity, wholesale energy prices at the local pricing nodes to which wind plants interconnect are often suppressed and the relationship to the cost of natural gas is diminished. Even absent transmission constraints, wind plants push wholesale energy prices lower when wind output is high. More generally, the temporal profile of wind output is not always well-aligned with customer load and system needs, potentially further reducing the energy market value of wind generation. Some of these tendencies also apply to wind's capacity value, which is impacted by the cost of capacity but also by regional rules that define the credit that wind receives for providing capacity.

Figure 54 shows the estimated historical wholesale energy and capacity market value of land-based wind across different regions of the country. Specifically, the energy market value of wind is estimated using plant-level hourly wind output profiles and real-time hourly wholesale energy pricing patterns at the nearest pricing node (i.e., locational marginal prices, LMPs). Plant-level capacity values are estimated based on the relevant capacity price or cost for the region in question, and local rules for wind's capacity credit.[44] Energy and capacity values are summed for each plant, and plant-level total value estimates are then averaged to estimate regional values. As a result, the analysis considers the output profile of wind, the location of wind, and how those characteristics interact with local wholesale energy and capacity prices and rules, yielding an estimate of the revenue that would have been earned had wind sold its output at the hourly LMP and considering any possible capacity-based revenue. The figure then contrasts those wholesale market value estimates for wind with nationwide generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) based on the years in which the PPAs were executed. The comparison between market value estimates and PPA prices is relevant in as much as PPA prices reflect the cost of wind to the purchaser, whereas wholesale market value reflects a portion of the value of that wind generation.

These estimates show that the wholesale market value of wind varies strongly by region. The market value of wind generally declined through 2020, increased in 2021, and then spiked in 2022 before dropping precipitously in 2023. Average wind PPA prices tended to well exceed the wholesale market value of wind from 2008 to 2012. With continued declines in PPA prices, however, those prices connected with the market value of wind in 2013 and have remained in competitive territory in subsequent years. This suggests that—with the help of the PTC, which reduces PPA prices—wind developers and offtakers have successfully been contracting at levels that are comparable in terms of both cost and value. In 2020, natural gas and wholesale electricity prices hit new lows, in part because of the economic impacts of the pandemic. Natural gas prices then rose in 2021 and again in 2022; in 2022, annual average natural gas prices were higher than in any year since 2008 (in real dollar terms, based on the Henry Hub spot price). With the increase in natural gas and electricity prices, 2022 wind market values rose to levels last seen in 2014 in several regions and were higher than recent PPA prices in many locations. However, those high market values for wind were temporary, with 2023 seeing a steep decline in natural gas prices and wind's market value across all ISO regions.

[44] The Appendix provides additional details on the methods used to estimate the wholesale energy and capacity value of wind.



Note: Hourly wind output profiles and wholesale prices are not available for all historical years for all regions.

Sources: Berkeley Lab, Hitachi, ISOs

Figure 54. Regional wholesale market value of wind and average levelized long-term wind PPA prices over time

Important Note on Price and Value Comparisons

Notwithstanding the comparisons made in this chapter, neither the wind prices nor wholesale market value estimates (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind (and solar) PPA prices with wholesale value and natural-gas cost estimates in this manner are the following:

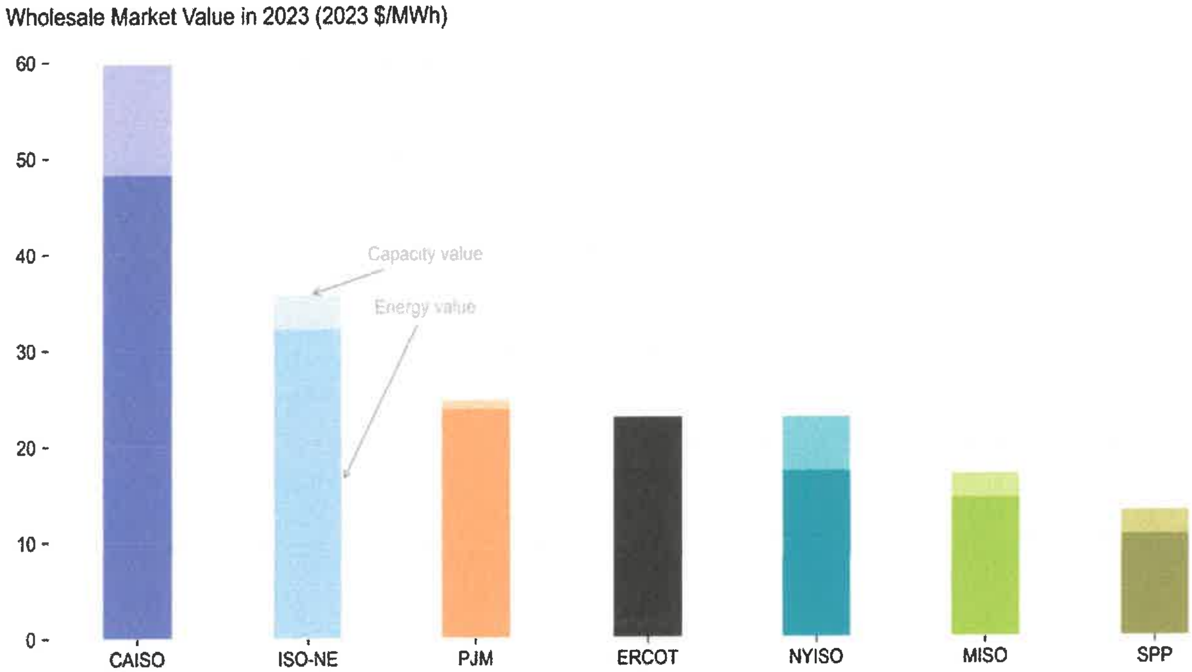
- Wind (and solar) PPA prices are reduced by federal and state incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by any financial incentives provided to thermal generation and its fuel production. Wholesale prices do not fully account for the health and environmental costs of various generation technologies (though a later section within this chapter assesses the health and climate benefits of wind), and for other societal concerns such as fuel diversity and resilience.
- Wind (and solar) PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs and may not fully reflect capital and fixed operating costs.
- Wind and solar PPA prices—once established—are fixed and known. The estimated wholesale market value of wind represents historical values whereas future natural gas prices are uncertain. Said another way, levelized wind (and solar) PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale value estimates are pertinent to just the specific historical years evaluated, and future natural gas prices reflect uncertain forecasts.

In short, comparing levelized long-term wind PPA prices with either yearly estimates of the wholesale market value of wind or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to other generation sources. Nonetheless, these comparisons still provide some sense for the short-term competitive environment facing wind energy and convey how those conditions have shifted over time.

The grid-system market value of wind in 2023 varied strongly by project location, from an average of $13/MWh in SPP to $60/MWh in CAISO

Figure 55 presents estimates of wind's wholesale market value, by region, but only for the latest year—2023. The figure also disaggregates the market value estimates into their constituent parts: energy and capacity.

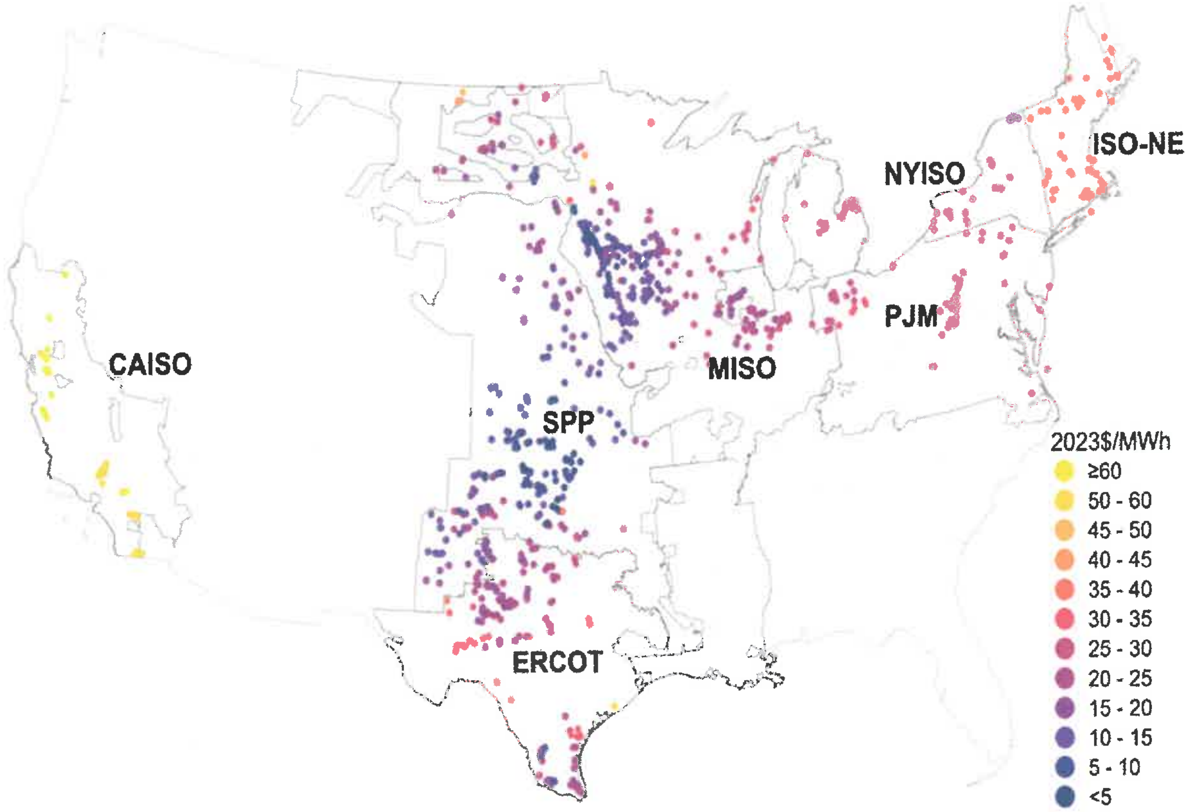
Though wind's market value declined in all regions in 2023, it spanned a wide range. Higher-value regions were CAISO ($60/MWh) and ISO-NE ($36/MWh). PJM ($25/MWh), NYISO ($23/MWh), and ERCOT ($23/MWh) were the next highest markets. The average market value of wind in 2023 was the lowest in SPP ($13/MWh) and MISO ($17/MWh). In all regions, energy value represented the largest share of the total value, with capacity value varying widely regionally and being lower in absolute magnitude.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 55. Regional wholesale market value of wind in 2023, by region

Figure 56 depicts the 2023 wind power market value estimates at a project level. These estimates range widely, with the 10th, 50th, and 90th percentile values equaling $7, $21, and $52 per MWh, respectively. The figure shows variability in market value not only across but also within regions, with within-region areas that face transmission congestion and high wind penetrations generally experiencing lower market value. Higher market value estimates are found in uncongested areas, areas with higher average wholesale prices, and areas where wind output profiles are more correlated with electricity demand. (Developments related to new transmission and wind energy are discussed in an accompanying text box).



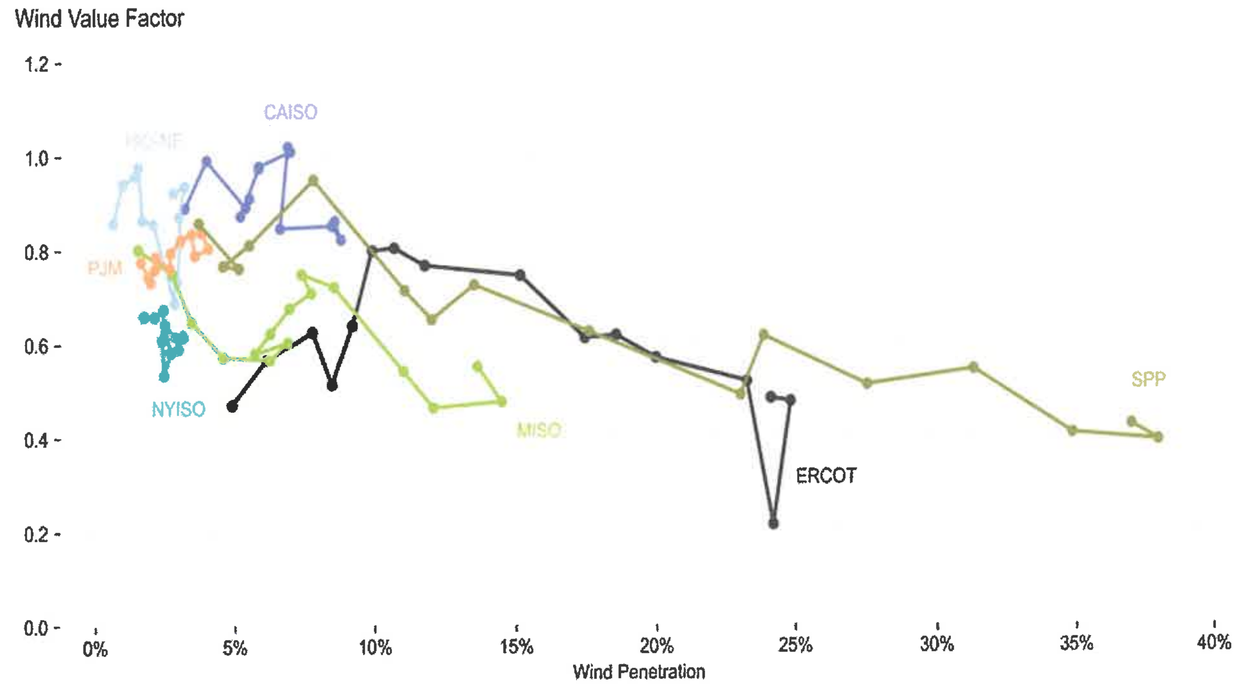
Sources: Berkeley Lab, Hitachi, ISOs

Figure 56. Project-level wholesale market value of wind in 2023

The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment

The regions with the highest wind penetrations (SPP at 37%, ERCOT at 24%, and MISO at 14%) have tended to experience the largest reduction in wind's value relative to the regional average value of a 24x7 flat-profile generator. The "value factor" of wind generation in 2023 was roughly 0.4, 0.5, and 0.6 in each of these high-penetration regions, respectively. Value factor is calculated separately in each region and represents the ratio of the average value of wind generation to the average value of a 24x7 flat profile at all generator locations. The 2023 wind value factor in NYISO was 0.6 but was higher in ISO-NE (0.9), CAISO (0.9), and PJM (0.8).

The progression of each region's value factor with wind penetration can be seen in Figure 57. While there is a loose correlation between penetration level and value factor, each region's value factor has progressed along a convoluted path. Millstein et al. (2021) show that differences between the regions' transmission infrastructure, and upgrades to that infrastructure, are primary reasons why value factors do not correlate more closely with penetration level. ERCOT's value factor illustrates this finding. In ERCOT, wind's value factor was 0.5 in 2008 but then increased with the completion of the Competitive Renewable Energy Zone (CREZ) transmission lines before subsequently declining with continuing wind penetration. In 2021, the value factor dropped to 0.2 due to conditions associated with extreme weather, but then rebounded in 2022 and 2023 to 0.5.



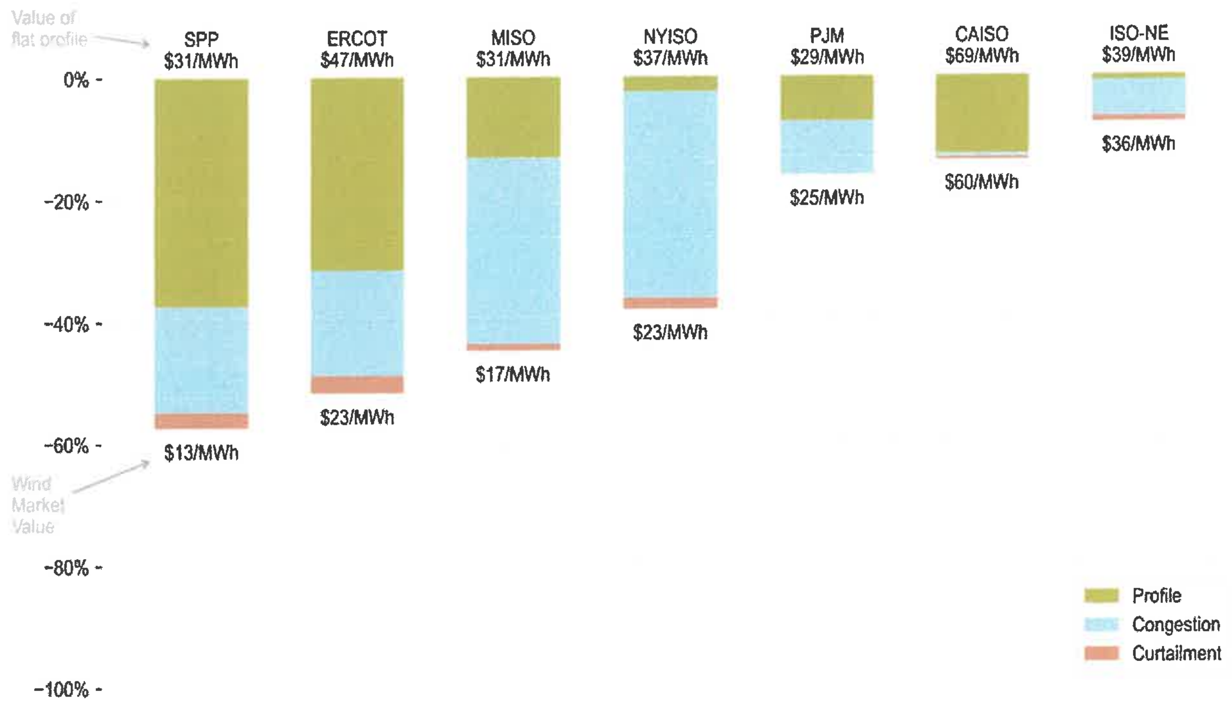
Sources: Berkeley Lab, Hitachi, ISOs

Figure 57. Trends in wind value factor as wind penetrations increase

Using methods further described in Millstein et al. (2021), Figure 58 shows the impact of three separate causes of reduction to the value of wind generation in 2023. As used here, the term value reduction is the opposite of value factor: a total value reduction of 40% would indicate a value factor of 0.6. The three causes of value reduction are: (1) profile value reductions: caused by the temporal correlation of wind generation with low market prices, (2) congestion value reductions: caused by the inability to serve the most valuable locations in a region due to transmission congestion, and (3) curtailment value reductions: caused by curtailment of output, typically due to wind plant operator response to low (usually negative) local prices.

The causes of wind value reductions vary by region. SPP, ERCOT, and PJM value reductions in 2023 were split between profile-based value reductions and congestion value reductions, albeit with wind's output profile playing a somewhat larger role in SPP and ERCOT. In MISO, NYISO, and ISO-NE, on the other hand, congestion-based value reduction dominates. CAISO faces the opposite extreme, with wind's profile being the dominant factor reducing market value. Curtailment value reductions did not reach above 3% in any region.

The value reductions associated with congestion could potentially be addressed with new within-region transmission infrastructure. Conversely, mitigating profile value reductions requires strategies beyond expansion of within-region transmission. Millstein et al. (2021) discusses a range of strategies to address profile value reductions, including cross-regional transmission and storage deployment, new sources of electricity demand sources, and regulatory and rate changes supporting responsive load. Kemp et al. (2023) further explore the relative value to wind (and solar) plants of adding energy storage versus the value of local transmission expansion, finding that the value of increased regional transmission is larger for wind plants than for solar plants, but that both types of plants see similar proportional value increases for adding energy storage.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 58. Impact of transmission congestion, output profile, and curtailment on wind energy market value in 2023

The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind

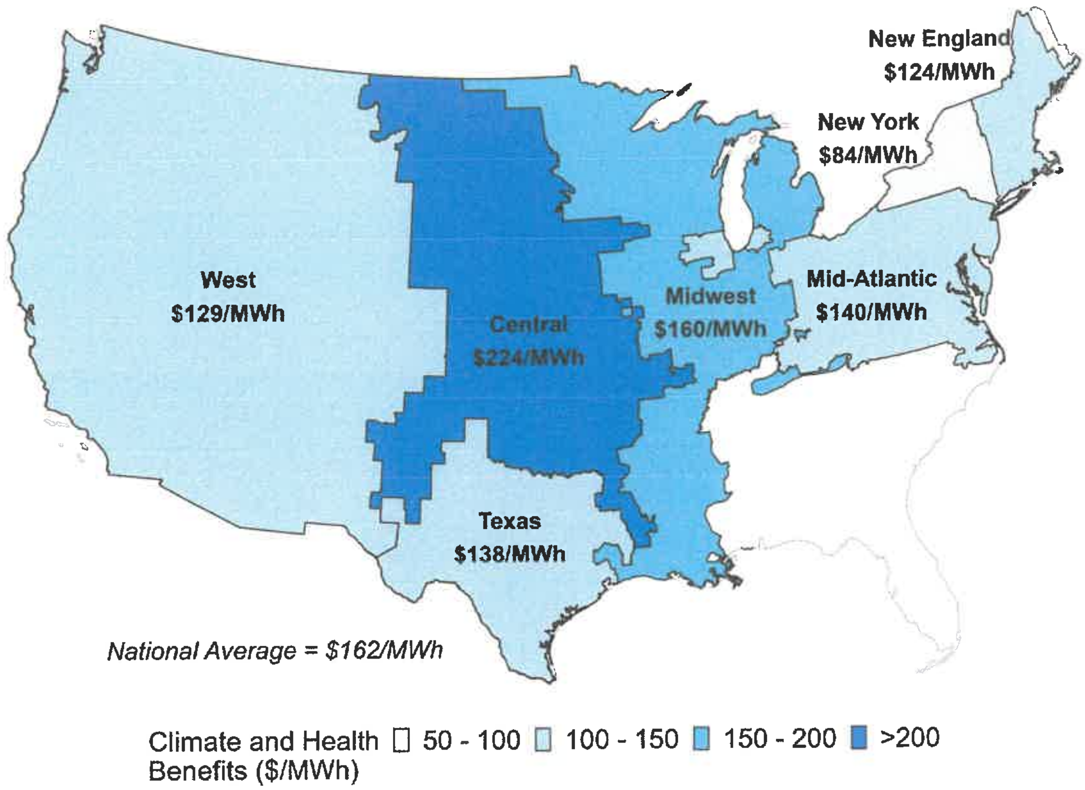
The benefits of wind in reducing health and climate burdens from polluting energy sources are not included in the earlier estimates of grid-system value and the comparisons of that value with PPA prices. Wind generation reduces power-sector emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), and sulfur dioxide (SO_2). These reductions, in turn, provide public health and climate benefits (Millstein et al. 2024). In this section, the health and climate benefits of wind power are estimated and compared, along with grid-system value, to the unsubsidized levelized cost of new wind plants built in 2023.[45]

Using methods described in the Appendix and Millstein et al. (2024),[46] Figure 59 presents the health and climate benefits from wind by region in the year 2023, considering almost all wind plants in the contiguous United States. Nationally, health and climate benefits together averaged $162/MWh-wind. Benefits were largest in the Central ($224/MWh) region and lowest in New York ($84/MWh). In the highest value regions, wind offsets more-polluting power plants than in other regions. Health and climate benefits are not reported in the Southeast due to the small number of wind plants in that region. Regional and national values presented here include both in-region emission impacts as well as cross-region impacts due to electricity trade across

[45] The goal is to compare some of the most important cost and benefit components from a societal perspective, but this comparison is not exhaustive. Not included are considerations of employment; local environmental, ecological, land-use, and community impacts; water use; mercury and primary particulate matter; and transmission or grid-integration costs not covered by grid-value estimates.

[46] Briefly, the per-MWh health and climate benefits of wind were estimated through a two-step process: first, determine the marginal avoided emission rate; second, multiply avoided emissions by a damage rate (i.e., health or climate impacts per ton of pollutant emitted) to determine the damage avoided from wind generation. Marginal avoided emission rates are derived using a regression approach based on Millstein et al. (2024). Damage rates for CO_2 emissions are set to equal the social cost of carbon (EPA 2023), and health damage rates for SO_2 and NO_x come from a suite of reduced complexity air quality health models. Health damage rates vary by the region in which the emissions occurred.

regional boundaries. The West is combined into a single large region due to the magnitude of trade across regional boundaries.

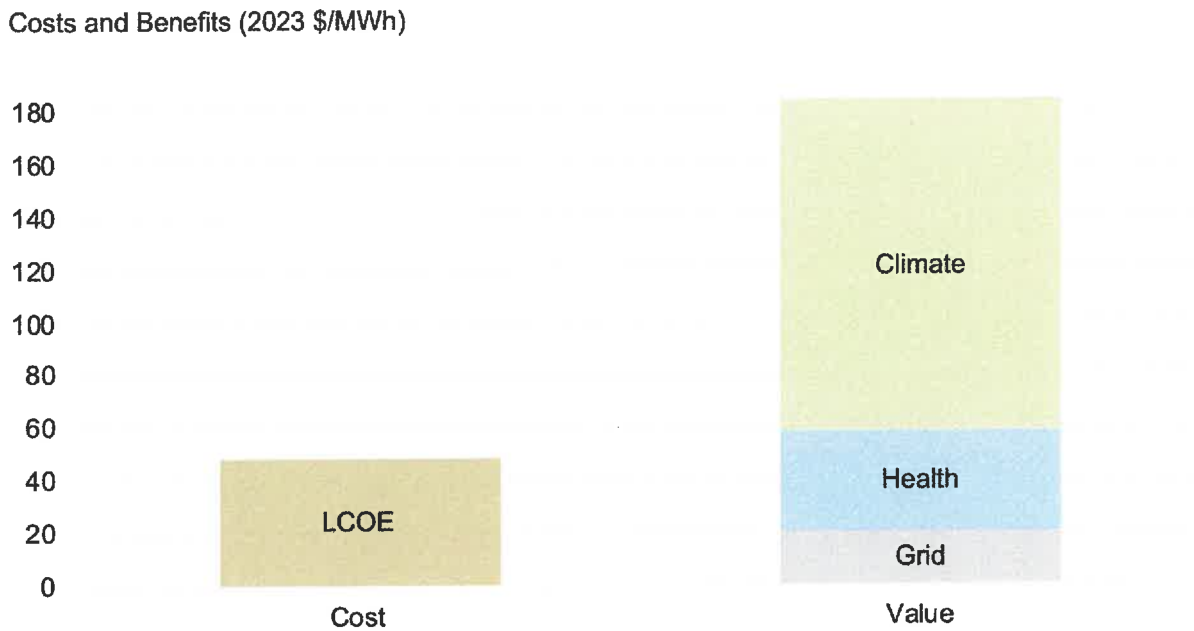


Note: Estimates not provided for the Southeast due to the small number of wind plants in that region.

Sources: Berkeley Lab, Form EIA-930

Figure 59. Marginal health and climate benefits from all wind generation by region in 2023

The national average climate, health, and grid-system value sums to three times the average LCOE of wind plants that came online in 2023 (see Figure 60). Climate benefits refer to reduced global damages from climate change and reflect the largest of the estimated values. Health benefits—which tend to be more regional in nature—are also significant. One caveat is that each national estimate is based on a slightly different regional weighting of plants – LCOE based on a set of recent plants, health and climate benefits based on the average national value from nearly all plants, and grid-system value based on all plants in the seven ISO/RTOs. These differences are not large enough to meaningfully impact the disparity between the LCOE and value estimates.



Sources: Berkeley Lab, EIA Form 930

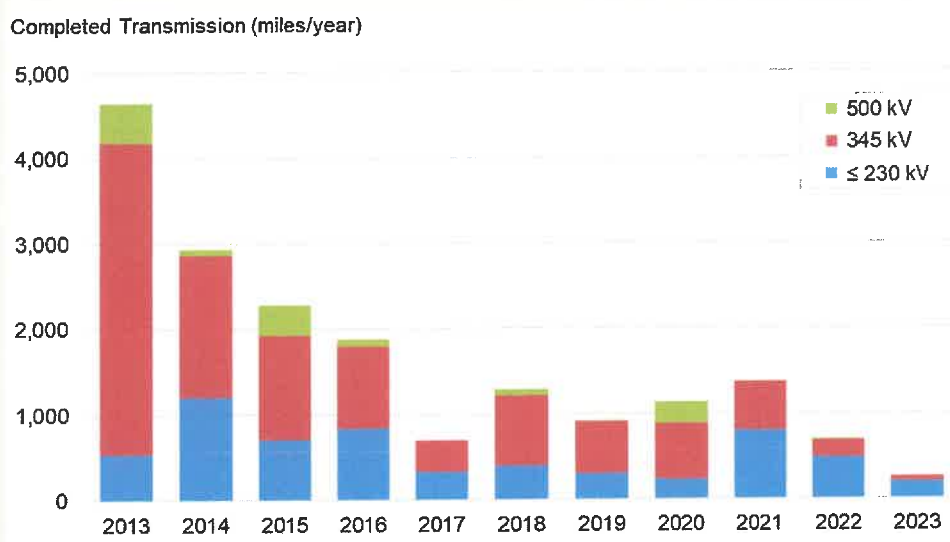
Figure 60. Marginal health, climate, and grid-value benefits from new wind plants versus LCOE in 2023

For simplicity, single values for health and climate benefits are presented above. However, these values represent central estimates from a range of plausible values. Low and high national health and climate benefit estimates range from \$54/MWh to \$383/MWh, representing the wide 5% to 95% range around the central estimate of \$162/MWh. Further discussion of uncertainty can be found in Millstein et al. (2024).

Transmission Investments and Wind Power

The areas with the greatest wind speeds are often distant from electricity load centers, making wind dependent on transmission infrastructure. Related, the low grid-system market value of wind in some areas of the country is, in part, driven by limited transmission and the resulting grid congestion.

Transmission additions reached a new low in 2023, with just 250 miles of new transmission lines coming online according to the Federal Energy Regulatory Commission (see figure below). The decline since the peak in 2013 is partly due to the completion of the transmission buildout in West Texas in 2013, as well as a significant buildout of larger-scale transmission in SPP and MISO in that same period. Since that time, much of the transmission buildout in the Unites States has focused on local reliability projects, and not the large-scale, long distance new transmission intended in part to access wind resources.



Source: FERC monthly infrastructure reports

A compilation of proposed transmission projects by the North American Electric Reliability Corporation shows similar trends. Proposals for future circuit miles dropped from 3,400 miles/year for the 2008–2014 reporting years (20% motivated by variable renewable integration vs. 55% for reliability) to 2,400 miles/year for the 2015–2023 reporting years (7% for renewable integration vs. 65% for reliability).[47]

Data on interconnection queues and transmission congestion provide further evidence of wind's reliance on and challenges with transmission. The median wind project reaching commercial operation in 2023 submitted an interconnection request more than 5 years prior (Rand et al. 2024). Other recent research has found that interconnection costs are on the rise across many regions of the country, and that wind typically faces higher interconnection costs than new natural-gas power plants (Seel et al. 2023).

Turning to transmission congestion, the analysis presented in this chapter finds that within-region transmission congestion reduced the grid-system market value of wind by an average of ~$7/MWh in 2023—a clear signal of the value of new transmission for wind power. Kemp et al. (2024) further find widespread transmission congestion across the United States, including across regional boundaries. Finally, as reported earlier, wind energy curtailment averaged 4.6% in 2023, up from 2.1% in 2016 and yet another signal of transmission constraints and their impact on the wind power sector.

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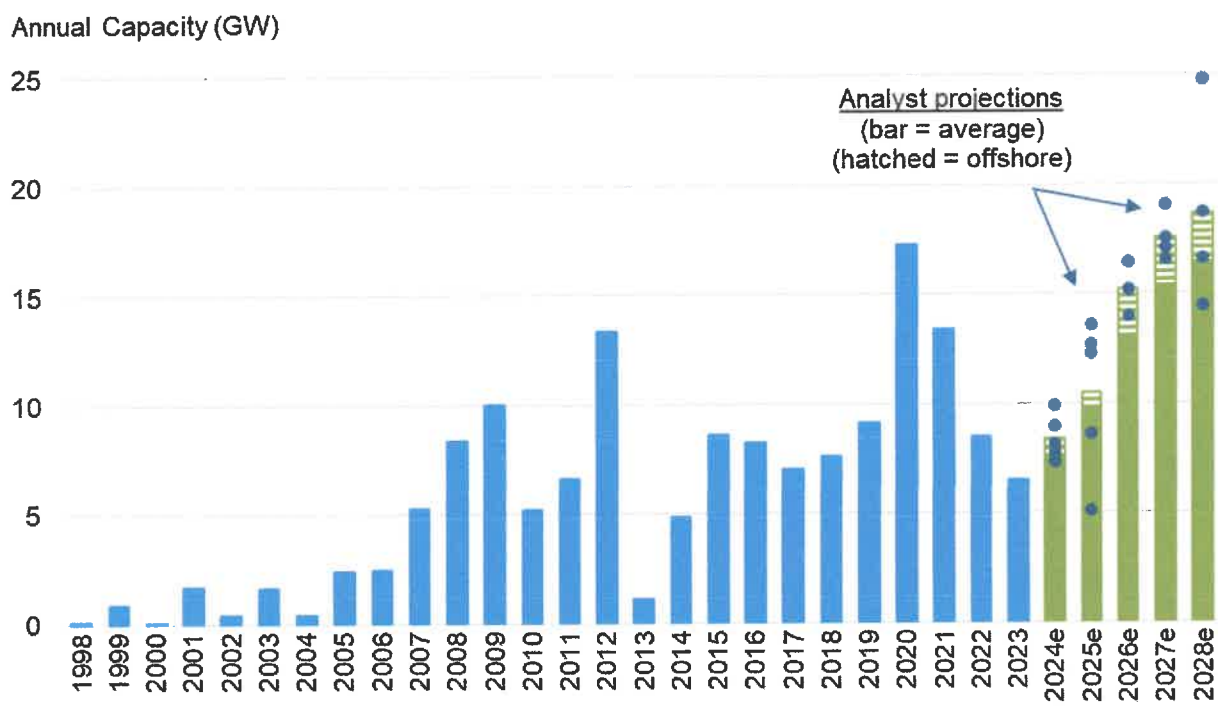
[47] Data are compiled from: https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx. Data include proposed transmission lines over the following 10-year period (e.g., the 2008 dataset reports transmission line proposals for 2009-2018).

9 Future Outlook

Energy analysts project growing wind deployment, spurred by incentives in the Inflation Reduction Act

Energy analysts project that annual total wind additions will grow in the coming years (BloombergNEF 2024, Wood Mackenzie 2024b, GWEC 2024, EIA 2024b, IEA 2023). Among the forecasts for the domestic market presented in Figure 61, expected land-based and offshore wind capacity additions range from 7.3 GW to 9.9 GW in 2024. Subsequent expected annual additions then generally ramp up through 2028, supported by expanded incentives in the Inflation Reduction Act (U.S. DOE 2023) as well as anticipated growth in offshore wind. In 2028, expected additions range from 14.5 GW to 24.8 GW. The majority of the expected additions over this 5-year period and in 2028 come from land-based wind, with offshore wind averaging 11% of the total.

These projected trends are driven in part by the passage of the Inflation Reduction Act in 2022. As noted earlier, IRA contains a long-term extension of the PTC at full value (assuming that new wage and apprenticeship standards are met) along with opportunities for wind plants to earn two 10 percent bonus credits that add to the PTC for meeting domestic content requirements and for being located energy communities. Analysts forecast growing impacts of IRA over time, partly reflecting the fact that wind project development, siting, and interconnection can take many years. Near-term additions are also influenced by the cost and performance of wind technologies, corporate wind energy purchases, and state-level renewable energy policies. Inflation, higher interest rates, limited transmission infrastructure, interconnection costs and timeframes, siting and permitting challenges, and competition from solar may dampen growth.



Sources: ACP, BloombergNEF (2024), Wood Mackenzie (2024b), GWEC (2024), EIA (2024b), IEA (2023)

Figure 61. Wind power capacity additions: historical installations and projected growth

Longer term, the prospects for wind energy will be influenced by the Inflation Reduction Act and by the sector's ability to continue to improve its economic position

The prospects for wind energy in the longer term will be influenced by the implementation of the Inflation Reduction Act, which not only provides extensions and expansions of deployment-oriented tax credits but also new incentives for the buildout of domestic supply chains. Also influencing deployment will be the sector's ability to continue to improve its economic position even in the face of challenging competition from other generation resources, such as solar and natural gas. Growing electricity loads may further motivate additional wind power deployment. Finally, changing macroeconomic conditions, corporate demand for clean energy, and state-level policies will also continue to impact wind power deployment, as will the buildout of transmission infrastructure, resolution of siting, permitting and interconnection constraints, and the future uncertain cost of natural gas.

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Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions and repowering in the United States (as well as certain details on the underlying wind projects) are sourced largely from ACP (2024). Annual wind power capital investment estimates derive from multiplying wind power capacity data by weighted-average capital cost data (provided elsewhere in the report). Data on non-wind electric capacity additions come from EIA (Forms 860 and 861).

Global cumulative (and 2023 annual) wind power capacity data are sourced from GWEC (2024) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Country-level wind energy penetration comes from IEA's Monthly Electricity Statistics.

The wind project installation map was created based on ACP's project database. Wind energy as a percentage contribution to statewide electricity generation and consumption is based on EIA data for wind generation divided by in-state total electricity generation or consumption in 2023.

Data on online hybrid power plants comes largely from EIA (updated when erroneous data are discovered). The wind hybrid/co-located data are compiled from the 2023 early release EIA 860 dataset. Projects are identified as hybrids with two approaches. The first approach involves identifying distinct power plants (e.g., wind and storage) that share the same EIA ID. This approach identifies most of the hybrid data summarized in the report. The second approach involves compiling data from Hitachi's Velocity Suite and matching power plants that have the same Hitachi Plant ID but different fuel types. These plants were then found in the EIA dataset and cross-checked against latitude and longitude information to confirm co-location.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO or utility. For more information, see Rand et al. (2024).

Industry Trends

Turbine manufacturer market share data are derived from the ACP project database. Data on recent U.S. nacelle assembly capability come from ACP (2024), as do data on U.S. tower and blade manufacturing capability. Manufacturer profitability data come from corporate financial reports.

Data on U.S. imports of selected wind turbine equipment come from the Department of Commerce, accessed through the U.S. Census Bureau, and obtained from the U.S. Census's USA Trade Online data tool (https://usatrade.census.gov/). The analysis of the trade data relies on the "customs value" of imports as opposed to the "landed value" and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report.

All trade codes used to track wind equipment imported in 2020 and later are exclusive to wind. In some previous years, some codes are exclusive to wind, whereas others are not. Assumptions are made for the proportion of wind-related equipment in each of the non-wind-specific HTS trade categories. These assumptions are based on: an analysis of trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with U.S. International Trade Commission and wind industry experts; U.S. International Trade Commission trade cases; and import patterns in the larger HTS trade categories.

Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis

HTS Code	Description	Years applicable	Notes
8502.31.0000	wind-powered generating sets	2005–2023	includes both utility-scale and small wind turbines
7308.20.0000	towers and lattice masts	2006–2010	not exclusive to wind turbine components
7308.20.0020	towers - tubular	2011–2023	mostly for wind turbines
8501.64.0020	AC generators (alternators) from 750 to 10,000 kVA	2006–2011	not exclusive to wind turbine components
8501.64.0021	AC generators (alternators) from 750 to 10,000 kVA for wind-powered generating sets	2012–2021	exclusive to wind turbine components
8501.64.0121	AC generators (alternators) from 750 to 10,000 kVA for wind-powered generating sets	2022-2023	exclusive to wind turbine components
8412.90.9080	other parts of engines and motors	2006–2011	not exclusive to wind turbine components
8412.90.9081	wind turbine blades and hubs	2012–2023	exclusive to wind turbine components
8503.00.9545	parts of generators (other than commutators, stators, and rotors)	2006–2011	not exclusive to wind turbine components
8503.00.9546	parts of generators for wind-powered generating sets	2012–2023	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014–2019	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[48]
8503.00.9570	machinery parts for wind-powered generating sets	2020–2023	exclusive to wind turbine components; nacelles when shipped without blades are included in this category

Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of ACP's project database.

Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, and specific power was compiled by Berkeley Lab within the U.S. Wind Turbine Database based on information provided by ACP, turbine manufacturers, standard turbine specifications, the FAA, web searches, and other sources. The data include projects with turbines greater than or equal to 100 kW that began operation in 1998 through 2023. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA "Obstacle Evaluation / Airport Airspace Analysis" data containing prospective turbine locations and total proposed heights, in combination with ACP data on near-term installations, were used to estimate future technology trends. Any FAA data with expiration dates between February 1, 2024 and July 25, 2025 were categorized as either "pending" turbines (for those that already had received an evaluation of "no hazard") or "proposed" turbines (for those that were still being evaluated). A portion of those turbines are categorized by Berkeley Lab, with input from ACP data and Hitachi's Velocity Suite data, as either "under construction" or in "advanced development." The former are projects that have been partially or fully constructed but have not

[48] The explicit inclusion of nacelles without blades was effective in 2014 because of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blades—which are essential to wind-powered generating sets as defined in the HTS.

been fully commissioned. The latter are not under construction but are highly likely to be in the next few years and have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership.

Performance Trends

Wind project performance data come predominantly from EIA Form 923. For performance periods before 2023, EIA data were verified and sometimes replaced with data from FERC's Electronic Quarterly Reports and FERC Form 1 filings, among a few other sources. Where discrepancies existed among these data sources, those discrepancies were handled based on the judgment of Berkeley Lab staff. For the 2023 performance period, we rely exclusively on EIA Form 923. A small amount of data were dropped where reporting errors were likely. Data on curtailment are from ERCOT, MISO, PJM, NYISO, SPP, ISO-NE, and CAISO.

The following procedure was used to estimate the quality of the wind resource in which wind projects are (or are planned to be) located. First, within the U.S. Wind Turbine Database, the location of individual wind turbines and the year in which those turbines were (or are planned to be) installed were identified using FAA Digital Obstacle (i.e., obstruction) files and FAA Obstacle Evaluation / Airport Airspace Analysis files, combined with Berkeley Lab and ACP data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from the average mapped 100-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites) and assuming no losses. For 2023 turbines, gross capacity factors are estimated using just the 100-meter wind speed and a state-level fixed effect based on relationships from the previous ten years (2013-2022). To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100%. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category, which includes all projects or turbines with an estimated gross capacity factor of less than 45%; the "medium" category, which corresponds to ≥45%–52%; and the "higher" category, which corresponds to ≥52%. Separate from wind resource quality, also reported are AWS Truepower estimates of site-average long-term wind speed, both at 100 meters and at hub height. Hub-height long-term wind speed estimates are developed by linearly interpolating between AWS Truepower estimates for 80 and 100 meters. Not all turbines could be mapped by Berkeley Lab for these purposes, but the final sample includes over 99% of turbines installed from 1998 through 2023 in the continental United States. Most of the turbines that are *not* mapped are more than a decade old.

Separate from the above, the relative strength of the average "fleet-wide" wind resource from year to year is estimated based on weighting each operational project-level wind resource (or "wind index") by its share of the total operational fleet-wide capacity for the particular year. For each individual wind plant, an annual wind index is calculated as the ratio of a particular year's predicted capacity factor to the long-term average predicted capacity factor (with the long-term average calculated from 1998-2023). Site-level available wind resources are calculated for each hour of each year based on ERA5 reanalysis wind speed data for each plant's location. ERA5 has a horizontal resolution of ~30 km × 30 km. Site-specific estimated wind speeds (with the geographic resolution previously noted) are interpolated between ERA5 model heights to the corresponding representative hub-height for each wind project. Hourly wind speeds at each project are then converted to wind power by applying project-specific power curves. In this case, power curves are based on the set of turbine-specific power curves derived from NREL's System Advisor Model, v2020.11.29 and vary based on a plant's average specific power (averaged across all turbines in the plant). This use of power curves is a simplification, but one that does account for the shift in wind plant design toward lower specific power turbines. The wind indices are calculated without accounting for wake, electrical, or other losses, or curtailment, and are based only on the ERA5 wind speeds. These indices are used to represent changes in the wind resource from one year to the next and reflect the ERA5-based strength of the total potential wind resource given the types of turbines that are deployed at each site. Note that these data and indices are used to characterize year-to-year variations in the strength of the wind resource, whereas AWS Truepower estimates are used to characterize the strength of the site-specific long-term annual average wind resource. The report uses AWS Truepower estimates for the latter need due to their higher geographic resolution.

Cost Trends

Historical U.S. wind turbine transaction prices were, in part, compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. Additional and more recent data come from Vestas, SGRE and Nordex corporate reports, BloombergNEF, and Wood Mackenzie.

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, EIA Form 860, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, the DOE and Electric Power Research Institute Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively; for projects installed from 2013 through 2021, EIA Form 860 data are used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not all equally credible, less emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer greater insight. Only cost data from the contiguous lower-48 states are included.

Wind project O&M costs come primarily from two sources: EIA Form 412 data from 2001 to 2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. A small number of data points are suppressed in the figures to protect data confidentiality.

Sales Price and Levelized Cost Trends

Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs. Supplemental data from LevelTen Energy are also reported, in both nominal (as reported—see associated data file) and real 2023 dollars. The 2023 dollar conversion assumes that LevelTen's reported prices in each quarter are for 12-year, flat-priced (in nominal dollars) PPAs that commence in the following calendar year. In each quarter, we deflate the 12-year nominal dollar price series to 2023 dollars using the GDP deflator (actual deflators historically, along with projected future deflators from the EIA's *Annual Energy Outlook 2023*), and then levelize the resulting 12-year real-dollar price series using a 4% real discount rate. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.

The analysis calculates the LCOE of wind based on LCOE input data collected, in large part, by Berkeley Lab and presented elsewhere in this report—and assessed as *expected* LCOE as of the listed commercial operation dates. These inputs include capital costs, capacity factors, operational expenses, financing costs, and assumptions about useful life. Specifically:

- For capacity factors, project-level data are levelized over the assumed useful life of each plant. Empirical project-level data are used where available, and performance degradation assumptions derived from our earlier analysis are employed for years in which project-level empirical data are absent (these rates apply for all projects in the sample irrespective of when they commenced service). For projects built in 2023 (that have not yet been operating for a full year), capacity factors are assumed to match the average capacity factor of projects built in the same region from 2020 to 2022.

- Based on Wiser et al. (2019), total operational expenses are assumed to fall from a levelized cost of $98/kW-year in 1998 (expressed in 2023 dollars) to $73/kW-year by 2003, $62/kW-year by 2010, and $52/kW-year by 2018 (and are interpolated linearly between these years). Projects built from 2019-2023 are indexed to the 2018 value but vary by COD year based on BloombergNEF's North American wind O&M price index (e.g., BloombergNEF 2023b). Note that these are projected future costs; actual operational expenditures could diverge from industry expectations, as they have in the past.
- The weighted average cost of capital assumes a 70%:30% debt-to-equity split (possible in the absence of the PTC). The cost of debt varies over time based on historical changes in the 20- and 30-year swap rates and bank spread (1998-2021); since 2022, debt costs are approximated with a 2% premium over a 10-year treasury rate. The assumed cost of equity generally declines over time, though with an uptick in recent years based in part on data from (BloombergNEF 2024). Financing costs are estimated as if the PTC were not available. These are assumptions for future returns; actual returns could differ depending on how performance, operational expenditures and project lifetimes track expectations.
- Project life is assumed to increase linearly from 20 years for projects built in 1998 to 30 years for projects built in 2020 and after, based on industry expectations (see Wiser and Bolinger 2019).
- A 35% corporate tax rate is assumed from 1998–2017 and 21% thereafter, with a constant 5% state tax rate over the entire period. Inflation expectations range from 1.9% to 3.1%. Five-year accelerated depreciation is applied for all vintages of wind projects.

Cost and Value Comparisons

To compare the price of wind to the cost of future natural gas-fired generation, the range of fuel cost projections from the EIA's *Annual Energy Outlook 2023* and *Short-Term Energy Outlook* are converted from $/MMBtu into $/MWh using heat rates derived from the modeling output.

To calculate the historical wholesale energy market value of wind, estimated hourly wind generation profiles are matched to hourly nodal real-time wholesale prices. The capacity value at each plant is also calculated, based on the modeled wind profiles and ISO-specific rules for wind's capacity credit and ISO-zone-specific capacity prices. The resulting estimates reflect the average $/MWh energy and capacity value for each plant and year. ISO-level average values are estimated by weighing plant-level value estimates by plant output.

To calculate the average energy and capacity value in $/MWh, the numerator is based on modeled hourly generation after curtailment, but the denominator is based on the total generation without curtailment. Curtailment is accounted for only in the numerator so that increased levels of curtailment will reduce the average $/MWh value. The MWh, in this case, reflects potential wind generation before curtailment. Note that public data do not broadly exist for hourly wind output profiles at the plant level. Consequently, the modeled wind generation estimates described earlier are leveraged, albeit adjusted for *curtailment* and corrected for *bias*. For modeled hourly profiles we use a different input meteorological model than was used for the wind index calculation described earlier. Instead of ERA5 we use NOAA's High-Resolution Rapid Refresh (HRRR) dataset. Compared to ERA5, HRRR reduces biases and increases hourly correlation to recorded generation (Davidson and Millstein 2022, Millstein et al. 2023). We are not able to use HRRR for the long-term wind index calculation because the HRRR records begin in 2014 (and HRRR methodology is updated over time). By applying a bias correction process to the generation estimates we can incorporate publicly available information on actual generation as well as site-specific HRRR modeled wind speeds. One exception to this process is for plants located in ERCOT. ERCOT provided high time-resolution records of plant level generation and curtailment going back to 2013, and, where available, those reported values are utilized.

Total *curtailment* is reported by each ISO for either each hour or each month. To correct HRRR output estimates for curtailment, plants are divided into three groups: plants receiving the PTC, plants that have aged out of the PTC, and plants that elected the 1603 Treasury Grant instead of the PTC. Note that we count plants that have been repowered as within the PTC group (assuming it has been less than 10 years since the repowering). Total reported hourly curtailment is distributed evenly across all plants within a particular ISO that face local hourly prices below a threshold defined for each group (initially, –\$23/MWh for PTC plants and \$0/MWh for the other two groups). A similar process is used to distribute monthly curtailment data.

Bias correction involves an iterative linear scaling approach so that: (1) the sum of estimated generation across all plants within each ISO matches the total wind generation reported by each ISO in each hour and (2) the annual total generation from each individual plant matches its expected annual output. The expected annual output is based on the modeled annual output adjusted for age-related performance decline (Hamilton et al. 2020) and curtailment. Also, a region-wide annual correction factor was applied based on EIA reported plant-level generation from the prior year. These region-wide correction factors were generally small, for example in MISO, SPP, ISO-NE, and PJM correction factors were less than 3%. But HRRR generation estimates were biased high in some regions; CAISO and NYISO correction factors were 1.32 and 1.16. (No bias correction was needed for ERCOT as we use actual reported plant generation profiles). Overall, the debiasing process ensures that both the hourly distribution of generation and the total annual generation matches both modeled and recorded ISO-level data.

Hourly nodal real-time wholesale electricity prices and hourly regional wind output profiles are from Hitachi's Velocity Suite database. Curtailment data are downloaded directly from each ISO, or in some cases, from Hitachi's Velocity Suite database. For each wind power plant, the nearest or most-representative pricing node is identified, which allows representative prices to be matched to each plant. For some regions, hourly wind output profiles are only available for a subset of the relevant years of the analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions.

Capacity value is estimated for each plant based on the bias-corrected, modeled wind profiles and ISO and ISO-zone specific capacity prices or costs, as well as relevant regional rules for wind's capacity credit. A separate capacity value is not calculated for ERCOT, because ERCOT runs an energy-only market that does not require load-serving entities to meet a resource adequacy obligation. In ERCOT, however, hourly Operating Reserve Demand Curve prices are added to nodal energy prices. Capacity value in ERCOT is incorporated into the energy markets. As for capacity prices and costs, many regions have organized capacity markets. In those cases, the analysis uses market-clearing prices from capacity market auctions in concert with ISO-rules or estimates for the capacity credit of wind. For regions where load-serving entities have a resource adequacy obligation but lack organized capacity markets, the analysis uses data from regulatory bodies to approximate capacity costs and regional estimates or rules for wind's capacity credit.

The analysis calculates the difference between wind value and flat-profile value (called "value reduction") and then further decomposes the value reduction into three separate causes: profile, congestion, and curtailment. Flat profile value is calculated in two steps. First, the average value of flat ("always-on") generation is calculated at all power plant pricing nodes in a region (both wind and other types of power plants). The regional flat value is then calculated by taking the weighted-average value across all these power plants with weights based on recorded energy output at each plant. The profile value of wind is calculated in a comparable manner to the regional flat value, but instead of using a flat profile, a wind plant output profile is applied to all power plants in a region (both wind and other types) and the regional weighted average value is calculated. This process is repeated for the profiles for all wind plants in a region to develop the regional average wind plant profile value. The reduction in wind value due to its profile is then calculated as the difference between the regional wind profile value and the regional flat value. Next, the value of wind generation at each wind plant is calculated given its output profile, and the regional average value is calculated across all wind plants. This provides a value of wind profiles at wind plants—in effect, the value of wind generation (not yet adjusted for curtailment). The profile value calculation finds the value of wind output at all generator locations and the wind generation value finds wind value only at wind generators, so the difference represents the impact of transmission congestion. Finally, the value of wind is adjusted for curtailment by increasing the total energy over which energy and capacity revenue are normalized. This final adjustment provides the overall value of wind at each plant. These methods are described in further detail in Millstein et al. (2021).

Turning to health and climate benefits, as mentioned in the main text, the values calculated here are based on the approach developed in Millstein et al. (2024) but updated with 2023 data. The approach is fully documented in Millstein et al. (2024), and the code used for the analysis is publicly available. A brief summary is included here: For each region, a regression is used to assess the operational impact of wind generation on natural gas and coal power plant dispatch (in most cases, hours with greater wind power have lower coal and gas dispatch, all else being equal). The key input data for this regression are hourly records of generation by source type. The approach accounts for imports and exports between regions, and time shifting of impacts through redispatch of hydropower. Recorded emission rates of coal and gas plants are then used to determine the emissions avoided from wind in each region. Health benefits are then calculated as a function of the total mass of pollutants avoided and where those reductions occur based on a suite of reduced-complexity air quality health impact models. Climate benefits are calculated as a function of the social cost of carbon, as described EPA (2023).

We present results for the 5^{th} - 95^{th} percentiles of the Monte Carlo simulations as described in Millstein et al. (2024). Input parameter uncertainty (i.e., standard deviations in the simulations) is determined directly through the regression results in the case of avoided coal and natural gas generation. Uncertainty in the emission rates of coal and gas plants is represented by the spread of emission rates across individual plants in each region, weighted by generation. Uncertainty in the reduced-order health impact models is represented by the spread of estimates across the set of models. The uncertainty range for the social cost of carbon was constructed based on EPA (2023) and has a similar center point, but wider uncertainty range than used in Millstein et al. (2024), which was based on Rennert et al. (2022). The uncertainty range used here includes outcomes across a range discount rates (1.5% - 2.5%) and across internal model variation within the GIVE model and was developed based on results presented in EPA (2023). Benefits in each region are calculated independently from each other.

Land-Based Wind Market Report: 2024 Edition

August 2024

Cover details: Sunrise at King Plains Wind Farm in Garber, Oklahoma. *Photo by Bryan Bechtold, NREL*

[smartcrawl_breadcrumbs]

World's Tallest Wind Turbine Begins Construction in Schipkau / Gicon Launches 365m Project in Germany

July 16, 2025 | Erik Seidel | Gicon | Schipkau | tallest wind turbine

In the municipality of Schipkau, Brandenburg, construction has officially begun on what will become the tallest wind turbine in the world. As G.Business reports, citing *renewz.de* and *RBB*, the turbine will reach a height of 365 meters at the tip of its rotor blades. The hub itself will be mounted at 300 meters above the ground.

To ensure structural stability at this extreme height, the tower is being built using a dual lattice frame.

A-13

consisting of an inner and outer steel structure. The innovative design was reportedly developed by a 90-year-old engineer from Leipzig.

The turbine is part of a new phase in renewable energy development, targeting high-altitude wind layers previously unused by standard onshore turbines. Measurements from a 300-meter wind testing tower showed consistently stronger and more reliable winds, offering performance comparable to offshore wind farms—at lower operating costs.

According to operator Gicon, the facility is expected to be operational in 2026. Long-term plans include up to 1,000 similar turbines across Germany. Because of their height, they can be installed between existing wind parks without taking up additional land or disrupting airflow patterns.

Despite some local resistance—such as an emergency legal petition from a nearby aviation club—the project received approval from the Berlin-Brandenburg Higher Administrative Court. Gicon has also pledged to share profits with the local community. Since 2015, similar profit-sharing models have generated over €3 million for local infrastructure, including a firetruck, school renovations, and road improvements.

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Using the United States Wind Turbine Database to Identify Increasing Turbine Size, Capacity and Other Development Trends

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Abstract

The purpose of this article was to analyze data associated with advances in wind energy across the United States. While governments, academia, and the private sector generally know patterns of wind turbine development (*i.e.* turbine size and capacity growing in recent years), there is no known independent, reliable, and/or updated summary of these variables. Using data collected by the Lawrence Berkeley National Laboratory and partners, this study used descriptive statistics to show turbine development and growth patterns from 1981-2019. The newly created United States Wind Turbine Database (USWTDB) represents the most comprehensive account of wind turbine information and was updated in January 2020. Variables I am interested in here are turbine manufacturer, state of project, turbine and project capacity, and turbine size. Findings provide empirical evidence to support the common, yet previously unrefined statements that wind turbines are growing larger in number, size and capacity. This growth is varied over spatial and temporal scales. I also provide evidence to show patterns of turbine manufacturing, with GE Wind dominating much of the US wind energy landscape today. I hope this work provides a timely resource for those interested in a variety of questions surrounding wind energy development in the United States. Perhaps more importantly, this analysis will hopefully inspire others to use what the USWTDB provides and answer larger questions surrounding wind energy futures.

Keywords

Wind Energy, Wind Turbines, USWTDB, Renewable Energy, Turbine Capacity, Turbine Size

1. Introduction

Responding to intersecting problems including global climate change, air pollu-

A-14

tion, and domestic energy insecurity, wind energy has emerged as a major source of low-carbon electricity generation. In the United States alone, there are now more than 60,000 utility-scale turbines, representing nearly 100 gigawatts of wind energy capacity and 15% of the global total [1] [2]. Much of this has been introduced over the past decade, and yet up until recently, there was no publicly accessible dataset that described wind turbines and their characteristics (e.g. size, capacity, location). Recognizing this void, researchers across three organizations—the Lawrence Berkeley National Laboratory (LBNL), the United Stated Geological Survey (USGS), and the American Wind Energy Association (AWEA)—came together in 2018 to create such a dataset. Aptly named The US Wind Turbine Database (USWTDB), information is provided on turbines dating back to 1981 and is updated on a quarterly basis. Apart from the USWTDB Viewer [3], which provides a simple and interactive way for anyone to visualize wind turbines across the country, there is no known resource for those who want to understand trends in US wind energy growth. More specifically, the Viewer and any other known resources do not provide any way to understand summarized and/or precise changes to US wind energy landscapes.

In this paper, I use the USWTDB to analyze patterns of US wind energy growth over four decades. For government, this will help those who debate and design policy. In industry, this may help businesses of all sizes understand current (and perhaps future) landscapes of the sector. For academics, I see this paper as providing an important starting-point for discussions around the clustering, size, and growing capacity of wind turbines. Echoing the benefits described by Rand *et al.* [2], this paper may also provide important context for groups interested in: climate change and air quality [4], local health and well-being [5], grid impacts [6], land requirements [7], local surface temperatures [8], sound and noise [9], property values [10] [11], renewable energy potentials [12], and acceptance research [13] [14] [15].

For all of these groups listed above—and more—there is a general understanding that turbines are getting larger in both in size, capacity and overall number. Yet, there is still a need for a study that analyses these trends in a systematic way. I answer what I see is a call for this kind of resource. In doing so, I provide a clear, accessible, and available-to-all report.

2. Methods

2.1. United States Wind Turbine Database

A full description of the USWTDB, including its process of creation, can be found in a recent publication by Rand *et al.* [2]. Here, I simply wish to clarify some important issues that directly relate to the variables used in this analysis. First, for many of the most pertinent variables, the USWTDB authors provide us their level of confidence (0 = not verified; 1 = no confidence; 2 = partial confidence; 3 = full confidence) regarding turbine characteristics (e.g. size, capacity, model, project name) and turbine location (coordinates). Of the total of 63,003 turbines, there was full confidence in turbine characteristics of 81% (9.5% with partial and 9.5% with no confidence). In terms of location, there was full confidence throughout 92.8% of the data (0.6% with partial and 6.5% with no confidence). This leaves us confident in the characteristics of 51,037 turbines and in the location of 58,494 turbines [2].

In most of the analysis here, I include only those turbines/projects with the highest level of confidence. This ensures transparency and should increase the reader's trust in the findings. Exceptions are seen when characteristics of wind turbines are not necessary (*i.e.* total number of turbines). As per the USWTDB, dismantled turbines are not included, but decommissioned turbines are. Residential-scale turbines (usually less than 65 kW and 30 metres in height) are not included in the dataset. Some exceptions to this may include smaller wind turbines built in California before 1990. At the time, these were considered to be utility-scale and thus are retained in the USWTDB.

2.2. Data Analysis

On March 28 2020, the USWTDB data was downloaded and input into SPSS 24 software. Based on Rand *et al.* [2] and verification of the data itself, the USWTDB included all turbines built and constructed by the end of 2019. The oldest wind turbines date back to 1981 (no confidence in turbine characteristics) or 1982 (full confidence in characteristics or any confidence in turbine location).

Before analysis took place, the dataset was cleaned to remove any missing variables. This was done for the variables of project year operational, project capacity, turbine capacity, turbine hub height, turbine rotor diameter, and turbine rotor swept area. I then used simple descriptive statistics to identify trends in the dataset. Based on a combination of what I saw as gaps in the literature, and what the dataset provided, this includes: leading turbine manufacturers, turbine capacity by year, the (physical) growth of wind turbines, and wind energy development by state (by year and decade). Below I present figures and tables that summarize such findings. Complete results of each section (via tables) can be found in the **Appendix A-H** [3].

3. Results

3.1. Wind Turbine Manufacturers

As of the end of 2019, General Electric (GE) Wind was by far the leading manufacturer of wind turbines across the United States (see **Figure 1**). Of the more than 51,000 turbines with full characteristics confidence, the company produced 21,774 (41.5%). Vestas (including Vestas North America; 24.1% or 12,322) produced the next highest number. At 4901 (9.6%), Siemens came in third. Though due to a 2017 merge with Gamesa (which later became Siemens Gamesa Renewable Energy), it may be argued that the new company is actually responsible for a total of 8137 turbines (15.9%) as of 2019. Mitsubishi (5.5%), Gamesa (5.2%), Suzlon (2.6%), Nordex (1.8%), Acciona (1.5%), NEG Micon (1.3%), Clipper (1.3%), Siemens Gamesea Renewable Energy (1.1%), and Repower (1.1%) represent the top 12 and include all those with at least 1% of turbines. A list of all those companies with at least five turbines as of 2019 (0.1% of total) can be found within the **Appendix** B.

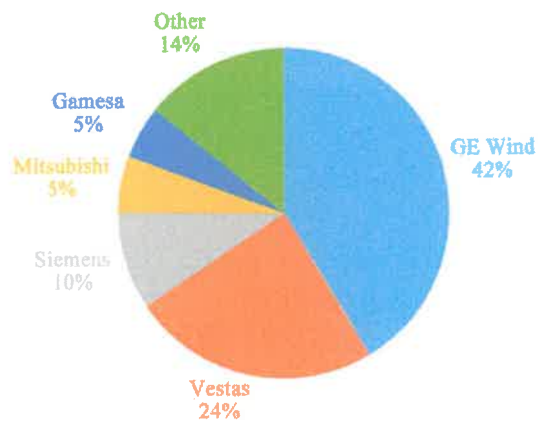
We can also look for recent changes in the above trends. As of 2009, things were much the same. GE Wind was still the leader (36.2%). Vestas was second (22.5%), followed by Mitsubishi (11.6%) and Siemens (6.1%). Going back two decades to 1999, Vestas was the undisputed leader with near a third (32.5%) of all turbines. Enron (20.5%) and NEG Micon (17.6%) followed.

3.2. Growth of New Turbine Capacity and Total Number of Turbines

Figure 2 shows the annual growth of average new turbine capacity and the annual number of new turbines. Because of gaps in data for turbine capacity through the 1980s and 1990s, here I include both the values given with full and partial confidence. The full dataset that makes up Figure 2 can be found within the **Appendix C**.

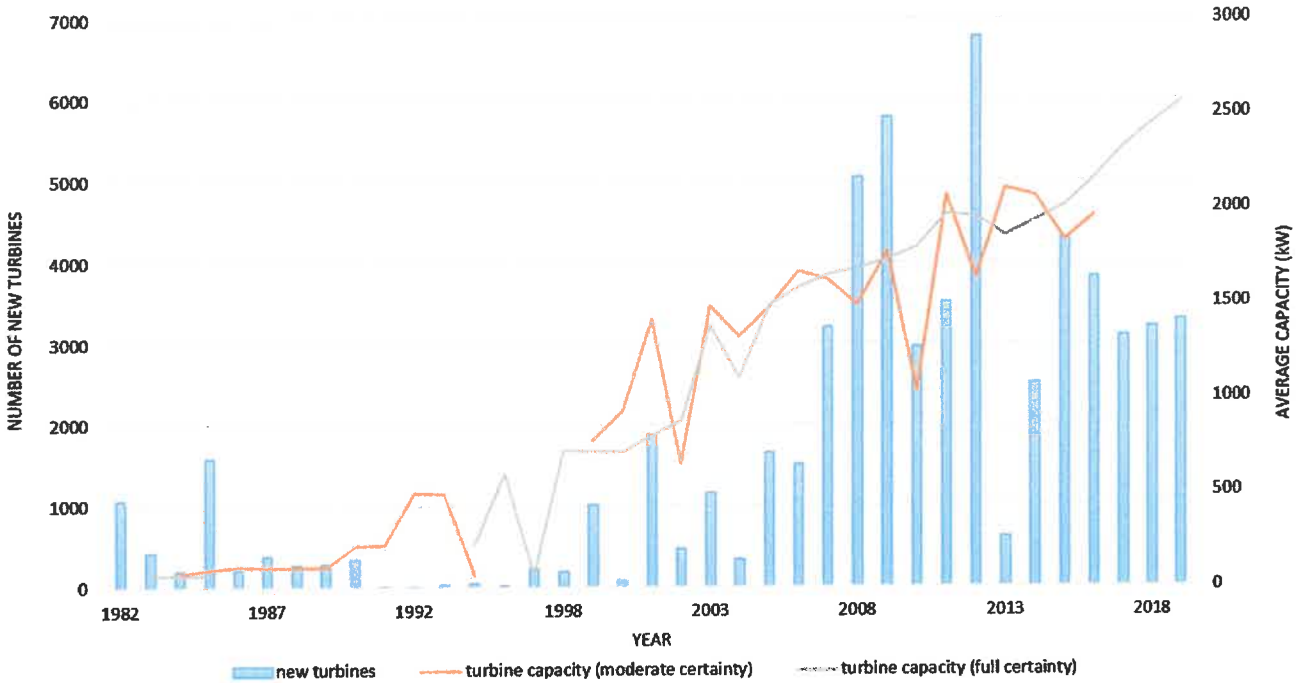
Of the 51,036 turbines with full confidence in capacity, the average (mean) turbine capacity was 1831.85 kW (1.85 MW). Though as the figure shows, this has varied throughout time. In 1990, the average turbine was just 218.16 kW (0.218 MW). In 2005, this reached nearly 1.5 MW. In 2014, this rose to 1.93 MW and finally in 2019, the steady rise continued, with the average turbine having a capacity of 2.56 MW. The turbine with the largest capacity (of all years) became operational in 2016 and had a capacity of 6 MW. It was associated with a five-turbine project called Block Island (Washington County, Rhode Island).

Using an expanded set of all development, we see the number of turbines has generally grown year over year—but with some notable spikes and valleys. Up until 2000, new turbines averaged just under 300 per year. There were just two years in this set of 18 that saw more than 1000 turbines becoming operational—1985 (n = 1596; all of which occurred across 16 wind farms in California), and



*Of the total number of wind turbines as of 2019 (n = 51,036). Though there were 51,037 turbines with full confidence in turbine characteristics, we found one turbine manufacturer as "missing". This may have been caused by a coding error.

Figure 1. Wind Turbines by manufacturer (percent of total*).



*For the year 1989, there was no information about average turbine capacity so I chose to insert a value that is equal to the average of the three preceding years. There were no turbines built in 1993 throughout the entire database, and so that year is not given a value (*i.e.* the year is ignored).

Figure 2. Number of wind turbines and average capacity (by year)*.

1999 (n = 1005; where 33 wind farms were built in 10 states).

From 2001 to 2019, the average number of turbines was 2897/year—though again with great variation. 2001 saw 1876 new turbines—a value that was not exceeded until 2007 when 3200 turbines became operational. This growth would continue until 2010 (n = 5780), when average turbines built from 2010-2011 dropped to just 3232. A recovery in 2012 marked the highest number of turbines ever built (n = 6774). Aside from a severe drop the following year (n = 610), new turbines have been relatively stable in recent history. This includes an average of 3366 turbines from 2014 to 2019.

3.3. Wind Turbine Development by State

Given our understanding of the general growth of wind energy, it is important to recognize the geographic distribution of wind turbine development (*i.e.* by state; see Figure 3 and **Appendix D**). Using the USWTDB's list of all turbines with a state/territory given, there are a few trends that stand out.

First is the dominance of California during the first two decades. From 1981-1991, California accounted for all new wind turbines (n = 4819; not shown). The late 1990s and 2000s brought with them much more diversity across the US energy landscape. By the end of 2009, there were 38 states with at least one turbine. Texas (n = 6094 or 22.2%) was just trailing behind California (n = 6278 or 22.9%) as the nation's leader. Other significant development had taken place in Iowa (9.2%), Minnesota (4.9%), Oregon (4.5%) and Washington state (4.3%).

From 2011-2019 there had been substantial growth in wind energy across the

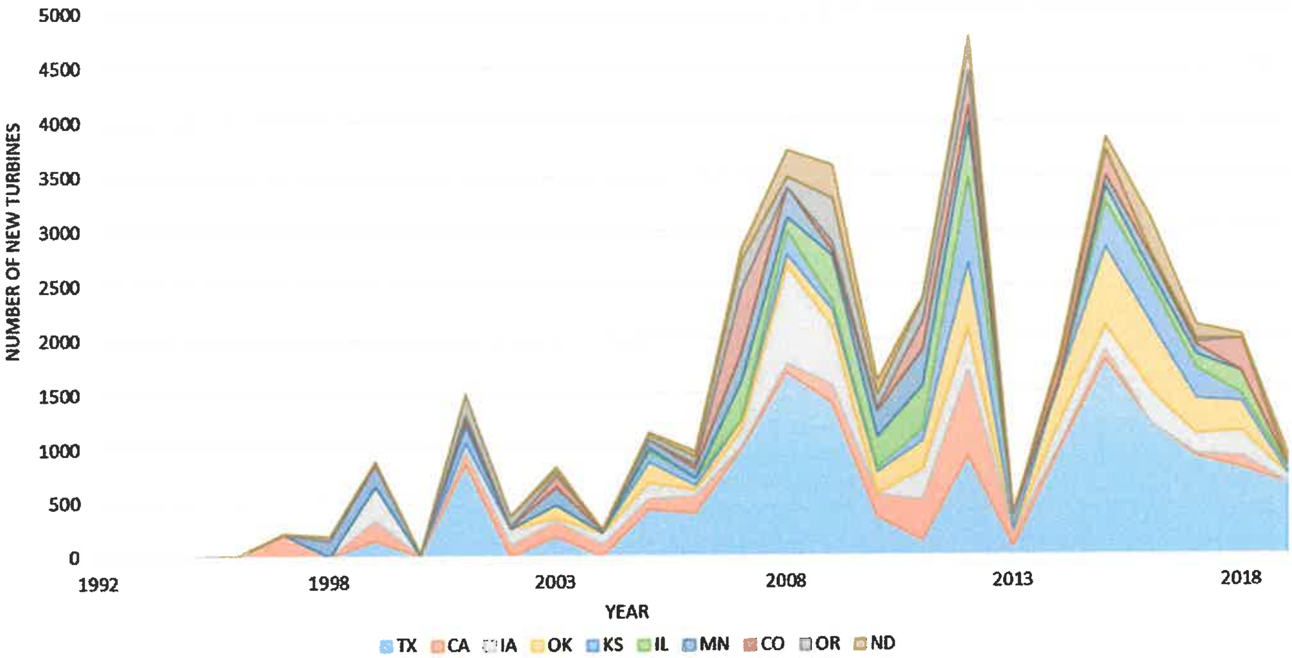


Figure 3. Number of new wind turbines by state and year (1992-2019; Top 10 states as of 2019).

United States. Again, when using the dataset of all turbines, there is a 2.24x increase in wind turbines from 2009 to 2019—strongly aided by "spikes" in 2012 and 2015. By the end of 2019, Texas was the leader in wind turbines (n = 14,852 or 24.2%) while California was a distant second (13%). Iowa was in third (8.7%) and Oklahoma moved to fourth (6.6%). As of 2019, there were 22 states with at least 1% of all turbines. There were 40 states and 2 territories (Puerto Rico and Guam) with at least one turbine.

3.4. Total Wind Energy Capacity by State

While the growth in number of turbines tells us something about the way wind energy development has taken place over the United States (Figure 3 and **Appendix D**), it is also helpful to understand the geographic distribution of wind energy capacity as well (Figure 4). That is because especially valuable given that more recently built turbines have capacities 5-6× larger than those from the 1980s (see Figure 2). Figures 4-6 below show the top 10 leading states in terms of total wind energy capacity—as well as total turbines and average turbine capacities—built in the 1990s, 2000s, and 2010s. The full dataset can be found in **Appendix E**.

Due to a concentration of new wind farms in Minnesota and Iowa in the late 1990s, both states overtook California by 2000. While still behind in total number of turbines, advancements in wind energy technology (re: capacity) allowed for this to happen. In line with Figure 3, from 2010 onwards Texas also became the undisputed leader in terms of capacity—with nearly 8000 MW in 2010 and nearly 25,000 MW by the end of 2019. Other notable states to emerge as wind energy leaders over the past decade include Oklahoma (n = 7033.33 MW) and

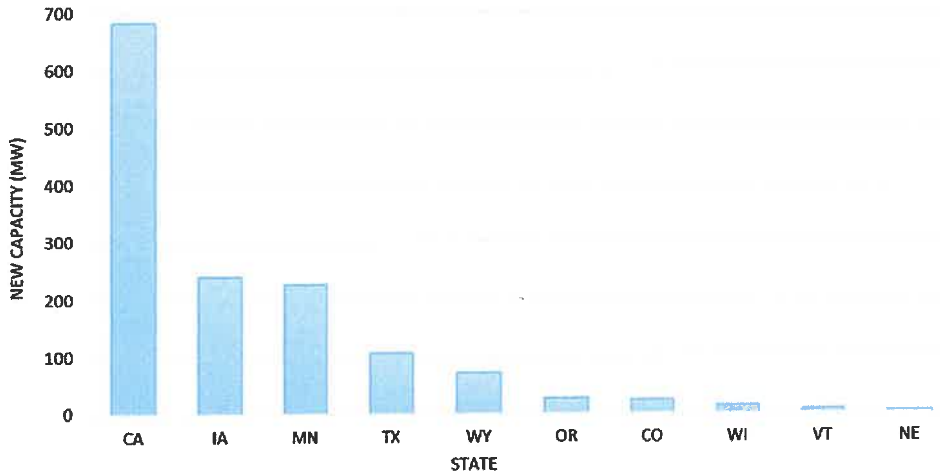


Figure 4. Total new wind energy capacity in the 1990s by state (Top 10 states in the 1990s).

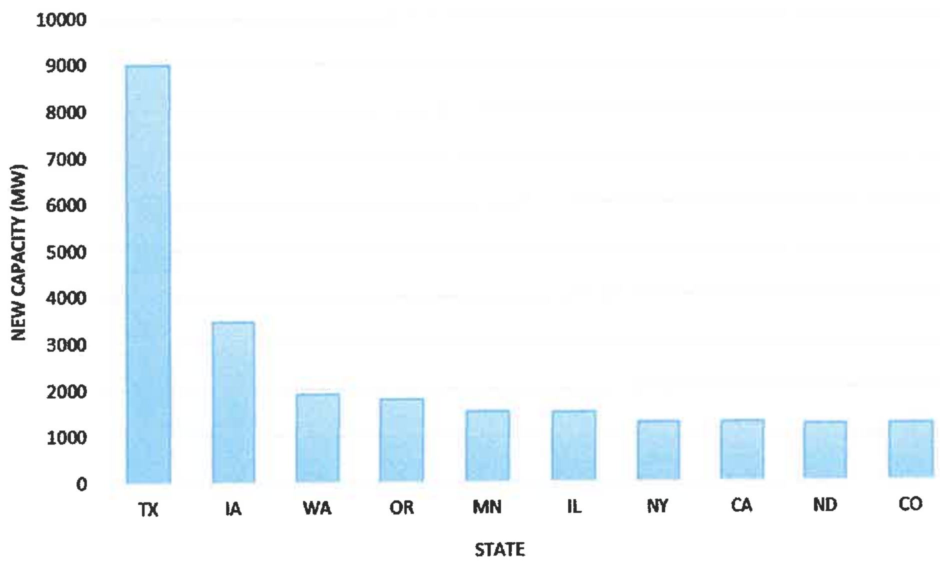


Figure 5. Total new wind energy capacity in the 2000s by state (Top 10 states in the 2000s).

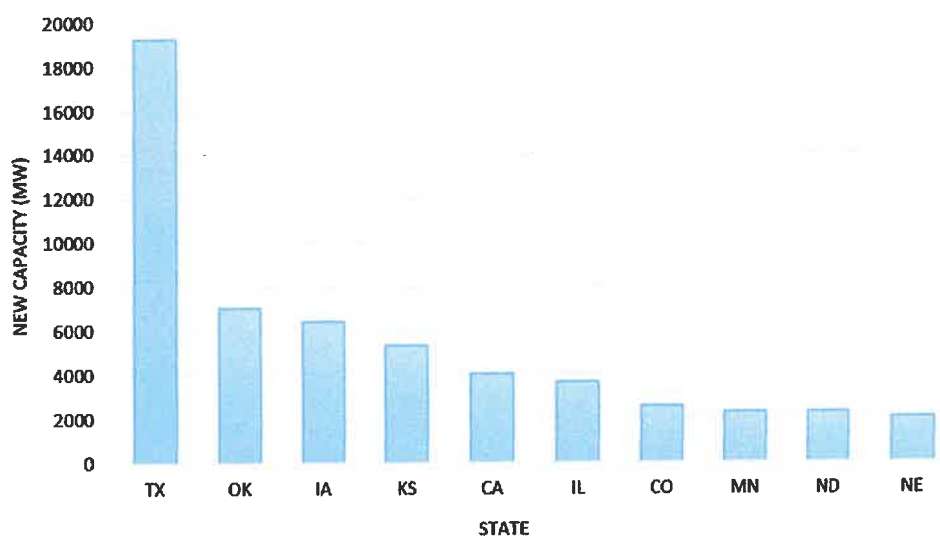


Figure 6. Total new wind energy capacity in the 2010s by state (Top 10 states in the 2010s).

Kansas (n = 5331.98 MW).

3.5. Turbine Size by Year

Finally, and corresponding to the growing capacity of wind developments, new turbines have grown in physical size since the 1980s. When using looking at hub height (*i.e.* the distance from the ground to the nacelle or centre of the wind turbine) there has been a 3.7× increase from 1985 (24.4 metres) to 2019 (90.3 metres). In looking at Figure 7 below (see also **Appendix F**), this rise has also been relatively constant, especially over the past 20 years. Again, due to inconsistencies in the data, I use turbine hub height data with full (n = 51,032) and partial (n = 4168) confidence.

Using only those turbines with full confidence in hub heights, as of 2019 the largest onshore wind turbine has a hub height of 130 metres and is single turbine part of the UL Advanced Wind Turbine Test Facility (built in 2018 in Randall County, Texas). This is a 1.6× increase since the early to mid-2000s, where the largest hub heights were 80 metres (see Figure 8 below). Today, there are 1482 turbines with a hub height of 100 metres or more. The multi-turbine wind development with the largest hub heights is the Hancock Wind Farm (Hancock County, Maine), which has 17, 116.5-metre turbines. More information on tallest turbines (per year), can be found in **Appendix G**.

Although it is the most common approach, hub height is just one way to measure turbine size. Rotor diameter and turbine rotor swept area, which is the total area covered through one full rotation of turbine blades, are also used. Looking at only those turbines with full characteristics confidence, we can see the rise of both of these values over the past two decades (see Figure 9 and **Appendix H**).

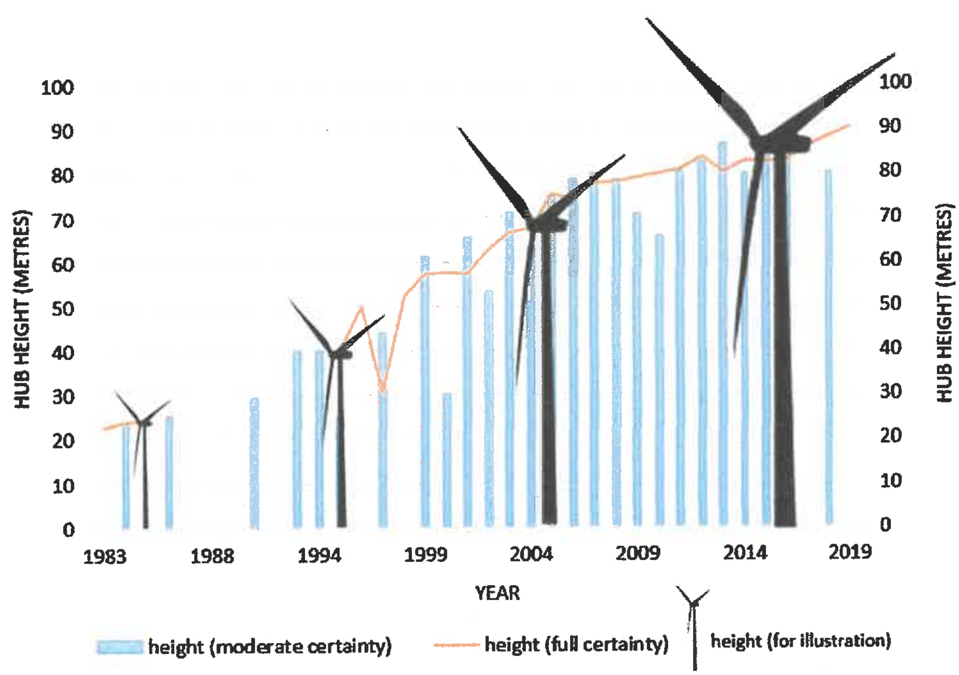


Figure 7. New turbine hub height (average) by year.

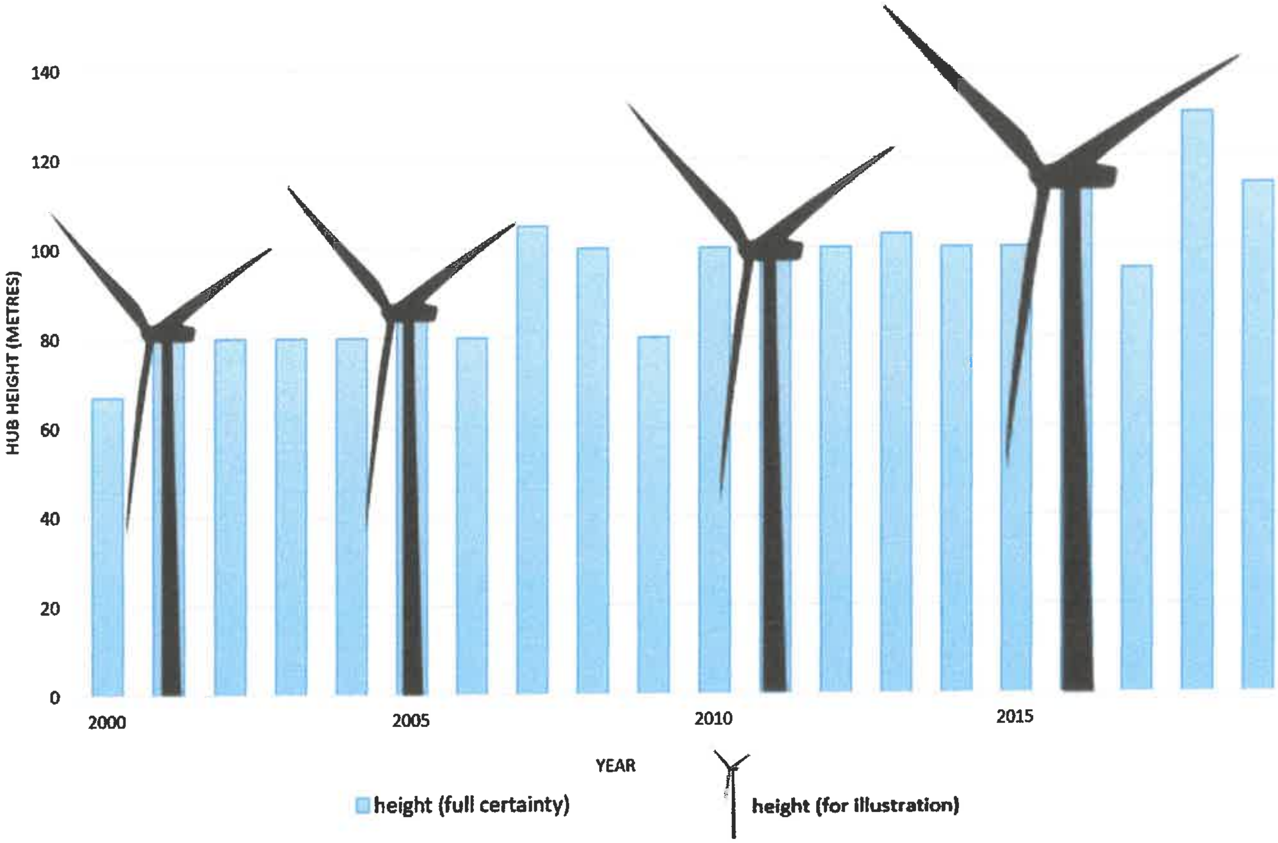


Figure 8. Largest turbine hub height (by year).

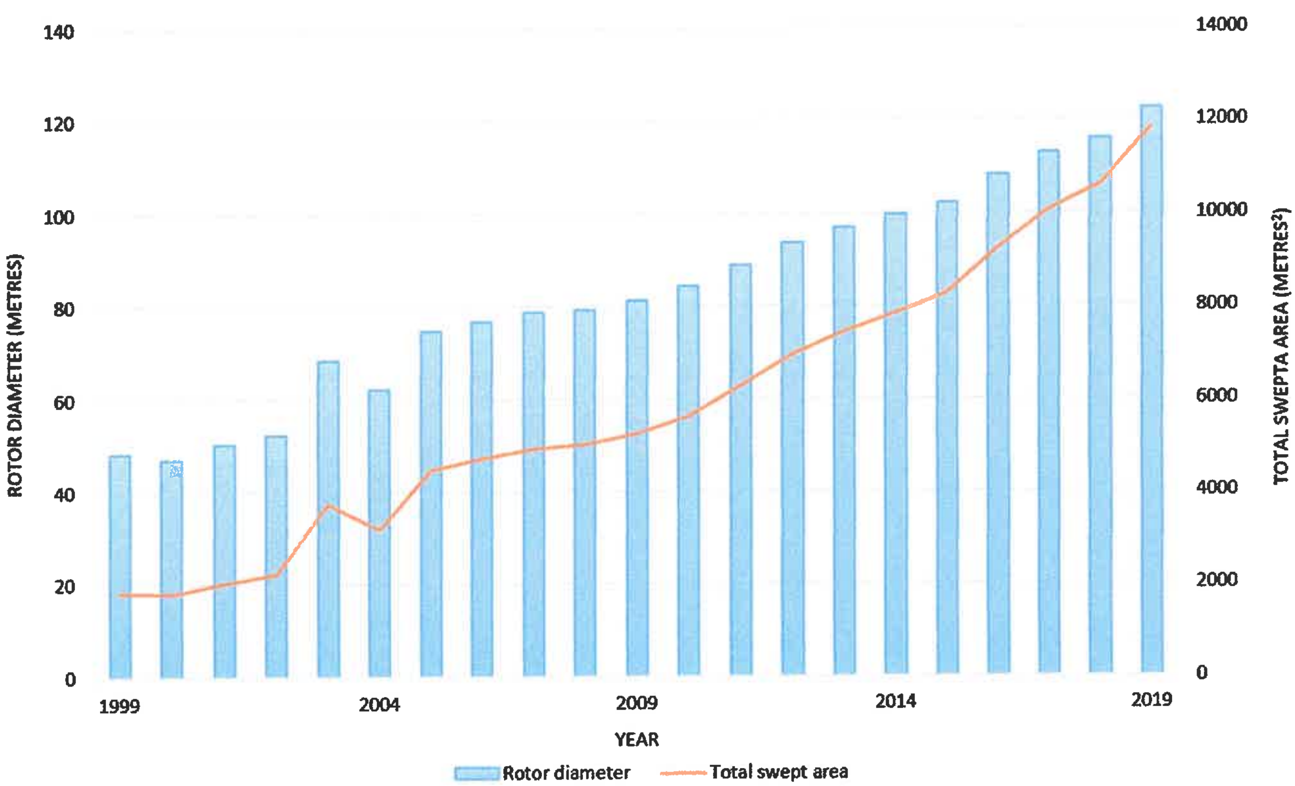


Figure 9. Average rotor diameter and total swept area by year.

Average rotor diameter increased from 48.22 metres in 1999 to 122.63 metres in 2019. The largest diameters during this same period ranged from 66 metres in 1999 to 150 metres (GE Haliade 150-6) in 2016.

Total swept area is a direct function of turbine diameter and thus why we see a perfect association between the two values in Figure 9. The total swept area is calculated by dividing the rotor diameter by two (*i.e.* to get radius/blade length), multiplying that value by itself, and then multiplying by the value of Pi (approx. 3.14159). It is represented through the following equation:

$$\text{Total swept area} = \pi * (\text{rotor diameter}/2)^2 \quad (1)$$

4. Discussion and Conclusions

Here I have presented a paper that has highlighted some major trends related to wind energy development across the United States. This was enabled by the newly-published United States Wind Turbine Database—an important, yet previously unsynthesized resource.

I have begun this important work here, quantifying patterns of wind energy growth in terms of variables such as total number of turbines, capacity, geographic distribution, and size. In existing literatures, these factors are often written about as assumptions. That is, phrases like "as turbines grow larger in size"—without quantification or citation—are increasingly common. I attempt to help move past the tendency to write in this way. More specifically, I show that in terms of manufacturing, and with 42% of the total, GE Wind is the undisputed leader as of 2019. Despite some significant peaks and valleys, the number of US turbines has generally increased year over year—with an average of over 3300 from 2014-2019. Average turbine capacity has also increased over the past four decades, and is now at just over 2.5 MW. In terms of geographic distribution, California may be labelled as the "early adopter" of wind energy, dominating all (small turbine) developments throughout the 1980s and much of the 1990s. Since then, Texas—and states like Iowa, Oklahoma and Kansas to smaller degree—have challenged and surpassed the "Golden State" in terms of both number of turbines and/or total capacity. Finally, I confirm the popular refrain of turbines getting physically larger since the 1980s. Growth of hub heights, rotor diameters and (thus) total swept areas, have seen very consistent growth over nearly 40 years. The largest turbines are now more than twice as tall (up to 130 metres) as they were just 20 years ago. Turbine rotor (blade) diameters have risen from approximately 50 metres in the early 2000s to just over 120 meters in 2019.

There are a few clear limitations of this study, some of which provide opportunities for further research. First, regarding the USWTDB itself, it included turbines that had been decommissioned. It would have been ideal if the dataset only included operational turbines, however even when not "spinning", there is an impact living near these structures. I suggest the USWTDB is edited to allow for analysis that identifies operational turbines, so that certain research questions would benefit as such. Second, and despite their best efforts [2], there were still some significant gaps in data throughout the USWTDB. These were especially prevalent throughout the 1980s and 1990s, so future research that depends on precise trends may want to focus on the past two decades only. Lastly, because the data only covered one country—albeit an important one in terms of global wind energy capacity—the results here are really only relevant to studies or reports that happen within the US. That said, and assuming there are similar datasets elsewhere, I hope this analysis inspires others to summarize the major trends in their jurisdiction.

All of these findings shared here should support a wide variety of actors—including governments, industry, and researchers—across an even wider area of inquiry. Given my expertise in the social acceptance of wind energy research [13] [14] [15], I see particular value to researchers here. I also want to highlight the opportunity for this research, and indeed the rich USWTDB as a whole, to help provide important context for a range of quantitative and qualitative studies. In the former, the dataset could be combined with other survey work. Fruitful research in this area could include health surveys and/or real estate sales data. In the qualitative realm, this data can also provide important context for case study research. For example, it may offer some important wind-farm specific characteristics that can help shape a common understanding of local development.

Acknowledgements

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Conflicts of Interest

The author declares no conflicts of interest regarding the publication of this paper.

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Appendix

A. State and Territories: Abbreviations

STATE	Abbreviation
Alabama	AL
Alaska	AK
Arizona	AZ
Arkansas	AR
California	CA
Colorado	CO
Connecticut	CT
Delaware	DE
District of Columbia	DC
Florida	FL
Georgia	GA
Guam	GU
Hawaii	HI
Idaho	ID
Illinois	IL
Indiana	IN
Iowa	IA
Kansas	KS
Kentucky	KY
Louisiana	LA
Maine	ME
Maryland	MD
Massachusetts	MA
Michigan	MI
Minnesota	MN
Mississippi	MS
Missouri	MO
Montana	MT
Nebraska	NE
Nevada	NV
New Hampshire	NH
New Jersey	NJ
New Mexico	NM
New York	NY
North Carolina	NC

Continued

North Dakota	ND
Ohio	OH
Oklahoma	OK
Oregon	OR
Pennsylvania	PA
Puerto Rico	PR
Rhode Island	RI
South Carolina	SC
South Dakota	SD
Tennessee	TN
Texas	TX
Utah	UT
Vermont	VT
Virgin Islands	VI
Virginia	VA
Washington	WA
West Virginia	WV
Wisconsin	WI
Wyoming	WY

B. US Wind Turbines by Manufacturer (As of 2019)

COMPANY	NUMBER OF WIND TURBINES[a]	PERCENTAGE OF TOTAL (%)
GE Wind	21,174	41.5
Vestas (and Vestas North America)	12,322	24.1
Siemens	4901	9.6
Mitsubishi	2796	5.5
Gamesa	2654	5.2
Suzlon	1306	2.6
Nordex	929	1.8
Acciona	758	1.5
NEG Micon	680	1.3
Clipper	676	1.3
Siemens Gamesa Renewable Energy	582	1.1
REpower	548	1.1
Bonus	404	0.8
Enron	396	0.8

Continued

Goldwind	186	0.4
Zond	156	0.3
Danwin	115	0.2
Nordtank	90	0.2
DeWind	84	0.2
Vensys	28	0.1
Northern Power Systems	26	0.1
Alstom	24	<0.1
Fuhrlander	19	<0.1
China Creative Wind Energy	17	<0.1
Sany	17	<0.1
Entegrity	16	<0.1
HZ Windpower	16	<0.1
NedWind	13	<0.1
EWT	11	<0.1
Vergnet	9	<0.1
Seaforth Energy	8	<0.1
PowerWind	7	<0.1
Guodian	6	<0.1
Windmatic	5	<0.1
Aeronautica	5	<0.1
RRB	5	<0.1
TOTAL	51,037	100.0

[a]Here I include only those wind turbines with full confidence in characteristics (n = 51,037) and those manufacturers with at least five turbines as of 2019. I thus exclude 22 manufacturers.

C. Turbine Capacity by Year

YEAR	NUMBER OF NEW WIND TURBINES[a]	MEAN TURBINE CAPACITY[b] (full certainty)	STANDARD DEVIATION	MEAN TURBINE CAPACITY[c] (moderate certainty)	STANDARD DEVIATION
1981	10	n/a	n/a	n/a	n/a
1982	1073	n/a	n/a	221.98	87.16
1983	432	65	0.00	n/a	n/a
1984	196	65	0.00	70.40	10.35
1985	1596	65	0.00	95.41	45.32
1986	212	n/a	n/a	107.50	90.19
1987	387	n/a	n/a	101.45	6.51
1988	277	160	0.00	105	.

Continued

1989	288	n/a	n/a	n/a	n/a
1990	347	n/a	n/a	218.16	30.02
1991	1	n/a	n/a	225	.
1992	2	250	.	500	.
1994	30	n/a	n/a	490	20.34
1995	44	225	0.00	65	.
1996	14	600	.	n/a	n/a
1997	231	65	0.00	561.43	181.34
1998	189	722.38	65.25	n/a	n/a
1999	1005	715.33	84.52	771.84	219.07
2000	82	715.92	327.05	929.55	233.67
2001	1876	798.19	254.30	1408.06	281.61
2002	462	875	351.89	652.00	678.54
2003	1153	1377.18	340.39	1482.65	133.48
2004	328	1101.77	418.19	1321.88	244.12
2005	1653	1488.19	300.88	1475.27	193.54
2006	1506	1578.32	413.67	1664.01	398.67
2007	3 200	1646.23	420.28	1619.85	284.39
2008	5046	1680.19	459.26	1488.81	219.71
2009	5780	1732.86	412.07	1770.12	806.20
2010	2960	1792.39	394.02	1033.80	858.73
2011	3504	1969.19	459.62	2065.00	536.99
2012	6774	1952	444.24	1630.35	353.79
2013	610	1853.66	373.50	2105.56	592.82
2014	2512	1933.34	358.33	2061.81	280.92
2015	4300	2012.99	329.81	1828.24	479.47
2016	3810	2157.08	442.62	1957.26	387.08
2017	3090	2321.77	411.27	n/a	n/a
2018	3200	2443.37	483.59	1525	1096.02
2019	3283	2558.96	491.23	n/a	n/a
TOTAL/AVERAGE	61463	1831.93*	604.28	1027.21	768.90

[a]Based on all turbines regardless of turbine characteristic or location confidence (n = 61,463). [b]I include all turbines with full confidence values in turbine capacity (n = 51,036). [c]I include all turbines with partial confidence values in turbine capacity (n = 6007).

D. New Turbines by State and Year (Decade)

1981-1989[a,b]

STATE	1981	1982	1983	1984	1985	1986	1987	1988	1989	1980s TOTAL
CA	10	1073	432	196	1596	212	387	277	288	4471

[a]I include all turbines, regardless of confidence of level, that provide a state/territory of each turbine (n = 4471). [b]All other states/territories with zero turbines in the 1980s are excluded within this table.

1990-1999[a,b]

STATE	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	1990s TOTAL
CA	347	1	1	0	30	42	13	207	2	187	830
MN	0	0	0	0	0	0	0	1	142	192	335
IA	0	0	1	0	0	2	0	2	3	312	320
TX	0	0	0	0	0	0	0	0	0	151	151
WY	0	0	0	0	0	0	0	0	2	108	110
OR	0	0	0	0	0	0	0	0	38	0	38
CO	0	0	0	0	0	0	0	0	0	29	29
WI	0	0	0	0	0	0	0	0	0	18	18
AK	0	0	0	0	0	0	6	0	6	0	12
VT	0	0	0	0	0	0	0	12	0	0	12
NE	0	0	0	0	0	0	0	0	2	1	3
ND	0	0	0	0	0	0	0	2	0	0	2
IL	0	0	0	0	0	0	0	1	0	0	1
MI	0	0	0	0	0	0	1	0	0	0	1
NM	0	0	0	0	0	0	0	0	0	1	1

[a]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 1863). [b]All other states/territories with zero turbines in the 1990s are excluded within this table.

2000-2009[a,b]

STATE	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2000s TOTAL
TX	0	852	0	186	0	434	395	980	1694	1402	5943
IA	0	91	150	32	108	152	67	161	912	534	2207
OR	0	181	102	41	0	50	67	260	102	403	1206
WA	0	270	37	12	0	83	260	165	104	243	1174
MN	18	41	18	165	28	77	81	263	269	41	1001
CA	10	108	104	141	104	93	152	21	71	173	977
IL	0	0	0	0	1	34	0	358	129	430	952
CO	0	48	0	108	5	1	40	591	1	83	877
NY	17	19	1	0	0	82	112	31	188	345	795
ND	0	1	3	41	0	22	50	111	247	301	776
OK	0	1	0	113	0	182	40	85	91	154	666
WY	31	49	0	80	0	2	0	0	226	274	662

Continued

KS	0	170	0	0	0	100	68	0	222	73	633
IN	0	0	0	0	0	0	0	0	88	529	617
NM	0	0	0	138	60	140	90	0	1	40	469
PA	0	16	0	63	0	0	25	65	32	211	412
MT	0	0	0	0	0	108	6	8	83	69	274
WI	0	20	0	0	1	0	0	0	216	37	274
SD	0	4	2	28	0	0	0	36	59	68	197
WV	0	0	44	0	0	0	0	0	132	0	176
MO	0	0	0	0	0	0	0	27	51	73	151
UT	1	0	0	0	0	1	0	0	9	98	109
ME	0	0	0	0	0	0	7	21	3	64	95
MI	0	2	0	0	0	0	0	0	80	7	89
ID	0	0	0	0	0	50	0	0	0	34	84
NE	0	1	0	0	0	36	0	0	0	27	64
AK	2	1	1	2	4	0	6	2	21	14	53
HI	0	0	0	0	0	0	36	14	0	0	50
AZ	0	0	0	0	0	0	0	0	0	30	30
MA	0	1	0	0	0	1	2	1	3	13	21
TN	3	0	0	0	15	0	0	0	0	0	18
NH	0	0	0	0	0	0	0	0	12	1	13
OH	0	0	0	2	2	0	1	0	0	4	9
NJ	0	0	0	0	0	5	0	0	0	0	5
RI	0	0	0	0	0	0	1	0	0	2	3
VT	0	0	0	0	0	0	0	0	0	2	2
AR	0	0	0	1	0	0	0	0	0	0	1
NC	0	0	0	0	0	0	0	0	0	1	1

[a]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 21,086).
[b]All other states/territories with zero turbines in the 2000s are excluded within this table.

2010-2019[a,b]

STATE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2010s TOTAL
TX	353	136	920	84	964	1796	1211	946	919	1429	8758
OK	195	257	596	0	369	710	602	323	290	18	3360
IA	5	282	385	26	219	226	304	195	506	690	2838
KS	46	112	802	141	1	413	376	277	210	235	2613
IL	284	405	493	0	0	153	93	139	233	161	1961
CA	212	375	789	115	36	94	3	23	114	6	1767
CO	35	262	308	18	153	232	36	36	300	35	1415
MN	229	332	152	2	32	100	145	100	41	106	1239

Continued

MI	10	121	353	103	207	0	44	101	19	114	1072
ND	128	9	80	1	65	118	311	124	45	145	1026
NE	43	85	73	46	161	47	221	45	232	56	1009
OR	129	209	253	0	0	0	6	25	0	56	678
NM	64	28	14	5	21	134	16	260	22	84	648
IN	184	1	128	1	101	65	0	106	61	0	647
WA	162	158	119	0	117	2	0	0	0	0	558
SD	229	51	0	0	11	98	0	0	18	83	490
ID	134	155	168	0	0	0	0	0	0	0	457
OH	15	58	166	2	1	7	49	34	49	6	387
MO	101	0	1	0	1	0	92	165	0	24	384
NY	2	67	78	52	16	6	40	7	77	1	346
PA	0	21	279	0	0	0	14	0	5	20	339
ME	41	72	19	0	3	57	91	8	0	0	291
MT	8	0	171	1	12	0	13	0	48	1	254
WY	186	0	0	0	0	0	46	0	0	0	232
WV	66	76	8	0	0	0	49	0	0	0	199
WI	11	90	11	1	0	0	0	49	0	0	162
AZ	31	6	62	0	0	15	0	0	0	0	114
NC	0	0	0	0	0	0	0	104	0	0	104
UT	0	68	0	0	0	1	28	0	0	0	97
MD	31	20	0	0	16	12	0	1	0	0	80
AK	13	4	45	4	2	4	0	0	4	1	77
HI	0	12	53	1	0	3	0	5	0	0	74
NH	0	0	57	0	0	5	0	0	0	9	71
MA	9	16	34	2	1	0	4	1	0	3	70
NV	0	0	67	0	3	0	0	0	0	0	70
PR	0	0	58	3	0	0	0	0	0	0	61
VT	2	16	25	1	0	0	0	15	0	0	59
RI	0	0	6	0	0	0	15	1	7	0	29
CT	1	0	0	0	0	2	0	0	0	0	3
DE	1	0	0	0	0	0	0	0	0	0	1
FL	0	0	0	1	0	0	0	0	0	0	1
GU	0	0	0	0	0	0	1	0	0	0	1
NJ	0	0	1	0	0	0	0	0	0	0	1

[a]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 34,043).
[b]All other states/territories with zero turbines in the 2010s are excluded within this table.

E. Total Capacity by State and Decade

1981-1989[a]

STATE	1980s TOTAL[b]	AVERAGE TURBINE CAPACITY (kW)[c]	STANDARD DEVIATION	TOTAL NEW CAPACITY (kW)	TOTAL NEW CAPACITY (MW)
CA	4471	79.40	34.08	354,997.40	355

[a]All other states/territories with zero turbines in the 1980s are excluded within this table. [b]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 4,471). [c]I include only turbine capacities with full confidence in the 1980s (n = 759).

1990-1999[a]

STATE[a]	1990s TURBINES TOTAL[b]	AVERAGE TURBINE CAPACITY (kW)[c]	SD	TOTAL NEW CAPACITY (kW)	TOTAL NEW CAPACITY (MW)
CA	1177	580.38	212.64	683,107.26	683.11
IA	320	745.82	42.29	238,662.4	238.66
MN	335	675.71	196.54	226,362.85	226.36
TX	151	702.18	119.11	106,029.18	106.03
WY	110	647.73	68.40	71,250.3	71.25
OR	38	660.00	0.00	25,080	25.08
CO	29	750.00	0.00	21,750	21.75
WI	18	660.00	0.00	11,880	11.88
VT[c]	12	545.83	202.77	6549.96	6.55
NE	3	660.00	0.00	1980	1.98
AK	12	74.09	50.59	889.08	0.89
NM[c]	1	660.00	.	660	0.66
MI	1	600.00	.	600	0.60
IL[c]	1	550.00	.	550	0.55
ND[c]	2	100.00	.00	200	0.20

[a]All other states/territories with zero turbines in the 1990s are excluded within this table. [b]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 1863). [c]I include only turbine capacities with full confidence (n = 1168).

2000-2009[a]

STATE	2000s TURBINES TOTAL	AVERAGE TURBINE CAPACITY (kW)	STANDARD DEVIATION	TOTAL NEW CAPACITY (kW)	TOTAL NEW CAPACITY (MW)
TX	5943	1515.71	530.75	9,007,864.53	9007.86
IA	2207	1568.76	479.78	3,462,253.32	3462.25
WA	1174	1613.20	598.88	1,893,896.8	1893.90
OR	1206	1485.64	590.58	1,791,681.84	1791.68
MN	1001	1505.24	389.81	1,506,745.24	1506.75
IL	952	1563.88	170.38	1,488,813.76	1488.81
NY	795	1601.16	285.57	1,272,922.2	1272.92

Continued

CA	977	1301.50	637.23	1,271,565.5	1271.57
ND	776	1585.43	224.97	1,230,293.68	1230.29
CO	877	1395.84	360.02	1,224,151.68	1224.15
OK	666	1722.03	307.14	1,146,871.98	1146.87
WY	662	1616.16	364.94	1,069,897.92	1069.90
IN	617	1678.03	261.68	1,035,344.51	1035.34
KS	633	1610.12	823.55	1,019,205.96	1019.21
PA	412	1790.53	309.98	737,698.36	737.70
NM	469	1238.02	460.55	580,631.38	580.63
WI	274	1571.23	119.49	430,517.02	430.52
MT	274	1439.05	289.94	394,299.7	394.30
WV	176	1875.00	217.12	330,000	330.00
SD	197	1620.47	292.99	319,232.59	319.23
MO	151	2029.14	138.13	306,400.14	306.40
UT	109	2084.67	489.21	227,229.03	227.23
ME	95	1837.89	647.94	174,599.55	174.60
ID	84	1742.86	296.28	146,400.24	146.40
MI	89	1607.30	224.18	143,049.7	143.05
NE	64	2204.06	696.25	141,059.84	141.06
AZ	30	2100	.00	63,000	63.00
HI	50	1126.67	423.32	56,333.5	56.33
TN	18	1610.00	437.17	28,980	28.98
NH	13	2000.00	.00	26,000	26.00
MA	21	926.25	597.45	19,451.25	19.45
OH	9	1250.83	852.00	11,257.47	11.26
AK	53	210.94	424.33	11,179.82	11.18
NJ	5	1500.00	.00	7500	7.50
RI	3	380.00	395.98	1140	1.14
VT[d]	2	100.00	.00	200	0.20
AR[d]	1	175.83	330.57	175.83	0.18
NC[e]	1	n/a	n/a	n/a	n/a

[a]All other states/territories with zero turbines in the 2000s are excluded within this table. [b]I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 21,086). [c]When available, I include only turbine capacities with full confidence (n = 18,045). [d]For these states, I use the average turbine capacities with moderate confidence (n = 2969). [e]There was no turbine capacity data for North Carolina's single turbine.

	2010-2019[a]				
STATE	2010s TURBINES TOTAL	AVERAGE TURBINE CAPACITY (kW)	STANDARD DEVIATION	TOTAL NEW CAPACITY (kW)	TOTAL NEW CAPACITY (MW)
TX	8758	2200.60	478.76	19,272,854.80	19272.85
OK	3360	2093.37	430.85	7,033,723.20	7033.72
IA	2838	2259.60	303.23	6,412,744.80	6412.74
KS	2613	2040.56	476.51	5,331,983.28	5331.98
CA	1767	2293.76	663.68	4,053,073.92	4053.07
IL	1961	1860.68	315.74	3,648,793.48	3648.79
CO	1415	1795.34	217.23	2,540,406.10	2540.41
MN	1239	1841.12	322.14	2,281,147.68	2281.15
ND	1026	2199.49	541.92	2,256,676.74	2256.68
NE	1009	2015.47	496.39	2,033,609.23	2033.61
MI	1072	1879.77	386.90	2,015,113.44	2015.11
OR	678	2237.86	389.78	1,517,269.08	1517.27
NM	648	2118.89	291.41	1,373,040.72	1373.04
IN	647	1972.26	549.34	1,276,052.22	1276.05
WA	558	2114.46	315.54	1,179,868.68	1179.87
SD	490	1738.42	240.91	851,825.80	851.83
ID	457	1813.14	332.71	828,604.98	828.60
OH	387	1996.03	323.75	772,463.61	772.46
ME	291	2590.31	702.21	753,780.21	753.78
NY	346	2159.73	559.10	747,266.58	747.27
MO	384	1873.27	247.18	719,335.68	719.34
PA	339	2049.00	349.15	694,611	694.61
MT	254	1708.55	377.22	433,971.70	433.97
WY	232	1722.08	312.09	399,522.56	399.52
WV	199	1780.40	324.06	354,299.6	354.30
WI	162	1874.84	276.33	303,724.08	303.72
NC	104	2000.00	.00	208,000	208
AZ	114	1807.96	232.66	206,107.44	206.11
MD	80	2477.27	199.43	198,181.6	198.18
NH	71	2600.81	483.03	184,657.51	184.66
UT	97	1728.02	360.89	167,617.94	167.62
NV	70	2300.00	.00	161,000	161
HI	74	2134.78	605.42	157,973.72	157.97
VT	59	2468.97	599.18	145,669.23	145.67
PR	61	2090.42	467.89	127,515.62	127.52

Continued

MA	70	1593.71	303.61	111,559.70	111.56
AK	77	1173.94	764.05	90,393.38	90.39
RI	29	2552.59	1772.13	74,025.11	74.03
CT	3	2850.00	.00	8550	8.55
DE	1	2000.00	.	2000	2
NJ	1	1500.00	.	1500	1.5
GU	1	275.00	.	275	0.275
FL[d]	1	n/a	n/a	n/a	n/a

[a] All other states/territories with zero turbines in the 2010s are excluded within this table. [b] I include all turbines, regardless of confidence of level, that provide a state/territory of each (n = 34,043). [c] When available, I include only turbine capacities with full confidence (n = 31,031). [d] There was no turbine capacity data for Florida's single turbine.

F. Size of Turbines by Year

YEAR	AVERAGE HUB HEIGHT[a] (metres; full certainty)	STANDARD DEVIATION	AVERAGE HUB HEIGHT[b] (metres; partial certainty)	STANDARD DEVIATION
1983	22.80	0.00	n/a	n/a
1984	24.00	0.00	24	.00
1985	24.39	0.29	n/a	n/a
1986	n/a		25.31	6.80
1987	n/a		n/a	n/a
1988	23.00	.00	n/a	n/a
1989	n/a	n/a	n/a	n/a
1990	n/a	n/a	29.32	2.76
1991	n/a	n/a	n/a	n/a
1992	43.00	.	40	.
1994	n/a	n/a	40	.00
1995	39.77	1.52	25	.
1996	50.00	.	n/a	n/a
1997	30.50	0.00	44.04	6.33
1998	52.29	3.56	n/a	n/a
1999	57.23	7.23	61.05	6.90
2000	57.56	9.29	30.00	.
2001	57.10	7.81	65.41	5.79
2002	62.74	5.83	53.25	37.83
2003	66.70	7.38	70.94	7.56
2004	67.63	9.39	63.32	2.43
2005	75.24	8.06	74.91	9.72

Continued

2006	74.30	9.51	78.67	4.61
2007	77.77	5.16	79.65	2.25
2008	78.14	4.77	78.61	7.45
2009	78.85	3.98	70.71	15.29
2010	79.79	2.25	65.89	21.86
2011	80.89	5.58	80.40	5.91
2012	83.75	9.26	82.61	7.01
2013	80.23	3.55	86.50	9.49
2014	82.85	5.61	79.65	3.81
2015	82.30	5.39	87.71	17.27
2016	82.98	6.02	88.05	18.73
2017	86.01	6.69	n/a	n/a
2018	88.26	5.87	80	.
2019	90.30	6.88	n/a	n/a
TOTAL/ AVERAGE	79	11.72	70.96	17.54

[a]I include all turbines with full confidence values in hub height (n = 51,035). [b]I include all turbines with partial confidence values in hub height turbine (n = 4168).

G. Largest Turbines by Year (Hub Height; 2000-2019)

YEAR	TALLEST TURBINE (HUB HEIGHT; METRES)[a]
2000	67
2001	80
2002	80
2003	80
2004	80
2005	85
2006	80
2007	105
2008	100
2009	80
2010	100
2011	100
2012	100
2013	103
2014	100
2015	100
2016	116.5

Continued

2017	95
2018	130
2019	114
TOTAL/AVERAGE	79

[a]I include all turbines with full confidence values in hub height from 2000-2019 (n = 49,105).

H. Turbine Rotor Diameter and Swept Area (1999-2019)

YEAR	AVERAGE ROTOR DIAMETER (metres; full certainty)[a]	STANDARD DEVIATION	AVERAGE TOTAL SWEPT AREA (metres^2; full certainty)[b]	STANDARD DEVIATION
1999	48.22	3.08	1833.71	195.30
2000	47.15	8.18	1798.27	598.58
2001	50.36	6.35	2023.83	549.64
2002	52.48	8.97	2226.36	813.07
2003	68.36	8.57	3727.21	885.81
2004	62.11	13.89	3170.71	1307.07
2005	74.78	9.33	4460.39	904.72
2006	76.71	10.76	4711.93	1192.97
2007	78.70	9.11	4929.53	1099.01
2008	79.28	9.93	5014.22	1154.89
2009	81.36	8.42	5254.04	1039.99
2010	84.22	7.67	5617.48	1024.65
2011	88.92	8.93	6272.06	1196.47
2012	93.62	10.65	6972.71	1488.44
2013	96.87	9.15	7435.97	1178.05
2014	99.59	7.40	7832.87	1131.63
2015	102.29	7.98	8267.02	1246.57
2016	108.26	7.57	9250.39	1267.75
2017	112.99	7.08	10066.30	1204.18
2018	115.96	8.09	10611.66	1489.73
2019	122.63	7.18	11850.43	1374.05
TOTAL/AVERAGE	90.81	19.14	6764.93	2654.08

[a]I include all turbines with full confidence values in rotor diameter and total swept area (n = 51,035)

STEELHEAD
a Vestas company

April 18, 2025

Randy Abrahamson
Tribal Historic Preservation Officer
Spokane Tribe
PO Box 100
Wellpinit, WA 99040
Email: [redacted]@spokanetribe.com

Subject: Harvest Hills Wind Project Updates and Fieldwork Notification

Dear Mr. Abrahamson,

On September 20, 2024, Whitman County Planning Director Alan Thompson sent you a notification letter regarding the Harvest Hills Wind project (the "Project") in Whitman County, Washington. Since then, Harvest Hills Wind LLC ("Harvest Hills") refined the Project's boundaries and footprint into micrositing corridors, which are the areas in which project facilities are planned (Figures 1 and 2).

Currently, Whitman County is revising their Wind Energy Ordinance and Harvest Hills is considering going through the state's Energy Facility Siting Evaluation Council (EFSEC) certification process instead of the County approval process; however, regardless of the permitting path, cultural resource surveys are necessary to inform Tribal consultation and ensure a low impact, regulatory compliant project. The purpose of this letter is to provide an update on these important processes and notify you of the upcoming archaeological pedestrian survey and work plan development.

Project Summary

The Project's proposed location is on the east of State Route 195 and south of State Route 272 in Whitman County and includes the following:

- Up to 45 Vestas V-163 4.5-MW wind turbine generators (WTG), each up to 699 feet tall;
- Short turbine access roads providing access from public roads to each WTG;
- 34.5-kV electrical collection lines buried 3-6 feet below ground and connecting the turbines to the substation;
- A collection substation located near the Point of Interconnection (POI);
- Up to three permanent met towers (up to 400 feet tall);
- A potential short above ground line (1-3 poles) linking the Project to the POI and to existing transmission; and
- A communications antenna for an Aircraft Detection Lighting System.

A-15

Harvest Hills developed the micrositing corridors shown in Figure 2 in response to a variety of factors, including leased land, the County's required setbacks, as well as other standard setbacks, and environmental factors. The above Project infrastructure and associated ground disturbances are planned entirely within the approximately 2,521-acre micrositing corridors, which are the focus of future study.

Regulatory Context

Both the County and EFSEC processes require Harvest Hills to complete a Washington State Environmental Policy Act (SEPA) environmental checklist, which includes an assessment of cultural resources. Additionally, Harvest Hills is seeking a lease from the Washington Department of Natural Resources (WA DNR) for potential development on a parcel of state land. Harvest Hills and the Project will comply with all relevant state regulations, including, without limitation, Revised Code of Washington (RCW) 27.44 (Indian Graves and Records), RCW 27.53 (Archaeological Sites and Records), RCW 68.50 (Human Remains), and RCW 68.60 (Abandoned and Historic Cemeteries and Historic Graves).

Cultural Resources Investigations

Historical Research Associates, Inc. (HRA) will complete archaeological and architectural surveys for the Project. HRA completed background research for the Project boundary and is currently planning for an archaeological pedestrian survey of the micrositing corridors to begin on May 2, 2025.

Archaeological Pedestrian Survey

HRA plans to conduct a pedestrian survey consisting of archaeologists walking transects spaced at intervals of 20 meters or less across the entirety of the micrositing corridors. During this survey, archaeologists will seek out and examine ground exposures (e.g., ditches, cut banks, plowed fields, other erosional exposures) looking for exposed archaeological materials. They will record their observations in field notebooks and record the surveyed areas with GPS technology. Upon encountering any archaeological artifacts or features within the micrositing corridor, HRA field personnel will document the resources in a manner that meets the standards of the Department of Archaeology and Historic Preservation (DAHP). The initial archaeological pedestrian survey for the Project is tentatively scheduled as a 6-day session beginning on May 2, 2025. The crew will be in the field between approximately 8:00 am and 5:00pm daily. Additional survey may be necessary after this period in response to weather or other delays, or in the event the entire micrositing corridor is not surveyed in the estimated 6-day period.

HRA is preparing a work plan for subsurface archaeological survey that will occur after the pedestrian survey. Findings from the pedestrian survey may be used to inform the work plan, which will be provided to your office for review and comment prior to conducting any subsurface archaeological investigations.

Architectural Survey

HRA is also developing a work plan for the built-environment survey for the project. That work plan will also be submitted for your review in advance of the built-environment field investigations, which are slated to begin this summer.

Request for Comment

Any input you have at this phase in the Project's development is greatly appreciated, as we would like to include any early input and involvement that you may be able to offer. Please let us know if you would like to have a call to connect directly to discuss the Project, or if you would like to participate in the initial phase of pedestrian survey or later phases of the archaeological investigations.

You may follow up directly with HRA Senior Archaeologist Jordan Pickrell (206-486-3491, jpickrell@hrassoc.com) if you have comments, concerns, or information related to the background research or field surveys. Harvest Hills welcomes any input you can provide and seeks to incorporate sources of information and present perspectives that are important to the Spokane Tribe.

Sincerely,

Dave Phillips

Dave Phillips, Director Environmental Affairs
[redacted]@vestas.com

Attachments:

- Figure 1 –Project Location
- Figure 2 – Micrositing corridors and project boundary aerial

Cc: Carol Evans, Spokane Tribe Chairperson [redacted]om>
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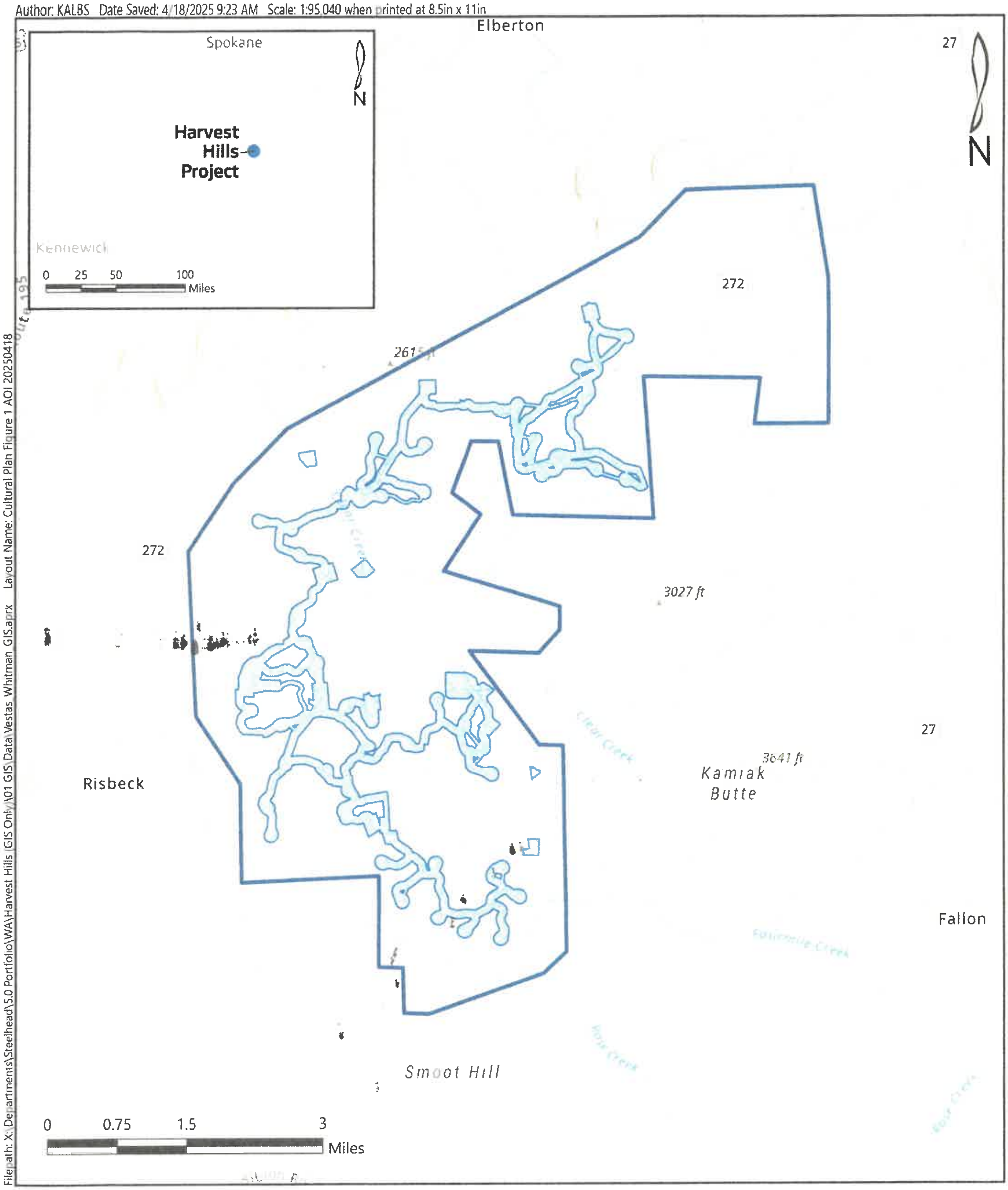
Author: KALBS Date Saved: 4/18/2025 9:23 AM Scale: 1:95,040 when printed at 8.5in x 11in

Filepath: X:\Departments\Steelhead\5.0 Portfolio\WA\Harvest Hills (GIS Only)\01 GIS\Data\Vestas_Whitman_GIS.aprx Layout Name: Cultural Plan Figure 1 AOI 20250418



Project AOI

Microsite Corridor

Figure 1

Project Location

Wind Project Updates and Fieldwork Notification

Harvest Hills Wind

Whitman County, WA

Basemap Sources: Esri, NASA, NGA, USGS, FEMA, Sources: Esri, TomTom, Garmin, FAO, NOAA, USGS, (c) OpenStreetMap contributors, and the GIS User Community, Sources: Esri, TomTom, Garmin, (c) OpenStreetMap contributors, and the GIS User Community

58 Turbines
105 MW Total - 1.8 MW/tower
380' Tall

Palouse Wind Existing Project

Wind farm powers up on the Palouse

Recently finished project touted to meet equivalent needs of 30,000 customers

-Photo courtesy of First Wind

A-16

January 17, 2013
Jessica Valencia

Work on the Palouse wind farm, a two-year project to construct turbines meant to generate electricity for Spokane-based Avista Corp., is now complete, an addition that the energy company says will pad its growing renewable energy portfolio.

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The 40-acre, 58-turbine wind farm, named Palouse Wind and situated eight miles west of Oakesdale, Wash., went online Dec. 13 and generates 105 megawatts of energy, or the equivalent of providing power for 30,000 Avista residential customers, company spokeswoman Anna Scarlett says. Oakesdale is about 43 miles south of Spokane.

Boston-based First Wind, a renewable energy company, developed and owns the wind farm, says Ben Fairbanks, business development manager for First Wind's western region. First Wind operates 16 wind farms across the U.S., including the one located on the Palouse.

Avista is buying all of the energy generated at the Palouse wind farm under a 30-year agreement, Fairbanks says.

While the turbines were being constructed between October 2011 and the end of last year, Fairbanks says the land impacted was closer to 400 acres. He says more than 80 percent of the affected land is located in wheat fields, and in most cases, farmers can plant up to the base of the turbines.

"Once the project is fully constructed, those areas are reclaimed and restored," Fairbanks says. "In most cases, the farmers have already been back in there planting."

About 40 different land owners are affected by the project, he says. Along with 28 land owners who have turbines located on their property, 12 have access easements or transmission easements, Fairbanks says.

First Wind leases the property it uses from farmers and Fairbanks says those leases, which range between 20 years and 40 years, will be extended if demand for wind energy in the Inland Northwest remains strong.

Fairbanks says First Wind currently employs four full-time workers who manage a team of 10 full-time Vestas employees at First Wind's office in Rosalia. Vestas, a Danish wind turbine manufacturer with U.S. headquarters in Portland, Ore., has blade, tower, and nacelle manufacturing facilities in Colorado. Scarlett says Avista doesn't have any employees stationed at the site.

Those associated with Vestas are on site to handle turbine maintenance.

Vestas provided the turbine parts for Palouse Wind. Fairbanks says parts were manufactured at Vestas' Colorado plants and shipped from there to Pasco, Wash. on rail lines and then trucked to the Palouse.

Fairbanks says it logged more than 250 tractor-trailer loads of turbine-part components while constructing the Palouse Wind complex.

During construction, Fairbanks says more than 40 Inland Northwest contractors and suppliers worked on the project, with around 15 contractors based in Spokane County and 14 based in Whitman County. At the peak of construction, between 250 and 300 people worked on the site daily in various roles, Fairbanks says.

Alan Thomson, Whitman County planner, says the county treasurer's office estimates it received roughly $1.1 million in sales tax payments related to the project between November 2011 and October 2012, before a roughly 75 percent state sales tax rebate Palouse Wind is slated to get back. Thomson says the 25 percent of remaining sales tax will be divided between the state and the county.

First Wind estimates Whitman County will receive $700,000 on average annually in property tax payments associated with the wind farm. Thomson says that property tax, which won't kick in until 2014, will help fund expenditures by taxing entities such as library and school districts.

"They'll all get a share of the overall moneys from this project," Thomson says.

Over a 20-year span, the county is expected to receive about $12 million in property tax revenues.

– incorrect – is 380' tall

The 58 Vestas v100 turbines stand 426 feet tall. From the ground to the hub, where the blades attach, the turbines stand 250 feet tall, with the blade diameter sweeping a space that is roughly the length of a football field, he says.

"One of the reasons why a project like this is feasible is advancement in turbine technology," Fairbanks says.

The turbine model used at Palouse Wind is different than those that might be used at other wind farms developed by the wind energy company.

Fairbanks says a turbine usually doesn't produce electricity unless it reaches a certain number of revolutions per minute, or RPM. The turbines will spin, but internal computers won't enable the transmission of electricity unless enough force is applied to the blades. With the model used at the Palouse, the power curve is flatter, meaning the turbines start producing electricity at a lower wind speed. Coupled with a longer blade, Fairbanks describes it as turning a bigger Ferris wheel, applying more force on the components.

A height-wind resource map published in partnership with the U.S. Department of Energy's Wind Program and the National Renewable Energy Laboratory examines the wind resource potential in the state of Washington for utility-scale development, referring to turbines between 262 and 328 feet high. Average annual wind speeds of 14.5 mph or greater are typically considered to be high enough for wind development, the U.S. Department of Energy says. The turbines installed by First Wind exceed the maximum height of resource map by almost 100 feet.

Fairbanks says Neff Ridge, where Palouse Wind is situated, is windiest between October and March.

In addition to Palouse Wind, Avista in 2008 acquired the development rights for a site in Reardan, located about 21 miles west of Spokane. Since then, the company has been evaluating and studying the site for potential development.

"For us, bringing wind on is a good thing because it helps us continue to give our customers energy at some of the lowest prices in the country," Scarlett says.

According to the resource map, Palouse Wind and the area west of Spokane that Avista is eyeing for future development both average 14.5 mph wind speed annually.

"It's really pairing the right technology with the right wind resource," Fairbanks says. "Engineering has gone into that understanding of matching the right turbine with the right wind speed to produce the most efficient and most energetic project."

In addition to Avista looking at the potential for wind energy in the Reardan area, Fairbanks says First Wind is permitted to erect upwards of four additional turbines at Palouse Wind in the future if warranted.

Scarlett says Avista has met state renewable energy mandates for 2012, without taking into account the electricity generated by Palouse Wind. The company was able to meet those minimum requirements through upgrades at its hydroelectric plants, Scarlett says. Under the voter-approved mandates, electric utilities must obtain 15 percent of their power from renewable sources by 2020.

With Avista's Kettle Falls Generating Station, a biomass plant, eligible to count toward the company's renewable energy portfolio as of last March, Scarlett says the Palouse wind farm's generated electricity may not even be counted toward the next round of mandates.

"The Palouse wind is just to meet energy needs and add renewable energy to the portfolio," Scarlett says.

Avista Corp.'s operating division, Avista Utilities, provides electricity to 361,000 customers and natural gas to 320,000 customers throughout the Inland Northwest and parts of Oregon.

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