BERKELEY LAB

LAND-BASED WIND MARKET REPORT

2024 EDITION

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Preparation and Authorship

This report was prepared by Lawrence Berkeley National Laboratory, with funding from the Wind Energy Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.

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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.

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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.

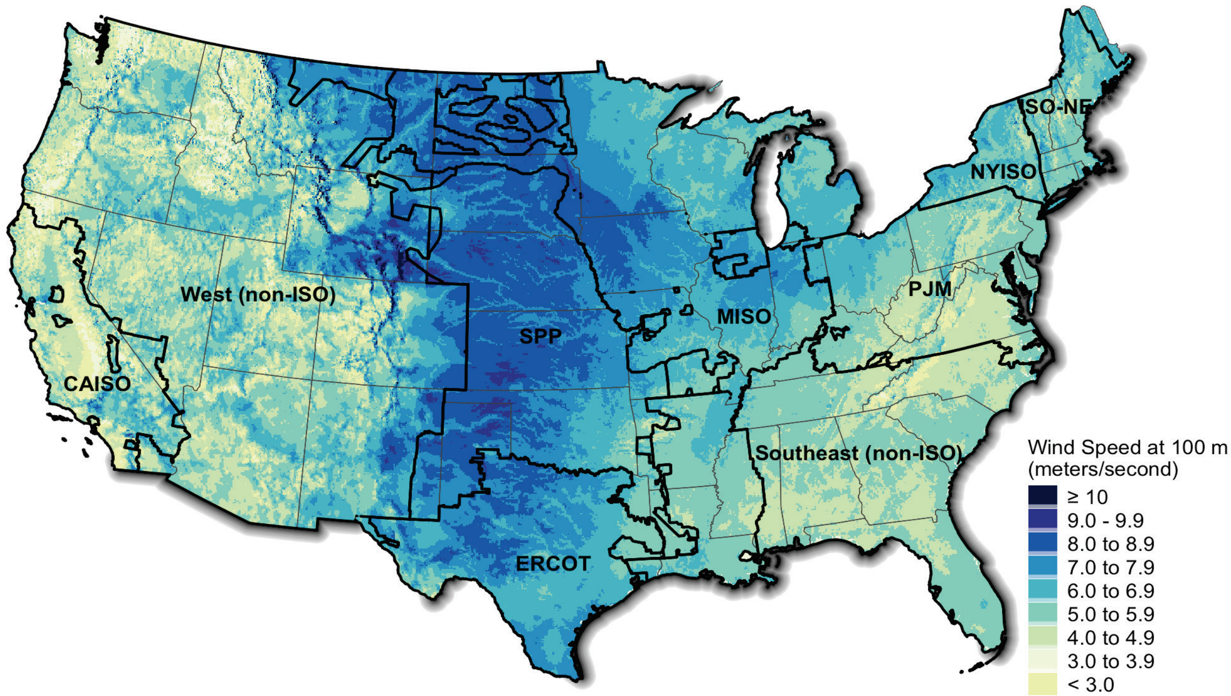
This annual report—now in its eighteenth year—provides an overview of trends in the U.S. wind power market, with a particular focus on land-based wind in the year 2023.

- 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.

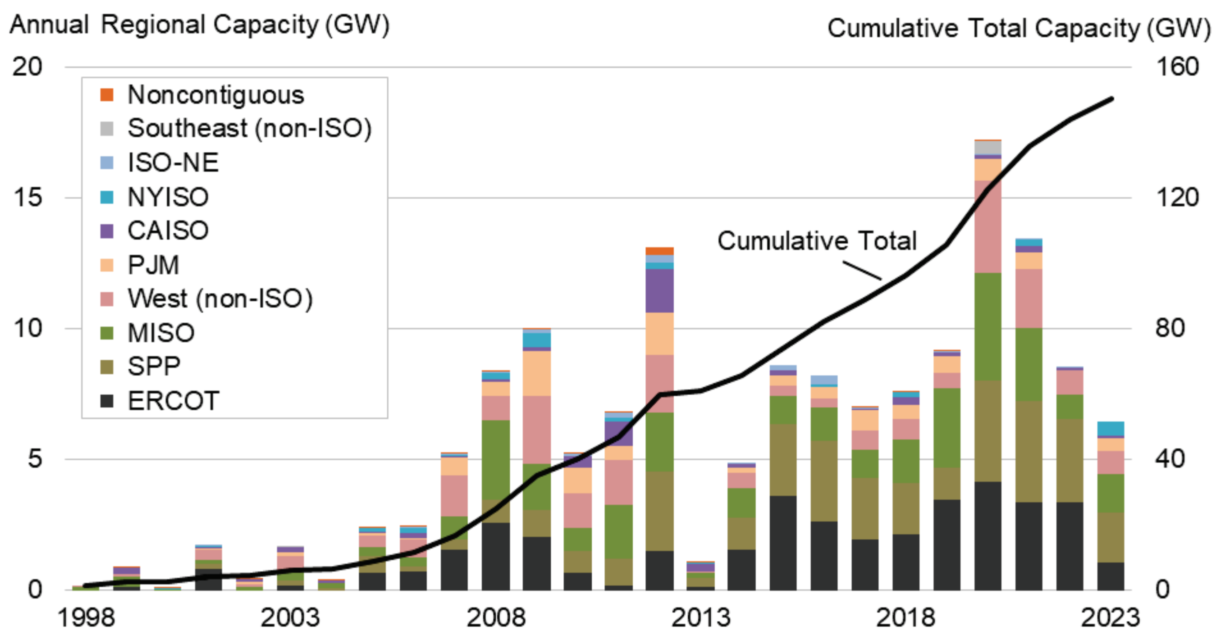
Much of the data included in this report were compiled by DOE's Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Clean Power Association (ACP—along 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.

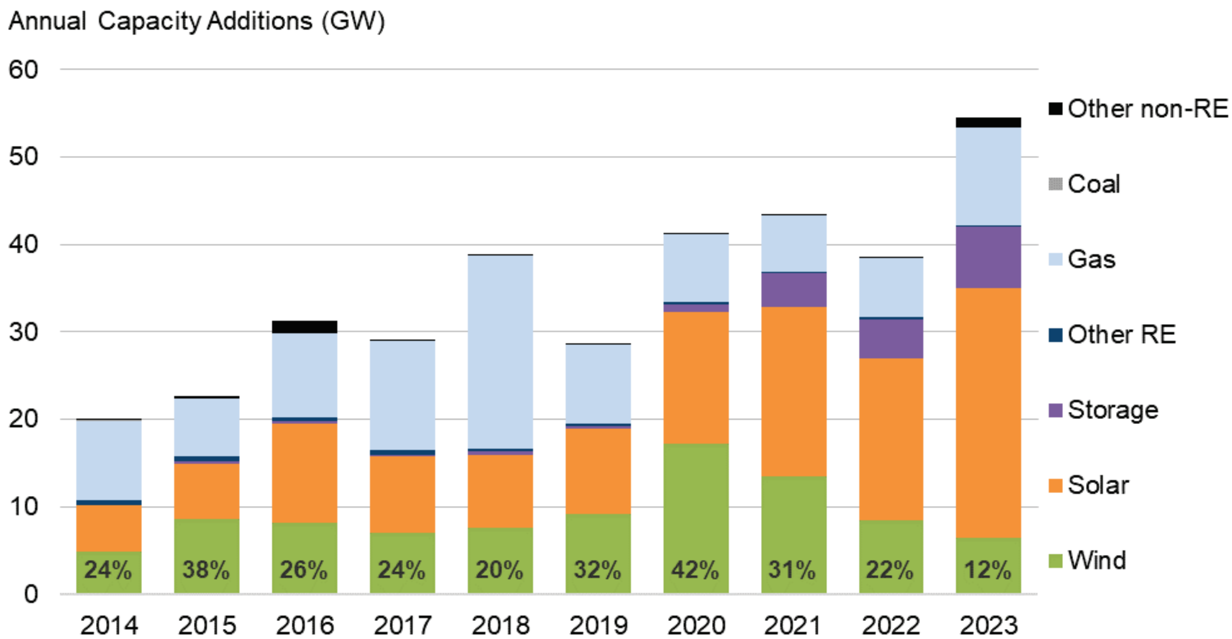
[11] This investment figure is based on an extrapolation of the average project-level capital costs reported later in this report and does not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

[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]

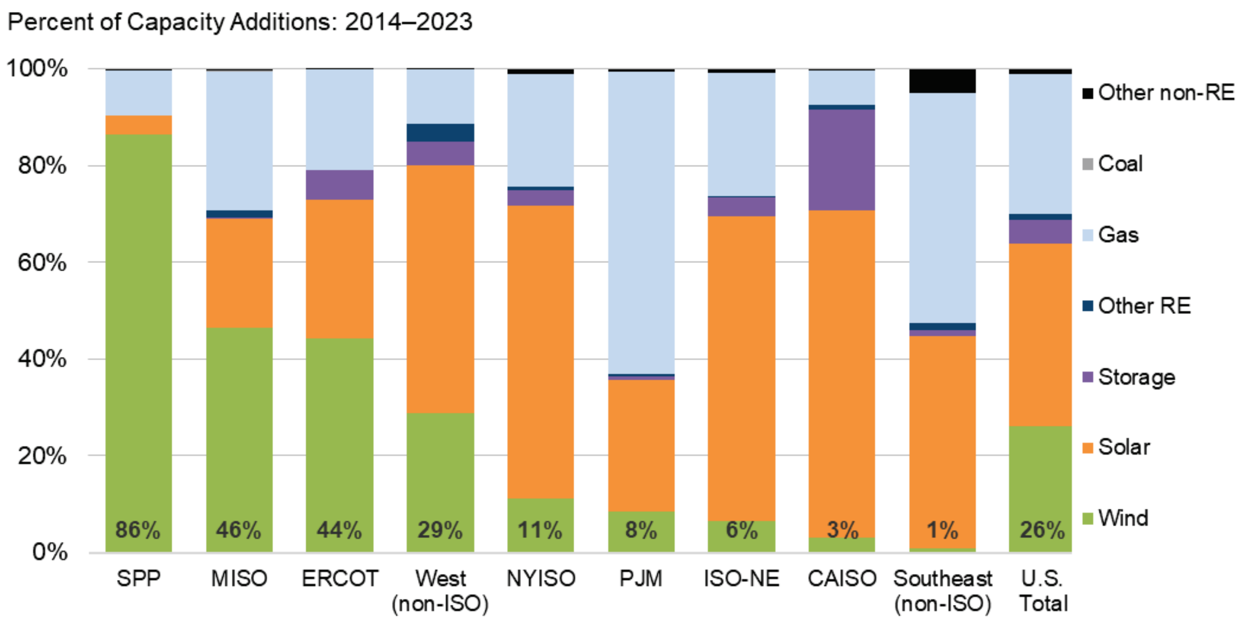


Sources: EIA, ACP

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

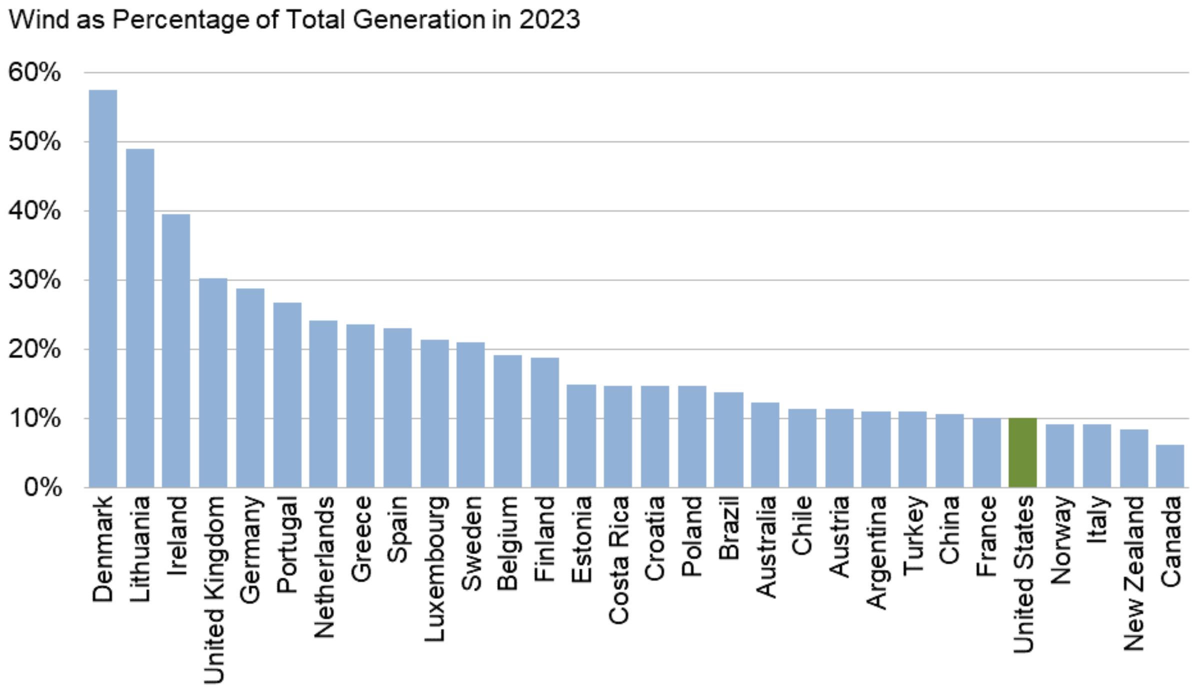
Annual Capacity (2023, GW)	
China	75.7
United States	**6.5**
Brazil	4.8
Germany	3.8
India	2.8
Netherlands	2.5
Sweden	2.0
France	1.8
Canada	1.7
United Kingdom	1.4
Rest of World	13.8
TOTAL	**117**

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.



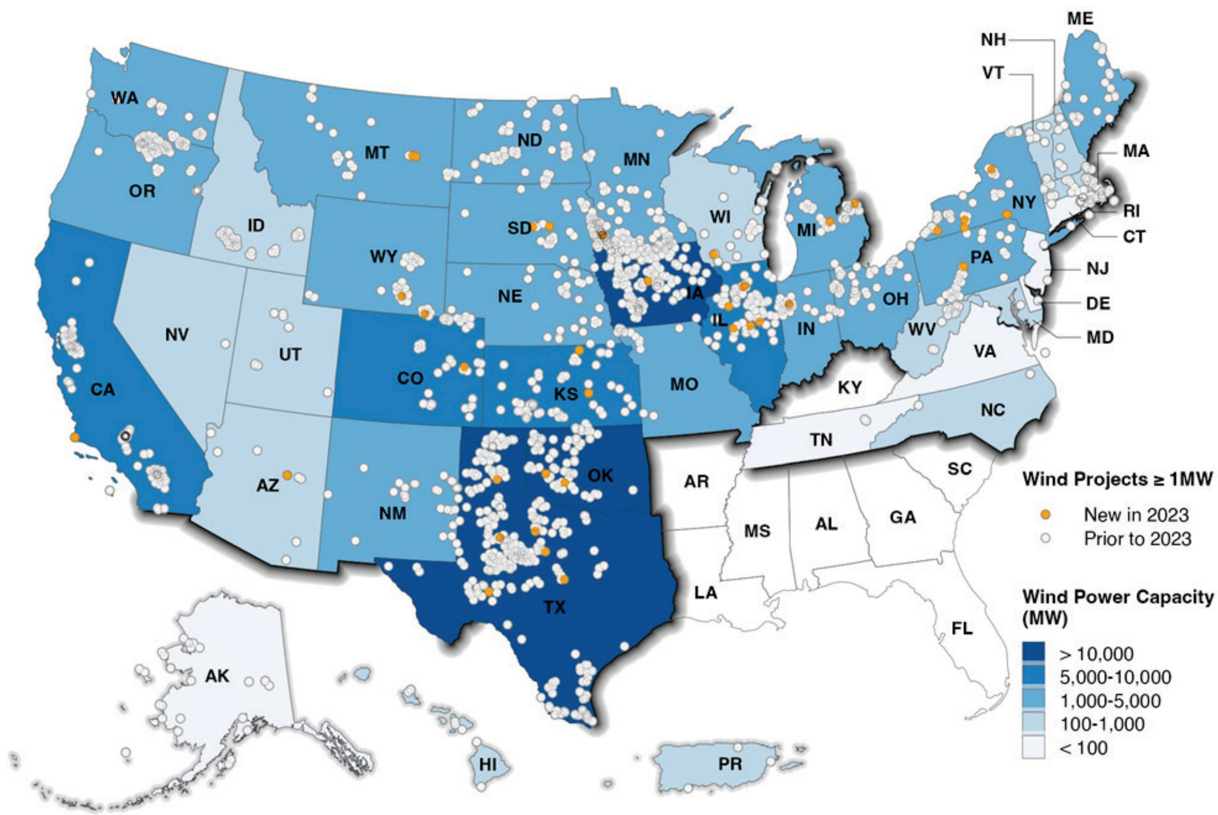
Source: IEA Monthly Electricity Statistics

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).

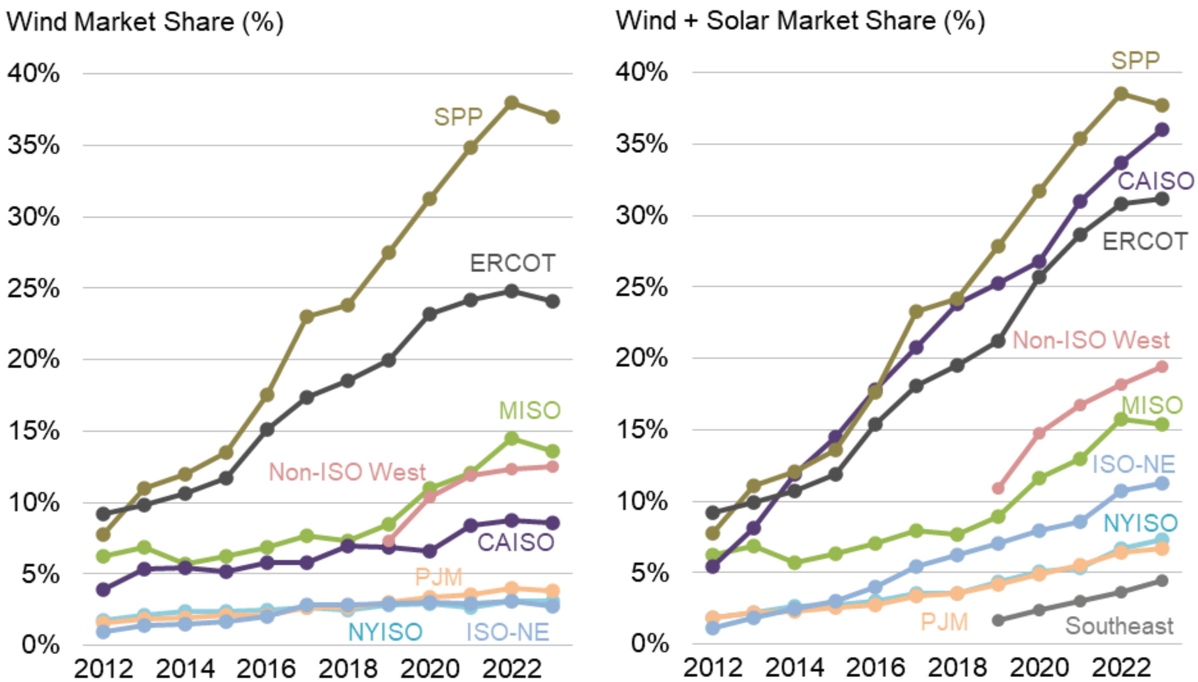
Table 2. U.S. Wind Power Rankings: The Top 20 States

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.



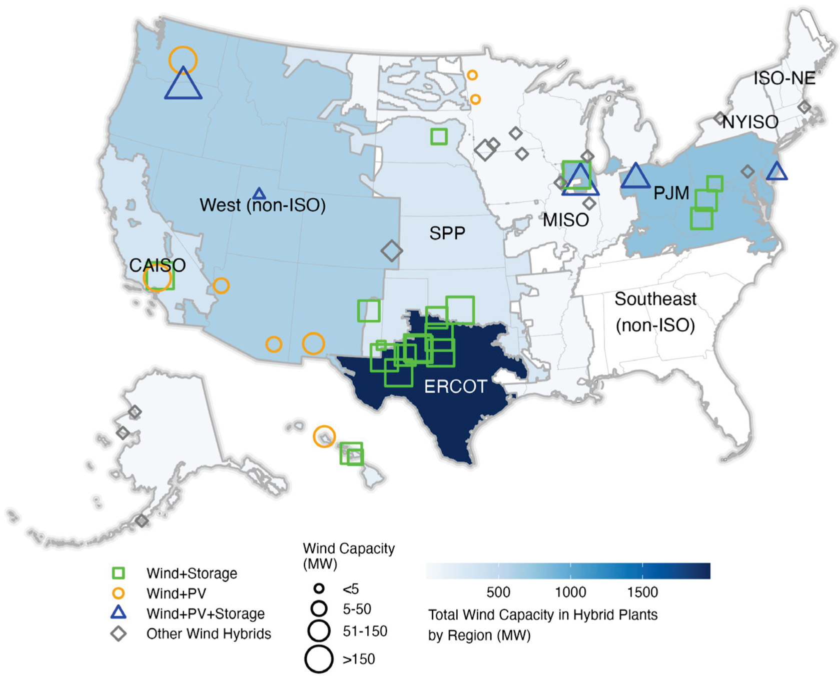
Sources: EIA, Hitachi, MISO, CAISO, SPP, NYISO, PJM, ISO-NE, ERCOT, Berkeley Lab

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).

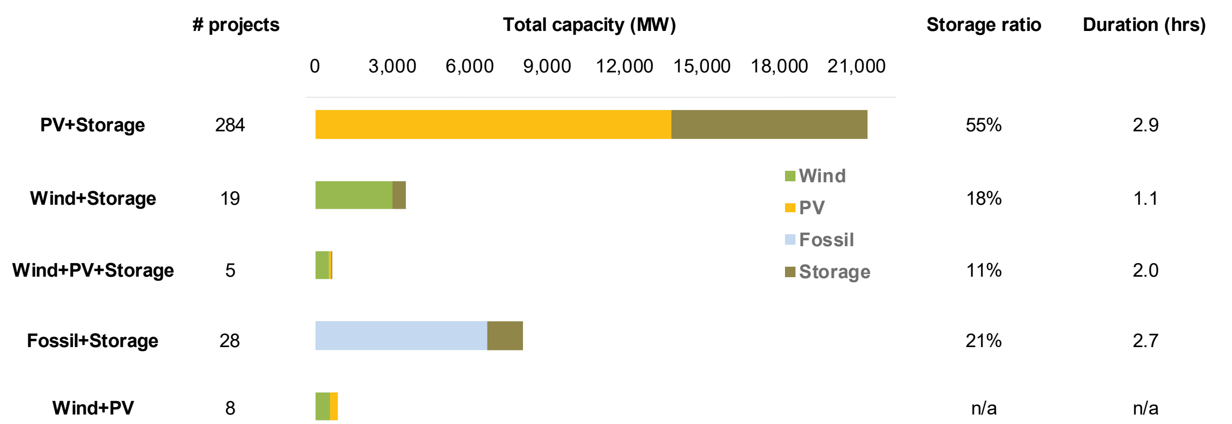
The most common type of wind hybrid project combines wind and storage technology, where 3 GW of wind has been paired with 0.5 GW of battery storage across 19 plants. All three new projects in 2023 combined these two technologies. Other combinations include wind and PV; wind, PV, and storage; wind and 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.

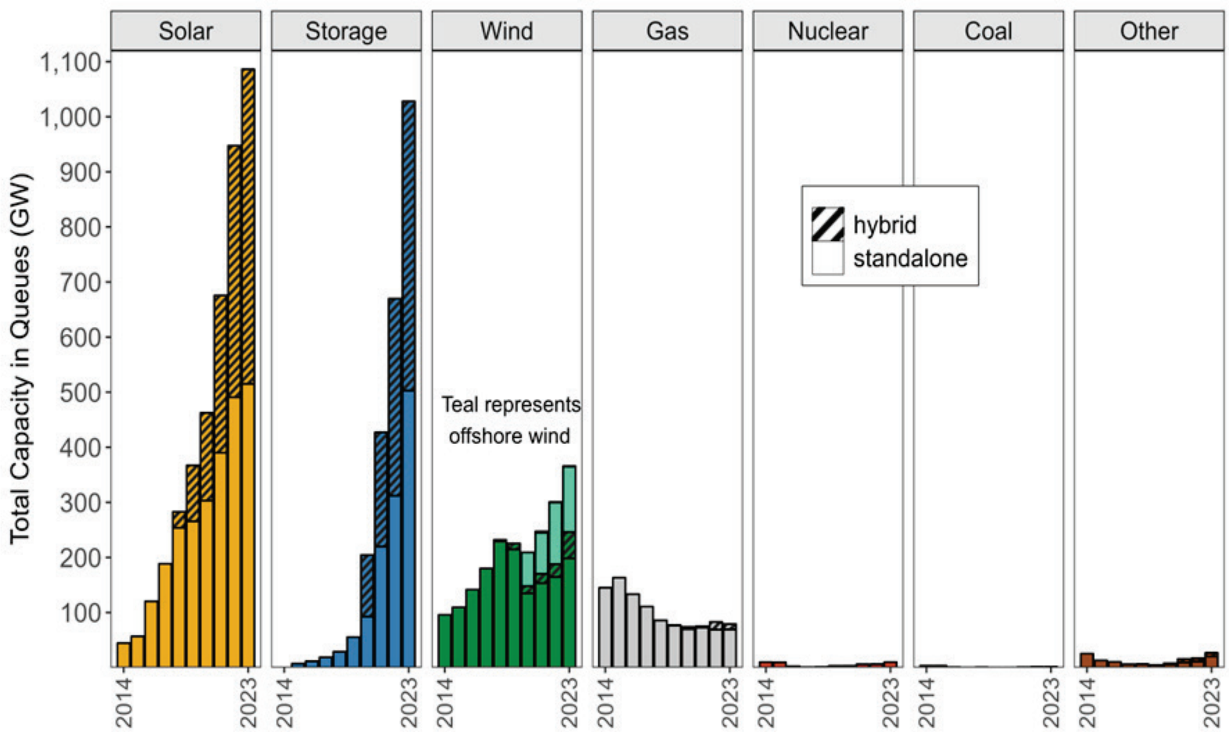
Sources: EIA-860 2023 Early Release, Berkeley Lab

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

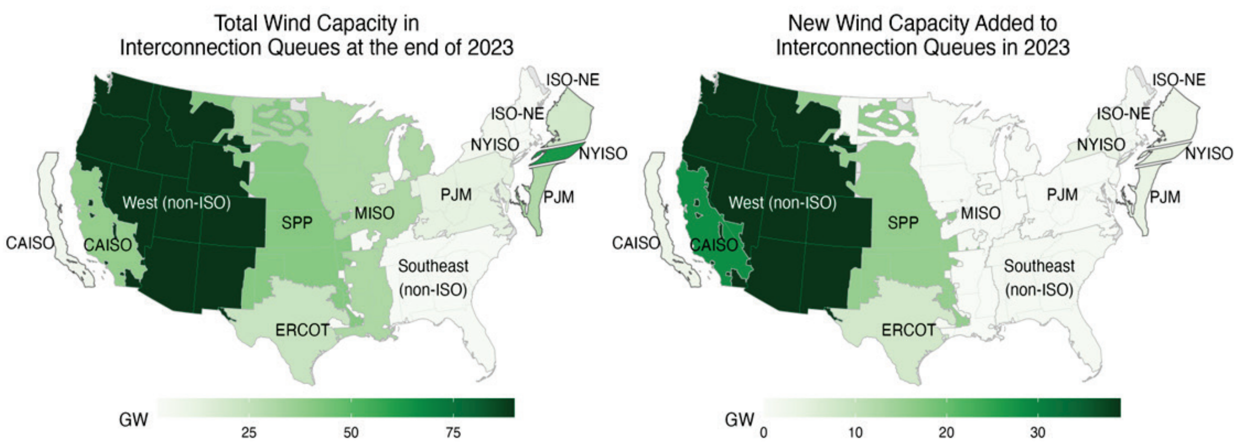
Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides an indication of developer interest. At the end of 2023, there were 366 GW of wind capacity in the queues reviewed for this report—a marked increase from the 300 GW in the queues the previous 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.

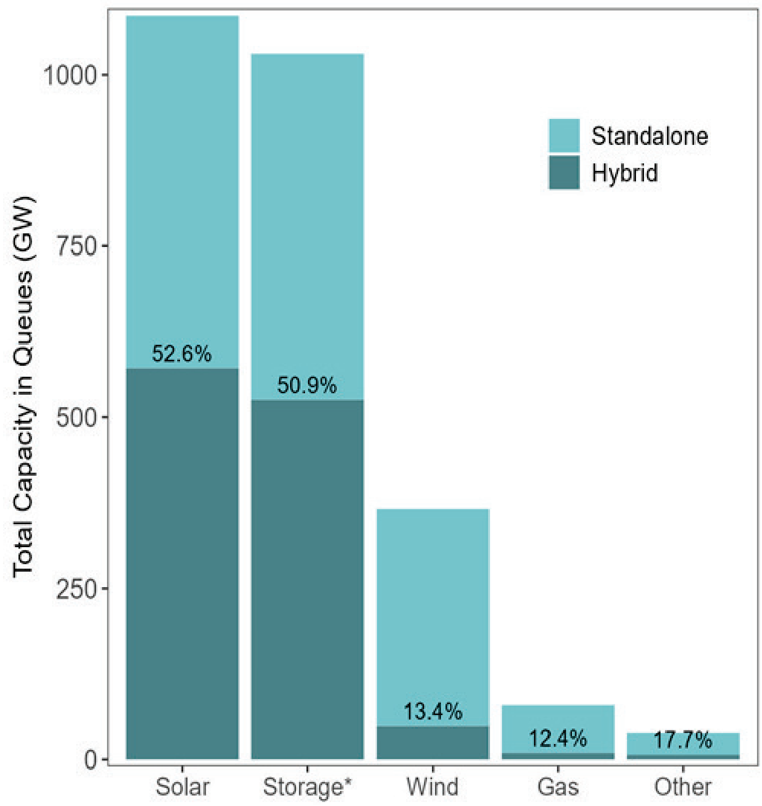
Source: Berkeley Lab review of interconnection queues

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).



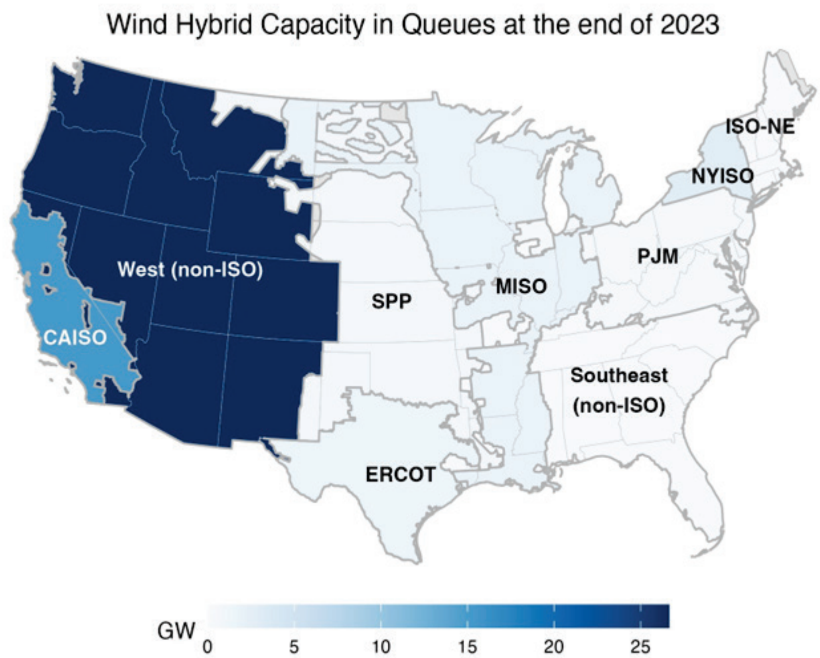
Note: Each bar reflects the listed resource type. A solar+storage hybrid will have its solar capacity in the 'solar' column and its storage capacity in the 'storage' column

*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.



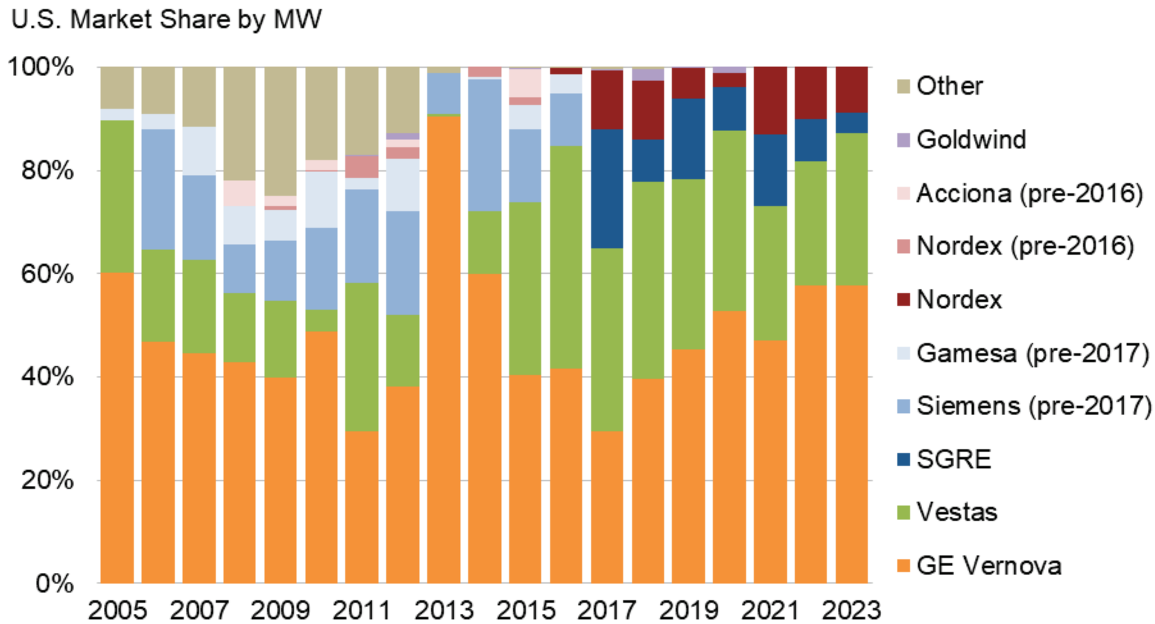
Source: Berkeley Lab review of interconnection queues

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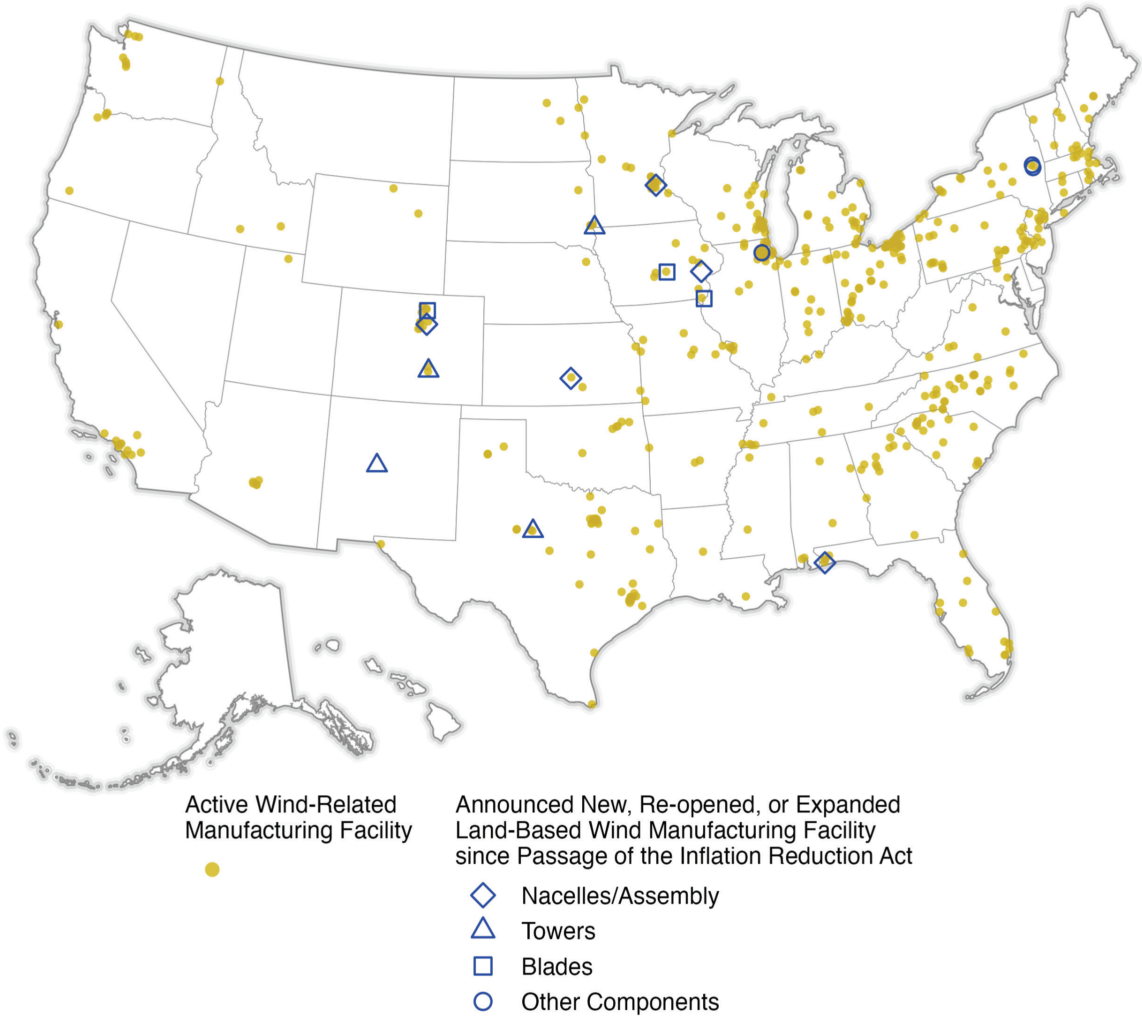
[17] Market share is reported in MW terms and is based on project installations in the year in question.
[18] See: https://www.energy.gov/invest

- 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

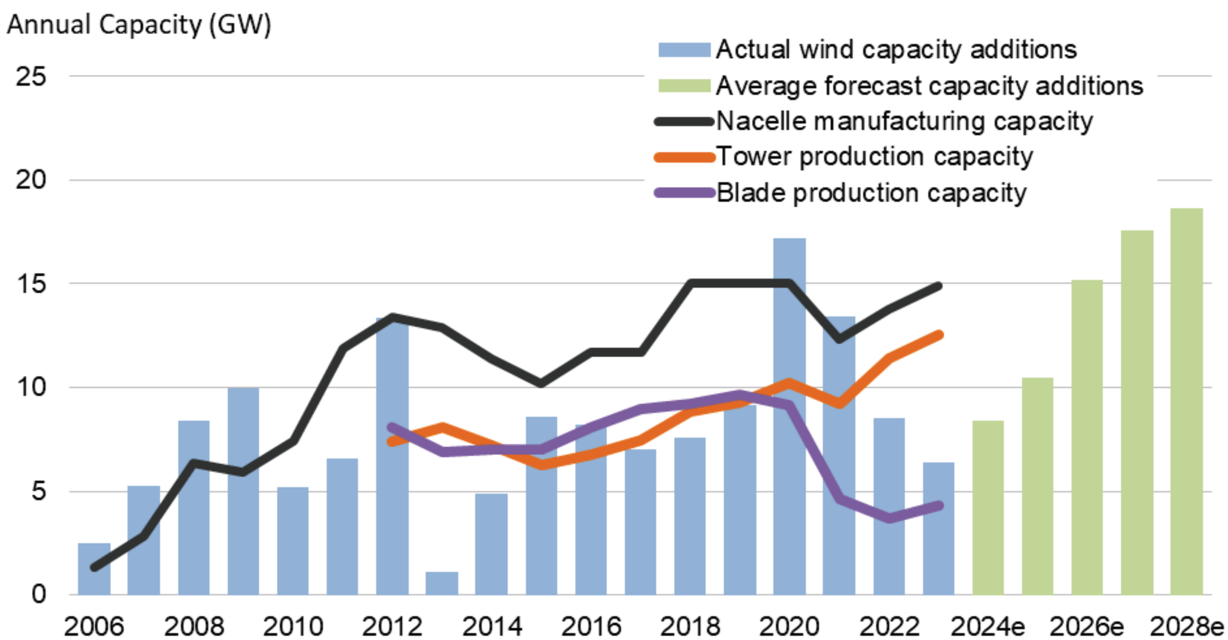
Domestic turbine nacelle assembly[19] capability is defined here as the maximum capacity of nacelles that can be assembled annually at U.S. plants operating at full utilization. This value grew from less than 1.5 GW in

[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.

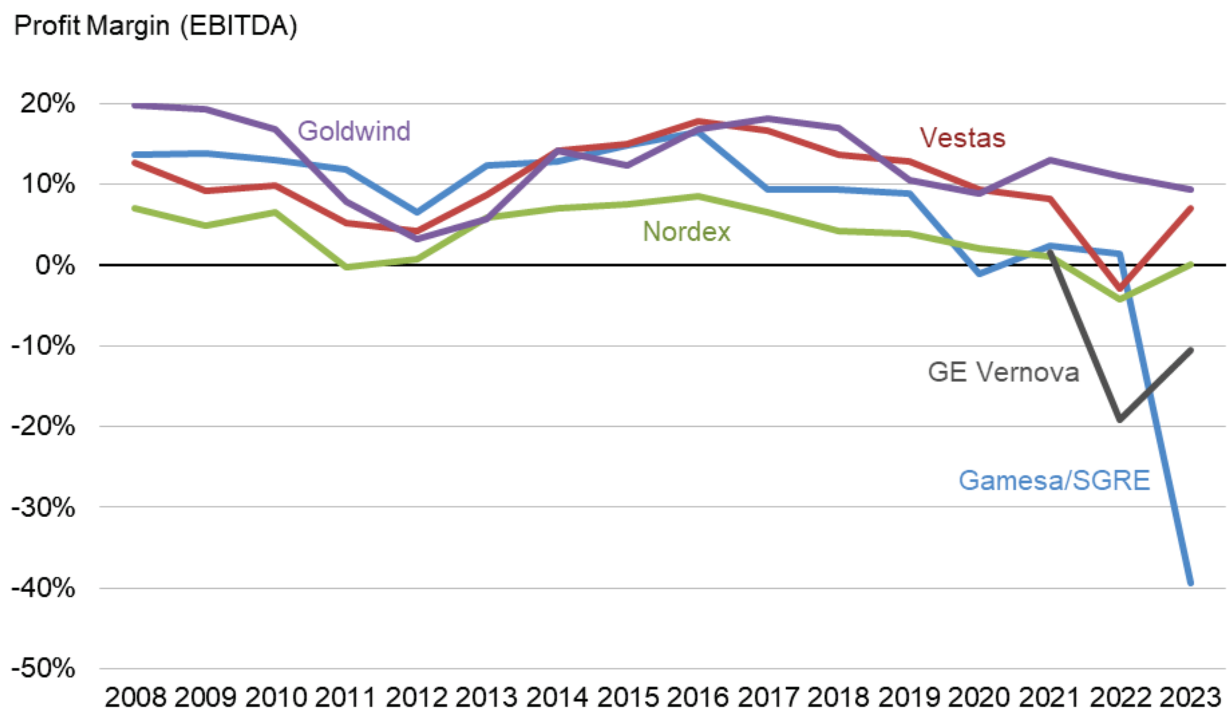
Figure 16 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future new installations (see Chapter 9, "Future Outlook"). It demonstrates that domestic manufacturing capability for towers and nacelle assembly remains reasonably well balanced 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.

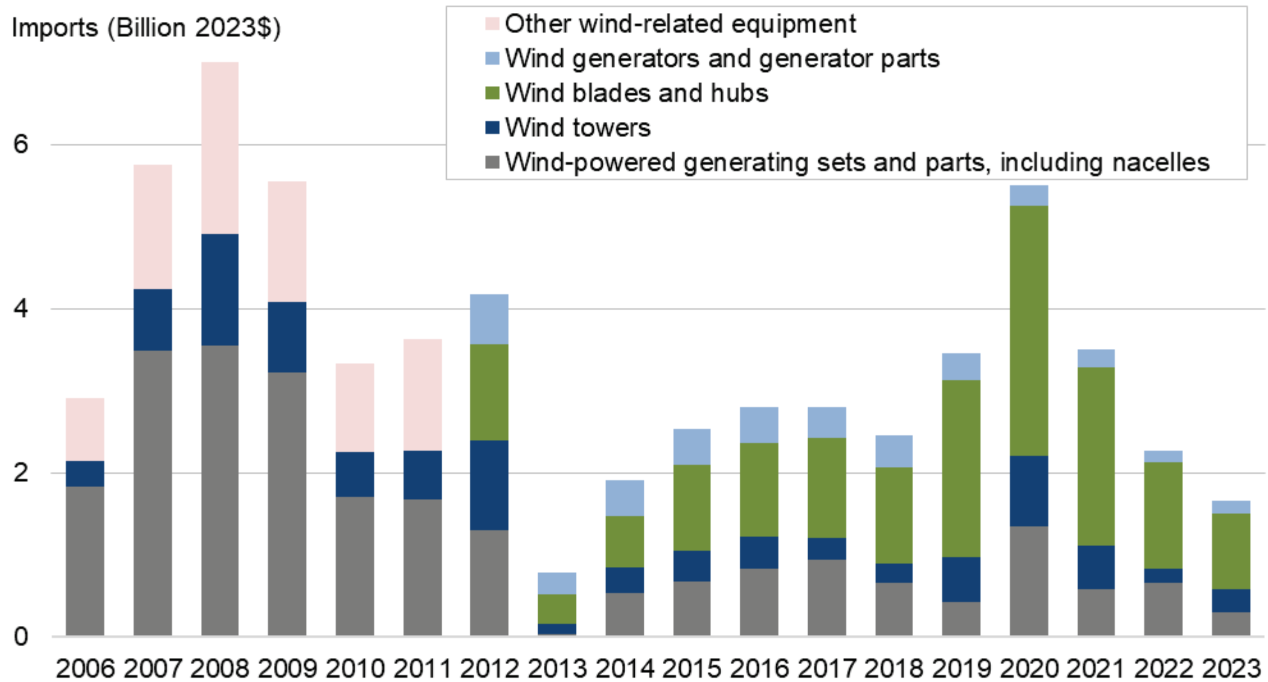
Figure 18 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. The figure shows imports of wind-powered generating sets and parts, including nacelles (i.e., nacelles with blades, nacelles without blades, and, in 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]

[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.



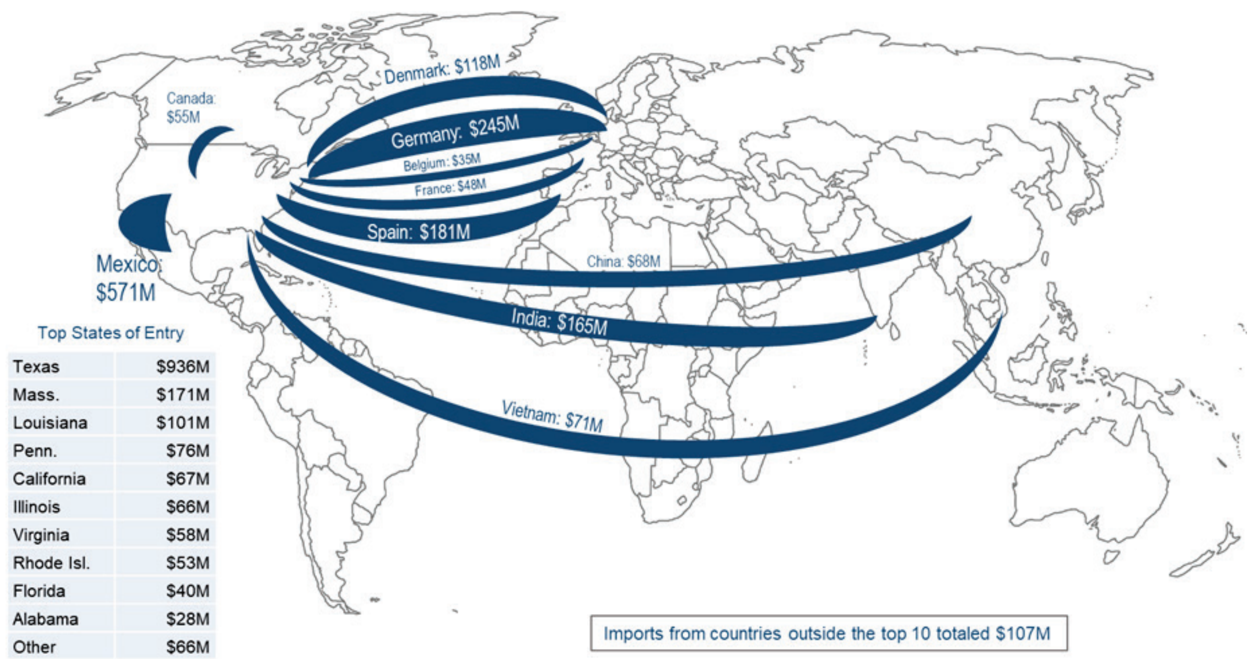
Note: Wind-related trade codes and definitions are not consistent over the full time period.

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.

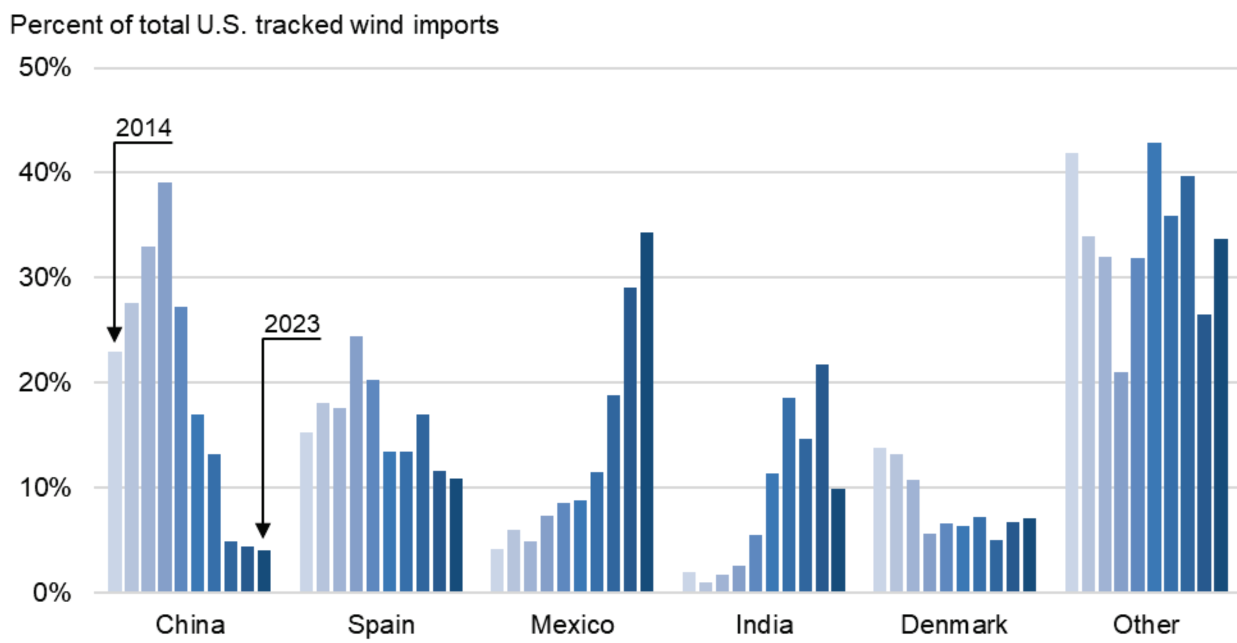
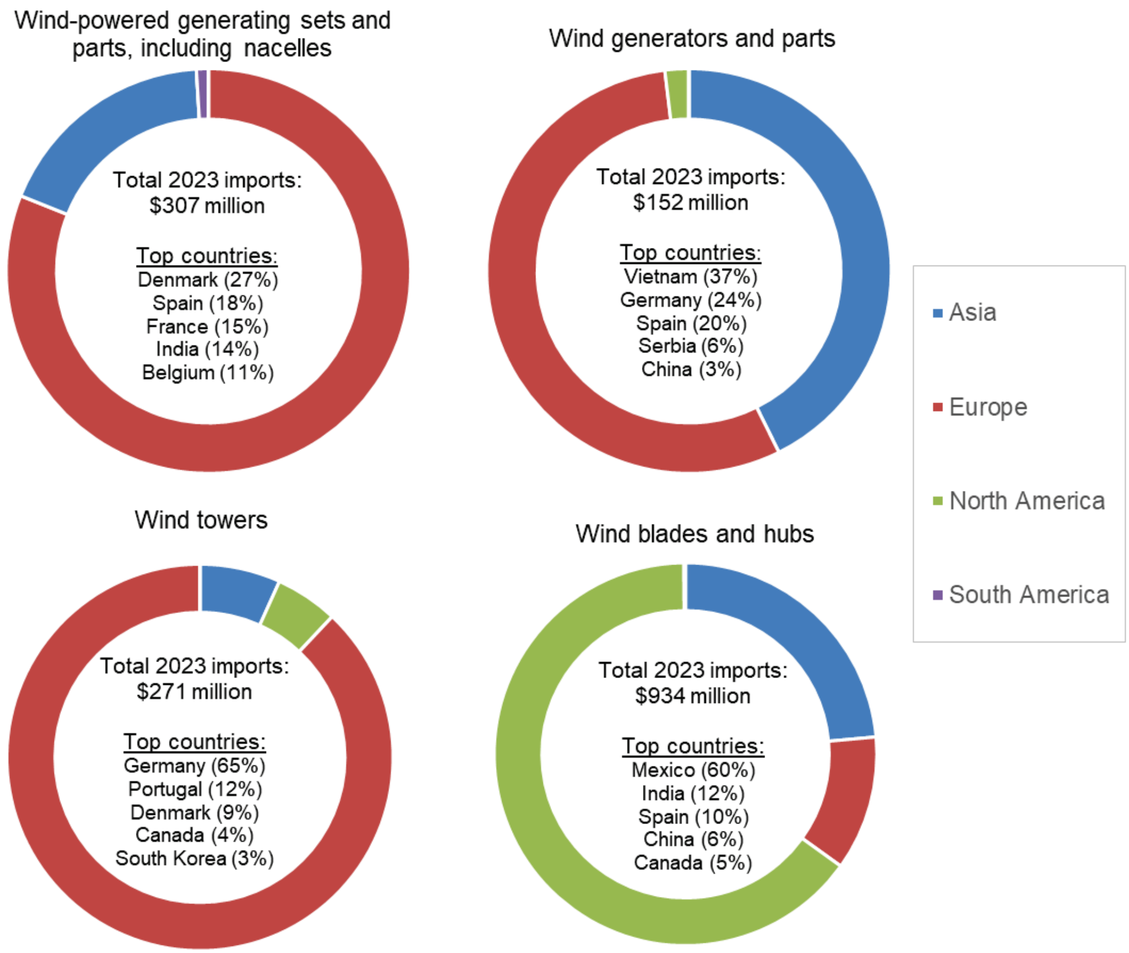


Figure 20. Wind equipment imports over time, by country: percent of total tracked wind-specific imports

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.

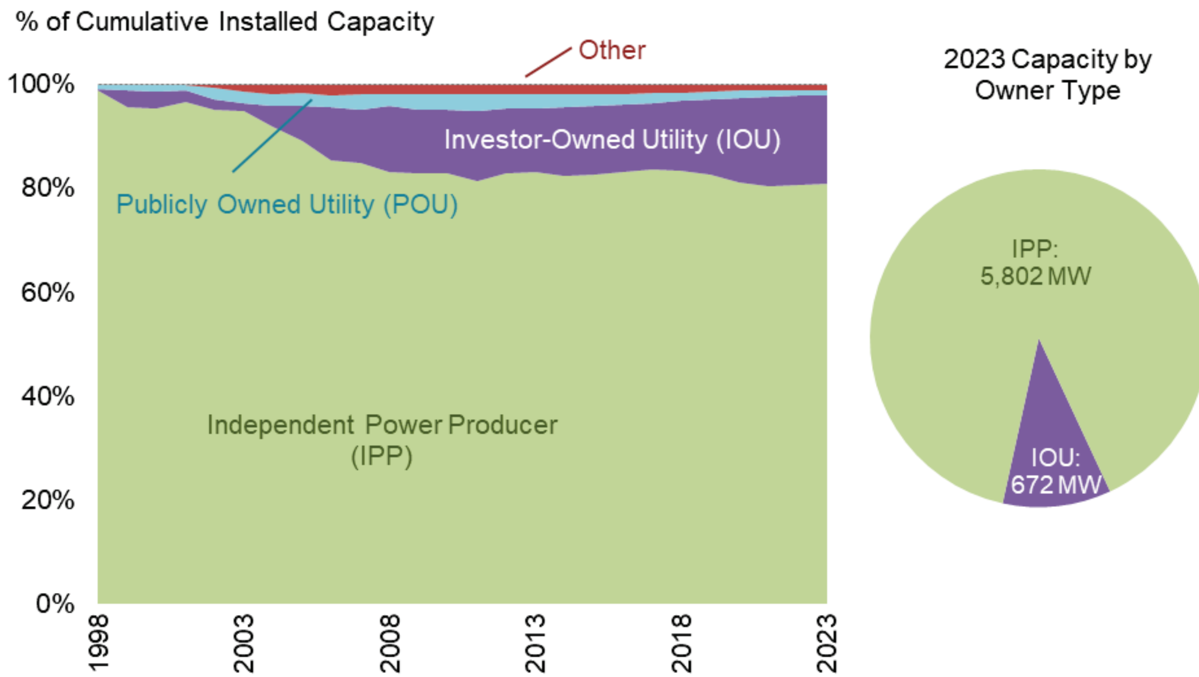


Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

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

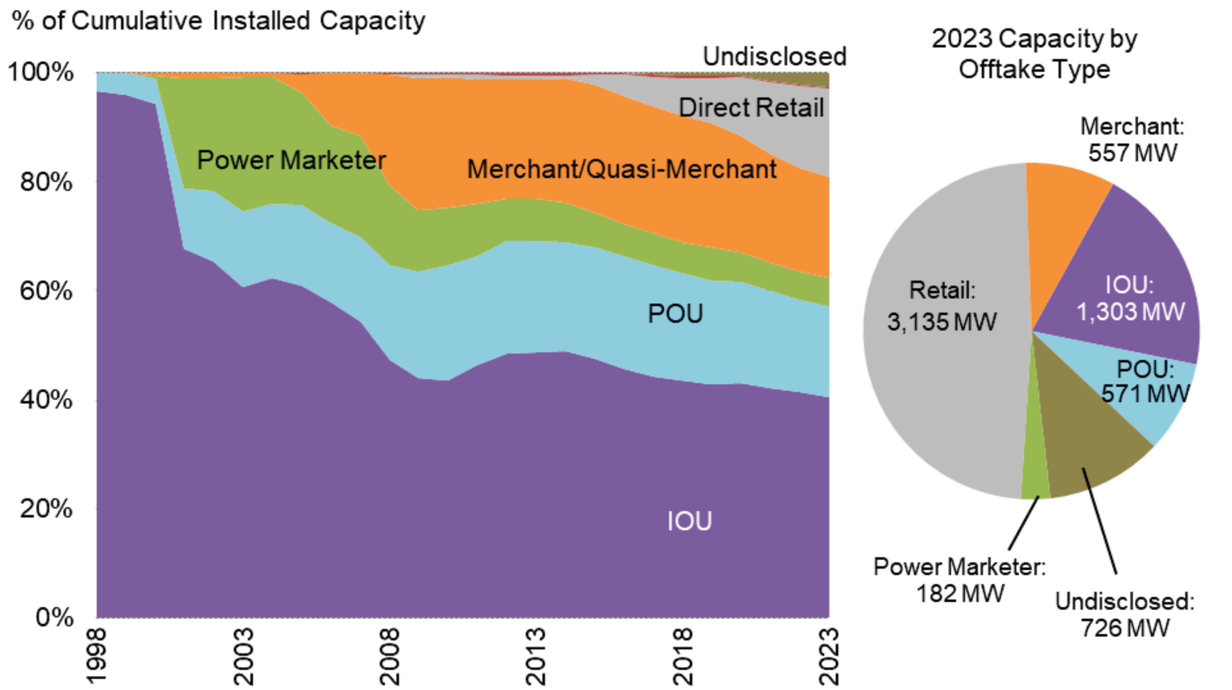
Whereas the prior section analyzes wind plant ownership, this section focuses on who uses or buys the wind generation from those plants. Electric utilities either own or buy the electricity from wind projects that, in total, represent 29% of the new capacity installed in 2023 (with the 29% split between 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

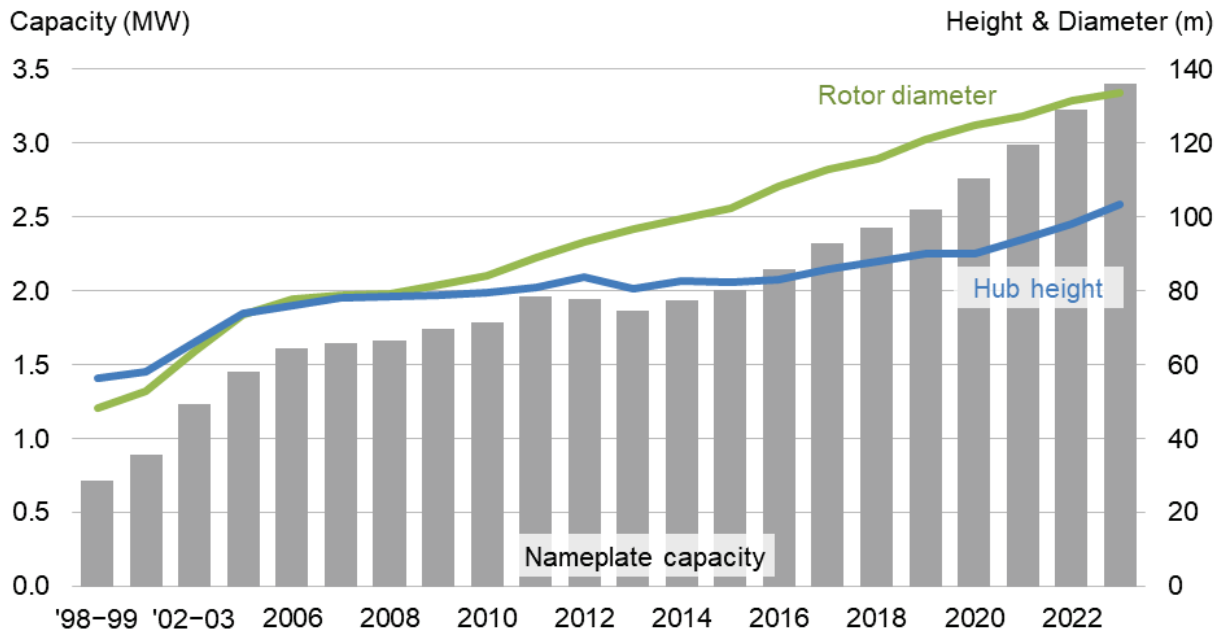
Figure 23. Cumulative and 2023 wind power capacity categorized by power offtake arrangement

[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.

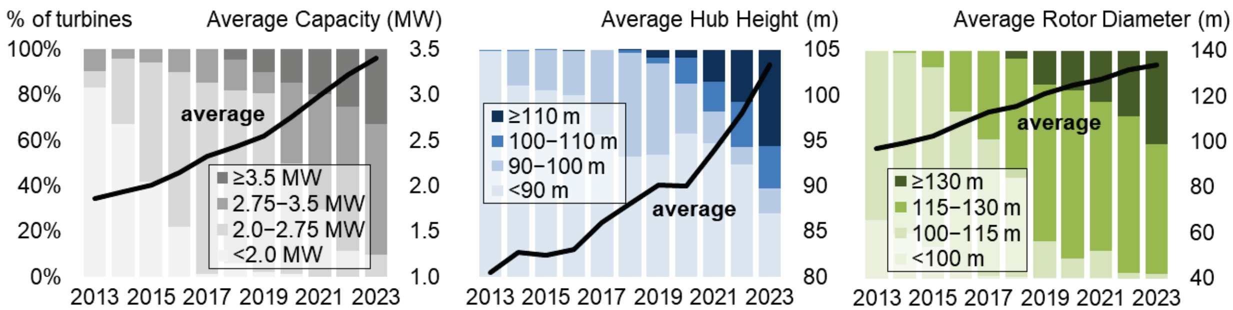


Sources: ACP, Berkeley Lab

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.



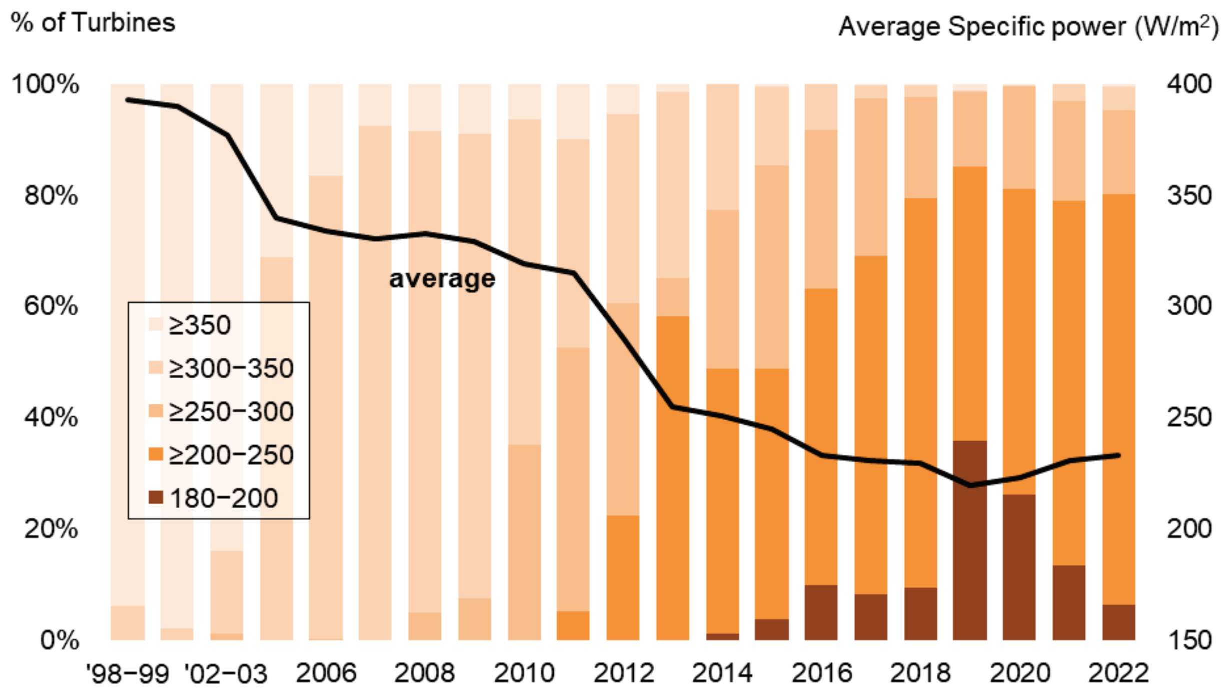
Sources: ACP, Berkeley Lab

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

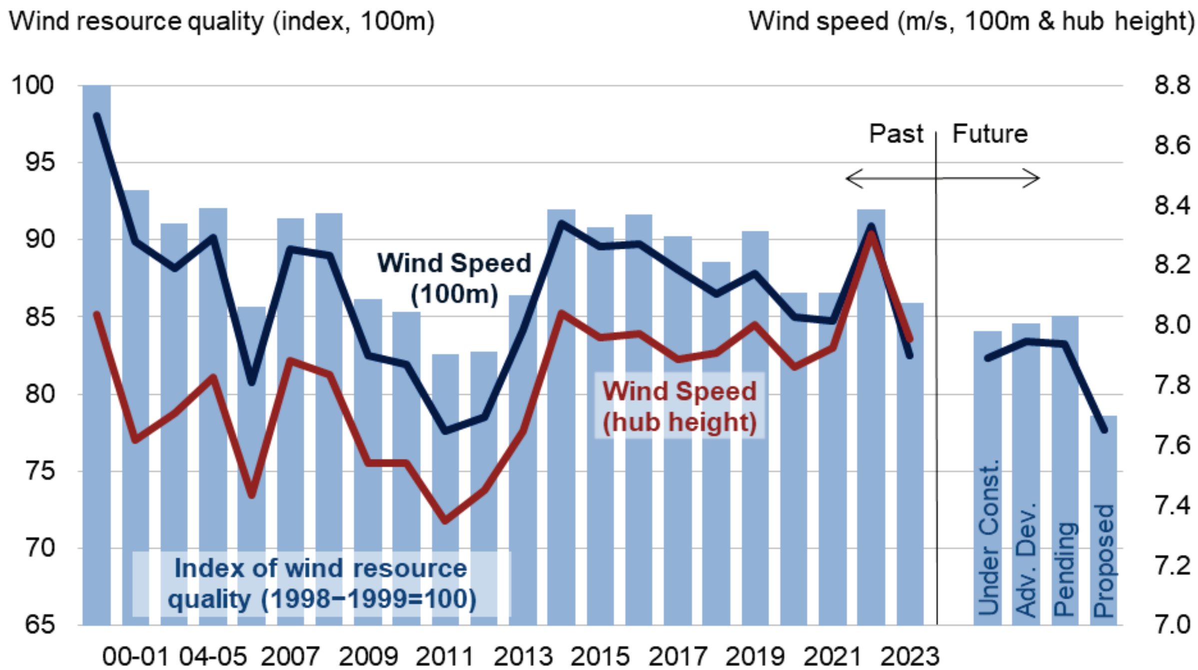
Wind turbines were deployed in lower wind-speed sites in 2023 than in recent years

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

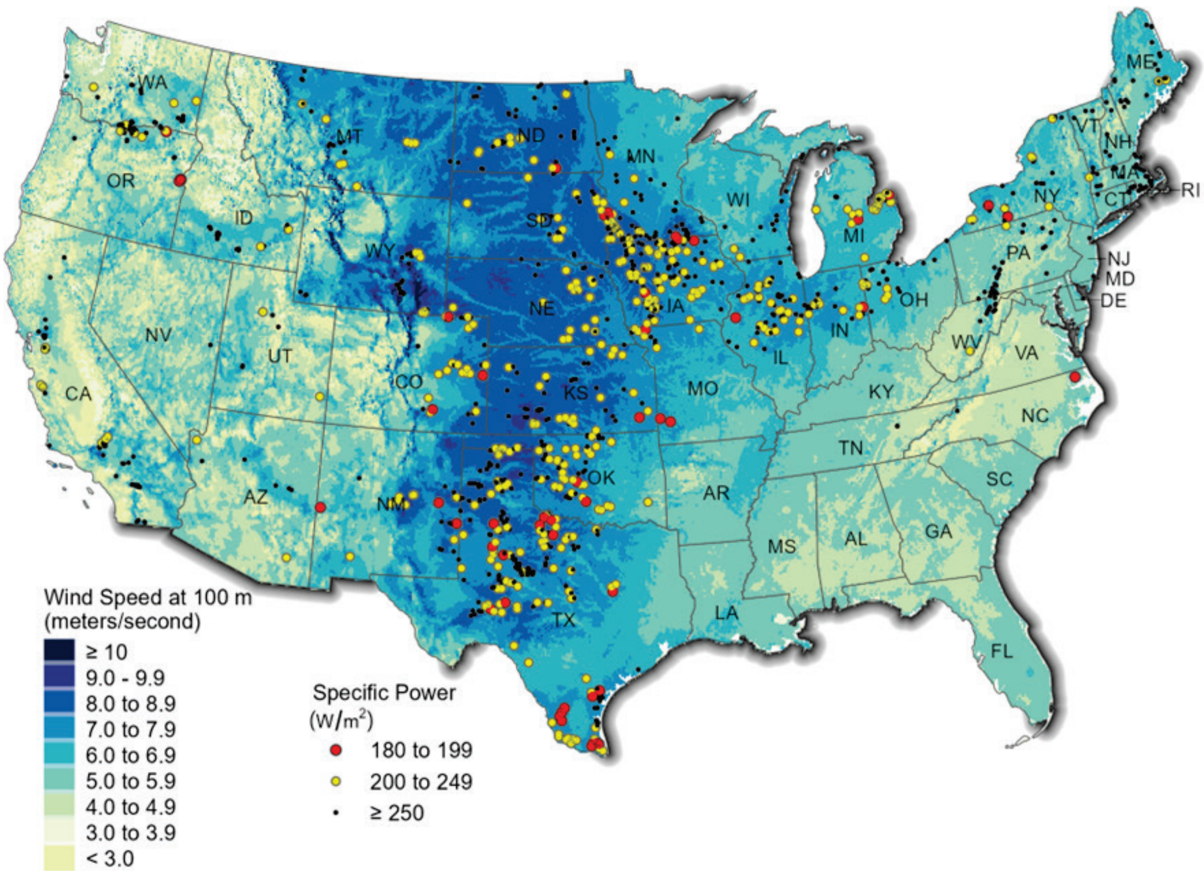
Figure 27. Wind resource quality by year of installation at 100 meters and at turbine hub height

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.

[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

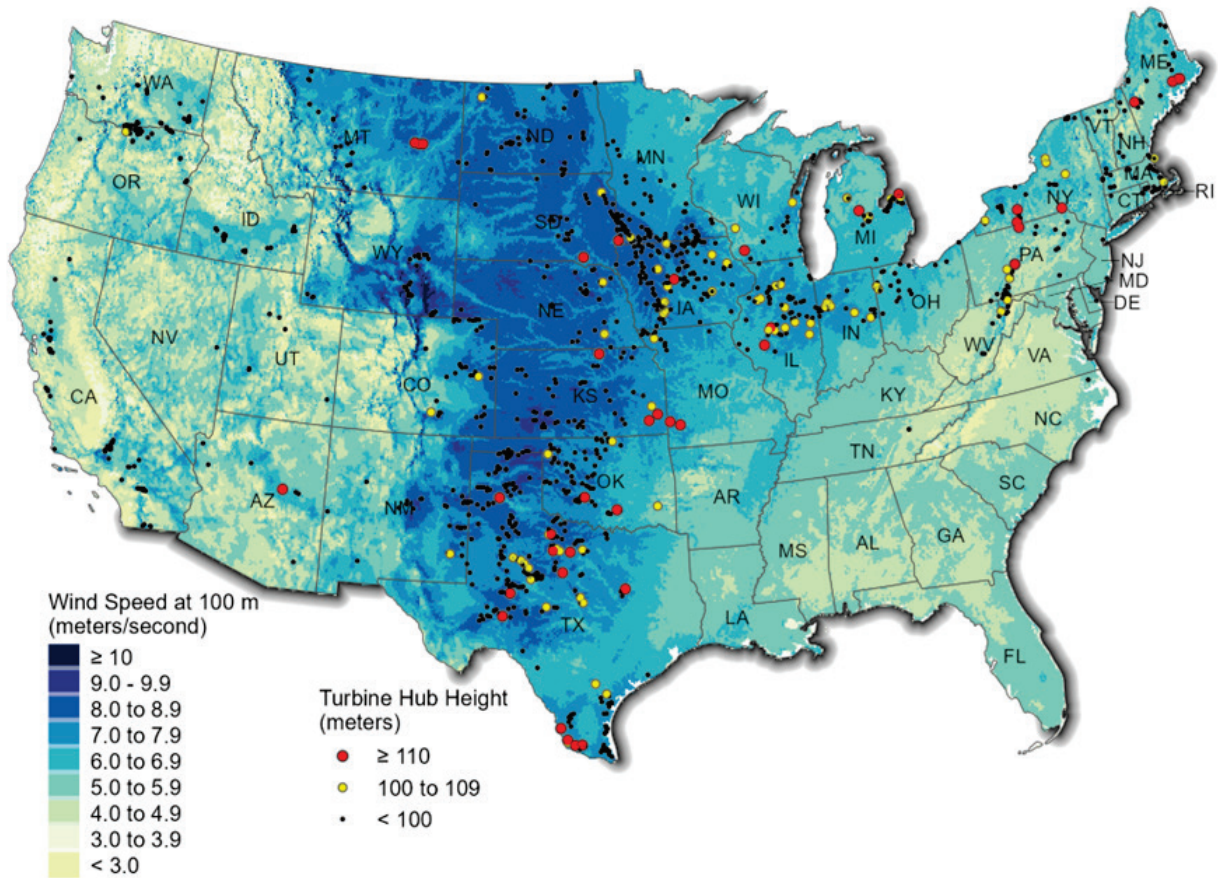
With the recent dominance of lower-specific-power turbines (defined here as turbines with specific power < 250 W/m^2), it comes as no surprise that such turbines have established a strong foothold across the nation and over a wide range of wind speeds (see Figure 28, which shows all U.S. wind projects).



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

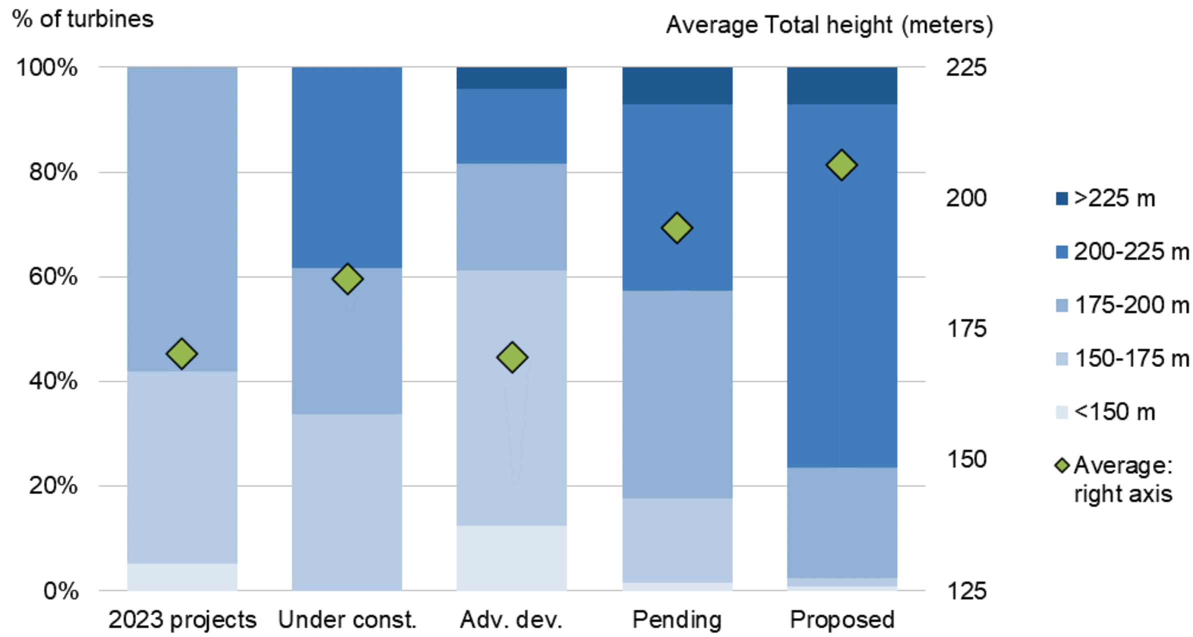
Figure 29: Location of tall tower turbine installations: all U.S. wind plants

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]

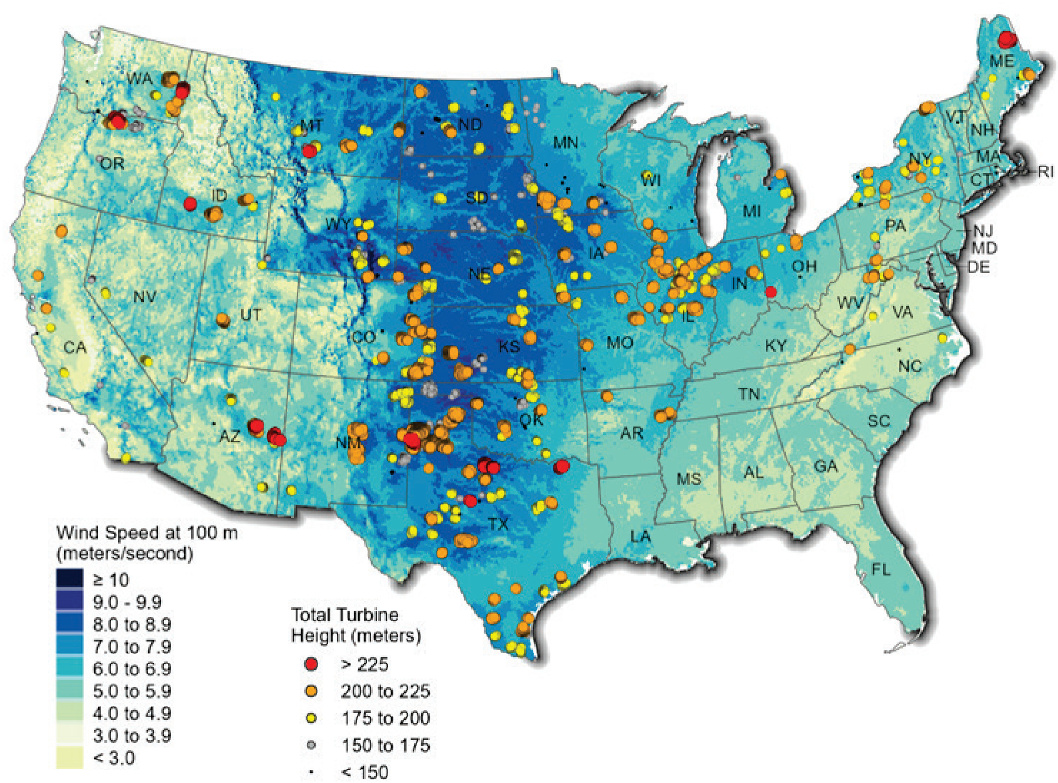
Average tip heights for projects that came online in 2023 are 170 meters, up from 164 meters for 2022 projects, and seem destined to climb higher in the next few years, reaching an average of 206 meters among the "proposed" turbines. The tallest turbines in the permitting process are over 225 meters. 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



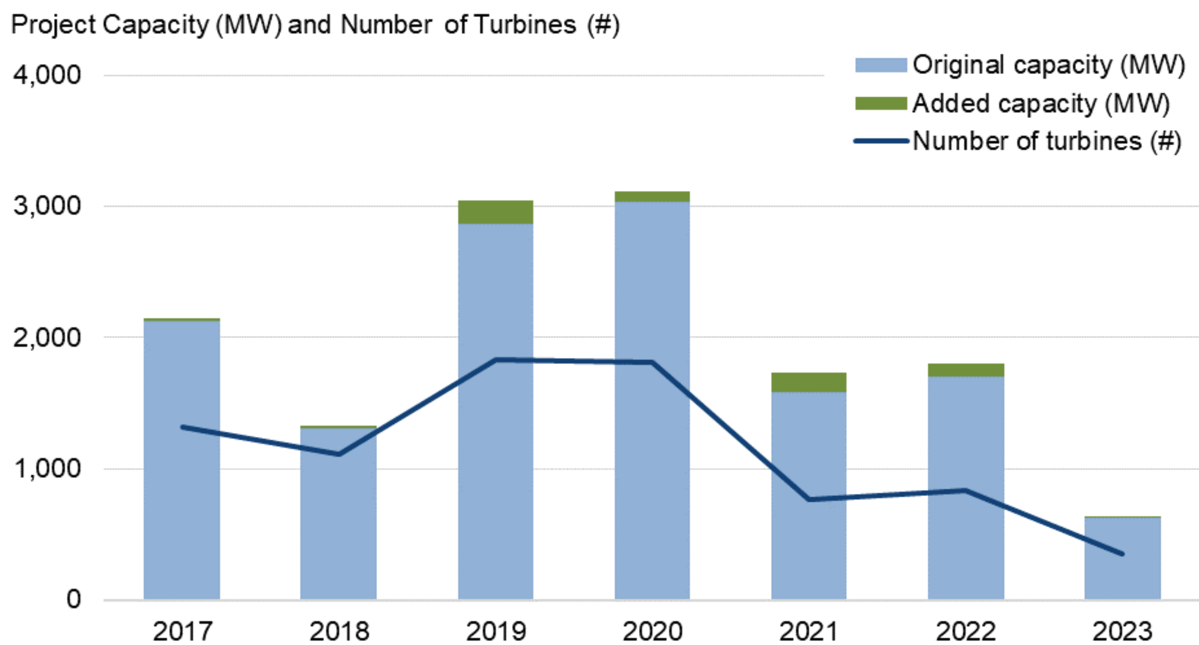
Note: Figure includes FAA data on under-construction, advanced development, pending, and proposed turbines

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

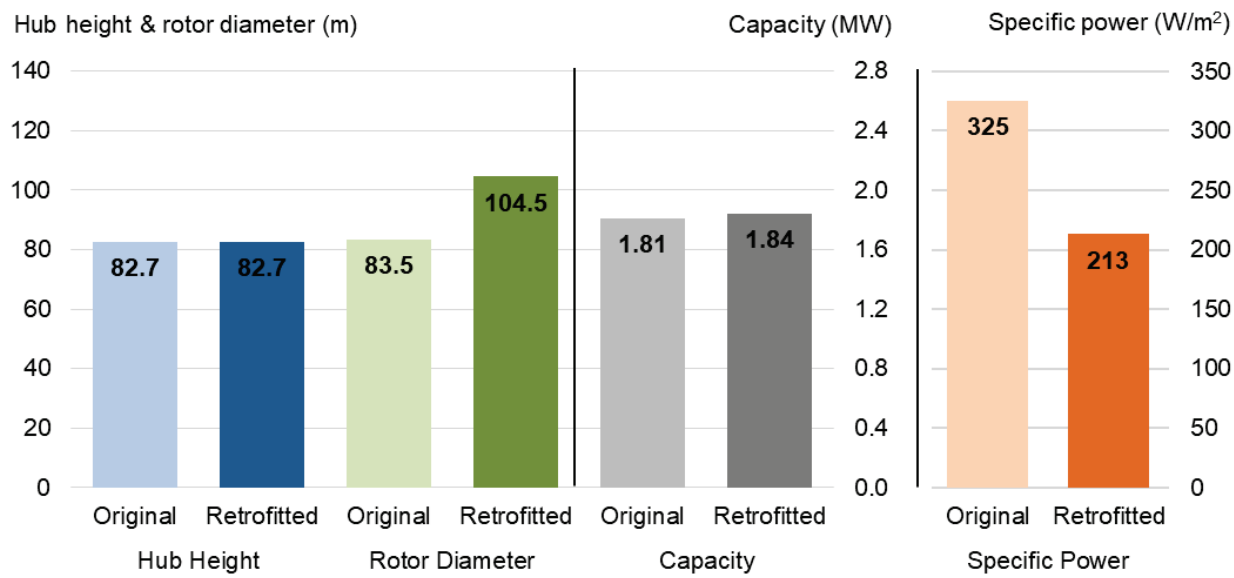
The trend of partial wind project repowering continued in 2023, albeit at a slower pace than in prior years, and involved replacing major components of turbines with more-advanced technology to increase energy production, extend project life, and access tax incentives. In 2023, 7 projects were partially 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).

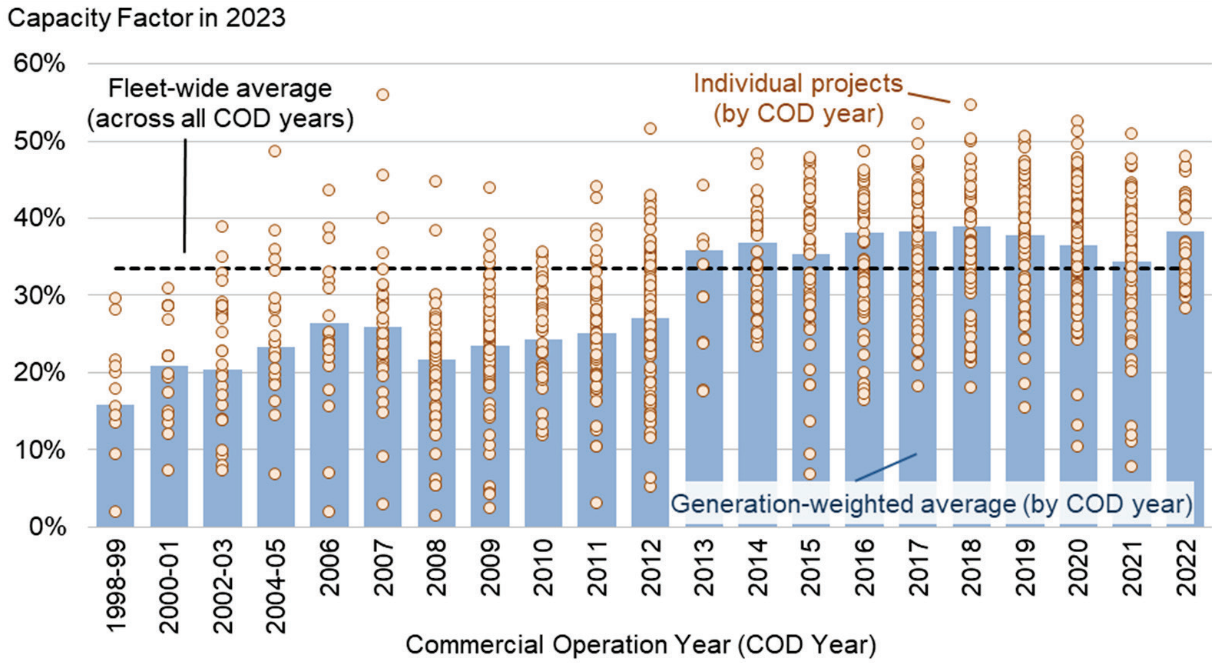
To start, Figure 34 shows both individual project and average capacity factors in 2023, broken out by commercial operation date.[31] From left to right, Figure 34 shows an increase in weighted-average 2023 capacity factors when moving from projects installed in the 1998–1999 period to those installed 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.

[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.

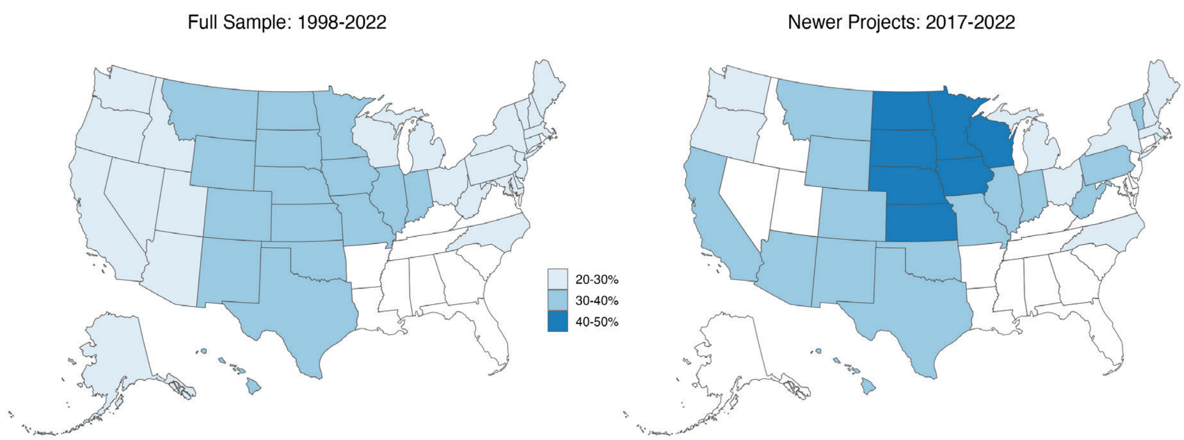


Sources: EIA, FERC, Berkeley Lab

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.



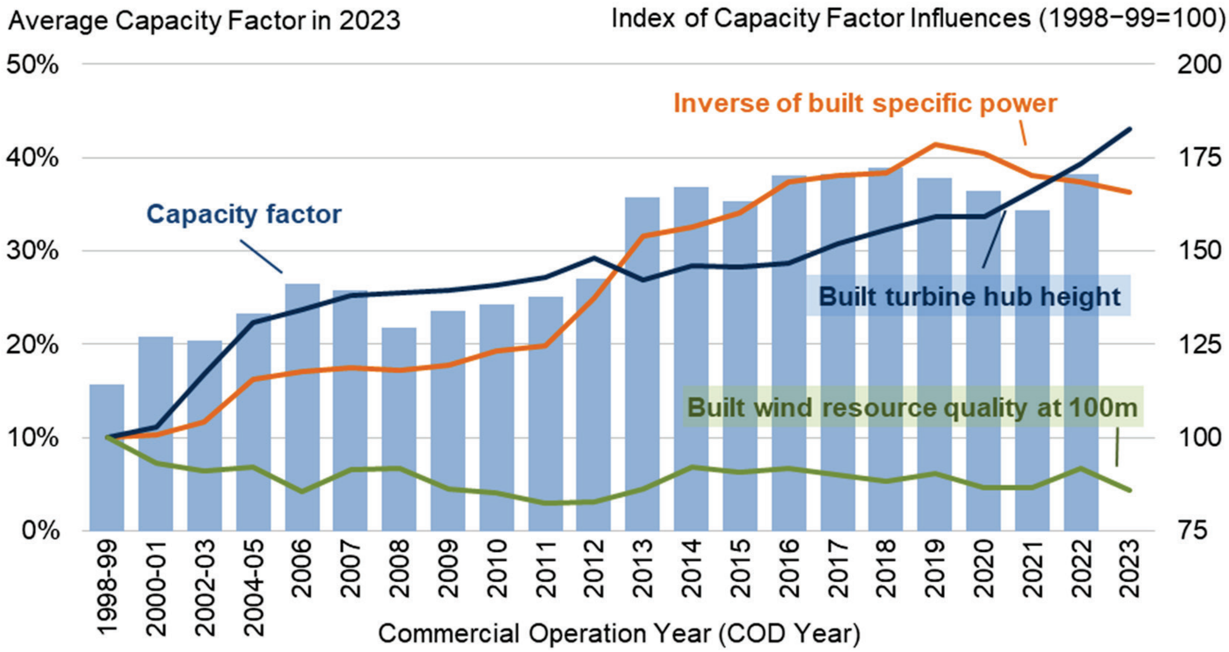
Note: States shaded in white have no projects in full sample (left) or in newer sample (right)

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.)



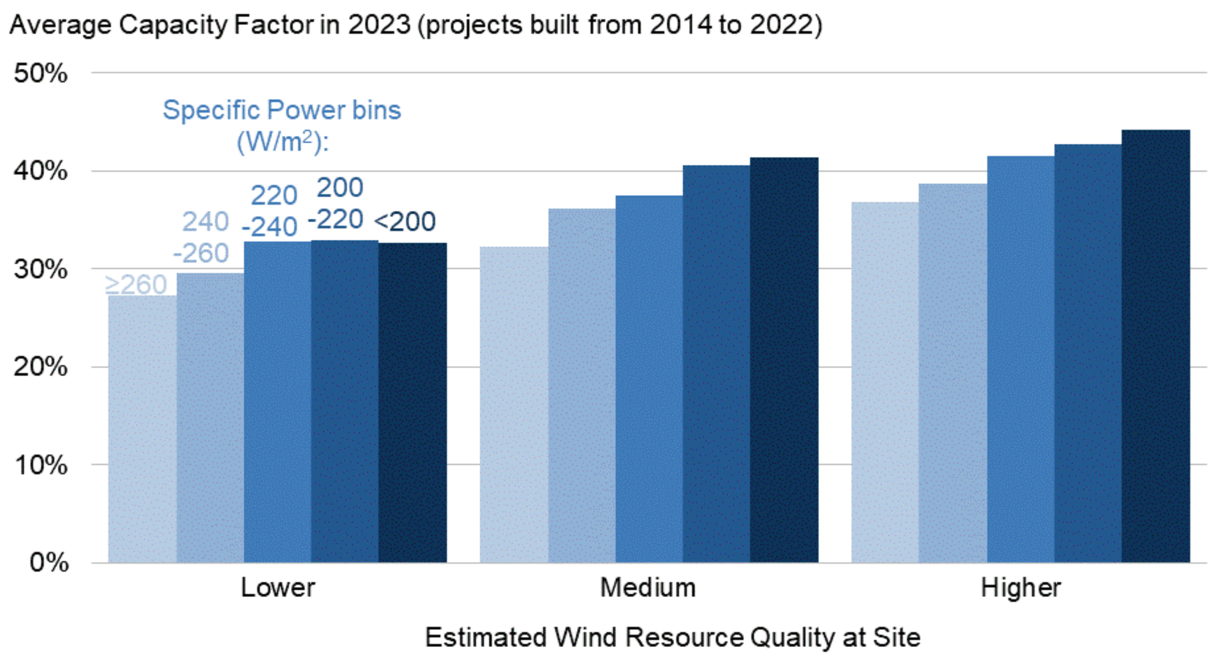
Note: To have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

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

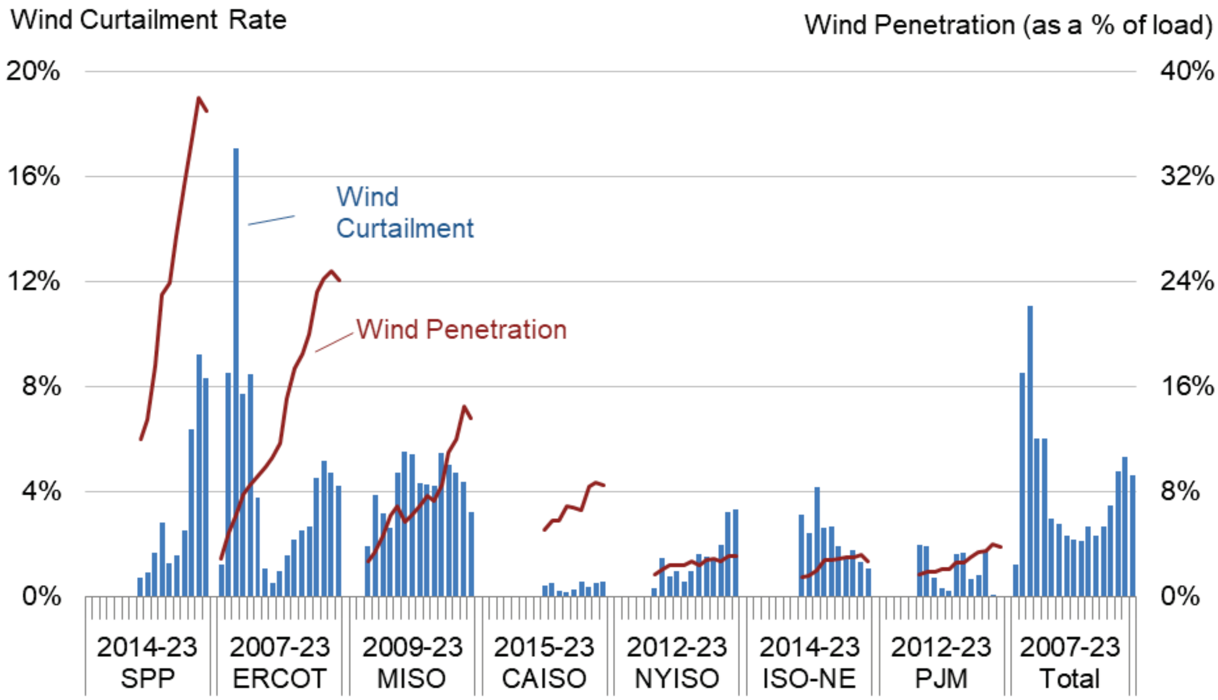
Figure 37. Calendar year 2023 capacity factors by wind resource quality and specific power: 2014–2022 projects

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

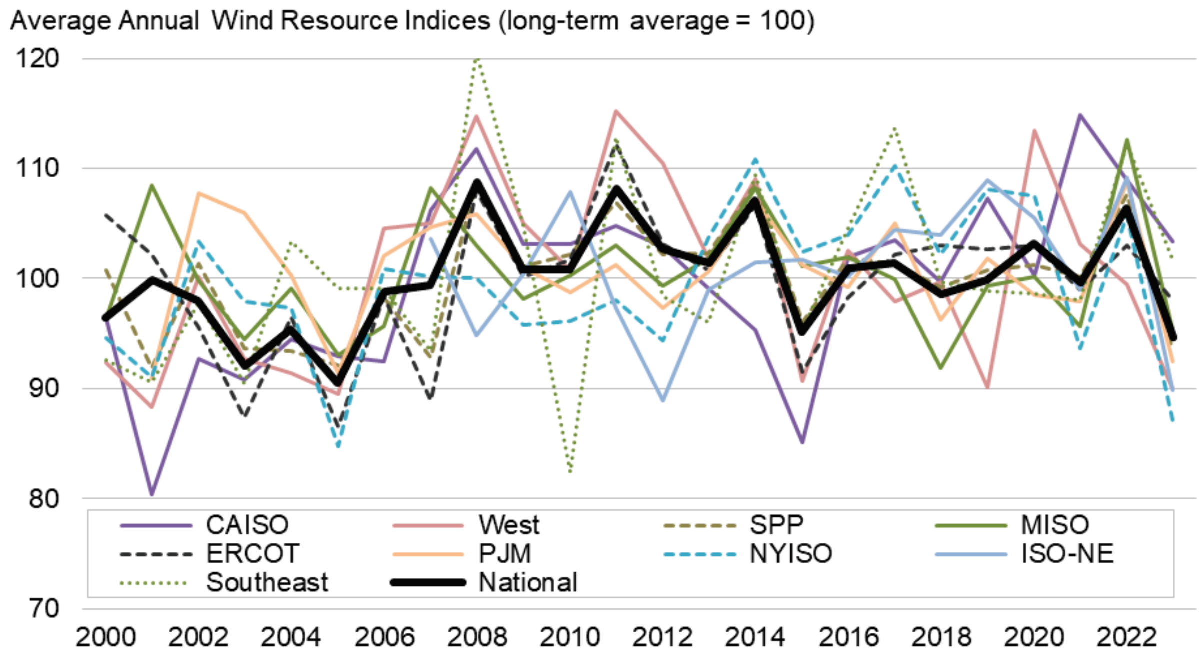
Curtailment rates in the other five ISO/RTO regions are lower: in 2023, 3.3% in NYISO, 3.2% in MISO, 1.1% in ISO-NE, 0.6% in CAISO, and at least 0.1% in PJM (the PJM data shown here likely reflect only a portion of overall wind curtailment, which the RTO does not regularly report). The overall wind power 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

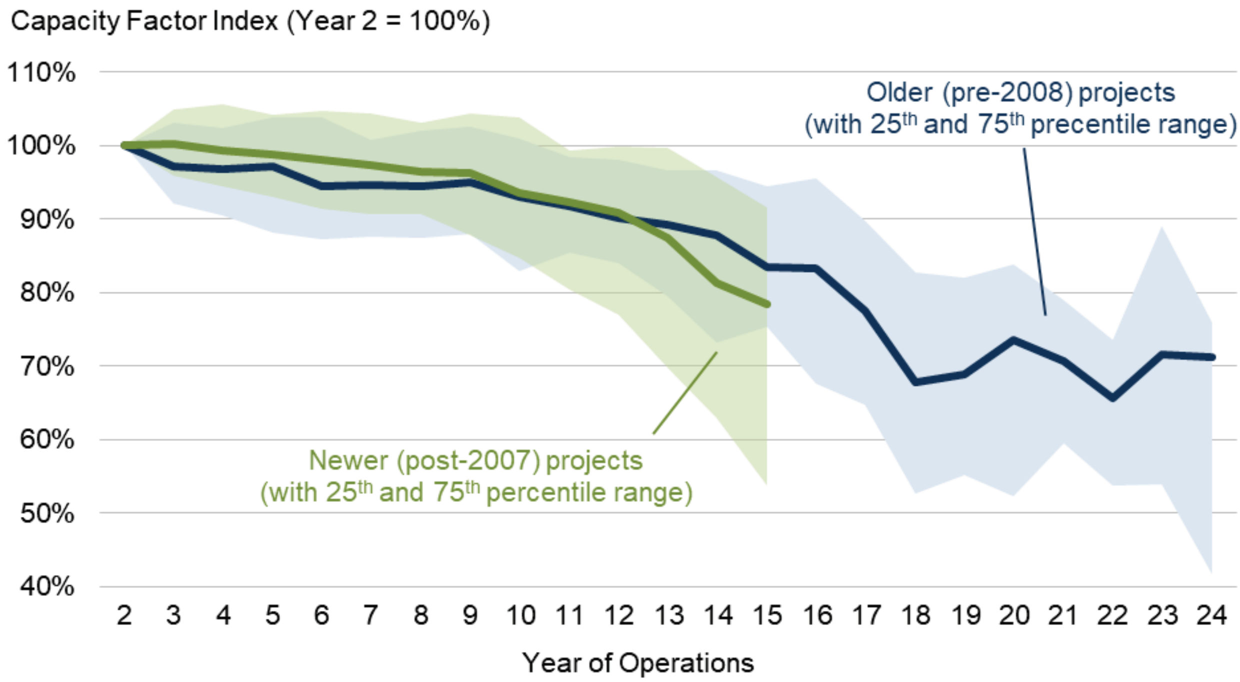
Figure 39. Inter-annual variability in the wind resource by region and nationally

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

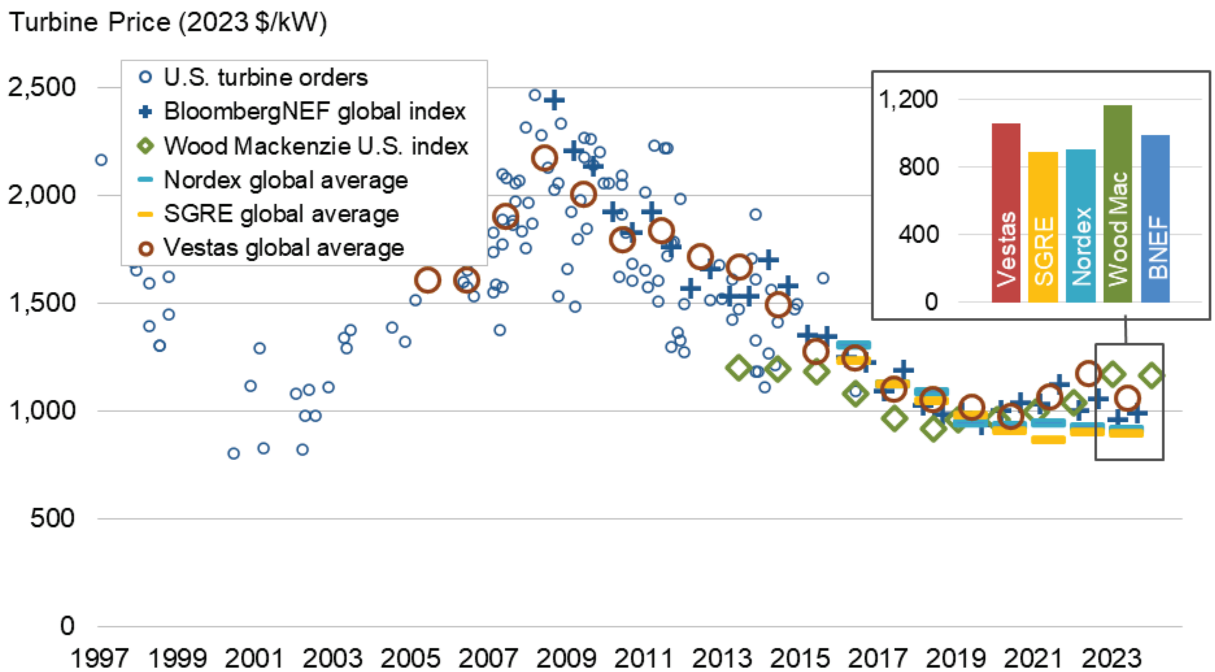
Taken together, Figure 34 through Figure 40 suggest that, to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of parameters. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal 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

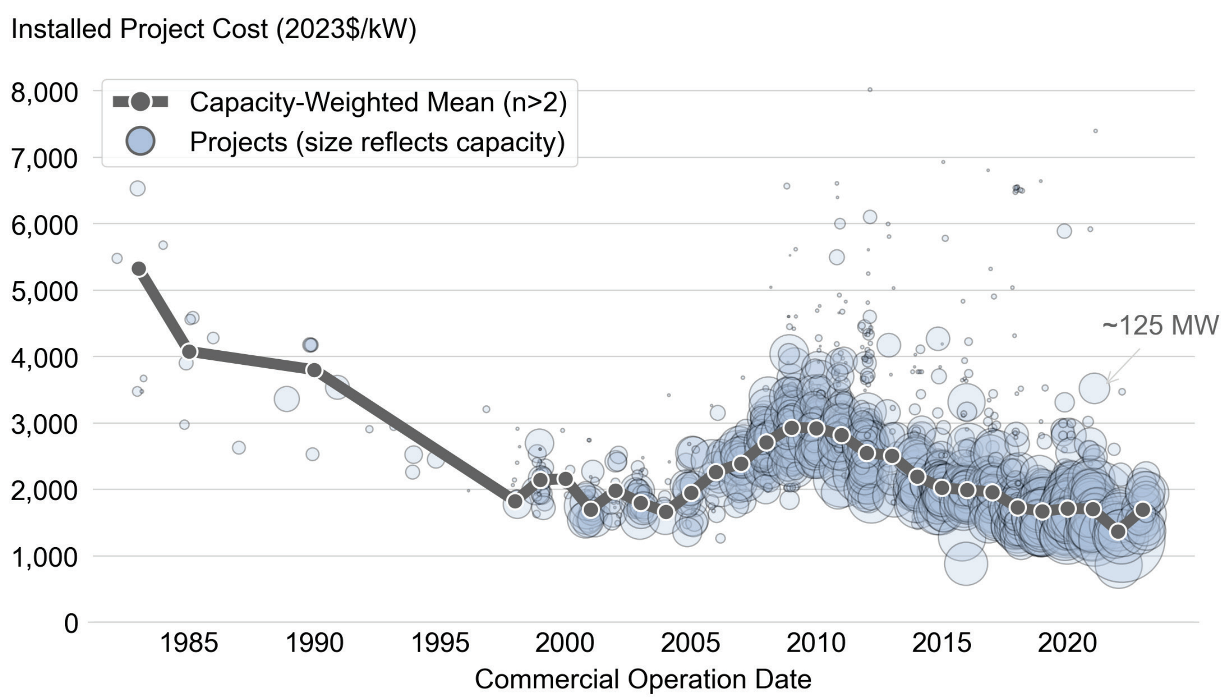
After hitting an initial low of roughly $1,000/kW, on average, from 2000 to 2002, wind turbine prices more than doubled, rising to an average of over $2,000/kW in 2008. This increase in turbine prices was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; 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).



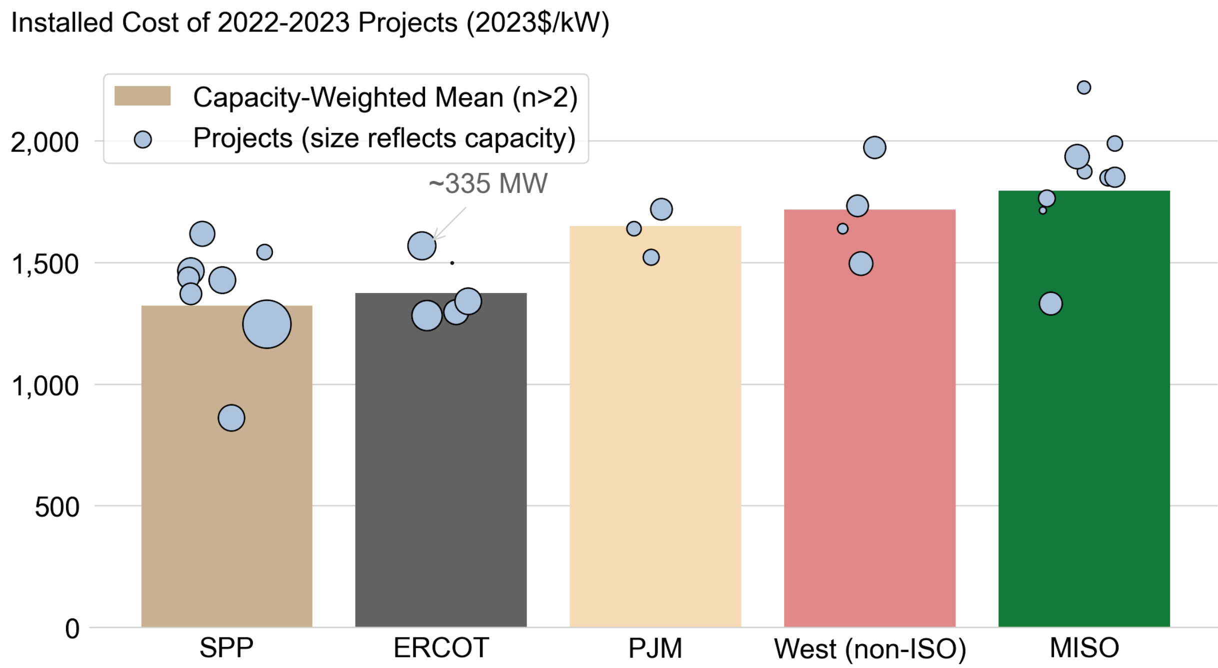
Note: Smallest bubble size reflects smallest wind project (< 1 MW), whereas largest bubble size reflects largest wind project (> 1,000 MW)
Sources: Berkeley Lab, EIA (some data points suppressed to protect confidentiality)

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.

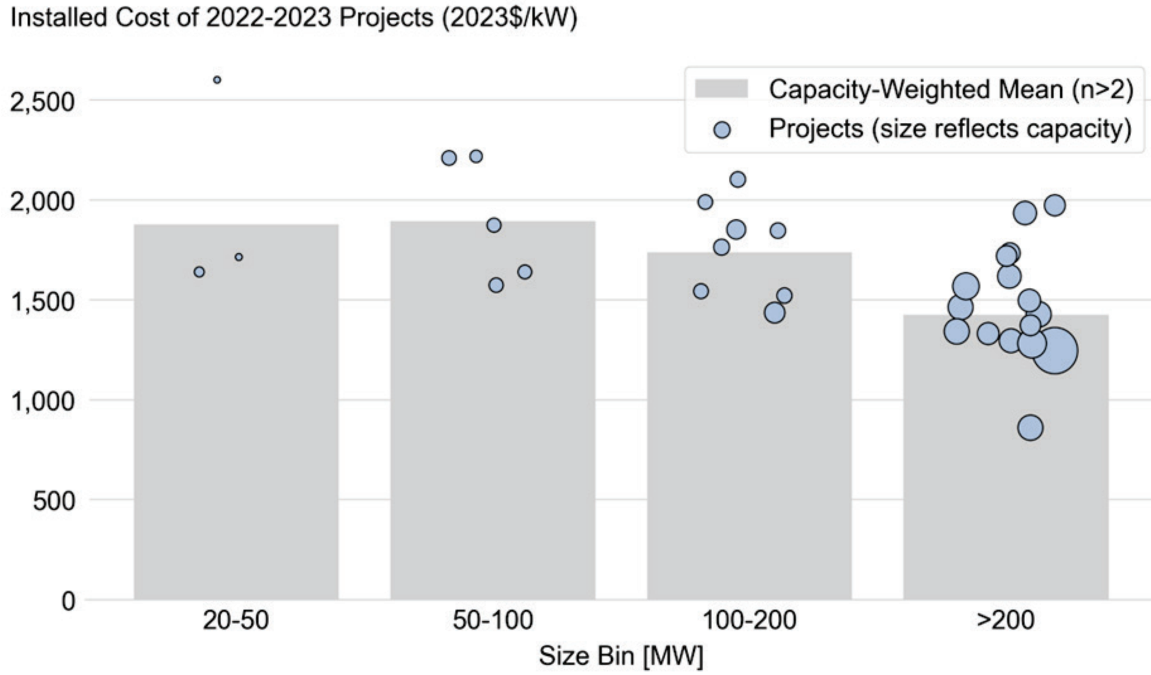


Notes: Other regions lack adequate data for inclusion; bubbles reflect projects that range from roughly 2 MW to 1,000 MW
Source: Berkeley Lab

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).

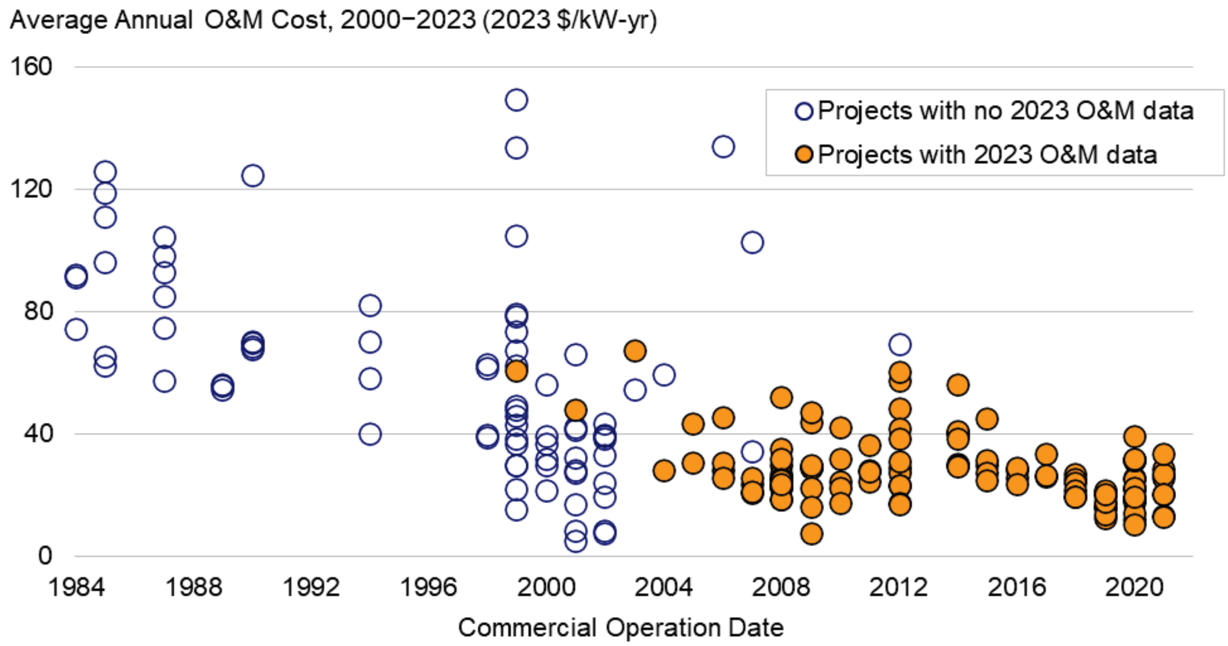
Berkeley Lab has compiled limited O&M cost data for 211 installed, land-based wind power projects, totaling 25,566 MW and with commercial operation dates of 1982 through 2022.[35] These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned 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,

[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.

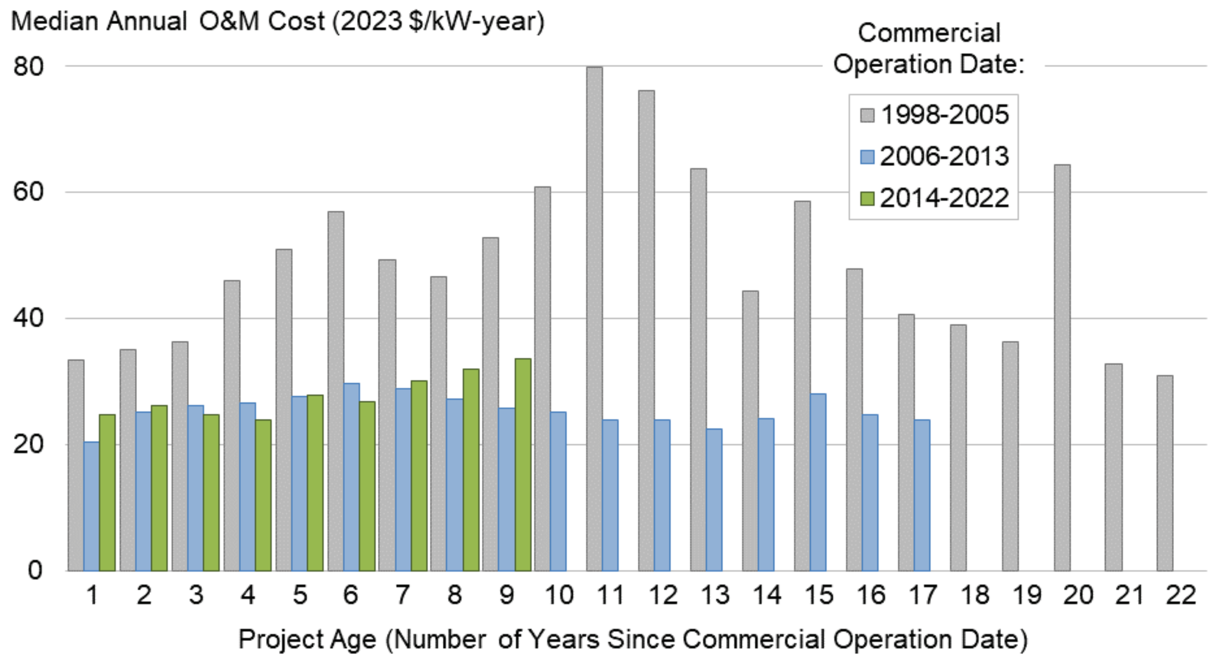


Source: Berkeley Lab; some data points suppressed to protect confidentiality

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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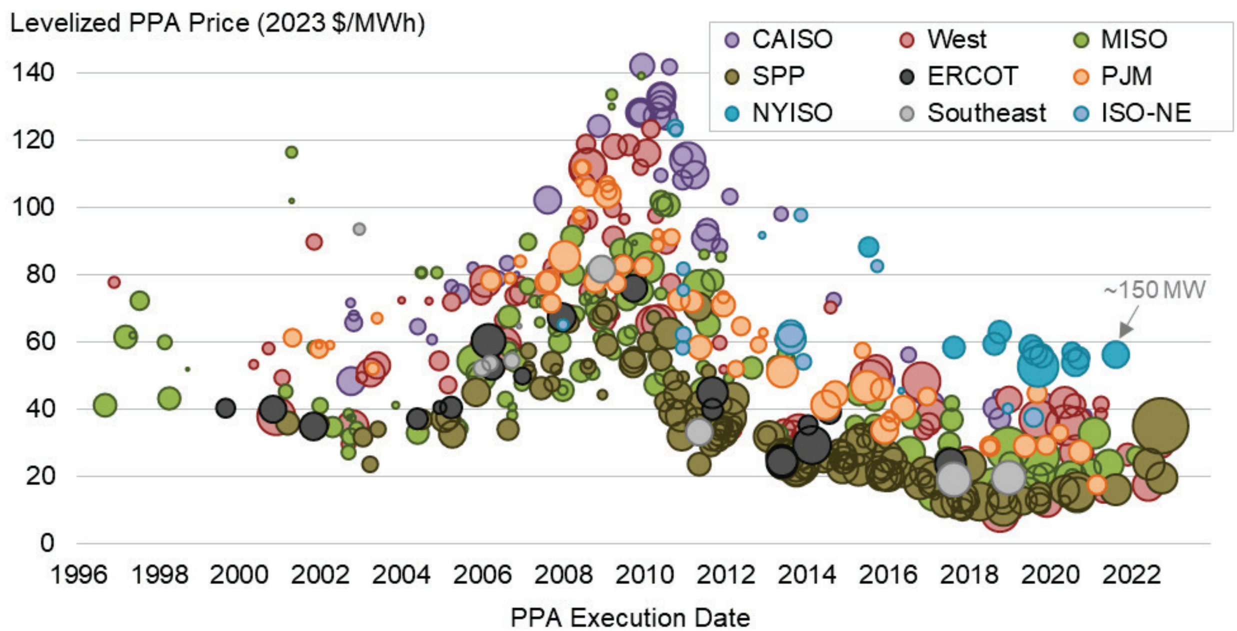
[37] Though some PPAs with corporate offtakers are included in the sample, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters a "contract for differences" with the corporate offtaker around an agreed-upon strike price. Because the strike price is not linked 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.

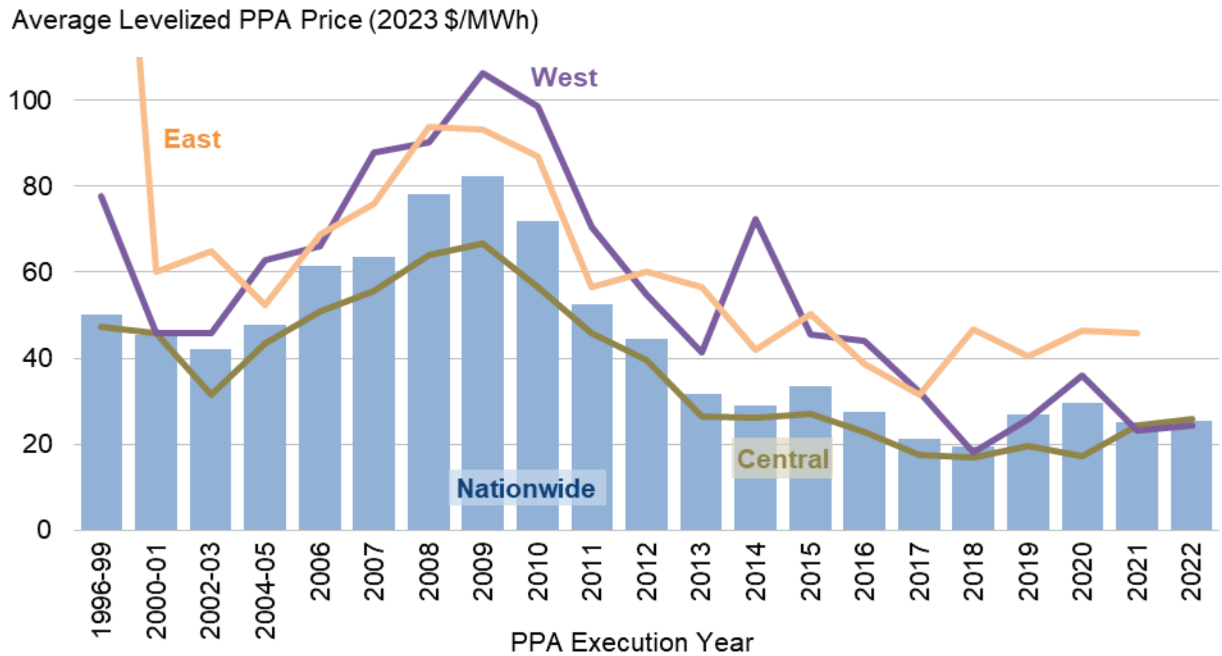


Note: Smallest bubble sizes reflect smallest-volume PPAs (<5 MW), whereas largest reflect largest-volume PPAs (>500 MW)

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

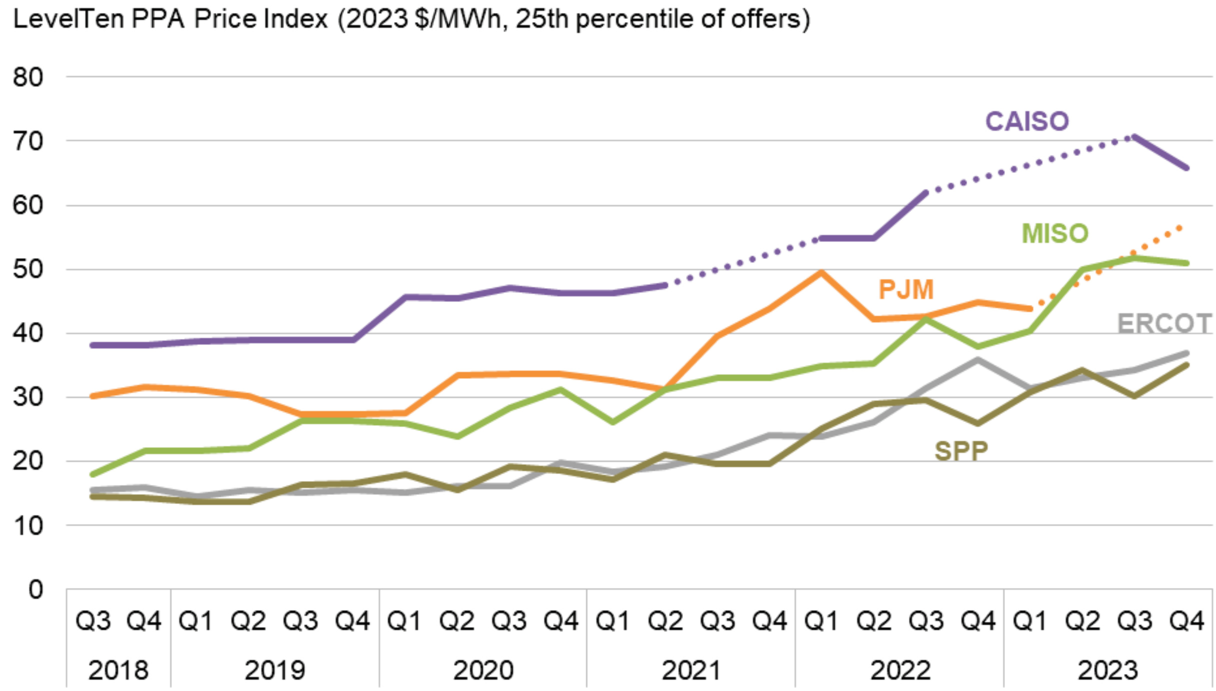
LevelTen Energy's PPA price indices confirm rising PPA prices and regional variation

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.

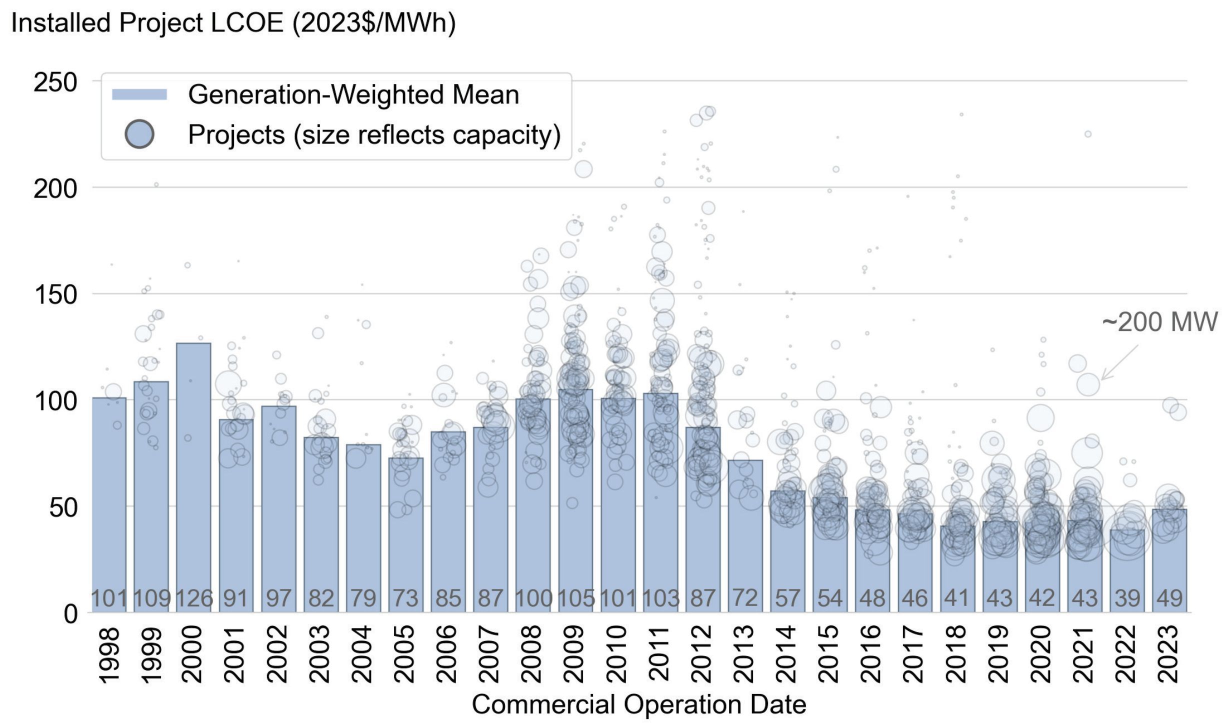
Source: LevelTen Energy

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.

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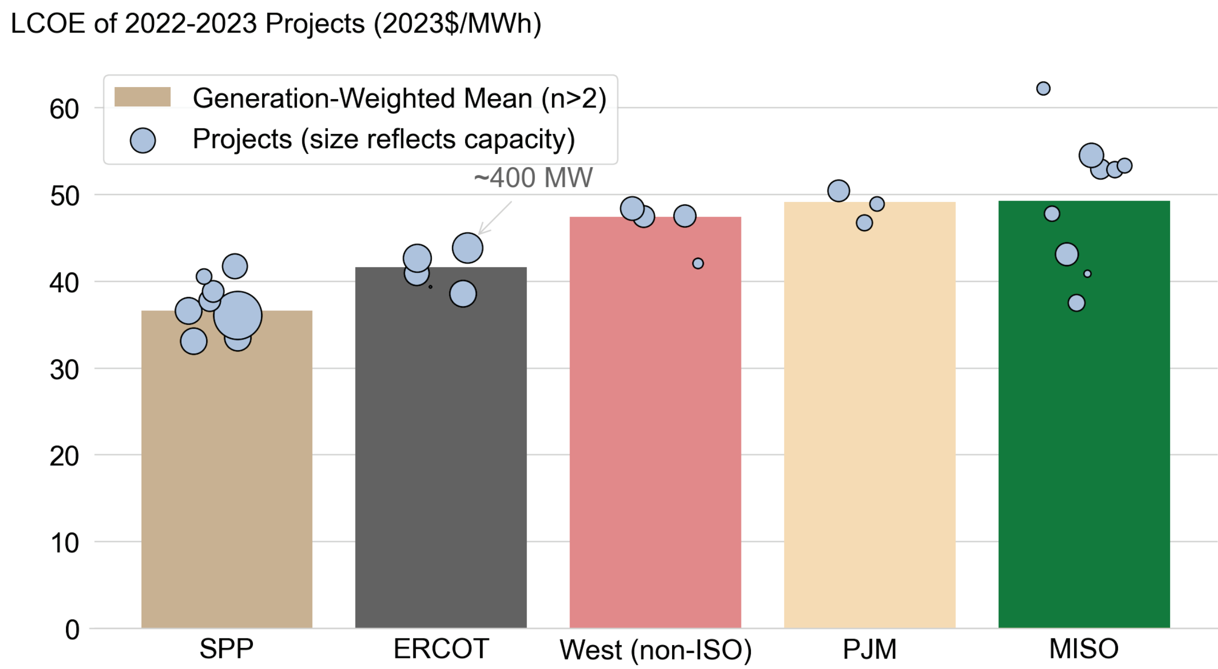
[40] Note that, each year, additional data become available that result in revisions to earlier-year data. This can include additional or superior installed cost data, updated capacity factors, changes in the assumed cost of capital, inflation, and more. See the appendix for additional details on the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

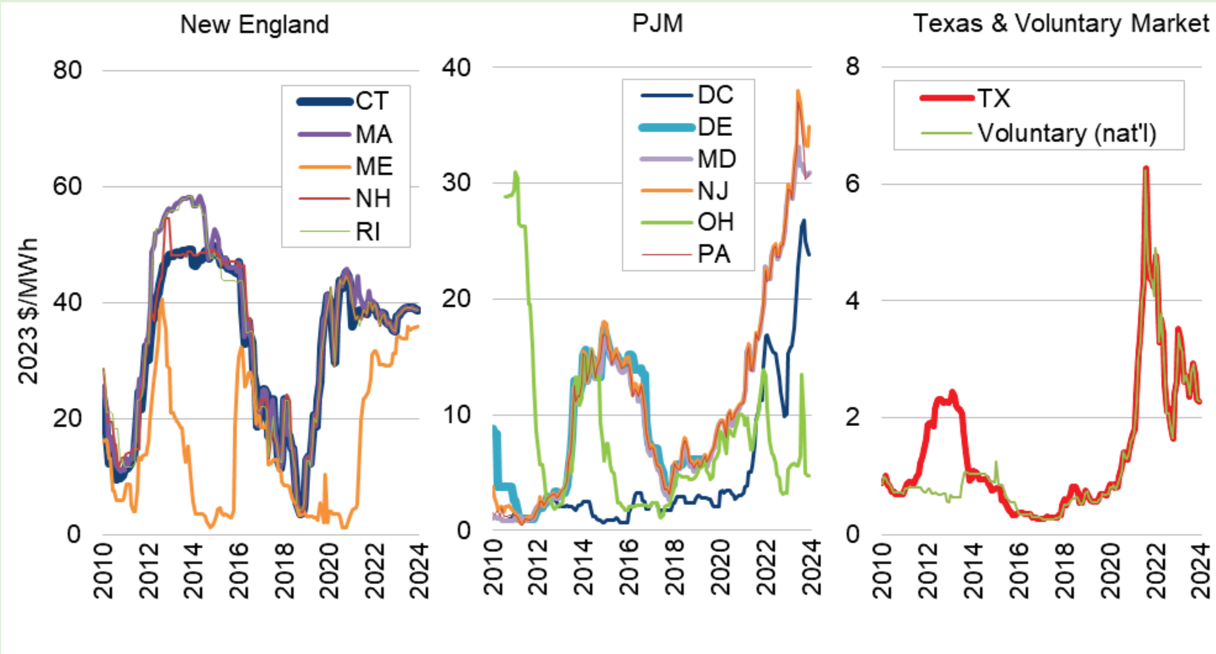
Figure 51. Estimated levelized cost of wind energy, by region

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.

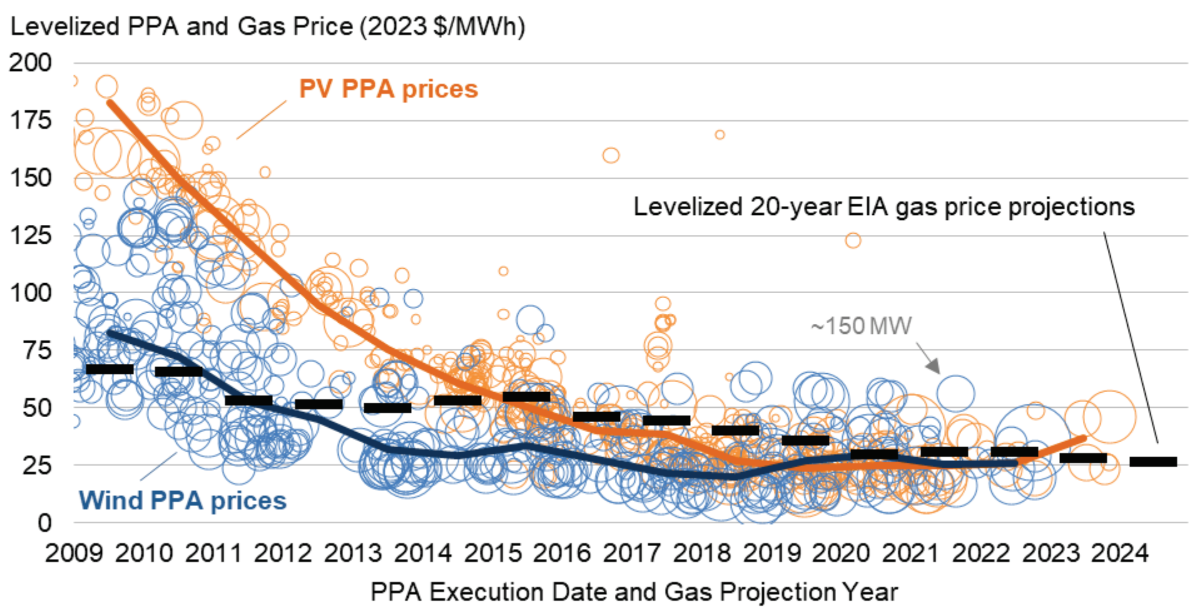
Source: Marex Spectron

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

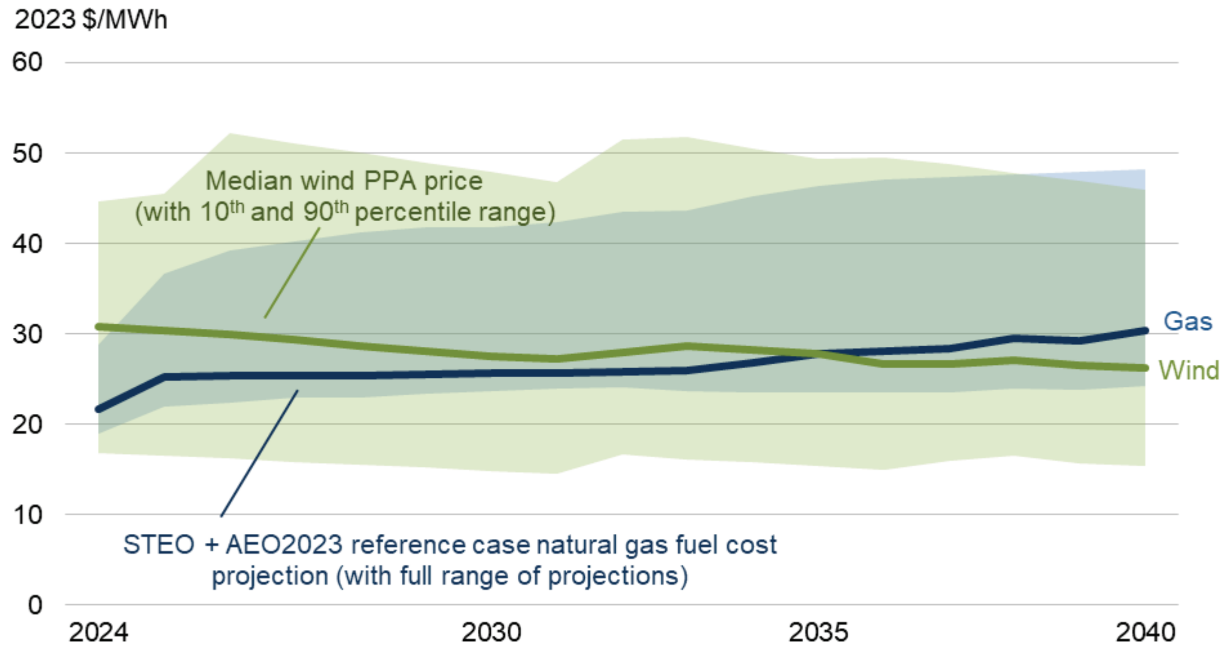
Rather than levelizing the wind PPA prices and gas price projections, Figure 53 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown) from PPAs executed in 2020–2022 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[43] 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.

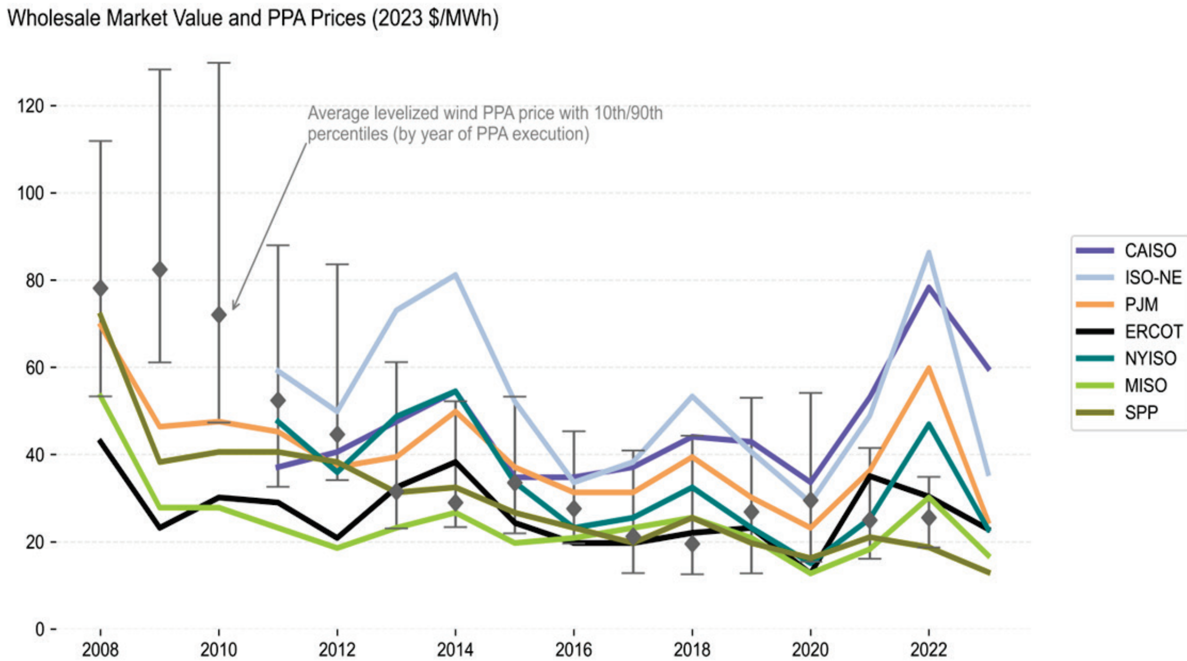
In all these cases, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, sales into wholesale markets create revenue 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:

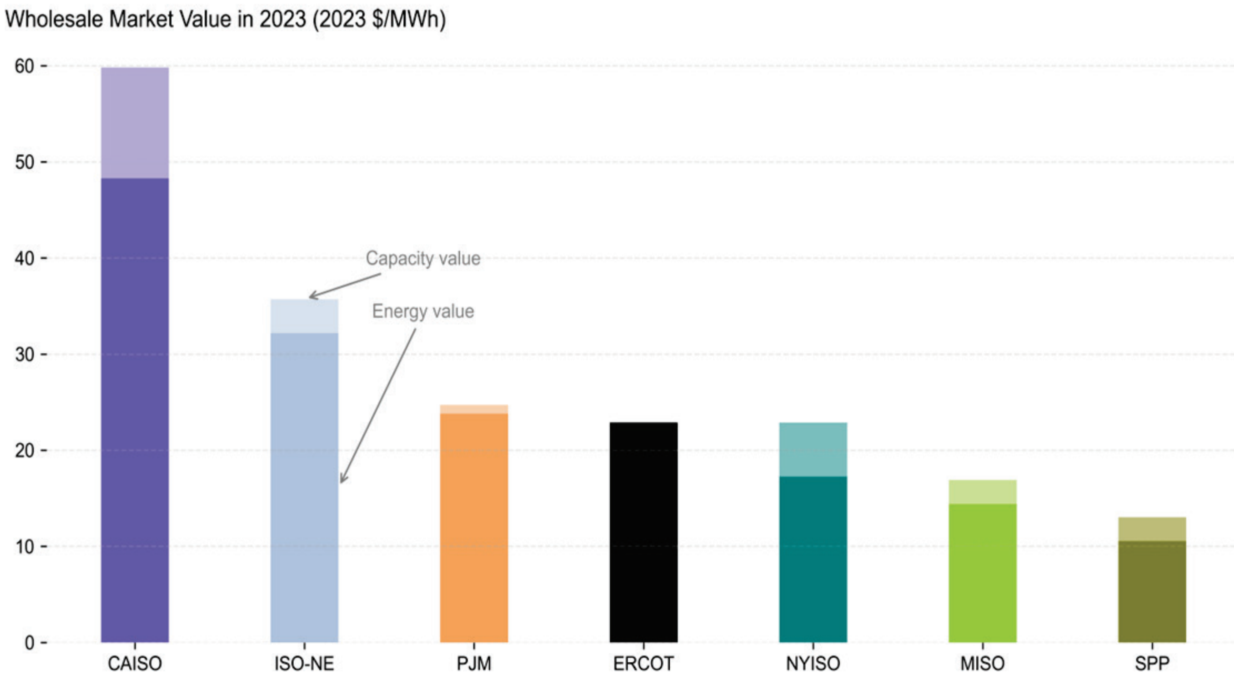
- Wind (and solar) PPA prices are reduced by federal and state incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by any financial incentives provided to thermal generation and its fuel production. Wholesale prices do not fully account for the health and environmental 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.

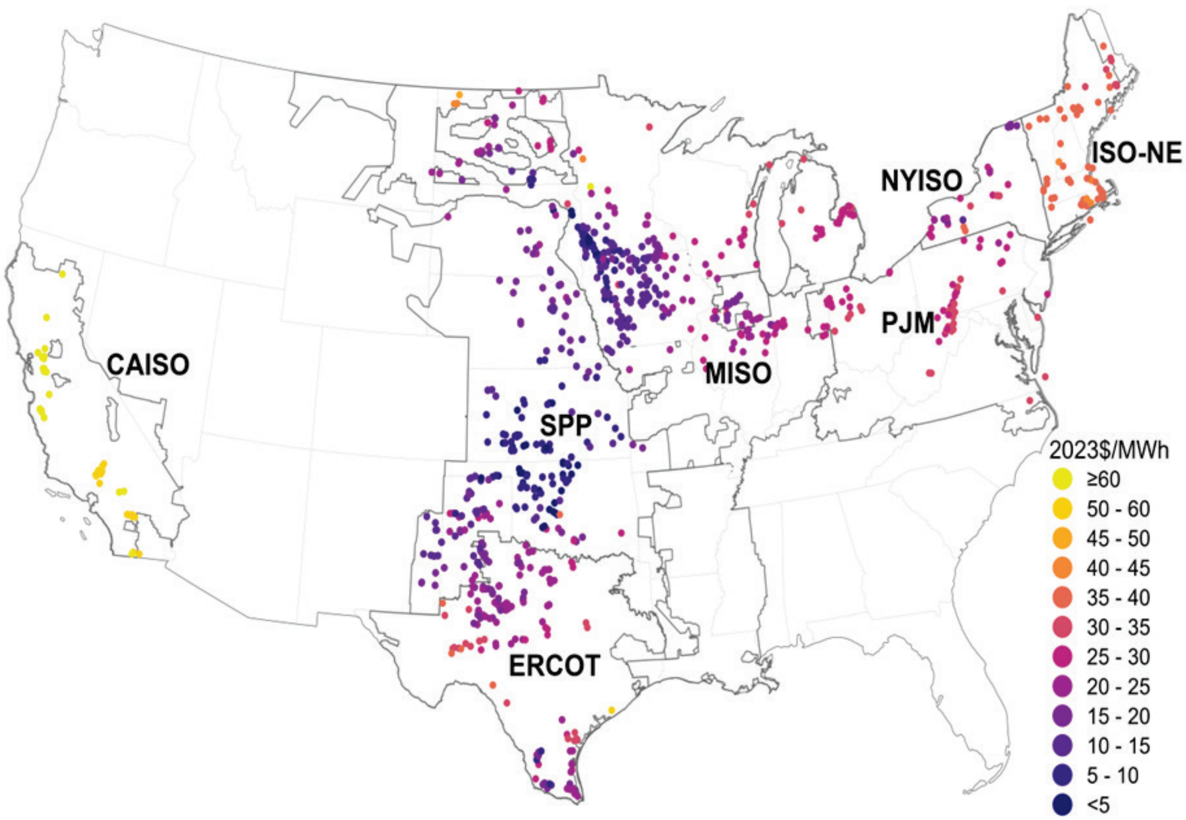
Though wind's market value declined in all regions in 2023, it spanned a wide range. Higher-value regions were CAISO ($60/MWh) and ISO-NE ($36/MWh). PJM ($25/MWh), NYISO ($23/MWh), and ERCOT ($23/MWh) were the next highest markets. The average market value of wind in 2023 was the lowest in SPP ($13/MWh) 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).



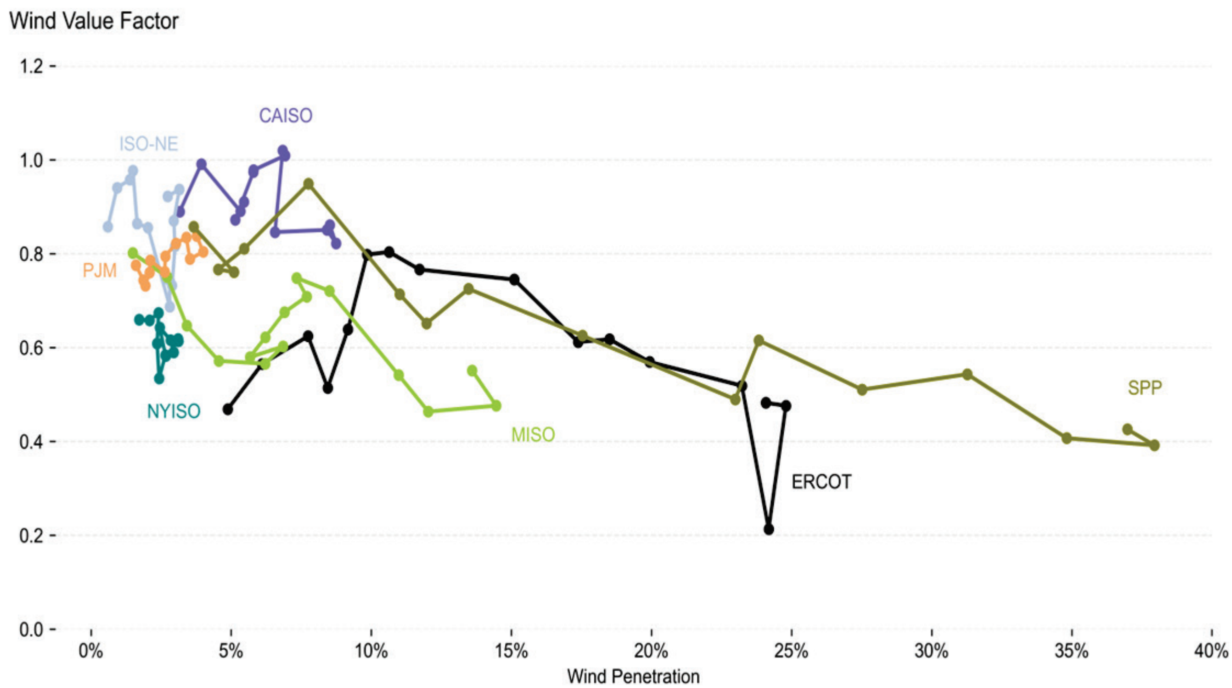
Sources: Berkeley Lab, Hitachi, ISOs

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.



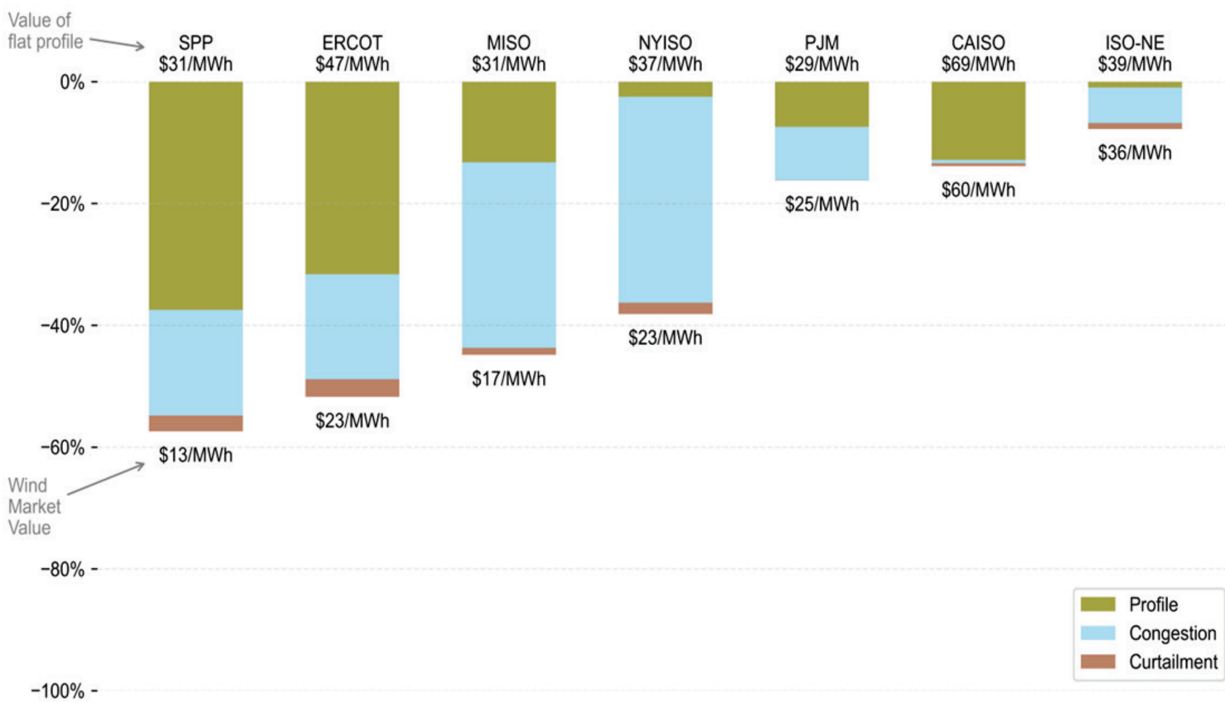
Sources: Berkeley Lab, Hitachi, ISOs

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

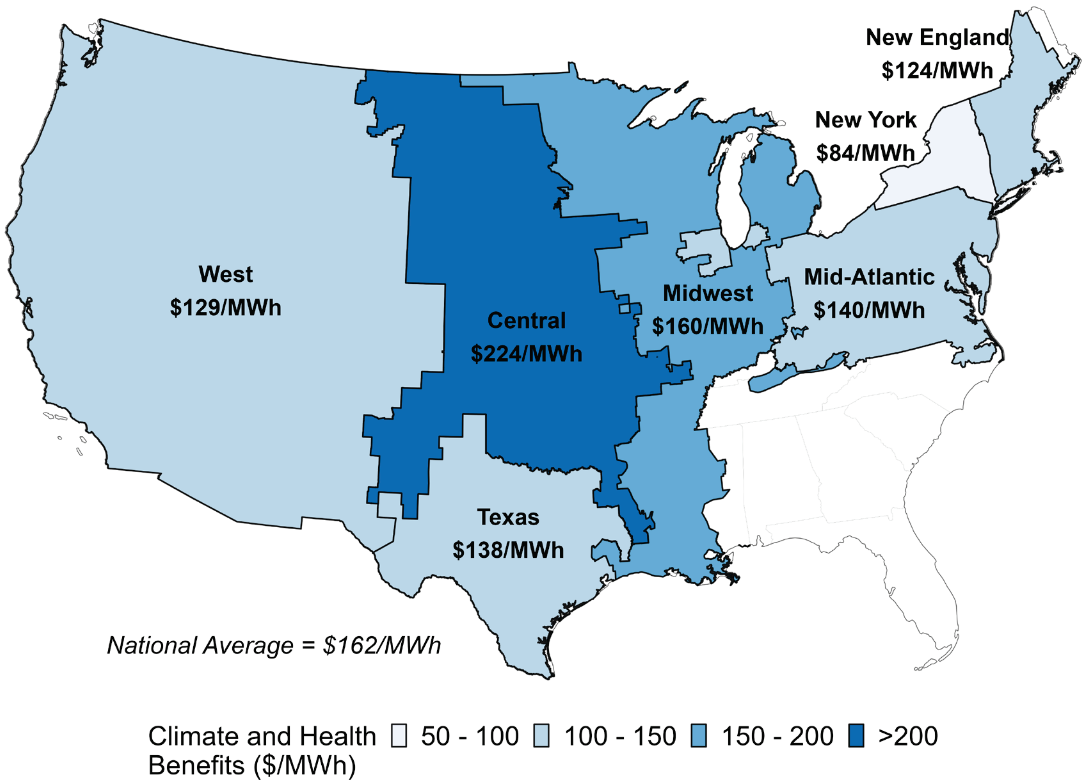
The benefits of wind in reducing health and climate burdens from polluting energy sources are not included in the earlier estimates of grid-system value and the comparisons of that value with PPA prices. Wind generation reduces power-sector emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), 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.

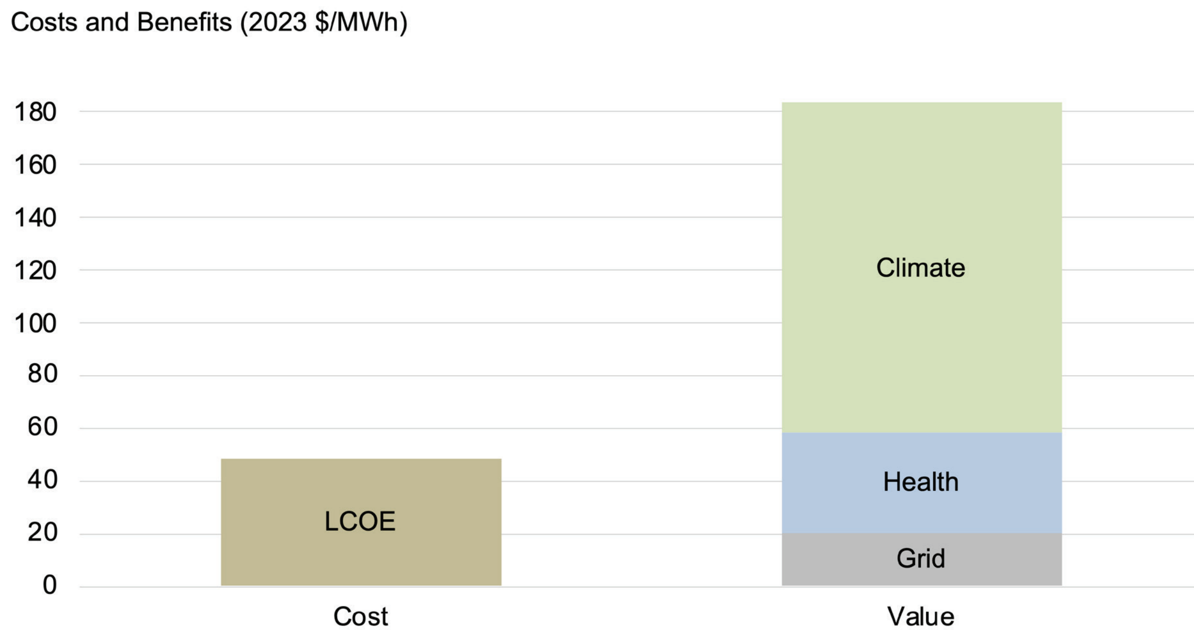


Note: Estimates not provided for the Southeast due to the small number of wind plants in that region.

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

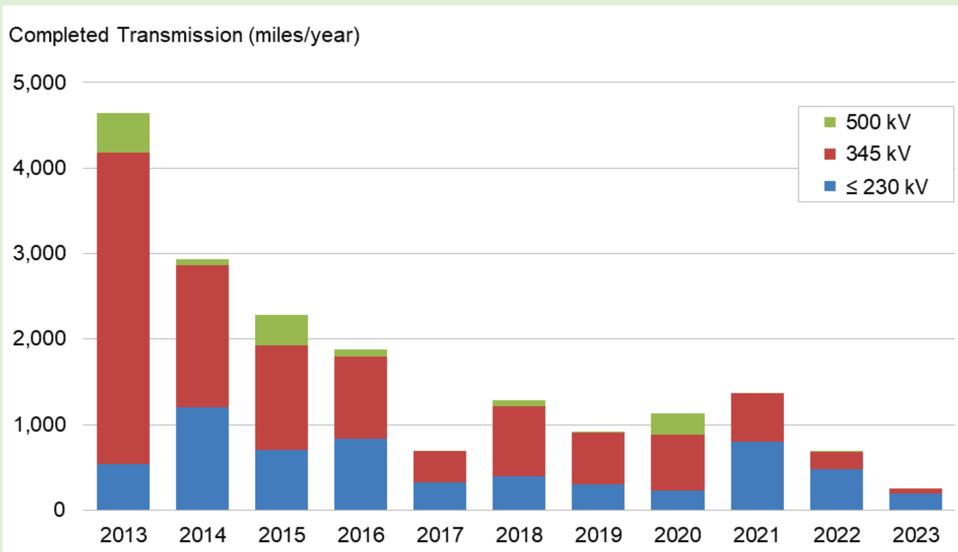
Figure 60. Marginal health, climate, and grid-value benefits from new wind plants versus LCOE in 2023

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.

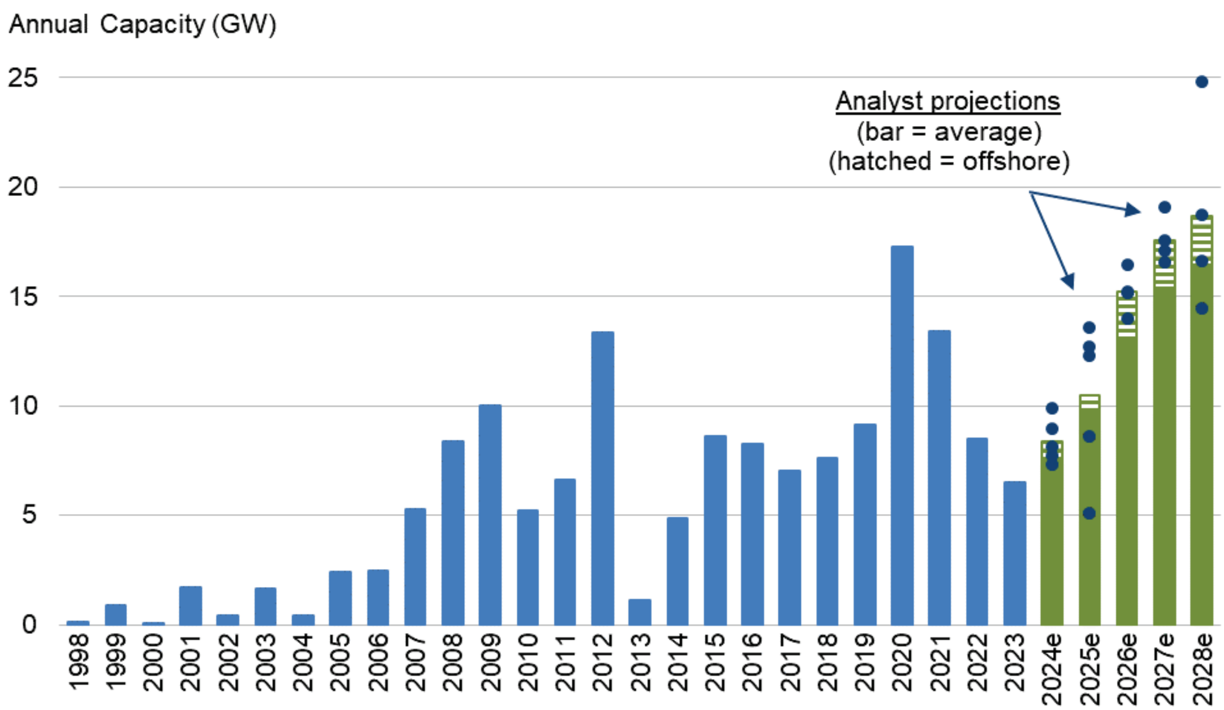
[47] Data are compiled from: https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx. Data include proposed transmission lines over the following 10-year period (e.g., the 2008 dataset reports transmission line proposals for 2009-2018).

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.

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