

U.S. DEPARTMENT OF
ENERGY

Office of
**ENERGY EFFICIENCY &
RENEWABLE ENERGY**

2017 Wind Technologies Market Report



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Acknowledgments

For their support of this ongoing report series, the authors thank the entire U.S. Department of Energy (DOE) Wind Energy Technologies Office team. In particular, we wish to acknowledge Patrick Gilman, Rich Tusing, and Valerie Reed. For reviewing elements of this report or providing key input, we also acknowledge: Patrick Gilman, Liz Hartman, Mikayla Rumph (DOE); Christopher Namovicz, Cara Marcy, Manussawee Sukunta (U.S. Energy Information Administration, EIA); Andrew David (U.S. International Trade Commission, USITC); John Hensley and Celeste Wanner (American Wind Energy Association, AWEA); Charlie Smith (Energy Systems Integration Group); Matt McCabe (Clear Wind); Ed DeMeo (Renewable Energy Consulting Services, Inc.); Danielle Preziuso (Pacific Northwest National Laboratory); Tyler Stehly (National Renewable Energy Laboratory, NREL); and Lawrence Willey (University of Wyoming). For providing data that underlie aspects of this report, we thank the EIA, Bloomberg New Energy Finance (BNEF), MAKE Consulting, and AWEA. Thanks also to Donna Heimiller and Billy Roberts (NREL) for assistance with the wind project and wind manufacturing maps as well as for assistance in mapping wind resource quality; and Carol Laurie (NREL) and Liz Hartman (DOE) for assistance with layout, formatting, production, and/or communications. Lawrence Berkeley National Laboratory's contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the DOE under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

List of Acronyms

AWEA	American Wind Energy Association
BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COD	commercial operation date
DOE	U.S. Department of Energy
EDPR	EDP Renováveis
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
IEC	International Electrotechnical Commission
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
m²	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
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewables portfolio standard
RTO	regional transmission organization
SGRE	Siemens Gamesa Renewable Energy
SPP	Southwest Power Pool
USITC	U.S. International Trade Commission
W	watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

Wind power capacity in the United States continued to experience strong growth in 2017. Recent and near-term additions are supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Wind capacity additions have also been driven by improvements in the cost and performance of wind power technologies, yielding low-priced wind energy for utility, corporate, and other power purchasers. The prospects for growth beyond the current PTC cycle remain uncertain, however, given declining tax support, expectations for low natural gas prices, and modest electricity demand growth.

Key findings from this year's *Wind Technologies Market Report* include:

Installation Trends

- Wind power additions continued at a rapid pace in 2017, with 7,017 MW of new capacity added in the United States and \$11 billion invested.** Supported by favorable tax policy and other factors, cumulative wind power capacity grew to 88,973 MW. In addition to this newly installed wind capacity, 2,131 MW of partial wind plant repowering was completed in 2017, mostly involving upgrades to the rotor diameters and major nacelle components of existing turbines in order to increase energy production with more-advanced turbine technology, extend project life, and access favorable tax incentives.
- Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2017, behind solar and natural gas.** Wind power constituted 25% of all capacity additions in 2017. Over the last decade, wind represented 30% of all U.S. capacity additions, and an even larger fraction of new capacity in the Interior (55%) and Great Lakes (44%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the Northeast (19%) and West (18%), and considerably less in the Southeast (2%). [See Figure 1 for regional definitions].
- Globally, the United States ranked second in annual wind capacity additions in 2017, but was well behind the market leaders in wind energy penetration.** Global wind additions equaled 52,500 MW in 2017, well below the record 63,600 MW added in 2015, yielding a cumulative total of 539,000 MW. The United States remained the second-leading market in terms of annual and cumulative capacity as well as annual wind generation, behind China. A number of countries have achieved high levels of wind penetration; end-of-2017 wind power capacity is estimated to supply the equivalent of 48% of Denmark's electricity demand, and roughly 30% of demand in Ireland and in Portugal. In the United States, the total wind capacity installed by the end of 2017 is estimated, in an average year, to equate to 7% of electricity demand.
- Texas installed the most capacity in 2017 with 2,305 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation.** New utility-scale wind turbines were installed in 24 states in 2017. On a cumulative basis, Texas remained the clear leader, with 22,599 MW of capacity. Notably, the wind capacity installed in Iowa, Kansas, Oklahoma, and South Dakota supplied 30%–37% of all in-state electricity generation in 2017.
- A record level of wind power capacity entered transmission interconnection queues in 2017; solar and storage also reached new highs in 2017.** At the end of 2017, there was 180 GW of wind power capacity seeking transmission interconnection, representing 36% of all generating capacity in the reviewed queues. In 2017, 81 GW of wind power capacity entered interconnection queues, second only to solar capacity additions. Energy storage interconnection requests have also increased in recent years. The Southwest Power Pool, Texas, and Mountain regions experienced especially sizable wind additions to their queues in 2017.

Industry Trends

- **Vestas, GE, and Siemens Gamesa captured 88% of the U.S. wind power market in 2017.** In 2017, Vestas captured 35% of the U.S. market for turbine installations, edging out GE at 29% and followed by Siemens-Gamesa Renewable Energy (SGRE) at 23%. Vestas was also the leading turbine supplier for land-based wind installations worldwide in 2017, followed by SGRE, Goldwind, and GE.
- **Some manufacturers increased the size of their U.S. workforce in 2017 or otherwise expanded their existing facilities, but expectations for significant long-term supply-chain expansion have become less optimistic.** Domestic wind sector employment reached a new high of 105,500 full-time workers in 2017. Moreover, the profitability of turbine suppliers has generally been strong over the last four years. Although there have been a number of plant closures over the last 5+ years, the three major turbine manufacturers serving the U.S. market have domestic manufacturing facilities. Domestic nacelle assembly capability stood at roughly 11.7 GW in 2017, and the United States had the capability to produce blades and towers sufficient for approximately 8.9 GW and 7.4 GW, respectively, of wind capacity annually. The domestic supply chain faces conflicting pressures, including significant near-term growth, but also strong competitive pressures and an anticipation of reduced demand as the PTC is phased out.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports.** The United States is reliant on imports of wind equipment from a wide array of countries, with the level of dependence varying by component. Domestic manufacturing content is highest for nacelle assembly (>85%), towers (70–90%), and blades and hubs (50–70%).
- **The project finance environment remained strong in 2017.** The U.S. wind market raised \$6 billion of new tax equity in 2017, on par with the three prior years. Project-level debt finance decreased to \$2.5 billion. Tax equity yields held at just below 8% (in unlevered, after-tax terms), while the cost of term debt hovered around 4% for much of the year, before pushing higher during the first half of 2018. Looking ahead, 2018 should be another busy year, given the abundant backlog of turbines that met safe-harbor requirements to qualify for 100% PTC, along with another reported 10 GW of safe-harbored turbines at 80% PTC, still to be deployed.
- **Independent power producers own the vast majority of wind assets built in 2017.** IPPs own 91% of the new wind capacity installed in the United States in 2017, with the remaining assets owned by investor-owned utilities (9%) and other entities (<1%).
- **Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant.** Electric utilities continued to be the largest off-takers of wind power in 2017, either owning wind projects (9%) or buying electricity from projects (36%) that, in total, represent 45% of the new capacity installed in 2017. Direct retail purchasers—including corporate off-takers—account for 24%. Merchant/quasi-merchant projects (20%) and power marketers (6%) make up the remainder (with 5% undisclosed).

Technology Trends

- **Average turbine capacity, rotor diameter, and hub height increased in 2017, continuing the long-term trend.** To optimize wind power project cost and performance, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2017 was 2.32 MW, up 8% from the previous year and 224% since 1998–1999. The average rotor diameter in 2017 was 113 meters, a 4% increase over the previous year and a 135% boost over 1998–1999, while the average hub height in 2017 was 86 meters, up 4% over the previous year and 54% since 1998–1999.
- **Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades.** Rotor scaling has been especially significant in recent

years. In 2008, no turbines employed rotors that were 100 meters in diameter or larger; in contrast, by 2017, 99% of newly installed turbines featured rotors of at least that diameter, with 80% of newly installed turbines featuring rotor diameters of greater than 110 meters, and 14% greater than or equal to 120 meters.

- **Turbines originally designed for lower wind speed sites have rapidly gained market share, and are being deployed in a range of wind resource conditions.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average “specific power”¹ (in W/m²), from 394 W/m² among projects installed in 1998–1999 to 231 W/m² among projects installed in 2017. In general, turbines with low specific power were originally designed for lower wind speed sites. Another indication of the increasing prevalence of lower wind speed turbines is that, in 2017, the overwhelming majority of new installations used IEC Class 3 and Class 2/3 turbines—turbines specifically certified for lower wind speed sites.
- **Wind turbines were deployed in somewhat lower wind-speed sites in 2017 in comparison to the previous three years.** With an estimated long-term average wind speed of 7.7 meters per second at a height of 80 meters above the ground, wind turbines installed in 2017 were located in lower wind-speed sites than in the previous three years; however, the 2017 average exceeds that for turbines installed from 2009 to 2013. Federal Aviation Administration data suggest that near-future wind projects will be located in similar or slightly better wind resource areas than those installed in 2017.
- **Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast.** Low specific power and IEC Class 3 and 2/3 turbines continue to be employed in all regions of the United States, and at both lower and higher wind speed sites. In parts of the Interior region, in particular, turbines designed for lower wind speeds continue to be deployed across a wide range of resource conditions. Meanwhile, the tallest towers continue to be deployed in the Great Lakes and Northeastern regions, in lower wind speed sites, with specific location decisions likely driven by the wind profile at the site.
- **Wind power projects planned for the near future continue the trend of ever-taller turbines.** Federal Aviation Administration permit data suggest that near-future wind projects will deploy progressively taller turbines, with a significant portion (>35%) of permit applications in early 2018 over 500 feet.
- **A large number of wind power projects continued to employ multiple turbine configurations from a single turbine supplier.** Nearly a quarter of the larger wind power projects built in 2016 and 2017 utilized turbines with multiple hub heights, rotor diameters and/or capacities—all supplied by the same original equipment manufacturer (OEM). This development may reflect increasing sophistication with respect to turbine siting and wake effects, coupled with an increasing willingness among turbine suppliers to provide multiple turbine configurations, leading to increased site optimization.
- **Turbines that were partially repowered in 2017 now have significantly larger rotors and correspondingly lower specific power ratings.** In 2017, 1,317 turbines totaling 2,131 MW of capacity were partially repowered. Larger rotors were installed on all of these repowered turbines, with an average increase of 12 meters, while only 10% saw increases in rated capacity. On average, these changes resulted in a 25% decrease in specific power, from 335 W/m² to 252 W/m². All of these turbines had been in service for just 9–14 years prior to being repowered, with the primary motivation for partial repowering being to increase operational efficiencies while also re-qualifying for the PTC.

¹ 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.

Performance Trends

- **Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability.** Wind project performance, as illustrated by data on capacity factors, has generally increased over time, driven largely by turbine scaling. However, inter-year variations in the strength of the wind resource and changes in the amount of wind energy curtailment have partially masked the influence of turbine scaling on wind project performance. On average, across the United States and for 2017 as a whole, wind speeds were near-normal as compared to earlier years, while wind energy curtailment remained modest at around 2.5%.
- **Turbine design changes are driving capacity factors significantly higher over time among projects located in given wind resource regimes.** Focusing on performance solely in 2017 helps identify underlying trends. The average 2017 capacity factor among projects built from 2014 to 2016 was 42.0%, compared to an average of 31.5% among projects built from 2004 to 2011 and just 23.5% among projects built from 1998 to 2001. The decline in specific power is a major contributor to these trends, but has been offset to a degree by a tendency—especially from 2009 to 2012—towards building projects at lower-quality wind sites. Controlling for these two influences shows that turbine design changes are driving capacity factors significantly higher over time among projects located in given wind resource regimes. Older projects, meanwhile, appear to suffer from performance degradation, particularly in their second decade of operations.
- **Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology.** Based on a sub-sample of wind projects built in 2015–2016, average capacity factors in 2017 were highest in the Interior region (43.2%). Not surprisingly, the regional rankings are roughly consistent with the relative quality of the wind resource in each region, and they reflect the degree to which each region has adopted turbines with lower specific power and/or taller towers. For example, the Great Lakes region has thus far adopted these new designs (particularly taller towers) to a larger extent than some other regions, leading to an increase in average regional capacity factors.

Cost Trends

- **Wind turbine prices remained well below levels seen a decade ago.** After hitting a low of roughly \$800/kW² from 2000 to 2002, average turbine prices increased to more than \$1,600/kW by 2008. Since then, wind turbine prices have steeply declined, despite increases in size. Recent data suggest pricing most-typically in the \$750–\$950/kW range. These price reductions, coupled with improved turbine technology, have exerted downward pressure on project costs and wind power prices.
- **Lower turbine prices have driven reductions in reported installed project costs.** The capacity-weighted average installed project cost within our 2017 sample stood at \$1,610/kW. This is a decrease of \$795/kW from the apparent peak in average reported costs in 2009 and 2010, but is roughly on par with—or even somewhat higher than—the installed costs experienced in the early 2000s. Early indications from a sample of projects currently under construction suggest that somewhat lower costs are on the horizon.
- **Installed costs differed by project size, turbine size, and region.** Installed project costs exhibit some economies of scale, at least at the lower end of the project size range. Additionally, among projects built in 2017, the Interior of the country was the lowest-cost region, with a capacity-weighted average cost of \$1,550/kW.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, projects installed over the past decade have, on average, incurred lower

² All cost figures presented in the report are denominated in real 2017\$,

operations and maintenance (O&M) costs than older projects in their first several years of operation. The data suggest that O&M costs have increased as projects age for the older projects in the sample, but hold steady with age among those projects installed over the last decade.

Wind Power Price Trends

- Wind power purchase agreement prices remain very low.** After topping out at \$70/MWh for power purchase agreements (PPAs) executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around or even below \$20/MWh—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country, where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from around \$55/MWh among contracts executed in 2009 to below \$20/MWh in 2017. Today’s low PPA prices have been enabled by the combination of higher capacity factors, declining installed costs, and record-low interest rates documented elsewhere in this report; the PTC has also been a key enabler over time. Regional and nationwide trends in the levelized cost of wind energy (LCOE) closely follow the PPA price trends—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2017. The lowest LCOEs are found in the Interior region, with a 2017 average of \$42/MWh and with some projects as low as \$38/MWh.
- The economic competitiveness of wind power has been affected by low natural gas prices and by declines in the wholesale market value of wind energy.** Given the location of wind projects and the hourly profile of wind generation, the average wholesale energy market value of wind has generally declined since 2008. Following the sharp drop in wholesale electricity prices (and, hence, wind energy market value) in 2009, average wind PPA prices tended to exceed the wholesale energy value of wind through 2012. Continued declines in wind PPA prices, however, brought those prices back in line with the energy market value of wind in 2013, and wind has generally remained competitive in subsequent years. The energy market value of wind in 2017 was the lowest in the Southwest Power Pool, at \$14/MWh, whereas the highest-value market was California at \$28/MWh. Meanwhile, the average future stream of wind PPA prices from contracts executed in 2015–2017 is lower than the Energy Information Administration’s latest projection of the fuel costs of gas-fired generation extending out through 2050.

Policy and Market Drivers

- The federal production tax credit remains one of the core motivators for wind power deployment.** In December 2015, via the Consolidated Appropriations Act of 2016, Congress passed a five-year extension of the PTC that provides the full PTC to projects that started construction prior to the end of 2016, but that phases out the PTC for projects starting construction in subsequent years (e.g., projects that started construction in 2017 get 80% of the PTC, which drops to 60% and 40% for projects starting construction in 2018 and 2019, respectively). In 2016, the IRS issued Notice 2016-31, allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. According to various sources, 30–70 GW of wind turbine capacity had been qualified for the full PTC by the end of 2016, with another 10 GW qualifying for the 80% PTC.
- State policies help direct the location and amount of wind power development, but wind power growth is outpacing state targets.** As of June 2018, renewables portfolio standards (RPS) existed in 29 states and Washington D.C. Of all wind capacity built in the United States from 2000 through 2017, roughly 49% is delivered to load-serving entities with RPS obligations. Among wind projects built in 2017, this proportion fell to 23%. Existing RPS programs are projected to require average annual renewable energy additions of roughly 4.5 GW/year through 2030.
- System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain.** Studies show that the cost of integrating wind energy into the grid varies widely, from often below \$5/MWh to close to \$20/MWh for wind power

capacity penetrations of up to or exceeding 40% of the peak load of the system in which the wind power is delivered. Grid system operators and others continue to implement a range of methods to accommodate increased wind energy penetrations. Just over 500 miles of transmission lines came online in 2017—less than in previous years. The wind industry has identified 26 near-term transmission projects that, if completed, could support considerable amounts of wind capacity.

Future Outlook

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next several years, before declining, driven by the five-year extension of the PTC and the progressive reduction in the value of the credit over time. Additionally, near-term additions are impacted by improvements in the cost and performance of wind power technologies, which contribute to low power sales prices. Other factors influencing demand include corporate wind energy purchases and state-level renewable energy policies. As a result, various forecasts show additions increasing in the near term, from more than 8 GW in 2018 to roughly 10–13 GW in 2020. Forecasts for 2021 to 2025, on the other hand, show a downturn in wind capacity additions in part due to the PTC phase-out. Expectations for continued low natural gas prices, modest electricity demand growth, and lower demand from state policies also put a damper on growth expectations, as do limited transmission infrastructure and competition from natural gas and solar energy. At the same time, the potential for continued technological advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state RPS requirements. Moreover, new transmission in some regions is expected to open up high-quality wind resources for development. Given these diverse and contrasting underlying potential trends, wind additions—especially after 2020—remain uncertain.

Table of Contents

Executive Summary **vii**

1 Introduction **1**

2 Installation Trends **3**

3 Industry Trends **11**

4 Technology Trends **25**

5 Performance Trends **38**

6 Cost Trends **48**

7 Wind Power Price Trends **57**

8 Policy and Market Drivers **66**

9 Future Outlook **73**

References **75**

Appendix: Sources of Data Presented in this Report **78**

List of Figures

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 80 meters	2
Figure 2. Annual and cumulative growth in U.S. wind power capacity.....	3
Figure 3. Relative contribution of generation types in annual capacity additions	4
Figure 4. Generation capacity additions by region (2008–2017).....	5
Figure 5. Approximate wind energy penetration in the 23 countries with the greatest installed wind power capacity.....	6
Figure 6. Location of wind power development in the United States.....	7
Figure 7. Generation capacity in 35 selected interconnection queues from 2013 to 2017, by resource type	9
Figure 8. Wind power capacity in 35 selected interconnection queues, by region	10
Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2017.....	11
Figure 10. Location of existing and new turbine and component manufacturing facilities	12
Figure 11. Number of wind turbine and component manufacturing facilities in the United States .	13
Figure 12. Domestic wind manufacturing capability vs. U.S. wind power capacity installations	15
Figure 13. Turbine OEM global profitability over time	16
Figure 14. Estimated imports of wind-powered generating sets, nacelles, towers, generators, and blades and hubs, as well as exports of wind-powered generating sets	17
Figure 15. Summary map of tracked wind-specific imports in 2017: countries of origin and U.S. districts of entry.....	18
Figure 16. Origins of U.S. imports of selected wind turbine equipment	19
Figure 17. Cost of 15-year debt and tax equity for utility-scale wind projects over time	21
Figure 18. Cumulative and 2017 wind power capacity categorized by owner type.....	22
Figure 19. Cumulative and 2017 wind power capacity categorized by power off-take arrangement	23
Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height for land-based wind projects	25
Figure 21. Trends in turbine nameplate capacity.....	26
Figure 22. Trends in turbine hub height	27
Figure 23. Trends in turbine rotor diameter	28
Figure 24. Trends in turbine specific power.....	29
Figure 25. Trends in turbine IEC class	30
Figure 26. Trends in specific power for IEC class 2, 2/3, and 3 turbines	31

Figure 27. Wind Resource Quality by Year of Installation at 80 meters..... 32

Figure 28. Deployment of turbines originally designed for lower wind speed sites, by region 33

Figure 29. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality 34

Figure 30. Total turbine heights proposed in FAA applications, over time..... 35

Figure 31. Percent of larger projects employing multiple turbine configurations from a single OEM 36

Figure 32. Change in average physical specifications of turbines that were partially repowered in 2017..... 37

Figure 33. Average sample-wide capacity factors by calendar year 38

Figure 34. Wind curtailment and penetration rates by ISO 40

Figure 35. Calendar year 2017 capacity factors by commercial operation date..... 41

Figure 36. 2017 capacity factors and various drivers by commercial operation date..... 42

Figure 37. Calendar year 2017 capacity factors by wind resource quality and specific power: 1998-2016 projects 43

Figure 38. Calendar year 2017 capacity factors by commercial operation date and wind resource quality 44

Figure 39. Post-COD changes in capacity factors over time suggest performance degradation 45

Figure 40. Calendar year 2017 capacity factors by region: 2015–2016 projects only 46

Figure 41. Calendar year 2017 capacity factors by region and specific power: 1998–2016 projects 47

Figure 42. Reported wind turbine transaction prices over time..... 48

Figure 43. Installed wind power project costs over time..... 50

Figure 44. Installed wind power project costs by project size: 2016–2017 projects..... 51

Figure 45. Installed wind power project costs by turbine size: 2016–2017 projects..... 51

Figure 46. Installed wind power project costs by region: 2016–2017 projects 52

Figure 47. Histogram of installed costs by MW and projects: 2016–2017 projects..... 53

Figure 48. Average O&M costs for available data years from 2000 to 2017, by COD..... 54

Figure 49. Median annual O&M costs by project age and commercial operation date..... 55

Figure 50. Levelized wind PPA prices by PPA execution date and region..... 58

Figure 51. Generation-weighted average levelized wind PPA prices by PPA execution date and region 59

Figure 52. Regional wholesale energy market value of wind and average levelized long-term wind PPA prices over time 61

Figure 53. Regional wholesale energy market value of wind in 2017, by region 62

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time..... 63

Figure 55. State RPS policies as of June 2018..... 68

Figure 56. Integration costs at various levels of wind power capacity penetration 70

Figure 57. Miles of transmission projects completed, by year and voltage 71

Figure 58. Transmission Line Activity: Completed in 2017, and Planned for Near Future..... 72

Figure 59. Wind power capacity additions: historical installations and projected growth..... 73

List of Tables

Table 1. International Rankings of Wind Power Capacity6

Table 2. U.S. Wind Power Rankings: The Top 20 States.....8

Table 3. Approximate Domestic Content of Major Components in 2017 20

Table 4. History of Production Tax Credit Extensions..... 67

Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis. 79

1 Introduction

Wind power capacity additions in the United States continued at a rapid pace in 2017. Recent and projected near-term growth is supported by the industry’s primary federal incentive—the production tax credit (PTC)—having been extended (with a phase-out schedule) through 2019 as well as a myriad of state-level policies. Wind capacity additions have also been driven by continued improvements in the cost and performance of wind power technologies, yielding low-priced wind energy for utility, corporate, and other power purchasers. At the same time, the prospects for growth beyond the current PTC cycle remain uncertain, given declining federal tax support, expectations for continued low natural gas prices, and modest electricity demand growth.

This annual report—now in its twelfth consecutive year—provides an overview of developments and trends in the U.S. wind power market, with a particular focus on the year 2017. The report 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; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into and exports from the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine size, hub height, rotor diameter, specific power, and International Electrotechnical Commission (IEC) Class. After that, the report discusses wind power performance, cost, and pricing. In doing so, it describes trends in project-level capacity factors, wind turbine transaction prices, installed project costs, and operations and maintenance (O&M) expenses. It also reviews the prices paid for wind power through power purchase agreements (PPAs) and how those prices compare to the value of wind generation in wholesale energy markets as well as forecasts of future natural gas prices. Next, the report examines market and policy factors impacting the domestic wind industry, including federal and state policy as well as transmission and grid integration issues. The report concludes with a preview of possible near-term market developments based on the findings of other energy 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 five broad regions on a map of average annual U.S. wind speed at 80 meters above the ground.³ These five regions will be referenced on many occasions throughout this report, whenever regional breakdowns or analysis is warranted, so they are defined here. Note that any such breakdowns, regional or otherwise, may not always add up to 100% due to rounding.

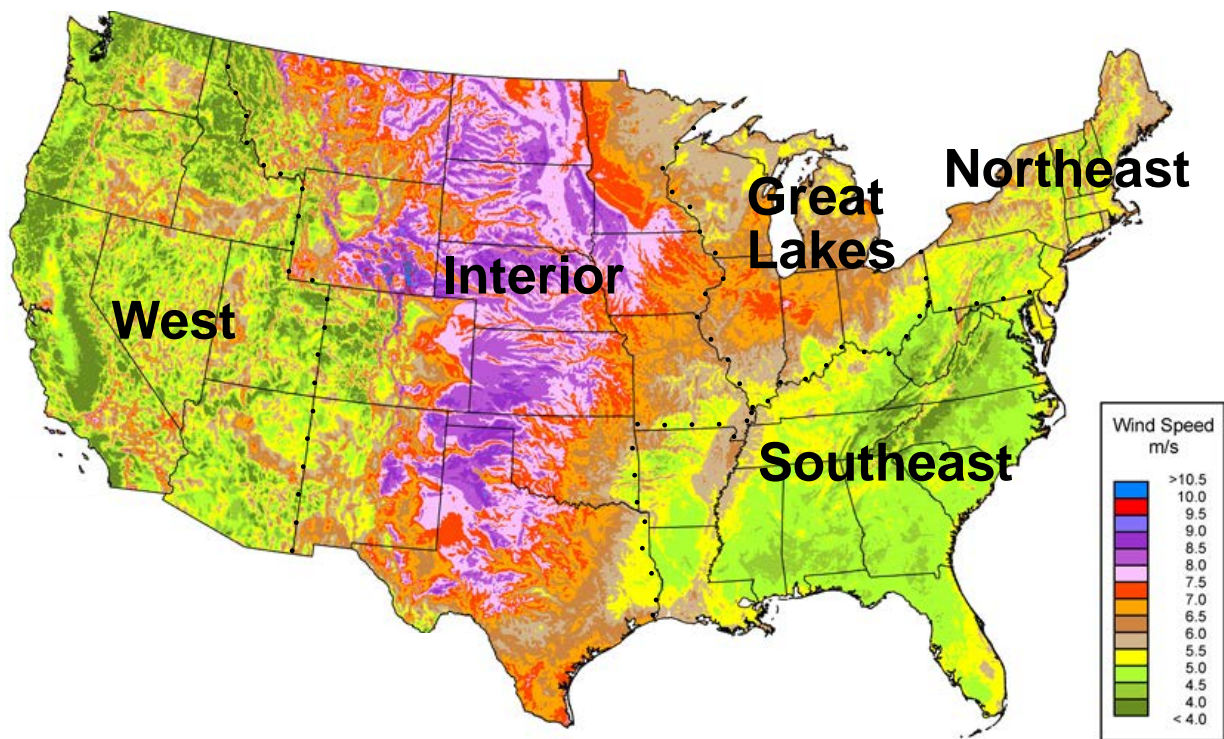
This edition of the annual report updates data presented in previous editions while highlighting trends and new developments that were observed in 2017. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.⁴ The U.S. wind power sector is multifaceted, and also 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)—the 2017 Distributed Wind Market Report.⁵ Additionally, because this report

³ The regional boundaries shown in Figure 1 have been delineated in an attempt to simultaneously satisfy three goals: have a relative uniformity in average annual wind speed within each individual region, include enough states in each region to enable sufficient wind project sample size for regional breakdowns and analysis, and adhere as closely as possible to traditional regional boundaries.

⁴ This 100-kW threshold between “smaller” and “larger” wind turbines is applied starting with 2011 projects to better match the American Wind Energy Association’s historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match AWEA’s reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.

⁵ See: <https://energy.gov/eere/wind/downloads/2017-distributed-wind-market-report>

has a historical focus—and because only one offshore wind project is operational in the United States—this report does not address trends in offshore wind power. A companion study funded by DOE that focuses exclusively on *offshore wind power* is also available as a PowerPoints slide deck—the 2017 Offshore Wind Market Update.⁶



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

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 80 meters

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 Wind Energy Association (AWEA). The Appendix provides a summary of the many data sources. In some cases, the data shown in the report 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 document primarily focuses on historical data, with an emphasis on the year 2017. With some limited exceptions—including the final section of the report—the report does not seek to forecast wind energy trends.

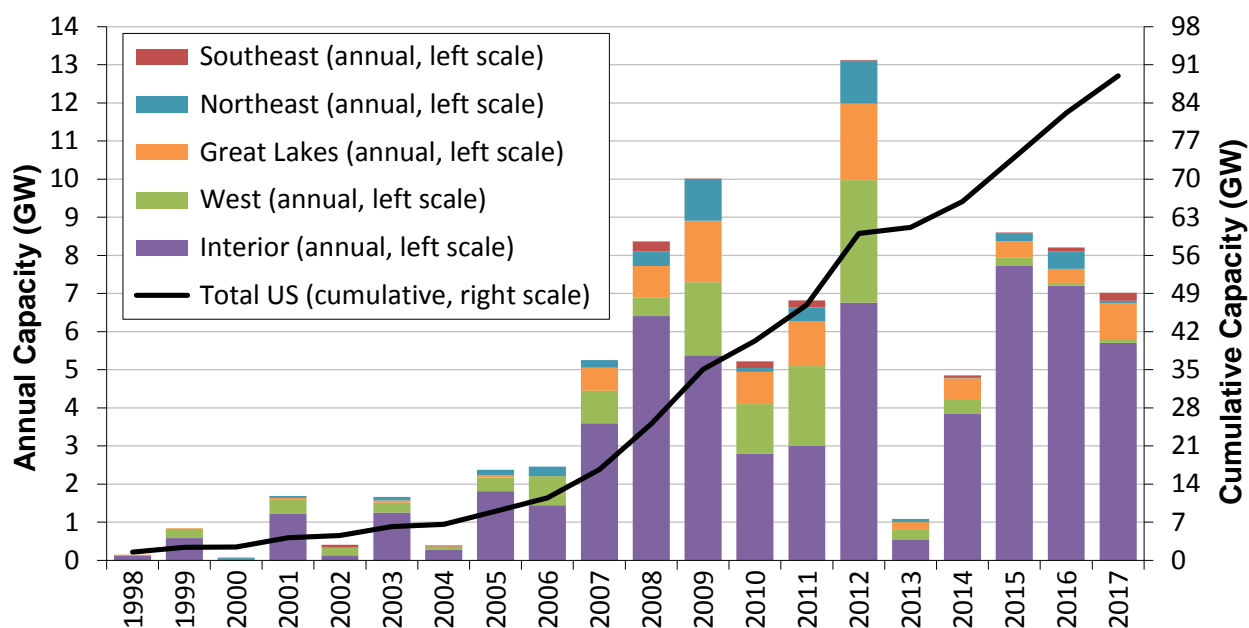
⁶ See: <https://energy.gov/eere/wind/downloads/2017-offshore-wind-market-report>

2 Installation Trends

Wind power additions continued at a rapid pace in 2017, with 7,017 MW of new capacity added in the United States and \$11 billion invested

U.S. wind power capacity additions equaled 7,017 MW in 2017, bringing the cumulative total to 88,973 MW (Figure 2).⁷ This growth represented \$11 billion of investment in new wind power project installations in 2017, for a cumulative investment total of roughly \$180 billion since the beginning of the 1980s.^{8,9} Over 80% of the new wind power capacity installed in 2017 is located within the Interior region (as defined in Figure 1).

A new trend is that of partial wind project repowering, in which major components of turbines are replaced in order to increase energy production with more-advanced turbine technology, extend project life, and access favorable tax incentives. In addition to the newly installed wind capacity reported above, 2,131 MW of partial repowerings were completed in 2017: 1,723 MW in Texas and 408 MW in Iowa. Upgrades and refurbishments resulted primarily in increased rotor diameters and the replacement of major nacelle components; turbine nameplate capacity increased by only 12.5 MW in aggregate,¹⁰ and there were no changes to tower height.



Source: AWEA WindIQ

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

As in previous years, growth was in part driven by continued improvements in the cost and performance of wind power technologies. State renewables portfolio standards (RPS) and corporate demand also played a role.

⁷ When reporting annual wind power capacity additions, this report focuses on *gross* capacity additions, and does not consider partial repowering. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning, or higher, reflecting partial repowering that increases nameplate capacities.

⁸ All cost and price data are reported in real 2017 dollars.

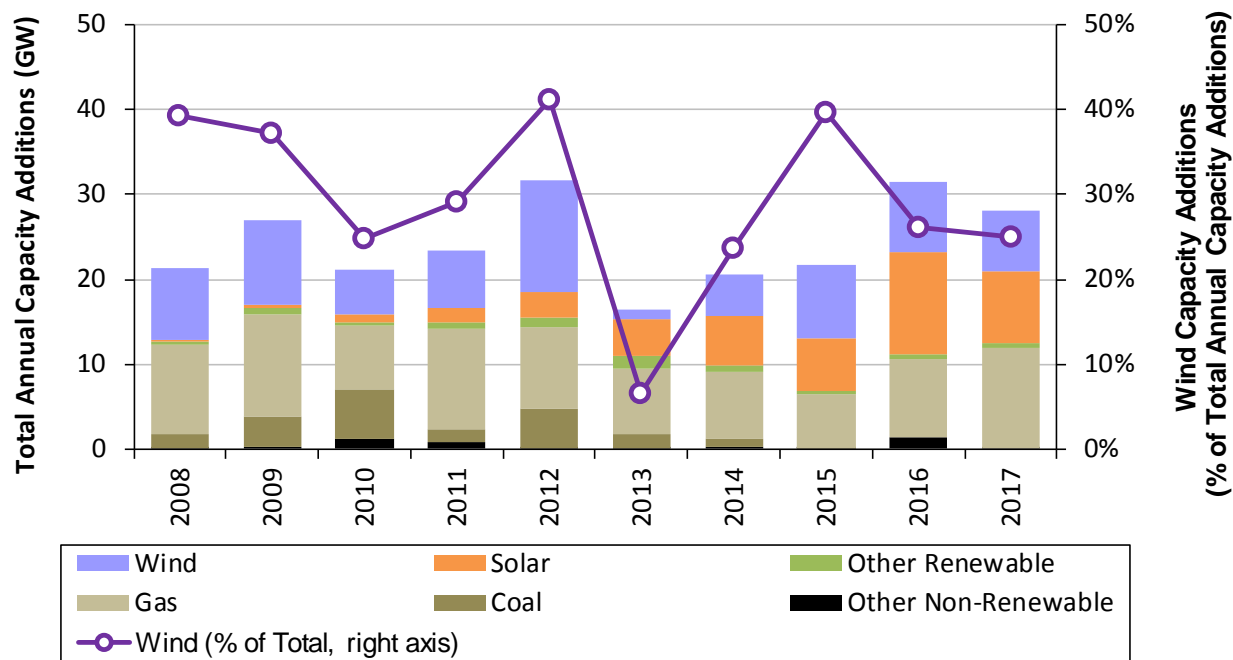
⁹ These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

¹⁰ This 12.5 MW increase in capacity from partial repowering activity is included in the cumulative data but not the annual data reported in Figure 2.

A crucial factor was the PTC, which, in December 2015, was extended for an additional five years—applying to projects that begin construction before January 1, 2020, but with a progressive reduction in the value of the credit for projects starting construction after 2016. Meanwhile, the ability of partially repowered wind projects to access the PTC was the primary motivator for the growth in partial repowering in 2017.

Wind power represented the third-largest source of U.S. electric-generating capacity additions in 2017, behind solar and natural gas

Wind power has comprised a sizable share of generation capacity additions in recent years. In 2017, it constituted 25% of all U.S. capacity additions and was the third-largest source of new capacity, behind solar and natural gas (Figure 3).¹¹ Wind power’s share of overall annual capacity additions declined slightly in 2017 relative to 2016.

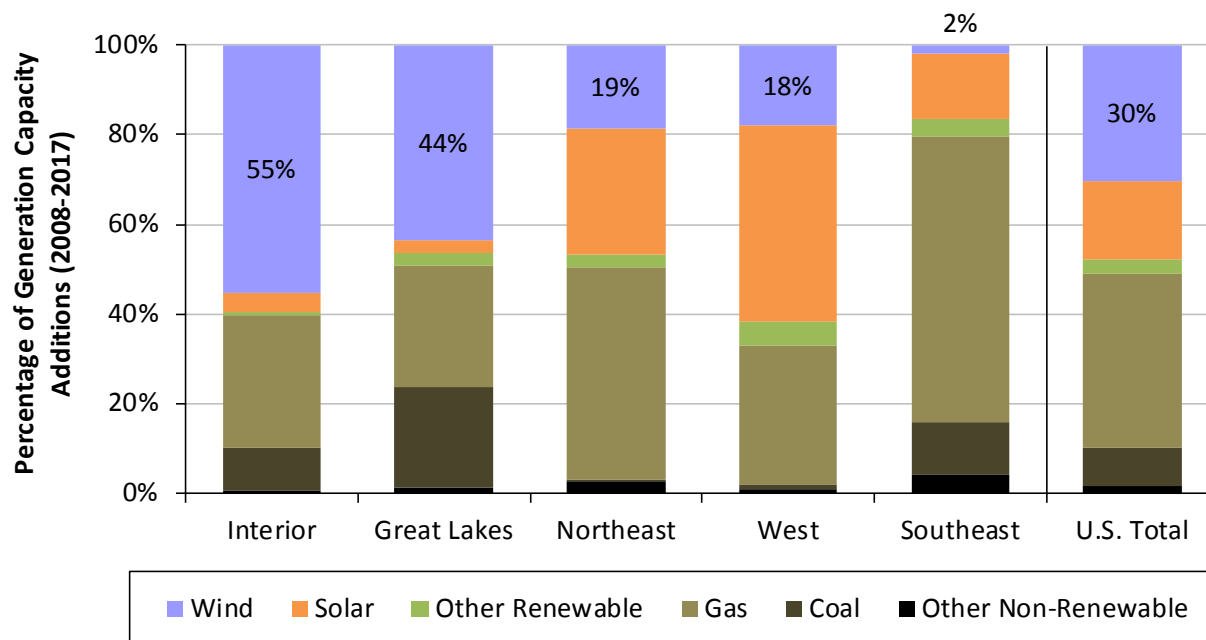


Sources: ABB, AWEA WindIQ, GTM Research, Berkeley Lab

Figure 3. Relative contribution of generation types in annual capacity additions

Over the last decade, wind power represented 30% of total U.S. capacity additions, and an even larger fraction of new generation capacity in the Interior (55%) and Great Lakes (44%) regions (Figure 4; see Figure 1 for regional definitions). Wind power’s contribution to generation capacity growth over the last decade is somewhat smaller—but still significant—in the Northeast (19%) and West (18%), and considerably less in the Southeast (2%).

¹¹ Data presented here are based on gross capacity additions, not considering retirements or partial repowering. Furthermore, they include only the 50 U.S. states, not U.S. territories.



Sources: ABB, AWEA WindIQ, GTM Research, Berkeley Lab

Figure 4. Generation capacity additions by region (2008–2017)

Globally, the United States ranked second in annual wind capacity additions in 2017, but was well behind the market leaders in wind energy penetration

Global wind additions equaled roughly 52,500 MW in 2017, below the 54,600 MW added in 2016 and below the record of 63,000 MW added in 2015. With its 7,017 MW representing 13% of new global installed capacity in 2017, the United States maintained its second-place position behind China (Table 1). Cumulative global capacity grew by 11% and totaled 539,000 MW at the end of the year (GWEC 2018),¹² with the United States accounting for 17% of global capacity—a distant second to China by this metric (Table 1).¹³ The United States also remains in second place, behind China, in annual wind electricity generation.

¹² Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2018) but are updated, where necessary, with the U.S. data presented here. Some disagreement exists among these data sources and others.

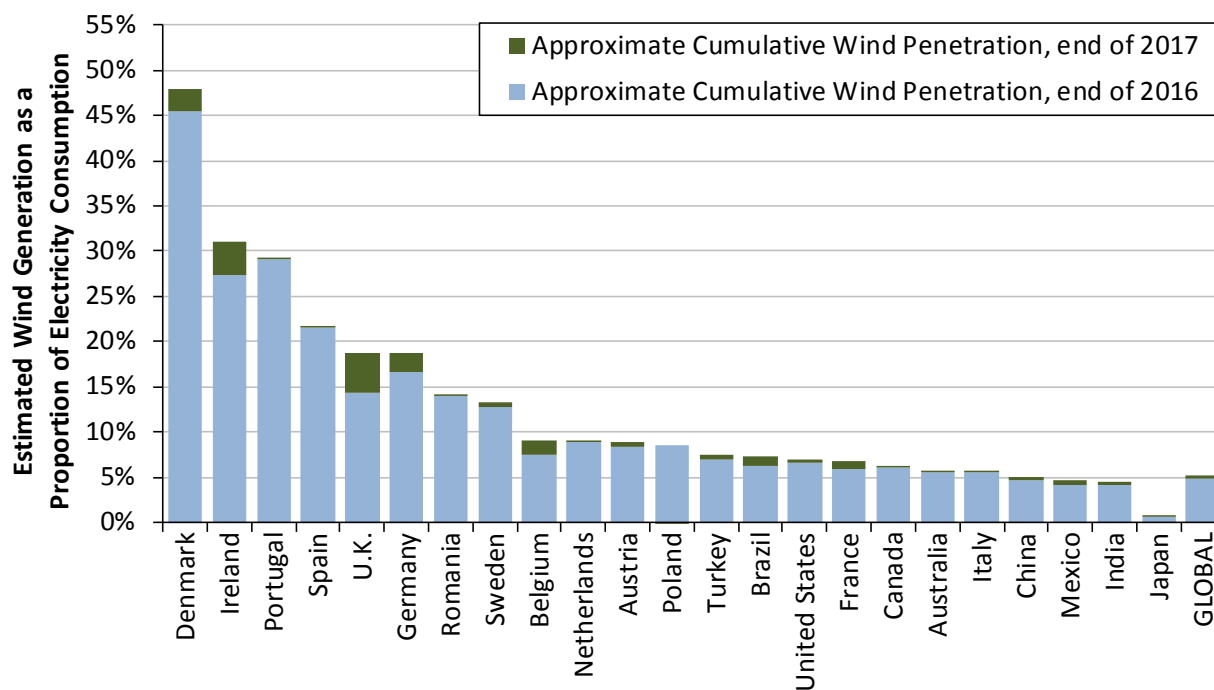
¹³ Wind power additions and cumulative capacity in China include capacity that was installed but that had not yet begun to deliver electricity by the end of 2017, due to a lack of coordination between wind developers and transmission providers and the lengthier time that it takes to build transmission and interconnection facilities. All of the U.S. capacity reported here, on the other hand, was capable of electricity delivery.

Table 1. International Rankings of Wind Power Capacity

Annual Capacity (2017, MW)		Cumulative Capacity (end of 2017, MW)	
China	19,660	China	188,392
United States	7,017	United States	88,973
Germany	6,581	Germany	56,132
United Kingdom	4,270	India	32,848
India	4,148	Spain	23,170
Brazil	2,022	United Kingdom	18,872
France	1,694	France	13,759
Turkey	766	Brazil	12,763
South Africa	618	Canada	12,239
Finland	535	Italy	9,479
Rest of World	5,182	Rest of World	82,391
TOTAL	52,492	TOTAL	539,019

Sources: GWEC (2018); AWEA WindIQ for U.S. capacity

A number of countries have achieved relatively high levels of wind energy penetration in their electricity grids. Figure 5 presents data on end-of-2017 (and end-of-2016) installed wind power capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors and then divided by projected 2018 (and 2017) electricity consumption. The figure covers the 23 countries that have the greatest cumulative installed wind power capacity. A number of other countries, such as Uruguay, also have high wind energy penetrations, but are not among the leaders in installed capacity and therefore are not included in the figure.



Sources: Berkeley Lab estimates based on data from GWEC, EIA, and elsewhere

Figure 5. Approximate wind energy penetration in the 23 countries with the greatest installed wind power capacity

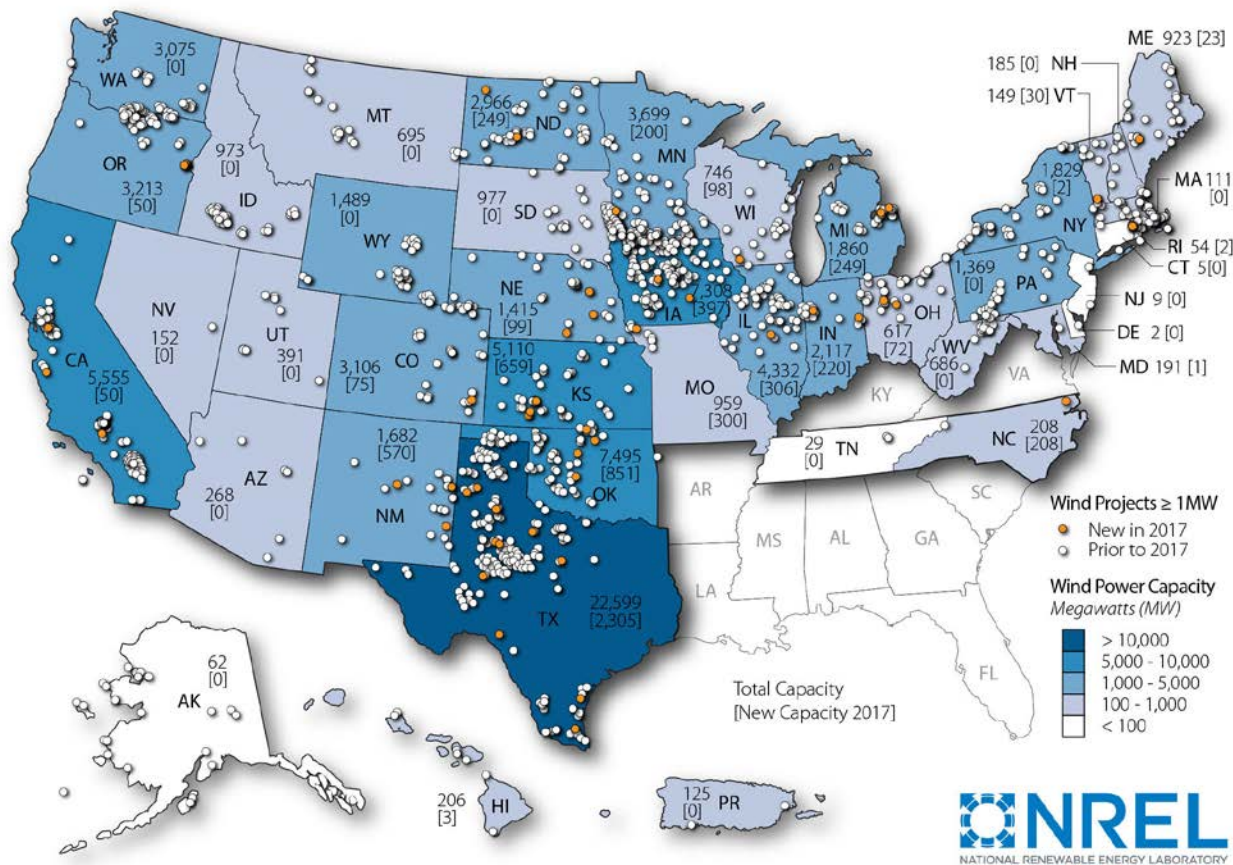
Using these approximations for the contribution of wind power to electricity consumption, end-of-2017 installed wind power is estimated to be able to supply the equivalent of 48% of Denmark’s electricity demand, and roughly 30% of electricity demand both in Ireland and Portugal. In the United States, cumulative wind

power capacity installed at the end of 2017 is estimated, in an average year, to equate to 7% of the nation’s total electricity demand. On a global basis, wind energy’s contribution is estimated at approximately 5%.

Texas installed the most capacity in 2017 with 2,305 MW, while fourteen states exceeded 10% wind energy penetration as a fraction of total in-state generation

New utility-scale wind turbines were installed in 24 states in 2017. Texas once again installed the most new wind capacity of any state, adding 2,305 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity—included Oklahoma, Kansas, New Mexico, and Iowa.

On a cumulative basis, Texas remained the clear leader, with 22,599 MW installed at the end of 2017—three times as much as the next-highest state (Oklahoma, with 7,495 MW). In fact, Texas has more wind capacity than all but five countries. States distantly following Texas in cumulative installed capacity include Oklahoma, Iowa, California, and Kansas—all with more than 5,000 MW. Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2017, with 26 of these above 500 MW, 18 above 1,000 MW, 12 above 2,000 MW, and 10 above 3,000 MW.



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2017.

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

Some states have reached high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2017 divided by total in-state electricity generation and by in-state electricity sales in 2017. 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 36.9% of electricity generated in the state coming from wind, followed by Kansas, Oklahoma, South Dakota, and North Dakota. As a fraction of in-state sales, North Dakota is the leading state, with 58.3% of the electricity sold in the state being met by wind, followed by Kansas, Iowa, Oklahoma, and Wyoming. Fourteen states have achieved wind penetration levels of 10% or higher when expressed as a percentage of generation, whereas 15 states have reached this threshold when expressed as a percentage of sales.

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

Installed Capacity (MW)				2017 Wind Generation as a Percentage of:			
Annual (2017)		Cumulative (end of 2017)		In-State Generation		In-State Sales	
Texas	2,305	Texas	22,599	Iowa	36.9%	North Dakota	58.3%
Oklahoma	851	Oklahoma	7,495	Kansas	36.0%	Kansas	47.1%
Kansas	659	Iowa	7,308	Oklahoma	31.9%	Iowa	43.0%
New Mexico	570	California	5,555	South Dakota	30.1%	Oklahoma	40.9%
Iowa	397	Kansas	5,110	North Dakota	26.8%	Wyoming	26.3%
Illinois	306	Illinois	4,332	Maine	19.9%	South Dakota	25.7%
Missouri	300	Minnesota	3,699	Minnesota	18.2%	New Mexico	19.7%
North Dakota	249	Oregon	3,213	Colorado	17.6%	Maine	19.5%
Michigan	249	Colorado	3,106	Idaho	15.4%	Colorado	17.5%
Indiana	220	Washington	3,075	Texas	14.8%	Nebraska	17.4%
North Carolina	208	North Dakota	2,996	Nebraska	14.6%	Texas	17.3%
Minnesota	200	Indiana	2,117	New Mexico	13.5%	Minnesota	16.7%
Nebraska	99	Michigan	1,860	Vermont	13.4%	Montana	14.8%
Wisconsin	98	New York	1,829	Oregon	11.1%	Oregon	13.5%
Colorado	75	New Mexico	1,682	Wyoming	9.4%	Idaho	10.4%
Ohio	72	Wyoming	1,489	Montana	7.6%	Illinois	8.3%
Oregon	50	Nebraska	1,415	California	6.8%	Washington	8.3%
California	50	Pennsylvania	1,369	Hawaii	6.5%	Hawaii	6.9%
Vermont	30	South Dakota	977	Washington	6.5%	California	5.5%
Maine	23	Idaho	973	Illinois	6.2%	Vermont	5.2%
Rest of U.S.	7	Rest of U.S.	6,774	Rest of U.S.	1.1%	Rest of U.S.	1.2%
TOTAL	7,017	TOTAL	88,973	TOTAL	6.3%	TOTAL	6.9%

Note: Based on 2017 wind and total generation and retail sales by state from EIA's Electric Power Monthly.

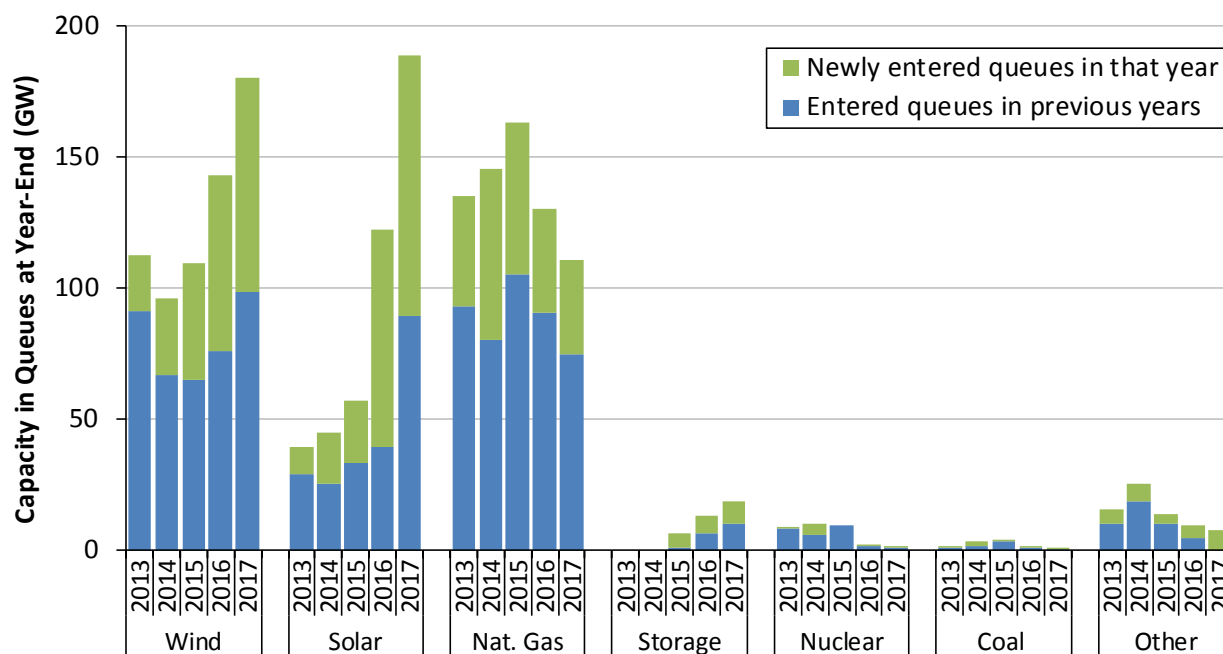
Sources: AWEA WindIQ, EIA

Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2017, wind penetration (expressed as a percentage of load) was 23.2% in the Southwest Power Pool (SPP), 17.4% in the Electric Reliability Council of Texas (ERCOT), 7.7% in the Midcontinent Independent System Operator (MISO), 6.0% in the California Independent System Operator (CAISO), 2.7% in the New York Independent System Operator (NYISO), 2.7% in the PJM Interconnection (PJM), and 2.6% in ISO New England (ISO-NE).

A record level of wind power capacity entered transmission interconnection queues in 2017; solar and storage also reached new highs in 2017

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 7 provides this information over the last five years for wind power and other resources aggregated across 35 different interconnection queues administered by independent system operators (ISOs), regional transmission

organizations (RTOs), and utilities.¹⁴ These data should be interpreted with caution: 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 (often, fewer than 25% of projects are subsequently built).



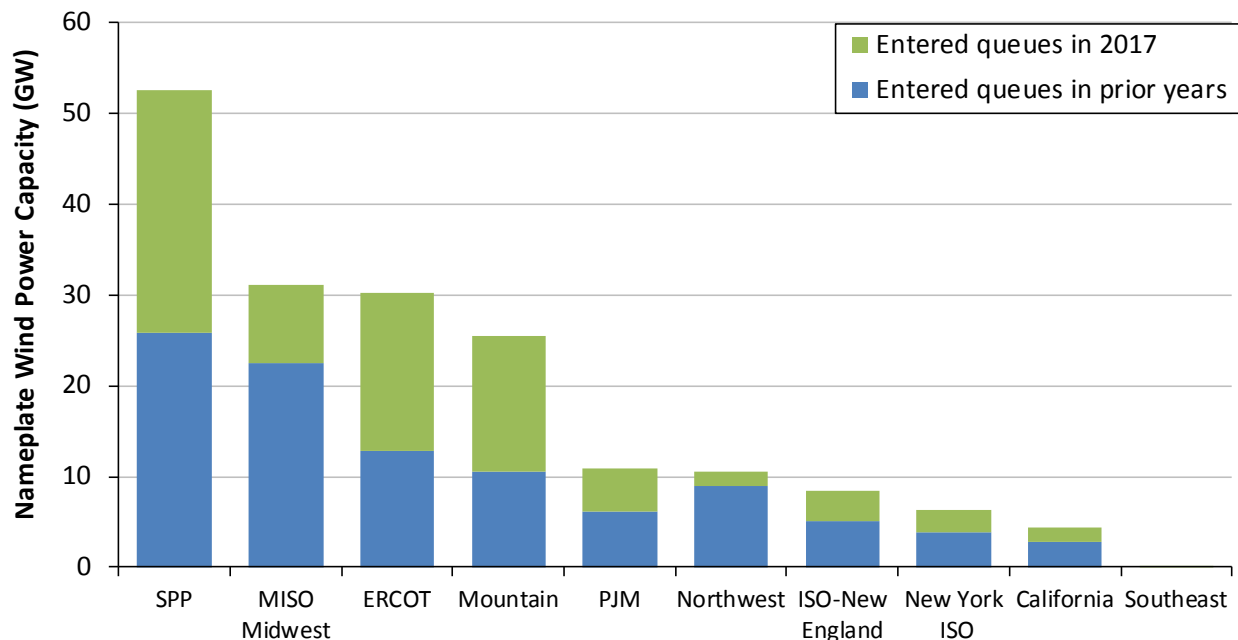
Source: Exeter Associates review of interconnection queues

Figure 7. Generation capacity in 35 selected interconnection queues from 2013 to 2017, by resource type

Even with this important caveat, the amount of wind capacity in the nation’s interconnection queues still provides at least some indication of the amount of planned development. At the end of 2017, there were 180 GW of wind power capacity in the interconnection queues reviewed for this report—a sizable increase from the 143 GW in the same queues just one year earlier and more than at any point since the end of 2011. In fact, a record level of wind power capacity entered interconnection queues in 2017 (at least since 2009, when Berkeley Lab started collecting queue data), 81 GW in total, exceeding the previous record of 67 GW in 2009. Wind was not the only technology to reach a new record in 2017, however, as solar additions outpaced wind. Storage additions have also rapidly increased in recent years. Wind represented 36% of all capacity in the sampled queues, compared to 37% for solar and 22% for natural gas.

The wind capacity in the interconnection queues is spread across the United States, as shown in Figure 8, with the largest amounts in SPP (29%), Midwest (17%), ERCOT (17%), and Mountain region (14%). Smaller amounts are found in PJM (6%), Northwest (6%), ISO-NE (5%), NYISO (4%), California (2%), and the Southeast (0.1%). The SPP, ERCOT, and Mountain regions experienced especially large annual additions in 2017.

¹⁴ 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 25 other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of over 80% of the U.S. total. Figures 7 and 8 only include projects that were active in the queue at the end of 2017 but that had not yet been built; suspended projects are not included.



Source: Exeter Associates review of interconnection queues

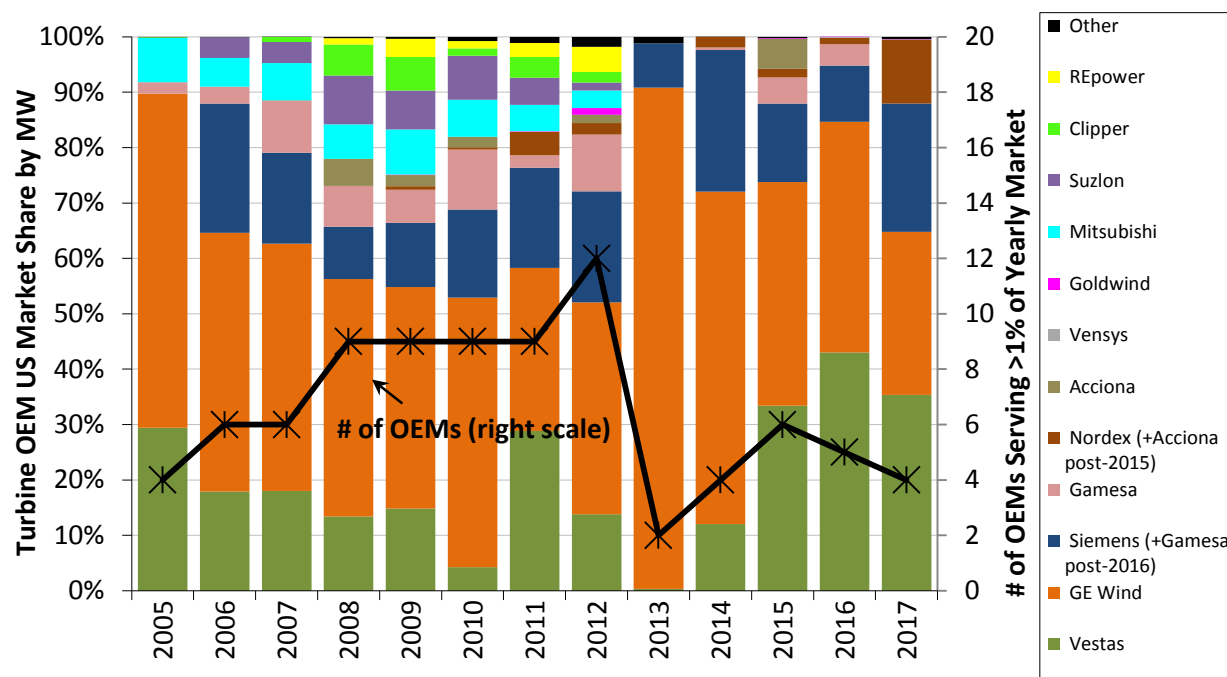
Figure 8. Wind power capacity in 35 selected interconnection queues, by region

As a measure of the near-term development pipeline, ABB (2018) estimates that, as of June 2018, approximately 40 GW of wind power capacity could be characterized in one of three ways: (a) under construction or in site preparation (12 GW); (b) in development and permitted (14 GW); or (c) in development with a pending permit and/or regulatory applications (14 GW). These totals are approximately 8 GW higher than at the same time last year. AWEA (2018b) reports that more than 33 GW of wind power capacity was under construction or at an advanced stage of development at the end of the first quarter of 2018. EIA (2017b) observed over 15 GW of planned additions for 2018 and 2019.

3 Industry Trends

Vestas, GE, and Siemens Gamesa captured 88% of the U.S. wind power market in 2017

Of the 7,017 MW of wind installed in 2017, Vestas supplied 35% (2,481 MW), with GE Wind coming in second (2,066 MW, 29% market share), followed more distantly by Siemens Gamesa Renewable Energy (SGRE, 1,625 MW, 23% market share) (Figure 9).¹⁵ Other suppliers included Nordex (806 MW), Haizhuang Windpower (28 MW), Goldwind (6 MW), and Vensys (3 MW).



Source: AWEA WindIQ

Figure 9. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2017

The black line in Figure 9 shows the number of turbine manufacturers serving more than 1% (by capacity) of the U.S. market in each year. As shown, the base of turbine suppliers expanded from just four original equipment manufacturers (OEMs) in 2005 to nine from 2008 to 2011 and twelve in 2012. Since 2012, however, the U.S. turbine market has been dominated by just a handful of OEMs—a trend that may continue to be supported in the future due to consolidation among OEMs. For example, the Nordex/Acciona merger took effect in April 2016 (in Figure 9, their combined operations are referred to solely as Nordex starting in 2016), while Siemens Wind Power and Gamesa consolidated their operations in April 2017 (and are combined under Siemens starting in 2017).

According to BNEF (2018a), Vestas was the leading supplier of land-based turbines worldwide in 2017, followed by SGRE, Goldwind, and GE. On a worldwide basis, Chinese turbine manufacturers continued to occupy positions of prominence, with four of the top ten spots in the ranking. To date, however, the growth of Chinese turbine manufacturers has been primarily based on sales to the Chinese market. GE is the only U.S.-owned utility-scale turbine manufacturer playing a role in the global supply of large wind turbines.

¹⁵ Market share is reported in MW terms and is based on project installations in the year in question.

Some manufacturers increased the size of their U.S. workforce in 2017 or otherwise expanded their existing facilities, but expectations for significant long-term supply-chain expansion have become less optimistic

As wind power capacity in the United States has grown, foreign and domestic turbine equipment manufacturers have localized and expanded operations in the United States. Yet, the wind industry’s domestic supply chain continues to deal with conflicting pressures: a surge in near-term expected growth from new installations and partial repowering, but also strong competitive pressures and expected reduced demand over time as the PTC is phased out. As a result, though some manufacturers increased the size of their U.S. workforce in 2017, market expectations for significant supply-chain expansion are less optimistic.

Figure 10 presents a non-exhaustive list of nearly 150 wind turbine and component manufacturing and assembly facilities operating in the United States at the end of 2017, focusing on the utility-scale wind market.¹⁶ Figure 11 segments those facilities by the type of component they primarily supply.

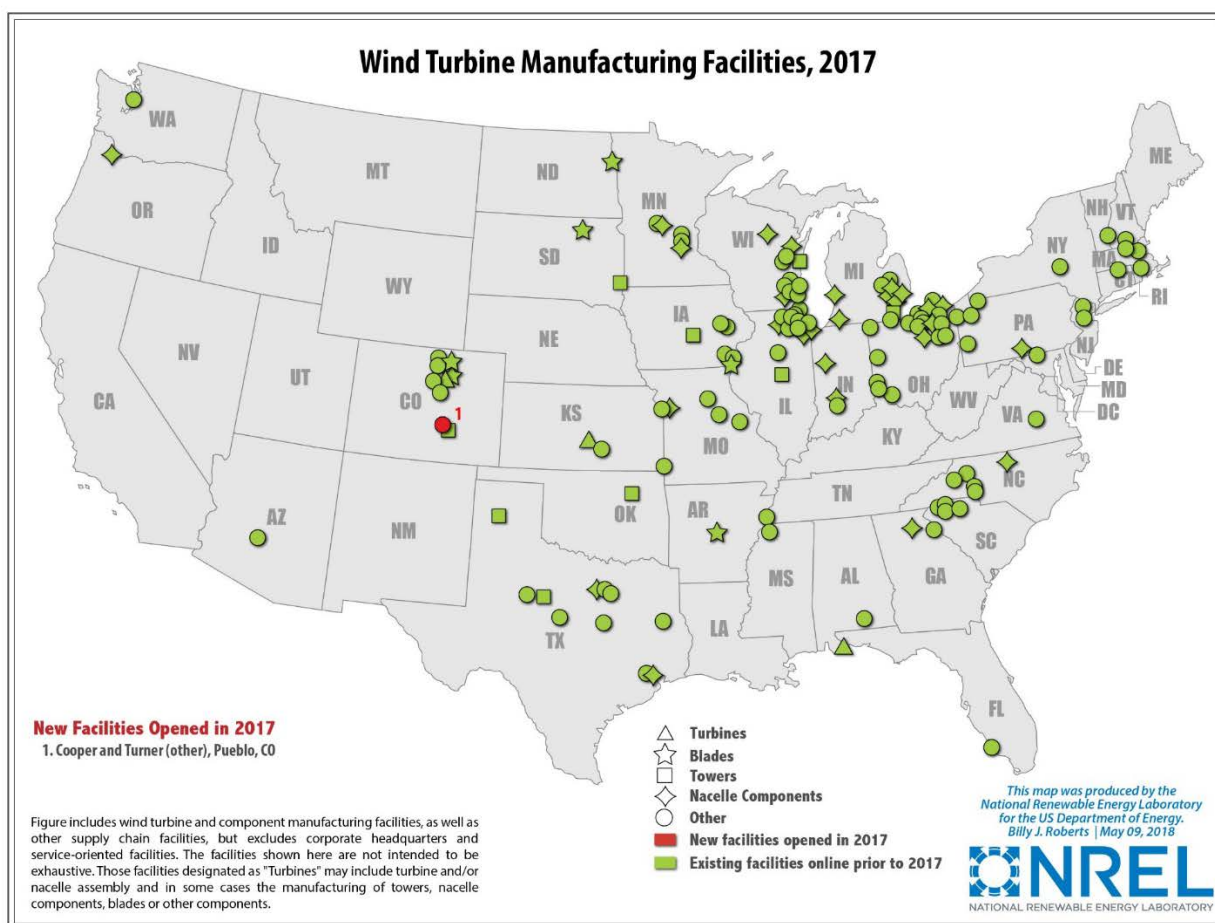


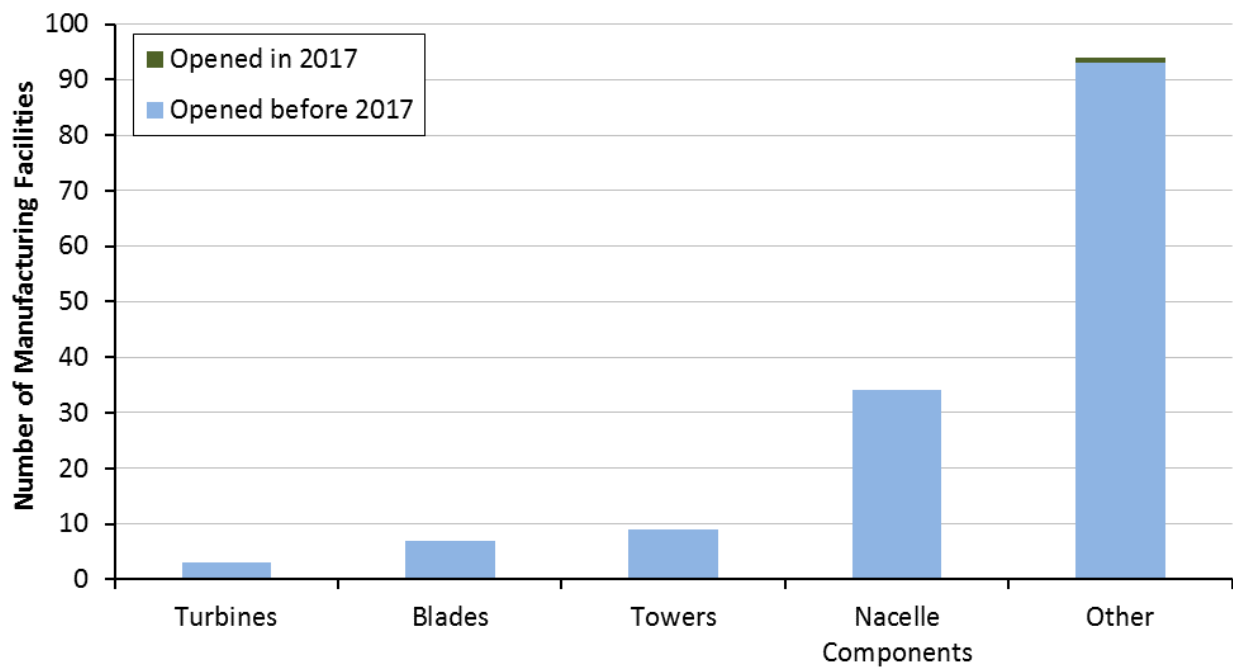
Figure 10. Location of existing and new turbine and component manufacturing facilities

One new wind-related manufacturing facility opened in 2017: Cooper and Turner, a precision steel stud bolt manufacturer located in Pueblo, Colorado. At the same time, at least three existing wind turbine or component

¹⁶ The data on manufacturing facilities presented here differ from those presented in AWEA (2018a) due, in part, to methodological differences. For example, AWEA includes data on a large number of smaller component suppliers that are not included in this report; the figure presented here also does not include research and development and logistics centers, or material suppliers. As a result, AWEA (2018a) reports a much larger number of wind-related manufacturing facilities.

manufacturing facilities were consolidated, closed, or stopped serving the industry in 2017 (Pacific Crest, Trinity Structural Towers, and Owens Corning). Additionally, in late 2017 MFG Wind announced that it would be closing its blade manufacturing facility in Aberdeen, South Dakota, though the company has since adjusted the timeframe for the closure due to a new order that will keep the facility open through the third quarter of 2018.

Notwithstanding the recent supply chain consolidation and slow additions of new facilities, there remain a large number of domestic manufacturing facilities. Additionally, multiple manufacturers either expanded their workforce in 2017 to meet demand (e.g., Vestas, Timken), began or completed expansions of existing facilities (e.g., LM Wind Power, SGRE), or leased new facilities to improve product distribution (e.g., Vestas—railcar fleet operations).



Note: Manufacturing facilities that produce multiple components are included in multiple bars. "Other" includes facilities that produce items such as: enclosures, power converters, slip-rings, inverters, electrical components, tower internals, climbing devices, couplings, castings, rotor hubs, plates, walkways, doors, bearing cages, fasteners, bolts, magnetics, safety rings, struts, clamps, transmission housings, embed rings, electrical cable systems, yaw/pitch control systems, bases, generator plates, slew bearings, flanges, anemometers, and template rings.

Source: National Renewable Energy Laboratory

Figure 11. Number of wind turbine and component manufacturing facilities in the United States

Figure 10 also highlights the spread of turbine and component manufacturing facilities across the country. Many manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers (OEMs). However, even states that are relatively far from major wind markets have manufacturing facilities. For example, most states in the Southeast have wind manufacturing facilities despite the limited number of wind projects in that region. Workforce considerations, transportation costs, and state and local incentives are among the factors that typically drive location decisions.

In 2010, 9 out of the 11 wind turbine OEMs with the largest shares of the U.S. market owned at least one domestic manufacturing facility (Acciona, Clipper, DeWind, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas). Since that time, a number of these facilities have closed, reflecting the increased concentration of the U.S. wind industry among the top OEMs, long-term demand uncertainty, mergers among OEMs, and a desire to consolidate production at centralized facilities overseas to gain economies of scale. For example, Alstom’s Amarillo, Texas facility was idled when the GE/Alstom merger was announced in 2014. Similarly, the

Nordex/Acciona merger that was completed in 2016 has left the future of the Acciona facility in West Branch, Iowa in question. For now, manufacturing at the plant is currently idled, though the facility still houses sales, office, and wind farm maintenance personnel.

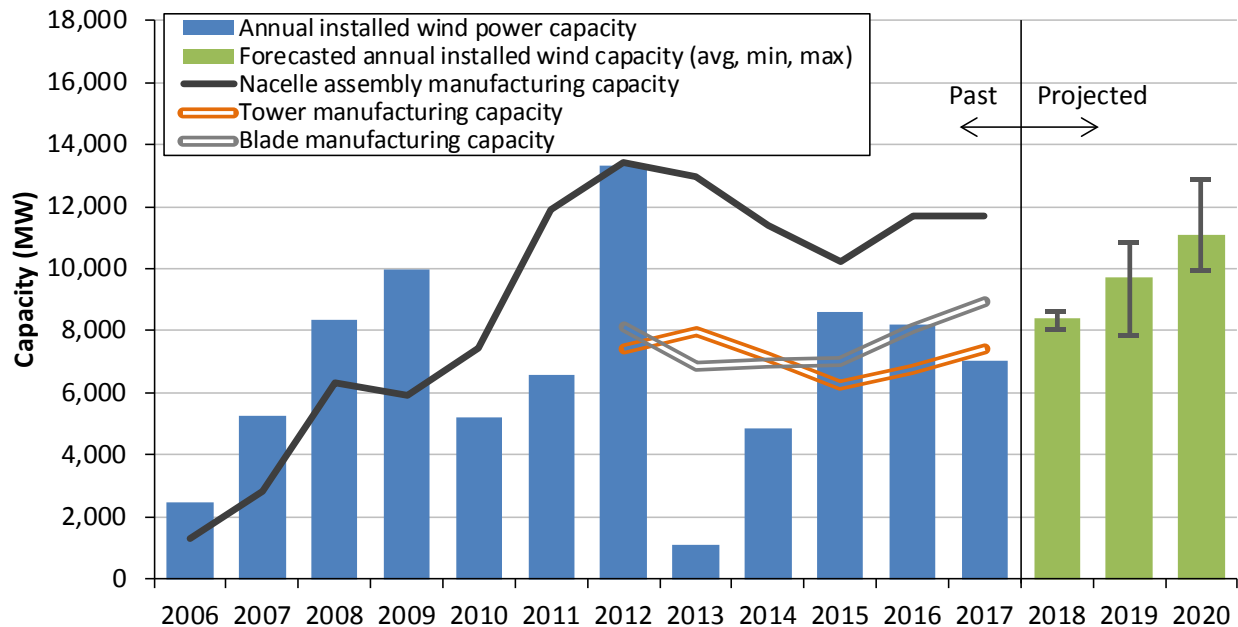
The merger between Siemens and Gamesa was finalized in April 2017, further consolidating the global wind turbine market. Now known as SGRE, the newly merged company announced layoffs in 2017 and early 2018 at both of its U.S. facilities (located in Hutchinson, KS and Fort Madison, IA). GE's purchase of blade manufacturer LM Wind Power was also finalized in April 2017. LM Wind Power will continue to supply blades to other turbine manufacturers while operating as an individual unit within GE Renewable Energy. With two locations in the United States (Little Rock, AR and Grand Forks, ND), the move is expected to strengthen GE's presence in the country.

Even with a consolidated market, each of the three major OEMs that serve the U.S. wind industry—GE, Vestas, and SGRE—had one or more operating manufacturing facilities in the country at the end of 2017. In contrast, 13 years ago in 2004, there was only one active OEM (GE) assembling nacelles domestically.¹⁷

An additional note of interest from 2017 was the entry of new composite producers into the U.S. market. Though not tracked within the wind turbine and component manufacturing and assembly facilities dataset otherwise reported here, composites are used in the manufacturing of some wind turbine components. A new China Hengshi fiberglass fabric facility in Columbia, South Carolina was announced, and a Mitsubishi Rayon carbon fiber facility in Evanston, Wyoming was newly acquired and transitioned to wind. Both of these facilities will supply composite materials for U.S. wind energy component manufacturers.

In aggregate, domestic turbine nacelle assembly capability—defined here as the maximum annual nacelle assembly capability of U.S. plants if all were operating at full utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, and stood at 11.7 GW in 2017 (Figure 12; AWEA 2018a). In addition, AWEA (2018a) reports that U.S. manufacturing facilities have the capability to produce more than 11,500 individual blades (~8.9 GW if using average sized turbines) and 3,200 towers (~7.4 GW) annually. Figure 12 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 blades, towers, and nacelle assembly is reasonably well balanced against historical market demand, though growth in domestic capability or additional imports may be necessary to fulfill the total anticipated demand of blades and towers in the coming three years, especially considering the expected continued growth in partial wind project repowering. Given the anticipated decline in wind power capacity additions as the PTC phases out, however, domestic manufacturing capability may exceed supply needs starting in 2021.

¹⁷ Nacelle assembly is defined here 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.



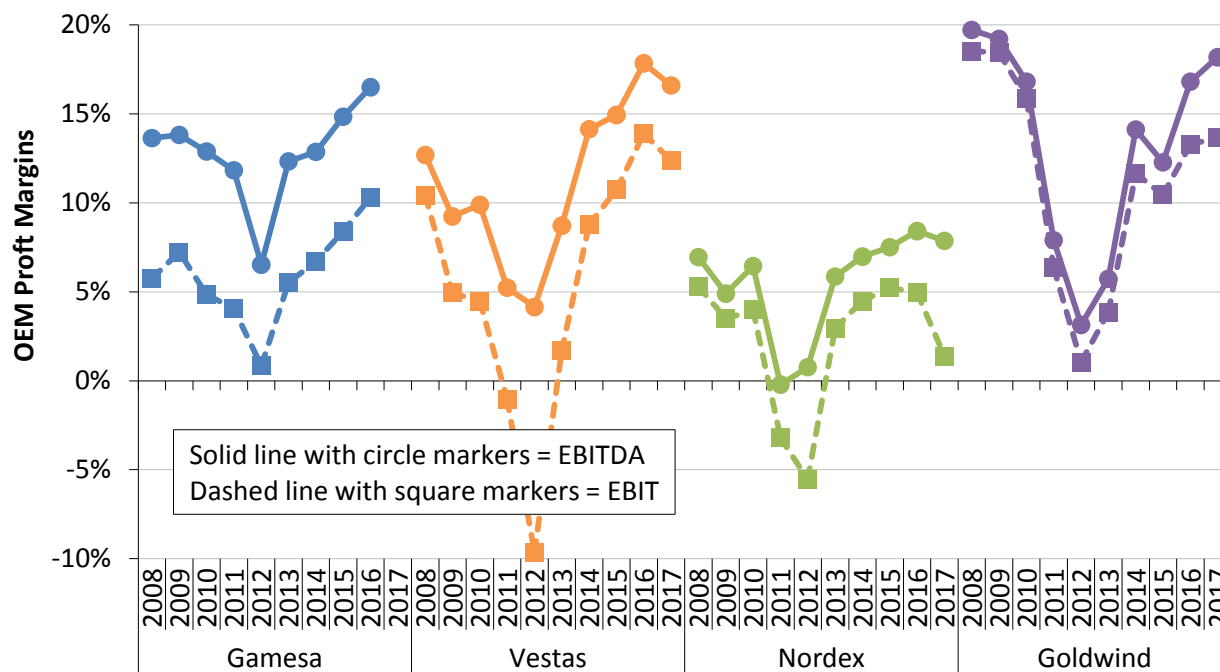
Note: Data on blade and tower manufacturing capacity are only available from 2012 to 2017

Sources: AWEA WindIQ, BNEF, IHS, Navigant, MAKE, Berkeley Lab

Figure 12. Domestic wind manufacturing capability vs. U.S. wind power capacity installations

Fierce competition throughout the supply chain has caused many manufacturers to execute cost-cutting measures in recent years. As a result of these cost savings, coupled with strong demand, the profitability of turbine OEMs has generally been strong (10% plus margins) in recent years (with the exception of Nordex), compared to near break-even in the 2011 through 2013 timeframe (Figure 13).¹⁸ Moreover, with recent and near-term expected growth in U.S. wind installations, wind-related job totals in the United States reached a new all-time high in 2017, at 105,500 full-time workers—a small increase over 2016 (AWEA 2018a). These 105,500 jobs include, among others, those in construction, development and transportation (~43,800), manufacturing and supply chain (~23,000), and operations and maintenance (~18,700).

¹⁸ Figure 13 only reports data for those OEMs that are “pure-play” wind turbine manufacturers. For example, although it is one of the largest turbine suppliers in the U.S. market, GE is not included because it is a multi-national conglomerate that does not report segmented financial data for its wind turbine division. Siemens is omitted for similar reasons, though in the future will be reported in conjunction with Gamesa as Siemens Gamesa Renewable Energy (SGRE) following the merger of the two in April 2017 (2017 margins are omitted due to complications surrounding the mid-year merger). Figure 13 depicts both EBIT (i.e., “earnings before interest and taxes,” also referred to as “operating profit”) and EBITDA (i.e., “earnings before interest, taxes, depreciation, and amortization”) margins.



Note: EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization; EBIT = Earnings Before Interest and Taxes. Gamesa's 2017 margins are not displayed due to complications surrounding mid-year merger with Siemens.

Sources: OEM annual reports and financial statements

Figure 13. Turbine OEM global profitability over time

Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports

The U.S. wind sector is reliant on imports of wind equipment, though the level of dependence varies by component. Some components have a relatively high domestic share, whereas others remain largely imported. These trends are revealed, in part, by data on wind equipment trade from the U.S. Department of Commerce.¹⁹

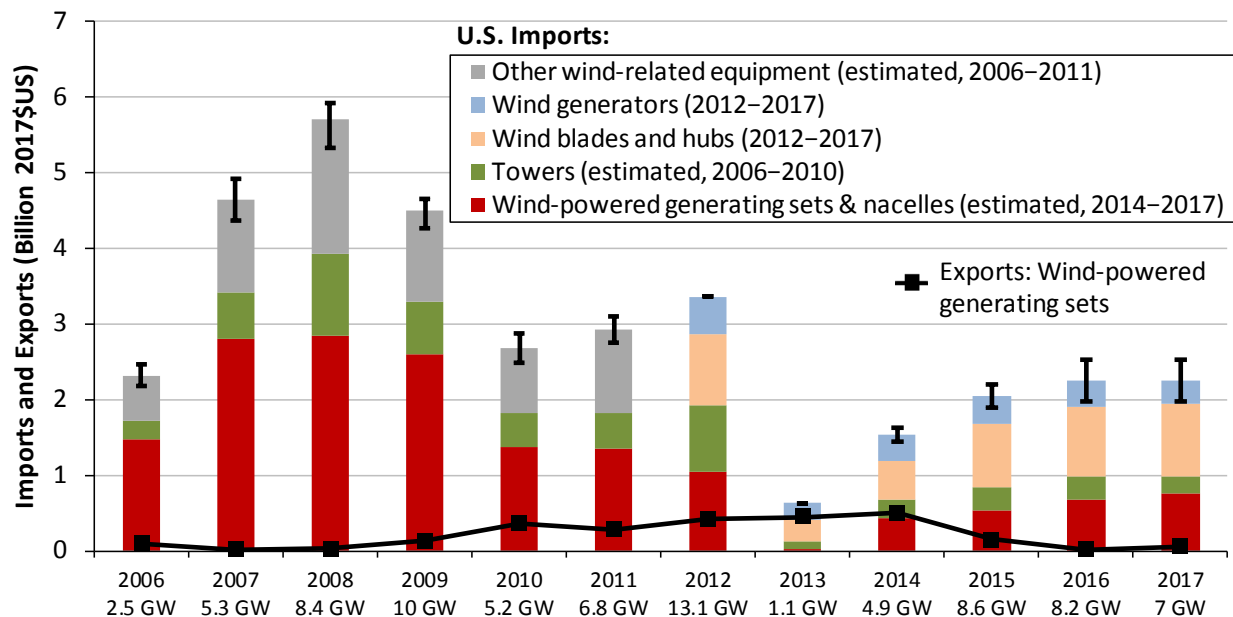
Figure 14 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. Specifically, the figure shows imports of wind-powered generating sets and nacelles (i.e., nacelles with blades, nacelles without blades, and, in some 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.²⁰ 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.

Import estimates should be viewed with particular caution because the underlying data used to produce Figure 14 are based on trade categories that are not all exclusive to wind. Some of the import estimates shown in Figure 14 therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. The error bars in Figure 14 account for uncertainty in these assumed fractions. In 2012 and 2013, all trade categories shown were either specific to or largely restricted to wind power, and therefore no error bars are shown. After 2013, only nacelles (when shipped alone) are included in a trade

¹⁹ See the Appendix for further details on data sources and methods used in this section, including the specific trade codes considered.

²⁰ 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.

category that is not largely exclusive to wind²¹, and thus the error bars shown for 2014 through 2017 only reflect the uncertainty in nacelle imports (and, in some cases, other turbine components internal to the nacelle shipped under this trade category). More generally, as noted earlier, Figure 14 does not show comprehensive data on the import of all wind equipment, as not all such equipment is clearly identified in trade categories. The impact of this omission on import and domestic content is discussed later.



Source: Berkeley Lab analysis of data from USITC DataWeb: <http://dataweb.usitc.gov>

Figure 14. Estimated imports of wind-powered generating sets, nacelles, towers, generators, and blades and hubs, as well as exports of wind-powered generating sets

As shown, the estimated imports of tracked wind-related equipment into the United States increased substantially 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 2017, imports of wind-related turbine equipment generally followed U.S. wind installation trends, bouncing back from the low of 2013. These overall trends are driven by a combination of factors: changes in the share of domestically manufactured wind turbines and components (versus imports), changes in the annual rate of wind installations (shown textually on the x-axis of Figure 14), and changes in wind turbine prices. Because imports of wind turbine component parts occur in additional, broad trade categories different from those included in Figure 14, the data presented here understate the aggregate amount of wind equipment imports.

Figure 14 also shows that exports of wind-powered generating sets from the United States generally increased through 2014, rising from just \$17 million in 2007 to \$498 million in 2014. Since then, however, there has been a steep decline in exports, falling to just \$17 million in 2016 before rising to \$60 million in 2017.²² The largest destination markets for these exports over the entire 2006–2017 timeframe were Canada (59%) and Brazil (27%); the destination of exports in 2017 was dominated by Canada (75%). U.S. exports of “towers and lattice masts” in 2017 totaled an additional \$39 million (down from a peak of \$175 million in 2012), with 17% of these exports going to Mexico and an additional 17% to Canada. The trade data for tower exports do not differentiate between tubular towers (primarily used in wind power applications) and other types of towers,

²¹ The trade code for tower imports is also not entirely 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.

²² Since 2014, some nacelles could be exported under a different trade category that is not exclusive to wind equipment, and so is not reported here. As such, trends in exports just of wind-power generating sets may be skewed low since 2014.

unlike the classification of tower imports from 2011 to 2017, which does differentiate between tubular and other types of towers. Although some of the tower exports are wind-related, the exact proportion is not known. Other wind-turbine component exports are not reported because such exports are likely a small and/or uncertain fraction of broader trade category totals. Nonetheless, it is clear that the United States has been and remains a net importer of wind turbine equipment.

Figure 15 shows the total value of selected, tracked wind-specific imports to the United States in 2017, by country of origin, as well as the main “districts of entry”²³: 50% of the import value in 2017 came from Asia (led by China), 36% from Europe (led by Spain), and 14% from the Americas (led by Mexico). The principal districts of entry were Houston-Galveston, TX (36%), Port Arthur, TX (13%), and Tampa, FL (13%).

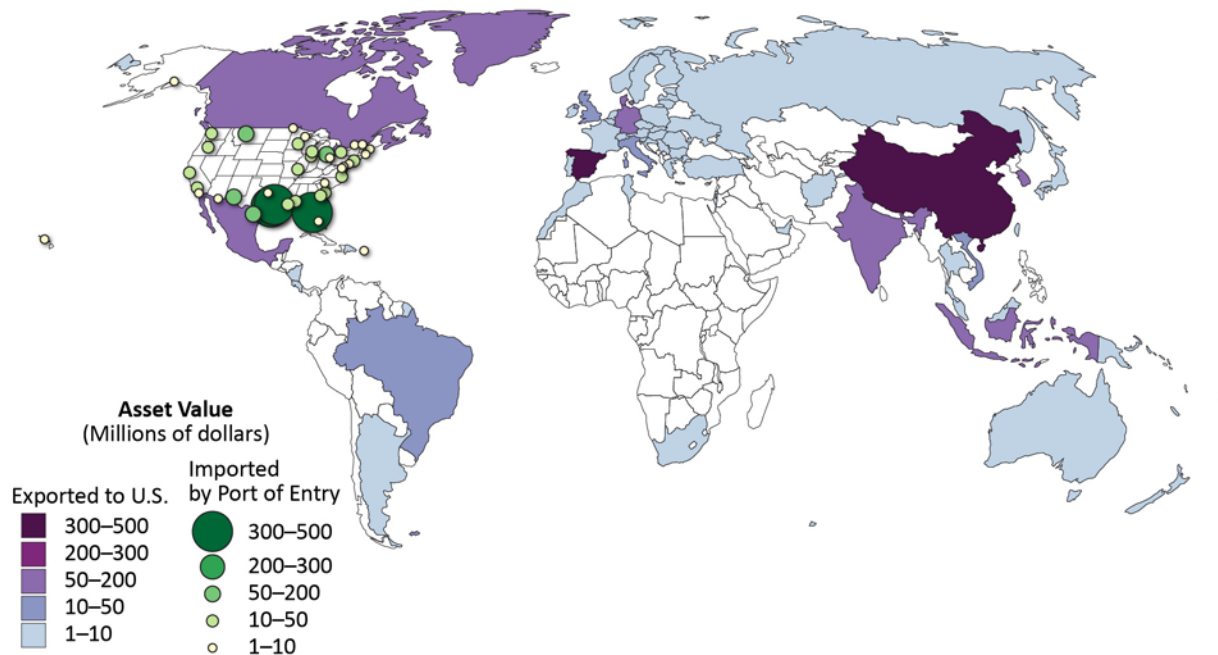
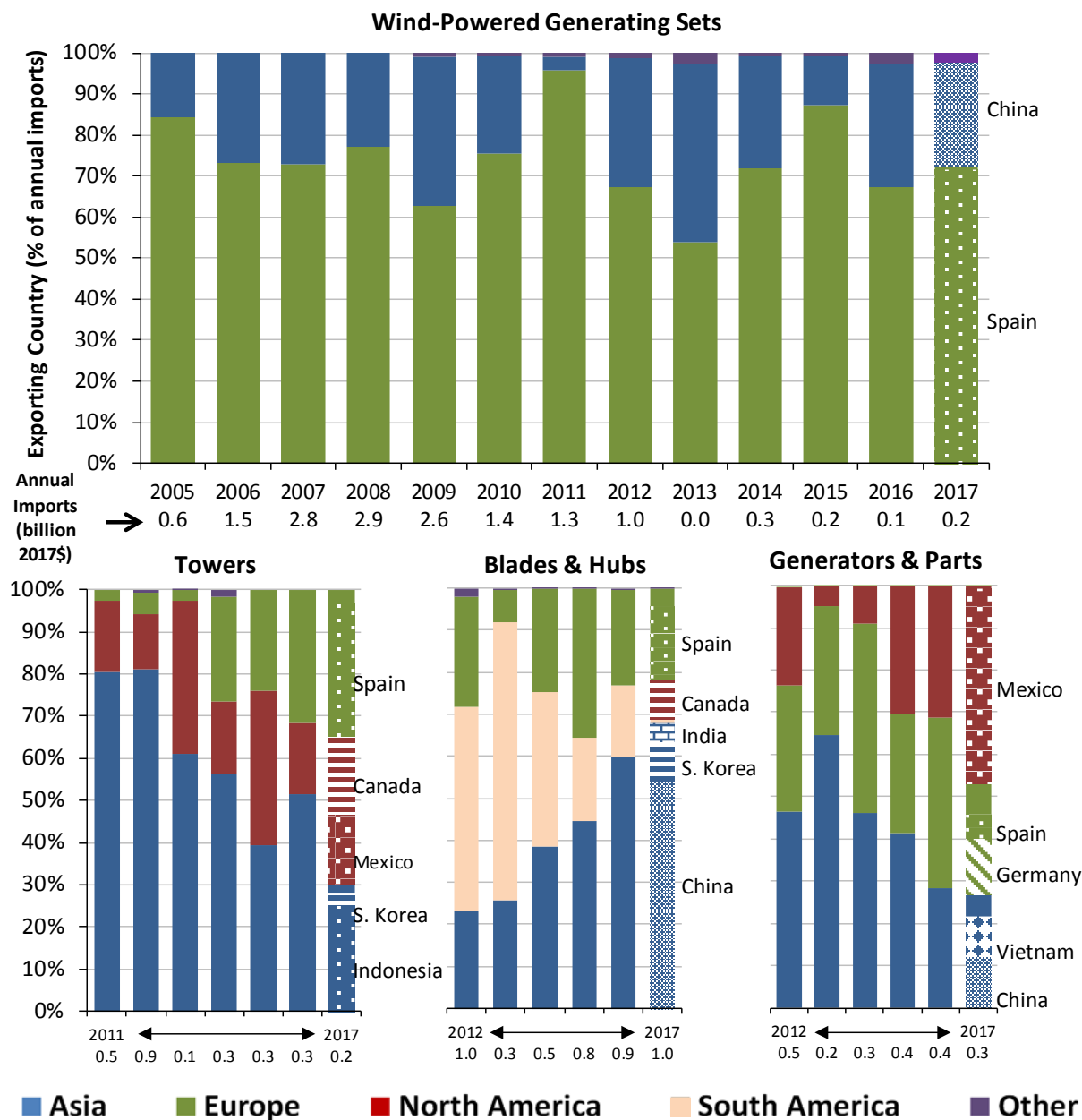


Figure 15. Summary map of tracked wind-specific imports in 2017: countries of origin and U.S. districts of entry

Looking behind the import data in more detail and focusing on those trade codes that are largely exclusive to wind equipment, Figure 16 shows a number of trends over time in the origin of U.S. imports of wind-powered generating sets, tubular towers, wind blades and hubs, and wind generators and parts.

²³ The trade categories included here are all of the wind-specific import categories for 2017, inclusive of towers, which is believed to be primarily related to wind (see the Appendix for details), and so the 2017 total import volume considered in Figure 15 differs from that in Figure 14. As noted earlier, imports of many wind turbine component parts occur in broad trade categories not captured by those included in this analysis; additionally, in the case of nacelles without blades, the trade code is not exclusive to wind and so related imports are not included in Figure 15 (though they are included in Figure 14). As such, the data presented in Figure 15 understate the aggregate amount of wind equipment imports into the United States. Note also that “districts of entry,” as used here, refers to, in some cases, multiple points of entry located in the same geographic region; note also that goods may arrive at districts of entry by land, air, or sea.



Source: Berkeley Lab analysis of data from USITC DataWeb: <https://dataweb.usitc.gov/>

Figure 16. Origins of U.S. imports of selected wind turbine equipment

For wind-powered generating sets, the primary source markets from 2005 to 2017 have been Europe and, to a lesser extent, Asia, with leading countries often being those that have been home to the major international turbine manufacturers such as Denmark, Spain, Japan, India, and Italy. In 2017, imports of wind-powered generating sets were dominated by Spain and China, though the total import value was relatively low (at \$209 million).²⁴ The share of imports of tubular towers from Asia was over 80% in 2011 and 2012 (almost 50% was

²⁴ Since 2014, some nacelles could be imported under a different trade category that is not exclusive to wind equipment, and so are not reported in the figure. As such, trends in imports of wind-powered generating sets before 2014 might be expected to differ from those shown in 2014 and after.

from China), with much of the remainder from Canada and Mexico. From 2013 to 2017, not only did the total import value decline relative to earlier years, but there were almost no imports from China and Vietnam from 2013 to 2015—likely a result of the tariff measures that were imposed on wind tower manufacturers from these countries.²⁵ Tower imports in 2017 came from a mix of countries from Asia (principally Indonesia), Europe (principally Spain), and North America (Canada and Mexico). With regard to blades and hubs, Asia (principally China) has become the dominant source market, the European share has been relatively stable, and imports from the Americas have decreased over time. Finally, the import origins for wind-related generators and generator parts were distributed across a number of Asian, European, and North American countries; in recent years, the role of Asian imports has decreased, while North American imports have increased.

Because trade data do not track all imports of wind equipment, it is not possible to use those data to establish a clear overall distinction between imported and domestic content. The trade data also do not allow for a precise estimate of the domestic content of specific turbine components. Nonetheless, based on those data, Table 3 presents rough estimates of the domestic content for a subset of the major wind turbine components used in new (and repowered) U.S. wind power projects in 2017. As shown, domestic content is relatively strong for large, transportation-intensive components such as towers, blades and hubs, and nacelle assembly.

Table 3. Approximate Domestic Content of Major Components in 2017

Towers	Blades & Hubs	Nacelle Assembly
70–90%	50–70%	> 85% of nacelle assembly

These figures, however, understate the wind industry’s reliance on turbine and component imports. This is because significant wind-related imports occur under trade categories not captured in Table 3, including wind equipment (such as mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing).²⁶ For example, an interview-based approach to estimating domestic content that was conducted in 2012 revealed that domestic content was relatively high for blades, towers, nacelle assembly and nacelle covers at that time, supporting the results depicted in Table 3. However, the domestic content of most of the equipment internal to the nacelle—much of which is not tracked in wind-specific trade data—was considerably lower, often well below 20%.²⁷

The project finance environment remained strong in 2017

With plenty of ongoing activity related to the buildout of 100% PTC safe-harbored projects, along with an additional ~10 GW of projects that qualified for 80% of the PTC’s nominal value by year’s end, 2017 was yet another busy year for financiers. Given the four-year safe harbor window in which to bring PTC-qualified projects online, however, some of these 100%- and 80%-PTC projects may not achieve commercial operations until 2020 or 2021, respectively (see Table 4, later, for details on the PTC phase-out schedule).

According to AWEA (2018a), roughly \$6 billion in third-party tax equity was committed in 2017 to finance about 6 GW of new wind projects and partial repowerings. This total dollar amount is roughly on par with the amount of tax equity raised in each of the previous three years (2014–2016). Partnership flip structures²⁸

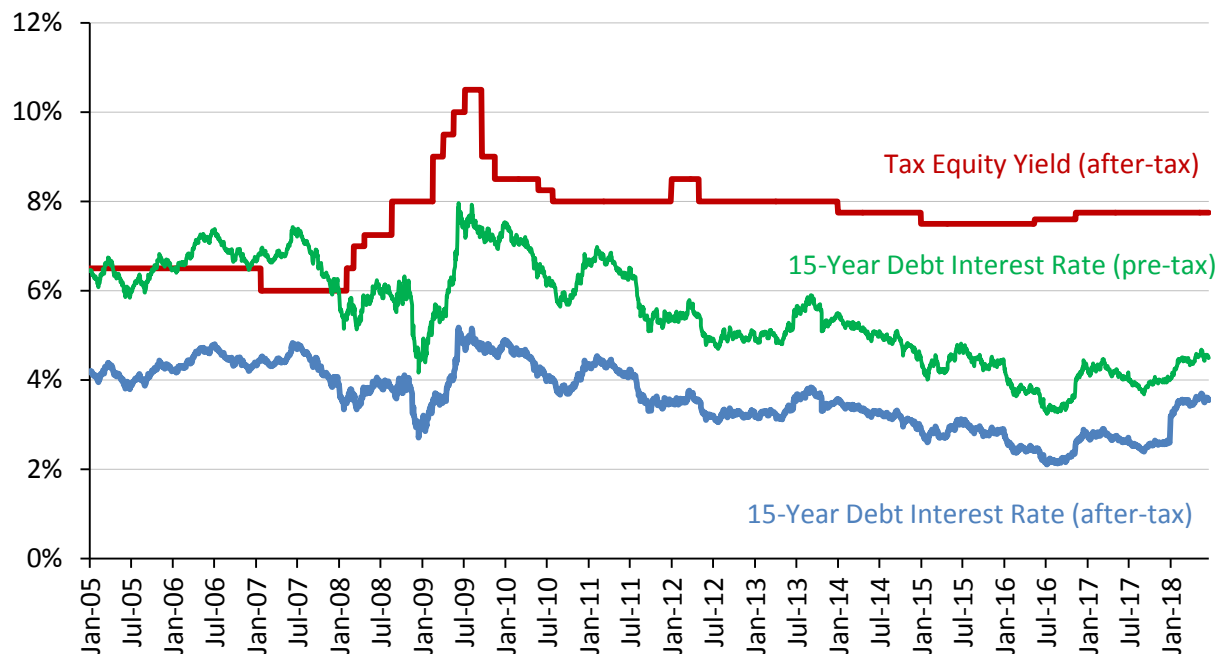
²⁵ In 2016, the Department of Commerce decided to reduce the anti-dumping duties to zero for a single company, which led to a large increase in tower imports from Vietnam in 2016. However, this company did not import towers from Vietnam in 2017.

²⁶ On the other hand, this analysis also assumes that all components imported into the United States are used for the domestic market and not used to assemble wind-powered generating sets that are exported from the United States. If this were not the case, the resulting domestic fraction would be slightly higher than that presented here.

²⁷ The interviews and analysis were conducted by GLWN, under contract to Berkeley Lab.

²⁸ A “partnership flip” is a project finance structure in which the developer or project sponsor partners with a third-party tax equity investor to jointly invest in and own part of the project. Initially, allocations of tax benefits are skewed heavily in favor the tax equity

remained the dominant tax equity vehicle, with indicative tax equity yields remaining just below 8% on an after-tax unlevered basis (Figure 17).



Sources: Intercontinental Exchange Benchmark Administration (<https://www.theice.com/iba>), BNEF (2017)

Figure 17. Cost of 15-year debt and tax equity for utility-scale wind projects over time

On the debt side, AWEA (2018a) reports that about 2.6 GW of new and existing wind capacity raised \$2.5 billion in project-level debt in 2017, a decrease from the \$3.4 billion raised in 2016. As they have in recent years, banks continued to focus more on shorter-duration loans (7–10 year mini-perms remained the norm²⁹), though an increasing number of banks are reportedly willing to lend for as long as 15 or even 18 years in some cases (Norton Rose Fulbright 2018). As shown in Figure 17, all-in interest rates on benchmark 15-year debt hovered around 4% through most of 2017, but have more recently moved a little higher in 2018. Short-term interest rates have also begun to rise, as the U.S. Federal Reserve Bank has ratcheted up the federal funds rate by 25 basis points on six separate occasions since mid-December of 2015 (after seven straight years of holding it at 0%). Although long-term interest rates are not directly linked to the Federal Reserve’s rate hikes to date, 3-month LIBOR (the base rate for project financings) does closely follow the Fed Funds rate, and 15-year swap rates have also independently been moving higher since mid-2017, pushing the all-in interest rate higher.

Finally, in late-December 2017, Congress passed (and the President signed into law) the Tax Cuts and Jobs Act, which contains a number of provisions with potential implications for wind project finance, including (but

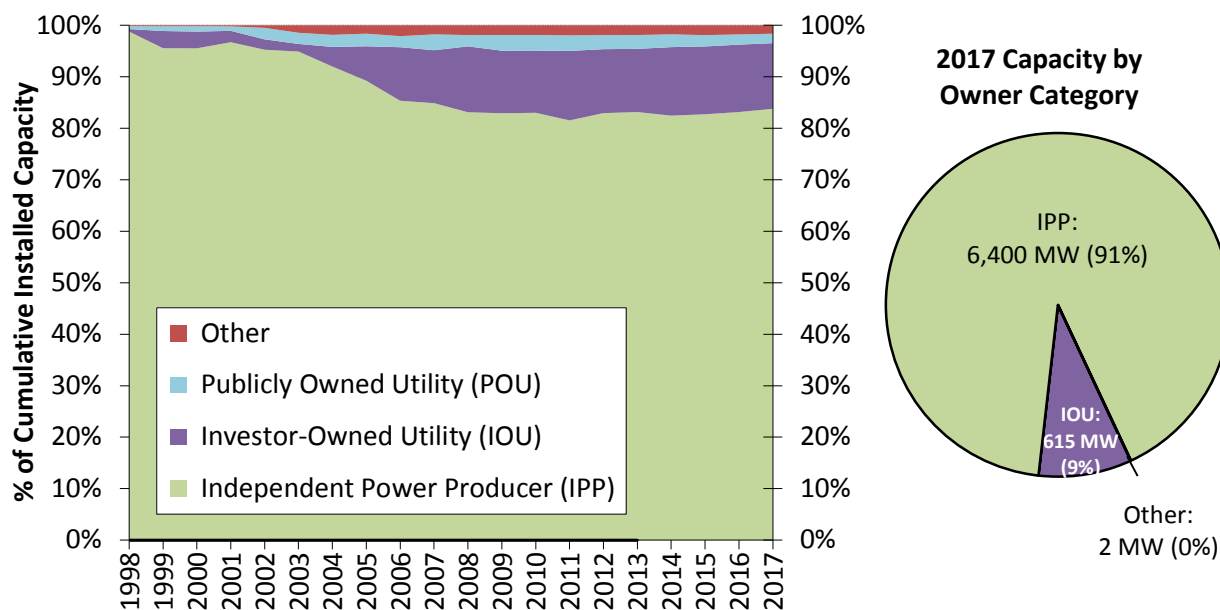
partner (which is able to efficiently monetize the tax benefits), but eventually “flip” in favor of the project sponsor partner once the tax benefits have been largely exhausted. Cash is also allocated between the partners, with one or more “flip” events, but in recent years has been increasingly directed towards the project sponsor to the extent possible, in order to support back leverage or dividend payments to YieldCo investors.

²⁹ A “mini-perm” is a relatively short-term (e.g., 7–10 years) loan that is sized based on a much longer tenor (e.g., 15–17 years) and therefore requires a balloon payment of the outstanding loan balance upon maturity. In practice, this balloon payment is often paid from the proceeds of refinancing the loan at that time. Thus, a ten-year mini-perm might provide the same amount of leverage as a 17-year fully amortizing loan but with refinancing risk at the end of ten years. In contrast, a 17-year fully amortizing loan would be repaid entirely through periodic principal and interest payments over the full tenor of the loan (i.e., no balloon payment required and no refinancing risk).

not limited to) a reduction in the corporate income tax rate (from 35% to 21%), the ability to fully expense (rather than depreciate) new and used equipment, restrictions on interest deductions, and a new Base Erosion Anti-abuse Tax (BEAT). Initial concerns revolved primarily around the ongoing availability of tax equity in particular, given that the lower corporate tax rate will reduce the tax liability of tax equity investors and the BEAT could prevent certain investors from being able to fully use the PTC (Norton Rose Fulbright 2018).³⁰ After a brief lull in early 2018, as investors absorbed the new legislation and assessed its impacts on their operations, however, the general consensus appears to be that the overall impact will be rather benign, and the market should continue to have ready access to investment capital over the next few years (CohnReznick Capital 2018).

Independent power producers own the vast majority of wind assets built in 2017

Independent power producers (IPPs) own 6,400 MW or 91% of the 7,017 MW of new wind capacity installed in the United States in 2017 (Figure 18). Investor-owned utilities (IOUs)—namely MidAmerican (334 MW) and Westar (281 MW)—installed a total of 615 MW (9%). Publicly owned utilities (POUs) do not own any of the new wind power capacity brought online in 2017. Finally, 2 MW of capacity falls into the “other” category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers).³¹ Of the cumulative installed wind power capacity at the end of 2017, IPPs own 84% and utilities own 15% (13% IOU and 2% POU), with the remaining 2% falling into the “other” category. Utility ownership should increase in the coming years as many utilities have recently announced plans to build and own new wind assets.



Source: Berkeley Lab estimates based on AWEA WindIQ

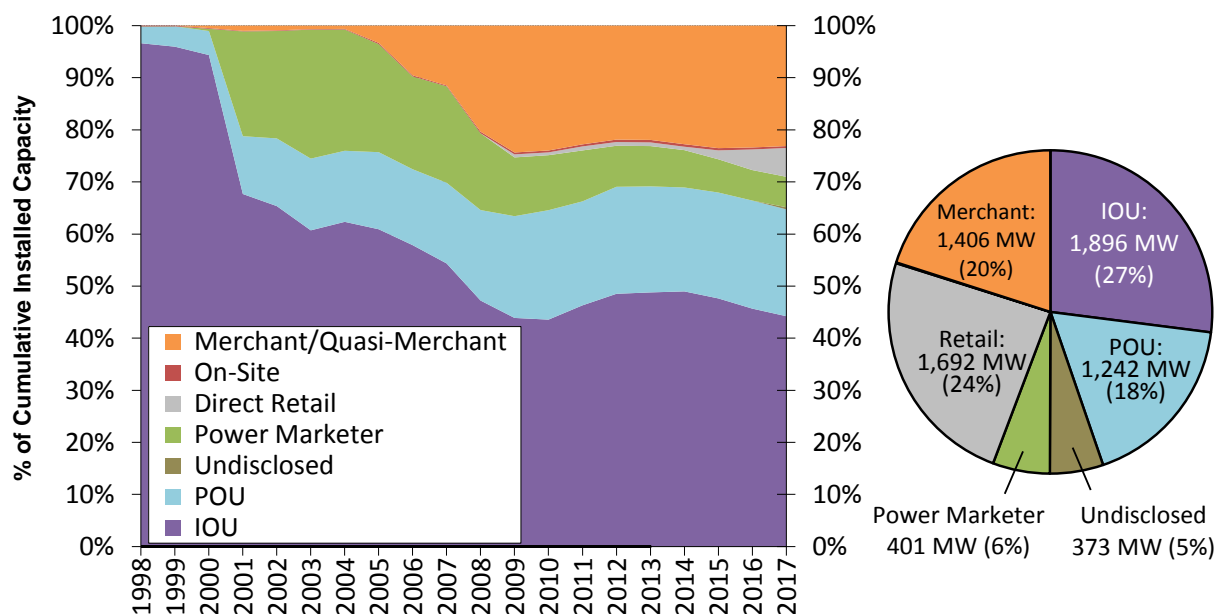
Figure 18. Cumulative and 2017 wind power capacity categorized by owner type

³⁰ The lower corporate tax rate also reduces the value of depreciation (or expensing) and interest deductions (and under the new law, interest deductions may be further limited if a company's net interest expense exceeds 30% of its adjusted taxable income). For example, in Figure 17, the notable spike in the after-tax 15-year interest rate on January 1, 2018 is a reflection of the overnight reduction in the corporate income tax rate from 35% to 21%.

³¹ 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. According to AWEA (2018a), 48.5 MW (0.7%) of 2017 wind capacity additions qualified as community wind projects.

Long-term contracted sales to utilities remained the most common off-take arrangement, but direct retail sales and merchant off-take arrangements were both significant

Electric utilities continued to be the largest off-takers of wind power in 2017 (i.e., ‘users’ of wind to serve load) (Figure 19), either owning wind projects (9%) or buying the electricity from wind projects (36%) that, in total, represent 45% of the new capacity installed last year (with the 45% split between 27% IOU and 18% POU). On a cumulative basis, utilities own (15%) or buy (50%) power from 65% of all wind power capacity installed in the United States (with the 65% split between 44% IOU and 21% POU).



Source: Berkeley Lab estimates based on AWEA WindIQ

Figure 19. Cumulative and 2017 wind power capacity categorized by power off-take arrangement

Merchant/quasi-merchant projects accounted for 20% of all new 2017 capacity and 23% of cumulative capacity. 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 period³²) rather than being locked in through a long-term PPA. Most of these projects are located within ERCOT in Texas, though there are some merchant/quasi-merchant projects within other markets, including PJM, MISO, SPP, and NYISO.

Direct retail purchasers of wind power, including both corporate and non-corporate off-takers, are supporting 1,692 MW or 24% of the new wind power capacity installed in the United States in 2017 (up from 10% of new capacity installed in 2015, but consistent with the level in 2016). Direct retail sales should continue to represent a sizable market in coming years, based on AWEA (2018a) estimates that 40% of all wind PPAs that were *executed* in 2017 were with non-utility purchasers (compared to 39% in 2016, 52% in 2015, and 18% for 2014—not all of which have yet achieved commercial operations).

Power marketers were very active throughout the first decade of this century following the initial wave of electricity market restructuring, but their influence has waned in recent years: just 6% of both 2017 and

³² Hedges are often structured as a “fixed-for-floating” power price swap—a purely financial arrangement whereby the wind power project swaps the “floating” revenue stream that it earns from spot power sales for a “fixed” revenue stream based on an agreed-upon strike price. For some projects, the hedge is structured in the natural gas market rather than the power market.

cumulative wind power capacity in the United States sells to power marketers, down from more than 20% (cumulative) in the early 2000s. Power marketers are defined here to include commercial intermediaries that purchase power under contract and then resell that power to others.³³

Finally, just 6 MW of the wind power additions in 2017 that used turbines larger than 100 kW were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.

³³ These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.

4 Technology Trends

Average turbine capacity, rotor diameter, and hub height increased in 2017, continuing the long-term trend

The average nameplate capacity of the newly installed wind turbines in the United States in 2017 was 2.32 MW, up by 224% since 1998–1999 and by 8% over 2016 (Figure 20).³⁴ The average hub height of turbines installed in 2017 was 86.0 meters, up 54% since 1998–1999 and 4% over the previous year. Average rotor diameters have increased at a more rapid pace than hub heights over the long term. The average rotor diameter of wind turbines installed in 2017 was 113.0 meters, up 135% since 1998–1999, and 4% over the previous year; this translates to a 459% growth in rotor swept area relative to 1998–1999. Trends in hub height and rotor scaling are two of several factors impacting the project-level capacity factors highlighted later in this report.

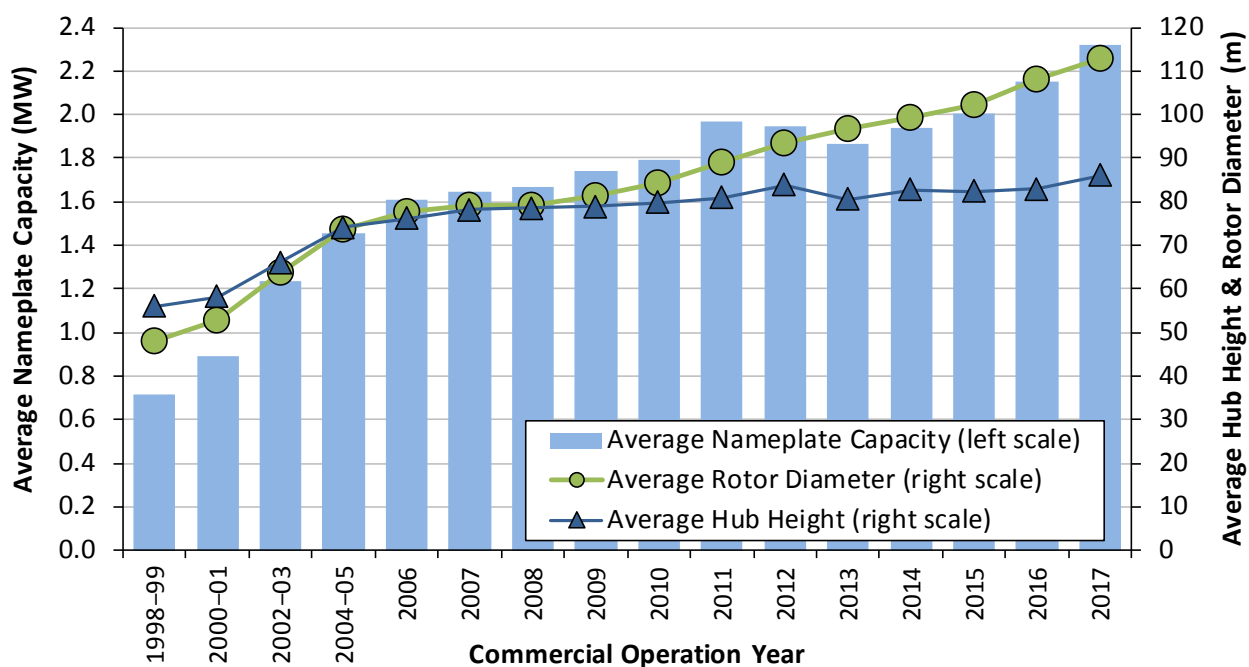


Figure 20. Average turbine nameplate capacity, rotor diameter, and hub height for land-based wind projects³⁵

Growth in average rotor diameter and turbine nameplate capacity have outpaced growth in average hub height over the last two decades

As indicated in Figure 20, and as detailed in Figure 21 through Figure 23, increases in nameplate capacity and rotor diameter have outpaced growth in average hub height in both over the last two decades, and in recent years, though there is evidence that further hub height scaling is imminent.

³⁴ Figure 20, as well as a number of the other figures and tables included in this report, combines 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.

³⁵ The data and trends reported in this Chapter as well as in Chapters 5, 6 and 7 are focused on land-based wind installations. The single, 30 MW offshore wind project in the U.S. is not captured in these chapters.

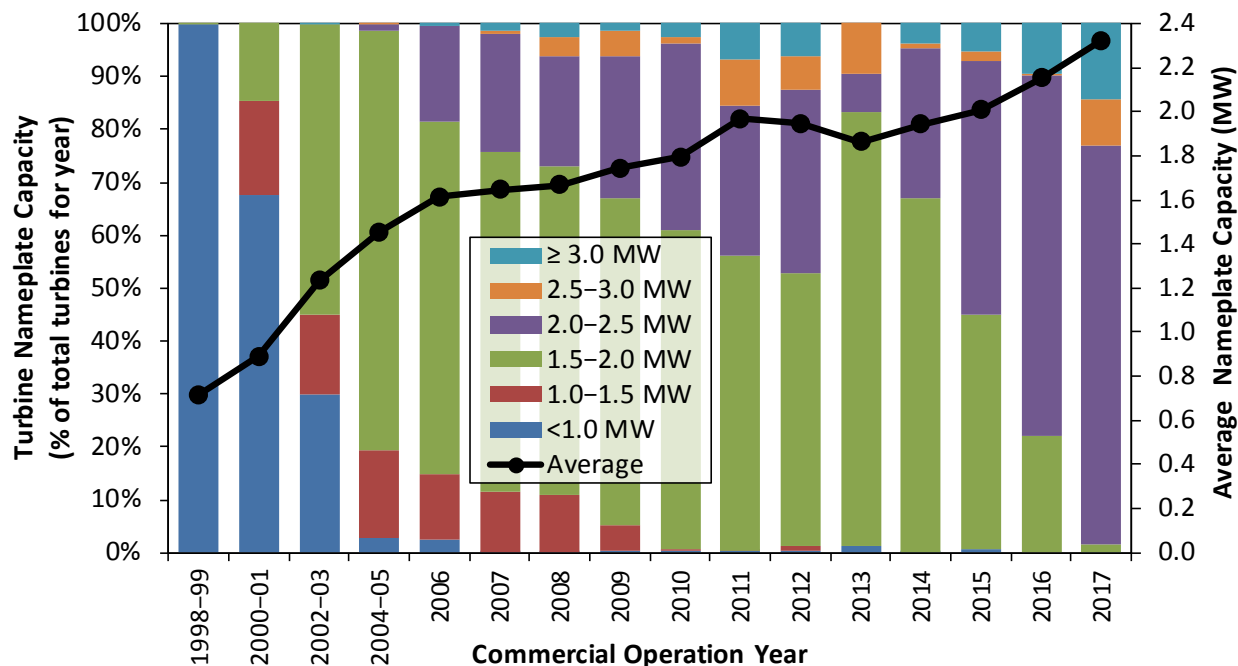


Figure 21. Trends in turbine nameplate capacity

Starting with turbine nameplate capacity, Figure 21 presents not only the trend in average nameplate capacity (as also shown earlier, in Figure 20) but also how the prevalence of different turbine capacity ratings has changed over time. The average nameplate capacity of newly installed wind turbines had largely held steady from 2011 through 2015, but has since grown. While it took just six years (2000–2005) for MW-class turbines to almost totally displace sub-MW-class turbines, it took another seven years (2006–2012) for multi-MW-class turbines (i.e., 2 MW and above) to gain nearly equal market share with MW-class turbines. In 2017, 2.0–2.5 MW turbines dominated the market (75% market share), with 2.5–3 MW and 3+ MW turbines also making up notable portions (9% and 14%, respectively).

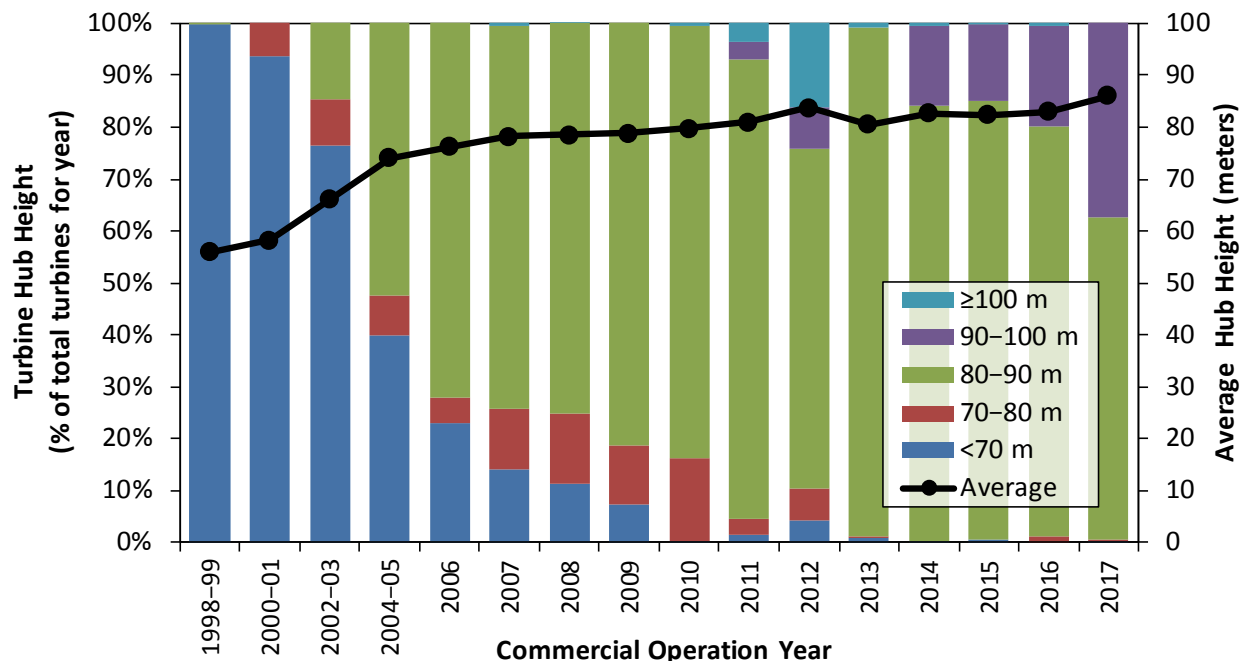


Figure 22. Trends in turbine hub height

The average hub height of wind turbines had held roughly constant from 2011 through 2015, but saw increases in 2016 and 2017 (Figure 22). 80-meter towers have dominated the market since 2006. However, 90- to 100-meter towers started to penetrate the market in 2011, and in 2017 had 37% market share. Although we saw the emergence of towers taller than 100 meters as early as 2007, that segment peaked (at least temporarily) in 2012 when 16% of newly installed turbines were taller than 100 meters. Since 2012, only 1% or less of newly installed turbines in each year have featured towers that tall, with none installed in 2017.

The movement towards larger-rotor machines has dominated the industry for some time, with OEMs progressively introducing larger-rotor options for their standard offerings and introducing new turbines that feature larger rotors. As shown in Figure 23, this increase has been especially apparent since 2009, with further growth in 2017. In 2008, no turbines employed rotors that were 100 meters in diameter or larger, while in 2017 99% of newly installed turbines featured such rotors. Rotor diameters of 110 meters or larger started penetrating the market in 2012; in 2017 they had 80% market share. Turbines with rotor diameters over 120 meters began to become more common in 2017, with 14% of the market.

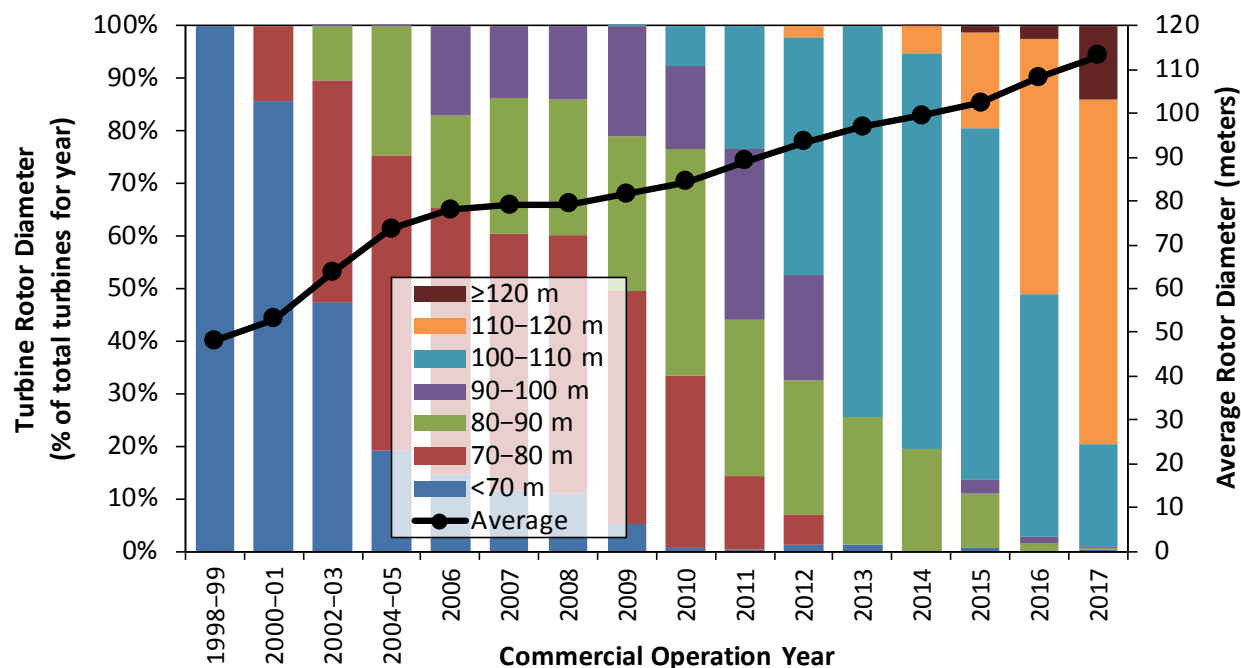


Figure 23. Trends in turbine rotor diameter

Turbines originally designed for lower wind speed sites have rapidly gained market share, and are being deployed in a range of wind resource conditions

The growth in the swept area of the rotor has been particularly rapid. With growth in average swept area (in m²) outpacing growth in average nameplate capacity (in W), there has been a decline in the average “specific power” (in W/m²) among the U.S. turbine fleet over time, from 395 W/m² among projects installed in 1998–1999 to 231 W/m² among projects installed in 2017 (Figure 24).

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 24 and as detailed in the next section, however, such turbines are now 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.

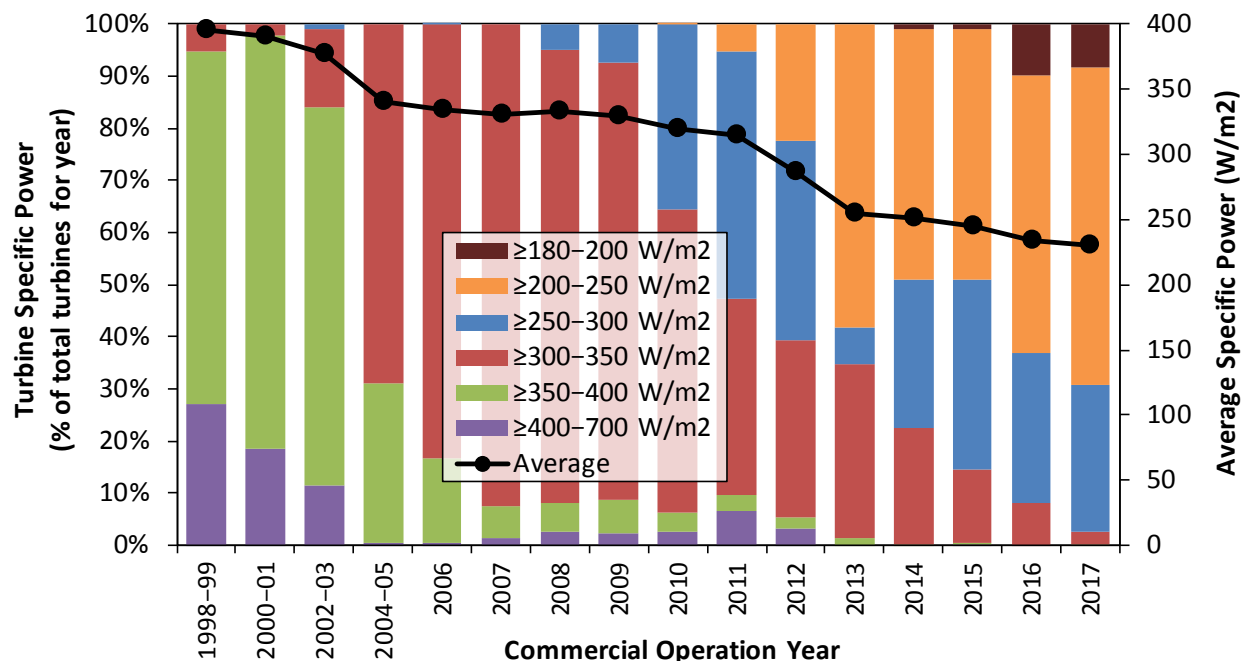
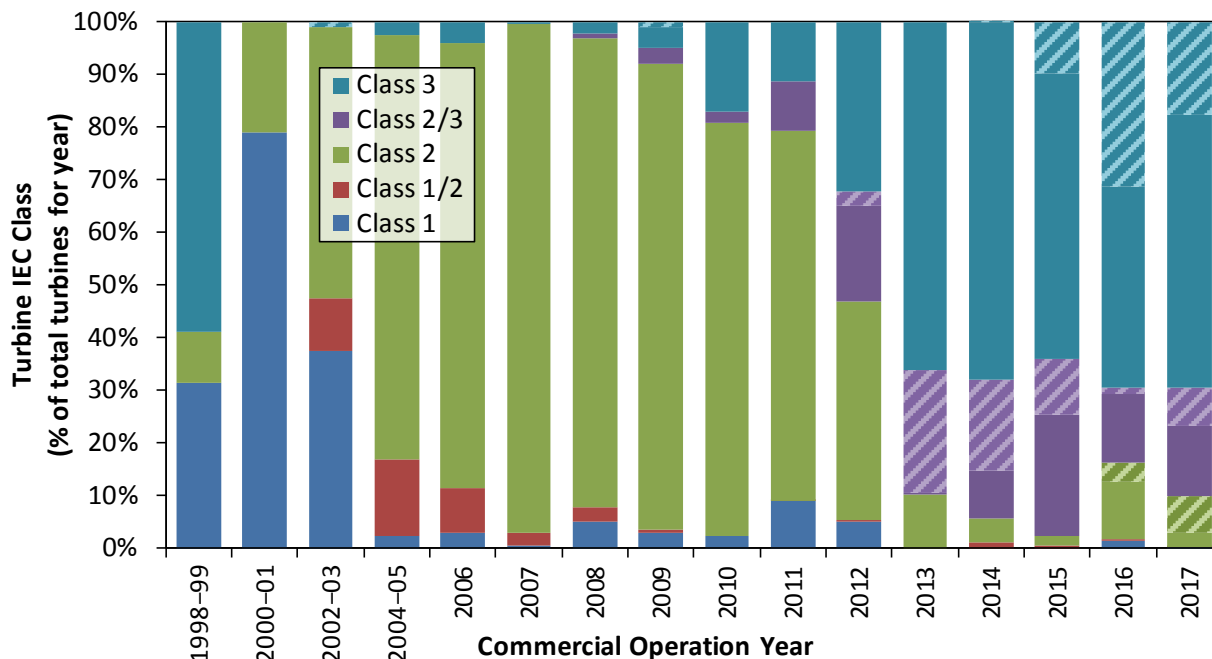


Figure 24. Trends in turbine specific power

Another indication of the increasing prevalence of machines initially designed for lower wind speeds is revealed in Figure 25, which presents trends in wind turbine installations by IEC Class. The IEC classification system considers multiple site characteristics, including wind speed, gusts, and turbulence. Class 3 turbines are generally designed for lower wind speed sites (7.5 m/s and below), Class 2 turbines for medium wind speed sites (up to 8.5 m/s), and Class 1 turbines for higher wind speed sites (up to 10 m/s). Some turbines are designed at the margins of two classifications, and are labeled as such (e.g., Class 2/3). Additionally, a significant portion of the turbines installed in recent years have been Class S-2, S-2/3, or S-3, which fall outside the standard IEC rating for those classes for one reason or another as specified by the turbine design (and are depicted with hash marks in Figure 25).³⁶

The U.S. wind market has clearly become increasingly dominated by IEC Class 3 turbines in recent years. In 2000–2001, Class 1 machines were prevalent. From 2002 through 2011, Class 2 machines dominated the market. Since 2011, there has been a substantial decline in the use of Class 2 turbines, and an increasing market share of Class 2/3 and Class 3 turbines. In 2017, 70% of the newly installed turbines were Class 3 machines, 21% were Class 2/3 machines, and 10% of turbines were Class 2 or lower (each including S turbines rated similarly).

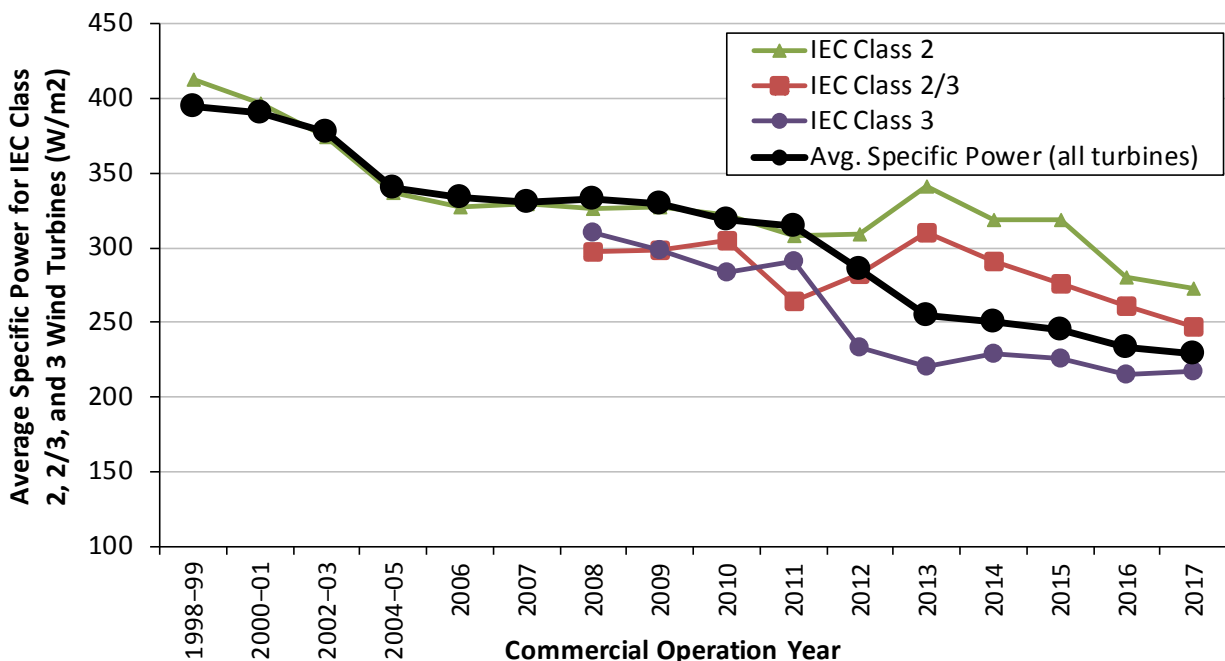
³⁶ The IEC Class S-2, S-2/3, or S-3 turbines are almost all manufactured by GE Wind. For example, GE rates its 1.7-103 turbine, with a 1.7 MW capacity and a 103 meter rotor diameter, as S-3, indicating that it most closely resembles an IEC Class 3 turbine. Others include GE 1.85-87 (S-2/3) and GE 2.4-107 (S-2). All of the “S” turbines are included in the reported IEC class using their closest class.



Note: Class S-2, S-2-3, and S-3 turbines are shown with hash marks in their respective bins

Figure 25. Trends in turbine IEC class

Moreover, Class 2, 2/3, and 3 turbine technology has not remained stagnant. Figure 26 shows the trend in average specific power across all turbines installed in each year (regardless of IEC Class, matching the average specific power line shown in Figure 24) and also the average specific power ratings of Class 2, 2/3, and 3 (i.e., medium and lower wind speed) turbines installed in the United States. Through 2011, the progressively lower specific power of Class 2 turbines, which dominated the market, drove the overall decline in fleet-wide specific power. Since 2012, the continued drop in fleet-wide specific power has been spurred on by both the penetration of Class 3 and Class 2/3 machines, and by the lower specific powers of all three classes. The overall trend in fleet-wide average specific power has therefore been driven both by the increased penetration of Class 2 and then Class 2/3 and 3 turbines, and by the progressively lower specific power ratings of turbines within each of these IEC classes.



Notes: Specific power averages are shown only for years where there were at least 40 new turbines installed with the respective IEC Class. Class S turbines are included in the figure in their corresponding class.

Figure 26. Trends in specific power for IEC class 2, 2/3, and 3 turbines

Wind turbines were deployed in somewhat lower wind-speed sites in 2017 in comparison to the previous three years

Figure 27 shows the long-term average wind resource for wind turbine installations by year. The figure depicts both the long-term site-average wind speed (in meters per second) at 80 meters for turbines installed that year (right scale) and an index of wind resource quality also at 80 meters (left scale).³⁷

Wind turbines installed in 2017 are located in sites with a long-term average 80-meter wind speed of 7.7 meters per second (m/s). This represents a lower average wind speed than for those turbines installed in the previous three years, but exceeds that for turbines installed from 2009 to 2013. Federal Aviation Administration (FAA) data on not-yet-built “pending” and “proposed” turbines suggest that near-future wind projects will be located in similar or slightly better wind resource areas than those installed in 2017.³⁸

Trends in the wind resource quality index—which represents estimates of the gross capacity factor for each turbine location, indexed to the 1998–1999 installations—are similar. They show a general decline in resource quality for turbines installed through 2011, an increase from 2012 to 2014, and then a decline since then.

Several factors could have driven these observed trends in average site quality. First, the increased availability of low-wind-speed turbines that feature higher hub heights and a lower specific power may have enabled the economic build-out of lower-wind-speed sites over time. Second, transmission constraints (or other siting

³⁷ The wind resource quality index is based on site estimates of gross capacity factor at 80 meters by AWS Truepower. A single, common wind-turbine power curve is used across all sites and timeframes, and no losses are assumed. We index the values to those projects built in 1998–1999. Further details are found in the Appendix.

³⁸ “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 will also not expire in 18 months but 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.

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 sites. The build-out of new transmission (the completion of major transmission additions in West Texas in 2013, for example), 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 opportunity 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. Finally, state policies sometimes motivate in-state or in-region wind development in lower wind resource regimes. As RPS policies have become a less-dominant driver of incremental wind additions in recent years (Barbose 2017), however, economic forces have focused new capacity additions in the Interior region of the country.

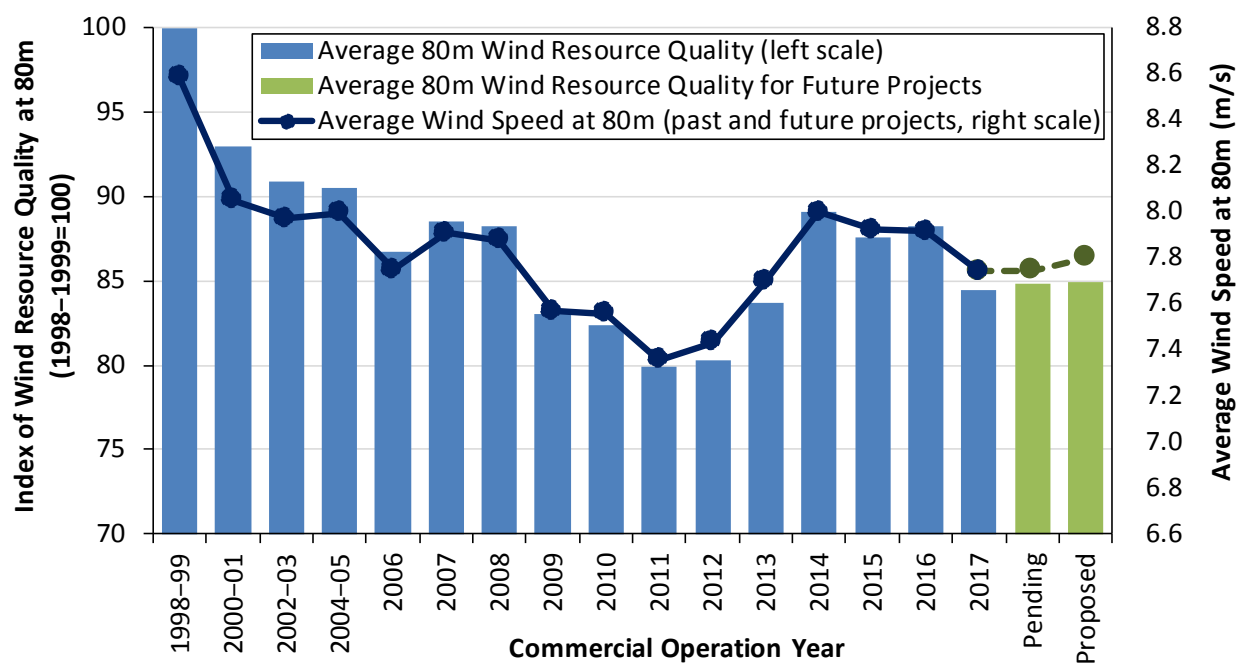


Figure 27. Wind Resource Quality by Year of Installation at 80 meters

Low specific power turbines continue to be deployed in both lower and higher wind speed sites; taller towers predominate in the Great Lakes and Northeast

One might expect that the increasing market share of turbines designed for lower wind speeds would be due to a movement by wind developers to deploy turbines in lower wind speed sites. Though there is some evidence of this movement historically (see Figure 27), it is clear in Figure 28 and Figure 29 that turbines originally designed for lower wind speeds have been deployed in all regions of the United States, in both lower and higher wind speed sites.

Figure 28 presents the percentage of turbines installed in four distinct regions of the United States³⁹ (see Figure 1 for regional definitions) that have one or more of the following three attributes: (a) relatively higher hub height, (b) relatively lower specific power, and (c) relatively higher IEC Class. It focuses solely on turbines

³⁹ Due to very limited sample size, we exclude the Southeast region from these graphs and related discussion.

installed in the 2015–2017 time period. Figure 29 presents similar information, but segments the data by the wind resource quality of the site rather than by the region in which the turbines are located.

Taller towers (i.e., 90 meters and above) saw higher market share during the 2015–2017 period in the Great Lakes (64%) and Northeast (54%) than in the Interior (17%) and West (0%), often in sites with lower wind speeds. This is likely largely due to the fact that such towers are most economical when deployed at sites with higher-than-average wind shear (i.e., greater increases in wind speed with height); such sites are prevalent in the Great Lakes and Northeast.

Lower specific power machines (i.e., under 250 W/m²) installed over this three-year period have been regularly deployed in all regions of the country, though their market share in the West (74%), Great Lakes (71%), and Interior (59%) exceeds that in the Northeast (17%). Similarly, these turbines have been commonly used in all resource regimes including at sites with very high wind speeds, though there is some drop-off in the deployment of lower specific power turbines as wind speed increases.

Turning to IEC Class, we see a somewhat similar story. Over this period, Class 3 and Class 2/3 machines had the largest market share in the Great Lakes (99%) and Interior (91%) regions, but also had significant market share in the West (82%) and Northeast (47%)

In combination, these findings demonstrate that low specific power and Class 3 and 2/3 turbines, originally designed for lower wind speed sites, have established a strong foothold across the nation and over a wide range of wind speeds.

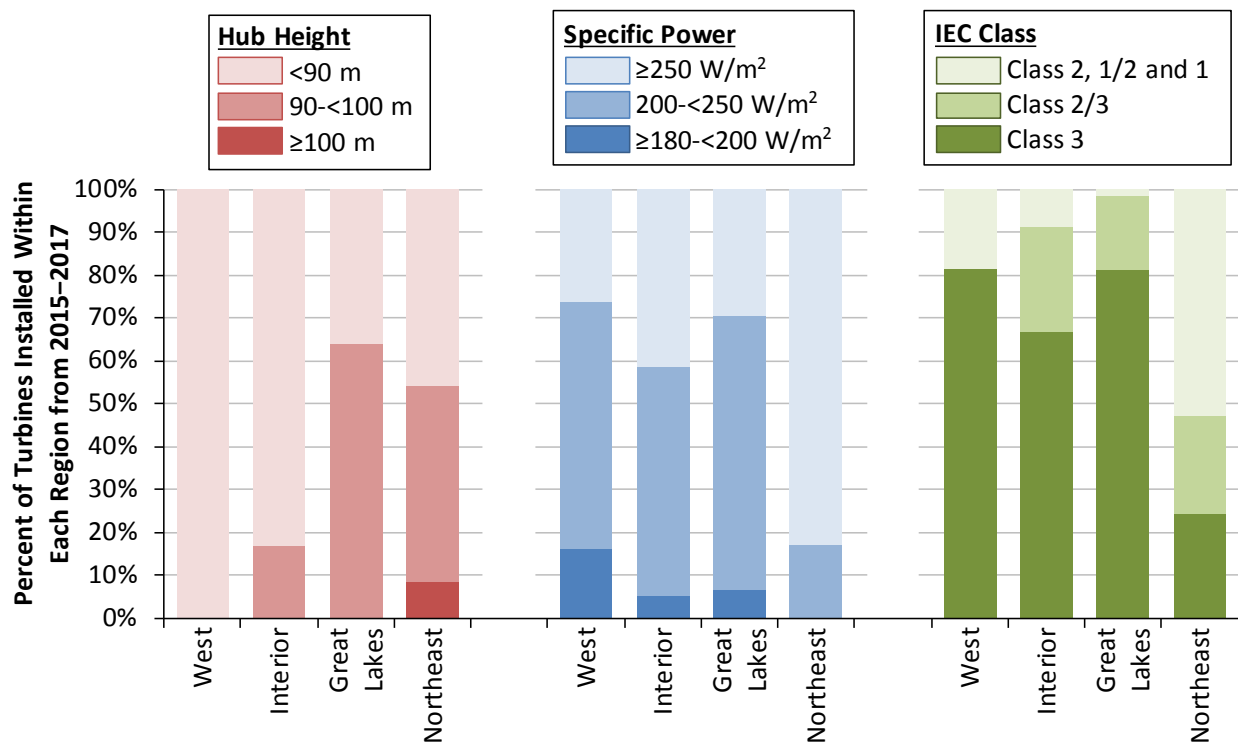
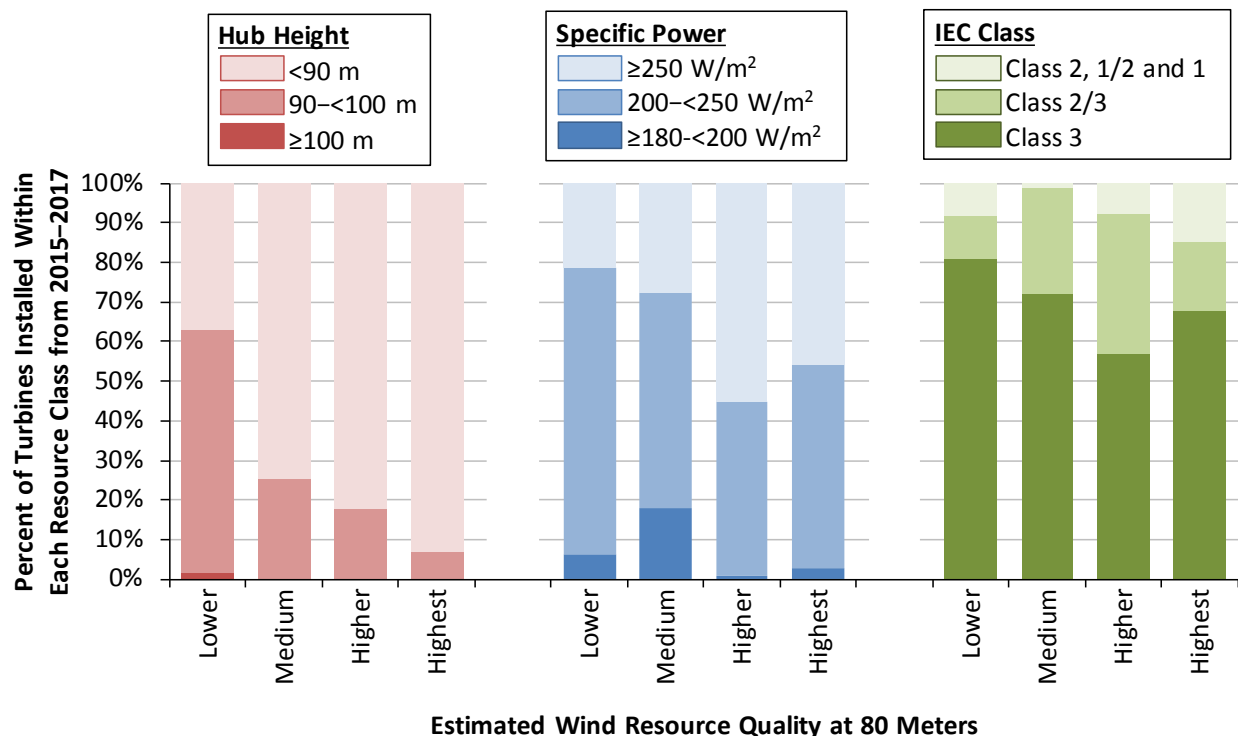


Figure 28. Deployment of turbines originally designed for lower wind speed sites, by region



Note: See the Appendix for details on how wind resource quality at each individual project site is estimated.

Figure 29. Deployment of turbines originally designed for lower wind speed sites, by estimated wind resource quality

Wind power projects planned for the near future continue the trend of ever-taller turbines

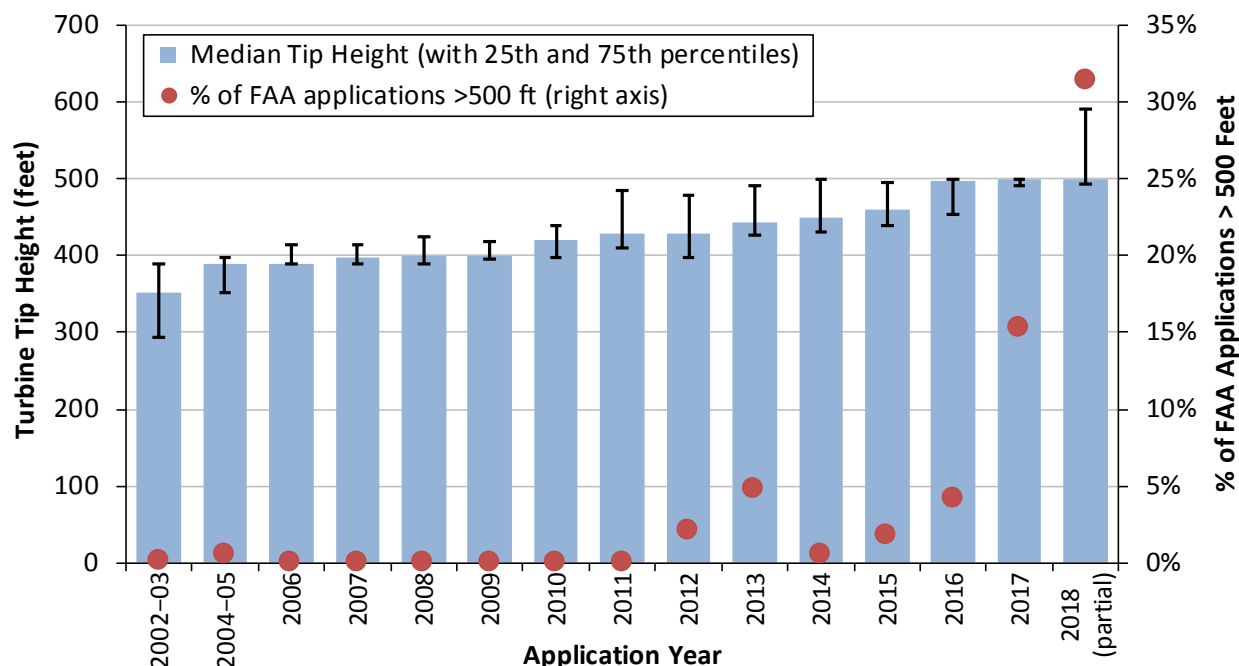
FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications are shown in Figure 30. The median tip height is shown, along with the 25th and 75th percentiles (left scale). The percentage of permit applications involving turbines over 500 feet at tip height is shown on the right scale. From 2002 through 2016, less than 5% of permit applications included turbines with a total height over 500 feet, growing to 15% of 2017 permits, and to 31% of 2018 permits (through late-May 2018). Similarly, although the medians approach 500 feet (152.4 meters) through 2018, the 75th percentile of 2018 permits-to-date indicates a significant portion over 500 feet in total height. Note that these data represent total turbine height, not hub height, and therefore include the combined effect of both tower and rotor size. Additionally, turbine heights reported in FAA permit applications can differ from what is ultimately installed.⁴⁰

The move towards turbines with total heights of over 500 feet is significant. There is anecdotal evidence that developers may have historically perceived a “soft cap” at 500 feet, dampening what might otherwise be higher total heights in previous years. Although the FAA may require a public comment period for any turbine proposed for higher than 499 feet, perhaps causing some developers to want to stay under that tip height, there are otherwise no height limitations imposed by the FAA.⁴¹ The recent growth in applications with turbines

⁴⁰ Historically, the FAA permit datasets have strongly conformed to subsequent actual installations on average, providing some confidence that the projected trends shown in the FAA permit data will come to pass.

⁴¹ See Title 14, Chapter I, Subchapter E, Part 77 of the Code of Federal Regulations, as well as “frequently asked question” #27 at <https://oiaa.faa.gov/oiaa/external/searchAction.jsp?action=showWindTurbineFAQs>

above 500 feet suggests that developers anticipate continued scaling in hub heights and rotor diameters, breaking through this earlier perceived “soft cap.”



Source: Federal Aviation Administration

Figure 30. Total turbine heights proposed in FAA applications, over time

A large number of wind power projects continued to employ multiple turbine configurations from a single turbine supplier

Among those wind projects built in 2017 that contained at least six turbines, nearly 25% used multiple turbines with different hub heights, rotor diameters and/or capacities—all supplied by the same OEM—continuing a trend started in 2016. As shown in Figure 31, this relatively high degree of intra-OEM turbine specialization within individual projects had not previously been prevalent in the U.S. market before 2016, with 2012 being the next highest year at 13%. Most of these turbines, in both 2016 and 2017, differed by all three of the major characteristics: hub height, rotor diameter, and capacity rating.

While there are multiple possible explanations for this recent trend, one is the possibility of increasing sophistication with respect to intra-project turbine siting and wake effects optimization, coupled with an increasing willingness among OEMs to provide multiple turbine configurations. A second possible explanation could involve how developers commonly qualify projects for the PTC—e.g., by ordering a modest subset of the required number of turbines prior to the applicable construction-start deadline (in order to incur at least 5% of total project costs, per IRS guidance), and then months later ordering the balance of required turbines, which by then might feature slightly different characteristics, like a larger rotor.

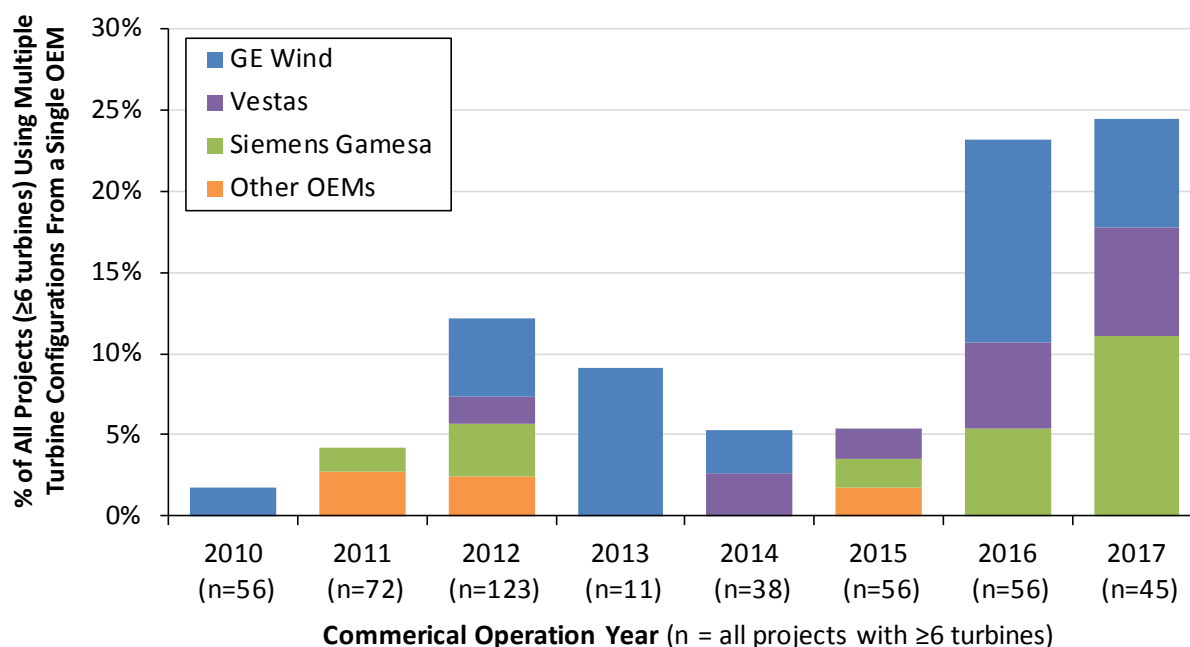


Figure 31. Percent of larger projects employing multiple turbine configurations from a single OEM

Turbines that were partially repowered in 2017 now have significantly larger rotors and correspondingly lower specific power ratings

A new trend is that of partial wind project repowering, in which major components of turbines are replaced in order to increase energy production with more-advanced turbine technology, extend project life, and access favorable tax incentives. The year 2017 saw 1,317 turbines totaling 2,131 MW (before repowering) being partially repowered, of which 1,123 turbines were GE and 194 were Siemens. Larger rotors were installed on all turbines, with an average increase of 12.2 meters (as shown in Figure 32).⁴² Because existing towers being reused, there was no increase in hub height. Overall, turbines increased from 1.62 MW to 1.63 MW in nameplate capacity on average. None of the Siemens turbines saw an increase in nameplate capacity, but 10% of the GE turbines were updated, 5% by 0.1 MW and 5% by 0.12 MW. Because of the substantial increase in rotor diameter and only a modest increase in nameplate capacity for a subset of the turbines, the retrofitting process resulted in a 25% decrease in specific power on average, from 335 W/m² to 252 W/m².

The turbines that were partially repowered in 2017 had initially been installed between 9 and 14 years ago, with 75% being between 10 and 12 years old. With regard to specific turbine models, 231 GE 1.5 MW turbines with 70.5 meter rotor diameters were retrofitted with 82.5-meter rotors across three sites in Texas and Iowa. Another 892 GE 1.5 MW turbines with rotor diameters of 77 meters were retrofitted with either 87 or 91-meter rotors across six project sites in Texas and Iowa. Finally, 194 Siemens 2.3 MW turbines with rotor diameters of 93 meters were retrofitted with 108-meter rotors across two project sites in Texas.

⁴² The exact rotor diameter for some GE turbines is unknown as of this report writing. Using FAA total height estimates and the known hub heights, though, estimates for the rotor diameters were made and used for the calculations included in this section.

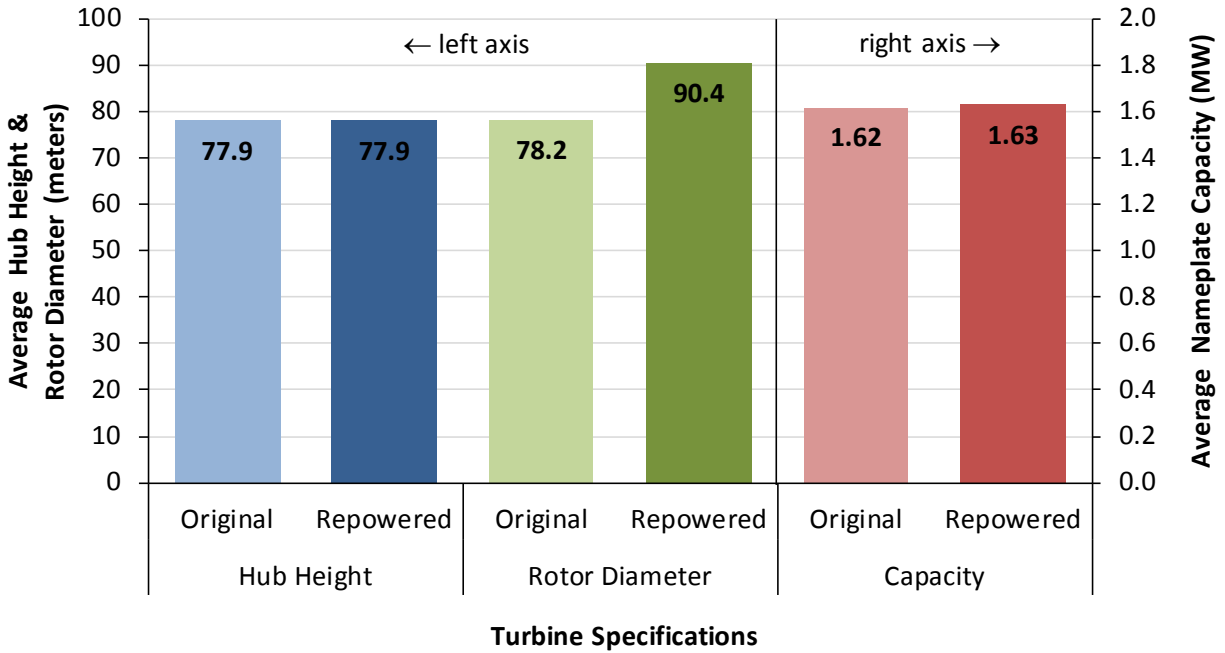


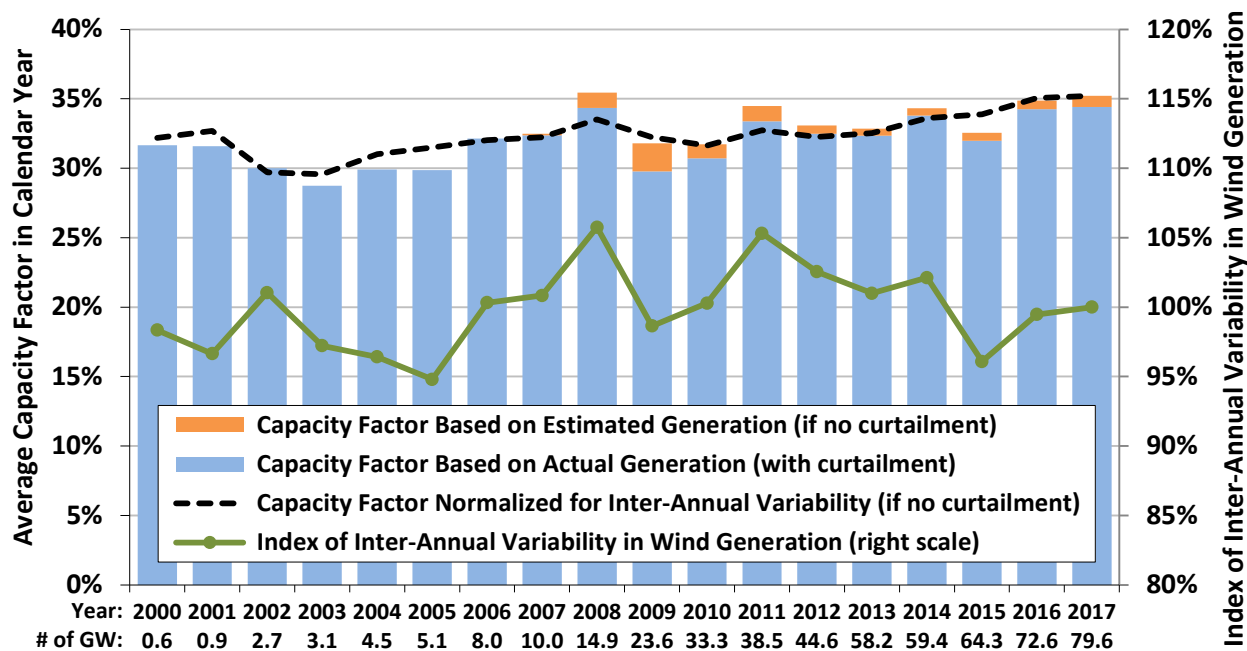
Figure 32. Change in average physical specifications of turbines that were partially repowered in 2017

5 Performance Trends

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors. The full data sample consists of 897 wind projects built between 1998 and 2016 totaling 79,620 MW (97% of nationwide installed wind capacity at the end of 2016).⁴³ Excluded from this assessment are older projects, installed prior to 1998. In addition, nine projects totaling 2.1 GW that were partially repowered in 2017 are excluded from the 2017 capacity factor sample, given that they were at least partly offline during a portion of the year. The discussion is divided into three subsections: the first analyzes trends in sample-wide capacity factors over time; the second looks at variations in capacity factors in 2017 by project age; and the third focuses on regional variations. 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.), though in a couple of cases we make adjustments for observed curtailment and inter-annual variability in the wind resource.

Sample-wide capacity factors have gradually increased, but have been impacted by curtailment and inter-year wind resource variability

The blue bars in Figure 33 show the average sample-wide capacity factor of wind projects in each calendar year among a progressively larger cumulative sample in each year, focusing on projects installed from 1998 through 2016.



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

Figure 33. Average sample-wide capacity factors by calendar year

Viewed this way—on a cumulative, sample-wide basis—one might expect to see a gradual improvement in capacity factor over time, as newer turbines with taller towers and lower specific power are added to the fleet. In general, the data appear to support this trend, with somewhat higher capacity factors in the later years. But

⁴³ Although some performance data for wind power projects installed in 2017 are available, those data do not span an entire year of operations. As such, for the purpose of this section, the focus is on projects with commercial operation dates from 1998 through 2016, often focusing on 2017 capacity factors for those projects.

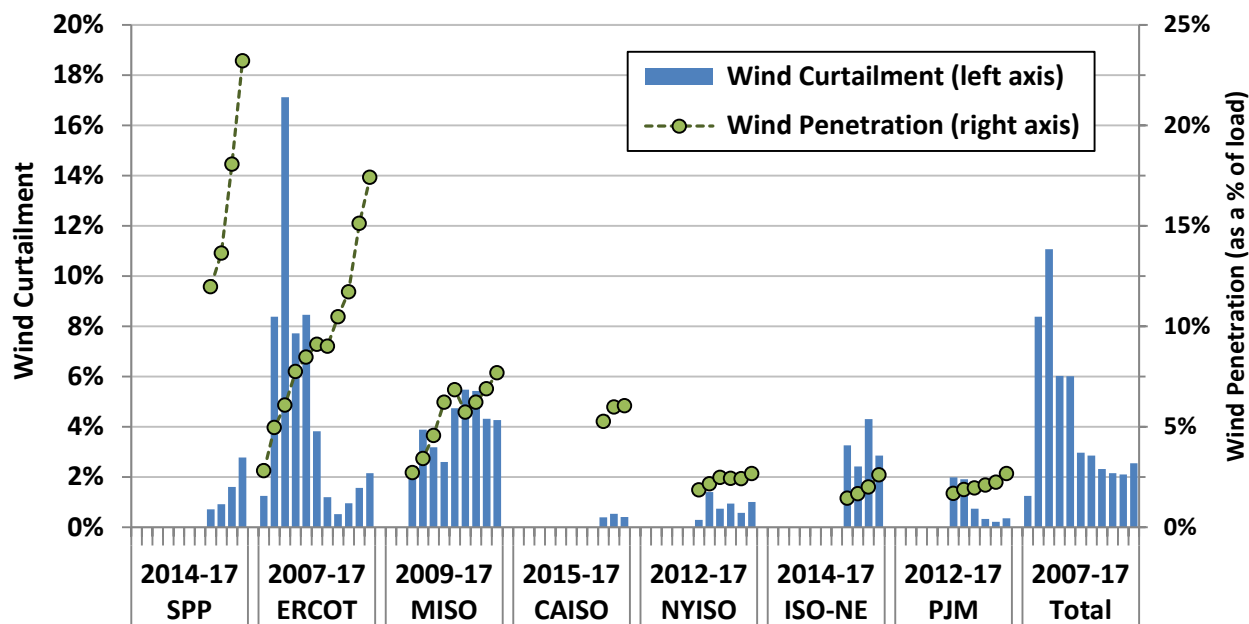
there is considerable year-to-year variability in the data, and several factors influence the apparent strength of this time-based trend. Two of those factors are discussed below—wind energy curtailment (the orange bars in Figure 33) and inter-year variability in the strength of the wind resource (the green line in Figure 33). Two additional factors—the average quality of the resource in which projects are located (e.g., recall from Figure 2 that most new capacity in recent years has been added to the windy Interior region) and performance degradation as projects age—are discussed in the next section. The next section also addresses more-directly the impact of wind turbine technology on project performance.

Wind Power Curtailment. Curtailment of wind project output results from transmission inadequacy and other forms of grid and generator inflexibility. For example, over-generation can occur when wind generation is high but transmission capacity is insufficient to move excess 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 curtailment for economic reasons—particularly among wind projects that do not receive the PTC. Curtailment might be expected to increase as wind energy penetrations rise, though as shown in Figure 34, this has not always been the case. For example, in areas where curtailment has been particularly problematic in the past—principally in Texas—steps taken to address the issue have significantly reduced curtailment, even as wind penetration has increased. Figure 34 shows that 2.2% of potential wind energy generation within the main Texas grid (ERCOT) was curtailed in 2017, down from 17% in 2009, roughly 8% in both 2010 and 2011, and nearly 4% in 2012. This decline in curtailment corresponds to the significant build-out of new transmission serving West Texas (collectively referred to as the Competitive Renewable Energy Zone upgrades), most of which were completed by the end of 2013.

The Southwest Power Pool (SPP) and New England ISO (ISO-NE) experienced wind curtailment in 2017 of 2.8% and 2.9%, respectively—similar to ERCOT, while the Midcontinent Independent System Operator (MISO) came in higher at 4.3%. The other three regions in Figure 34 were all at 1% or less, leaving the overall wind power curtailment rate across regions at 2.5%. Curtailment rates for all regions shown in Figure 34 include both “forced” (i.e., required by the grid operator for reliability reasons) and “economic” (i.e., voluntary as a result of wholesale market prices) curtailment.

Wind power curtailment reduces sample-wide capacity factors. While the blue bars in Figure 33 reflect actual capacity factors—including the negative impact of curtailment events—the orange bars add back in the estimated amount of wind generation that has been curtailed within the seven areas shown in Figure 34, to estimate what the sample-wide capacity factors would have been absent this curtailment. As shown in Figure 33, sample-wide capacity factors would have been on the order of 0.5–2 percentage points higher nationwide from 2008 through 2017 absent curtailment in just these ISOs. Estimated capacity factors would have been even higher if comprehensive curtailment data were available for all areas of the country.⁴⁴

⁴⁴ The seven ISOs included in Figure 34 collectively contributed 84% of total U.S. wind generation in 2017.



Notes: All curtailment percentages shown in the figure represent both forced and economic curtailment. PJM's 2012 curtailment estimate is for June through December only. For each year, the total reflects only those ISOs for which we have curtailment data.

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

Figure 34. Wind curtailment and penetration rates by ISO

Inter-Year Wind Resource Variability. The strength of the wind resource varies from year to year. That said, for the second year in a row, wind speeds across the continental United States in 2017 were generally “near normal” overall. This pattern can be seen in the solid green line in Figure 33, which shows an index of the historical inter-annual variability in the wind resource among the U.S. fleet over time⁴⁵ (data presented by AWS Truepower (2018) is consistent with these estimates).

Movements in sample-wide capacity factor from year to year are clearly influenced by this natural inter-year variability in the strength of the national wind resource. If this wind resource variability is controlled for, the overall trend in fleet-wide capacity factor (denoted by the dashed black “weather-normalized” line) appears to be much smoother, and in general gradually upward sloping—i.e., much as one would expect as newer turbines with taller towers and lower specific power are added to the fleet.⁴⁶

Turbine design changes are driving capacity factors significantly higher over time among projects located in given wind resource regimes

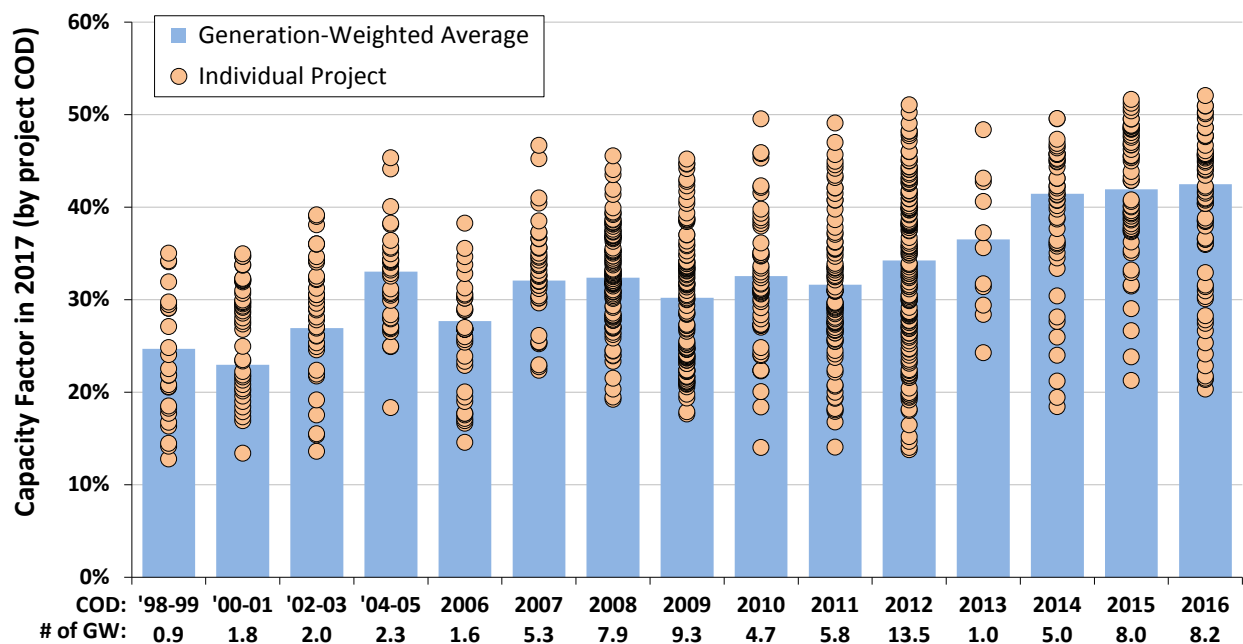
One way to partially control for the time-varying influences described in the previous section (e.g., annual variation in the wind resource or changes in the amount of wind curtailment) is to focus exclusively on

⁴⁵ The green line in Figure 33 estimates changes in the strength of the average “fleet-wide” wind resource from year to year and is constructed by downscaling MERRA reanalysis wind speed data to individual project locations, applying applicable wind turbine power curves, and then aggregating up to the fleet level (see the Appendix for more details). Note that this LBNL index of inter-annual variability differs from the AWS Truepower wind resource quality data presented elsewhere, in that the former shows variability from year to year across the entire fleet, while the latter focuses on the multi-year long-term average wind resource at specific wind project sites.

⁴⁶ The dashed black weather-normalized line in Figure 33 is derived by dividing the empirical sample-wide capacity factor (with curtailment added back in) by the index of inter-annual variability.

capacity factors in a single year, such as 2017.⁴⁷ As such, while Figure 33 presents sample-wide capacity factors in each calendar year, Figure 35 instead shows only capacity factors in 2017, broken out by commercial operation date. Wind projects built in 2017 are again excluded, as full-year performance data are not yet available for those projects.

Figure 35 shows an increase in weighted-average 2017 capacity factors when moving from projects installed in the 1998–2001 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011 show little if any improvement in average capacity factors recorded in 2017. This pattern of stagnation is finally broken by projects installed in 2012–2013, and even more so by those that achieved commercial operations in 2014–2016. The average 2017 capacity factor among projects built from 2014 to 2016 was 42.0%, compared to an average of 31.5% among all projects built from 2004 to 2011, and 23.5% among all projects built from 1998 to 2001.



Source: Berkeley Lab

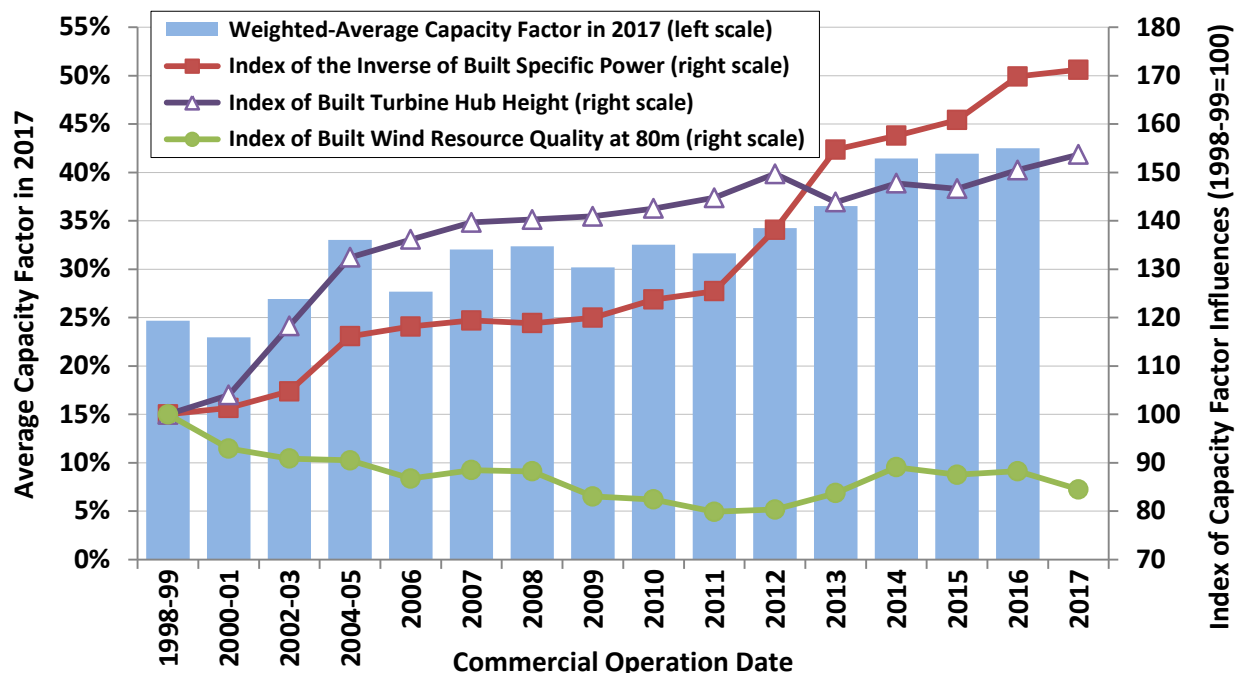
Figure 35. Calendar year 2017 capacity factors by commercial operation date

The trends in average capacity factor by commercial operation date seen in Figure 35 can largely be explained by several underlying influences shown in Figure 36. First, there has been a trend towards progressively lower specific power and higher hub heights—both of which should boost capacity factors, all else equal. Second, there was a progressive build-out of lower-quality wind resource sites through 2012 (which should hurt capacity factors, all else equal), followed by deployment at more energetic sites thereafter. Finally, as shown later, project age itself could be a fourth driver, given the possible degradation in performance among older projects.

The first two of these influences—the decline in average specific power and the increase in average hub height among more recent turbine vintages—have already been well-documented in Chapter 4. They are shown yet again in Figure 36 in index form, relative to projects built in 1998–1999 (with specific power shown in inverse

⁴⁷ Although focusing just on 2017 does control (at least loosely) for some of these known time-varying impacts, it also means that the *absolute* capacity factors shown in Figure 35 may not be representative over longer terms if 2017 was not a representative year in terms of the strength of the wind resource (though as mentioned above, 2017 was a fairly average wind year in the United States overall) or wind power curtailment.

form, to correlate with capacity factor movements). All else equal, a lower average 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. Meanwhile, at sites with positive wind shear, increasing turbine hub heights can help the rotor to access higher wind speeds. Counterbalancing the decline in specific power and the increase in hub height, however, has been a tendency to build new wind projects in lower-quality wind resource areas,⁴⁸ especially among projects installed from 2009 through 2012⁴⁹ as shown by the wind resource quality index in Figure 36. This trend reversed course in 2013 and 2014, and has largely held steady since then, though with a dip in 2017.



Note: In order 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).

Source: Berkeley Lab

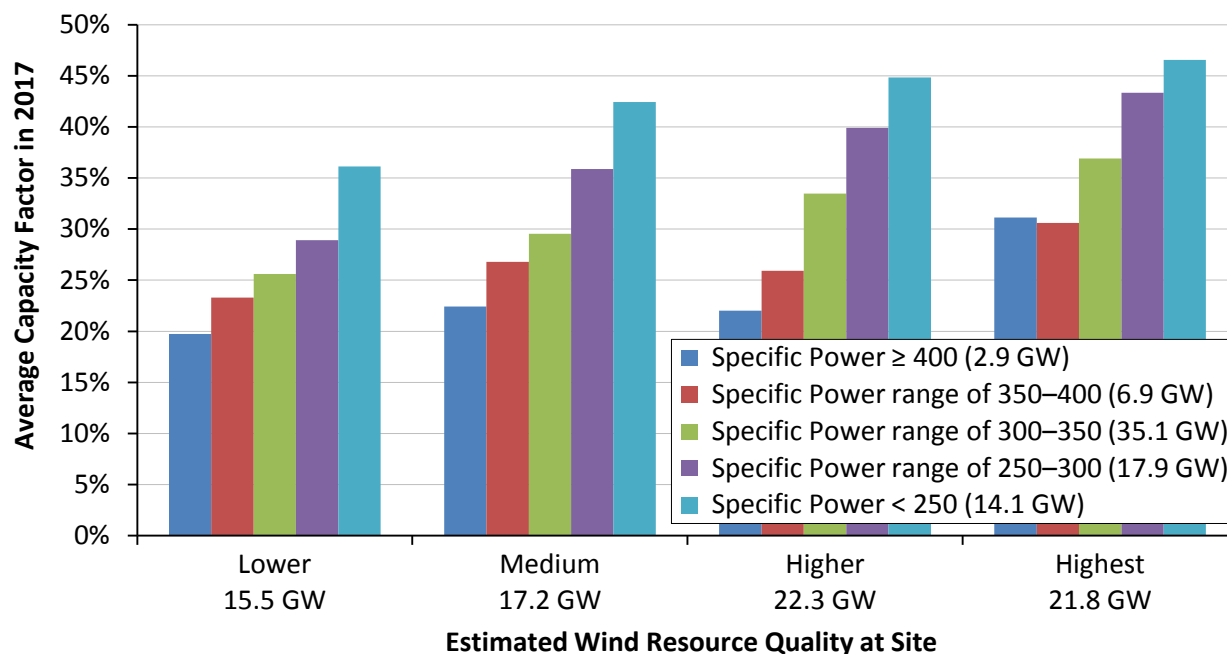
Figure 36. 2017 capacity factors and various drivers by commercial operation date

In Figure 36, the significant improvement in average 2017 capacity factors from among those projects built in 1998–2001 to those built in 2004–2005 is driven by both an increase in hub height and a decline in specific power, despite a shift towards somewhat-lower-quality wind resource sites. The stagnation in average capacity factor that subsequently persists through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. Finally, the sharp increase in average capacity factors among projects built after 2011 is driven by a steep reduction in average specific power coupled with a marked improvement in the quality of wind resource sites (while average hub height remained relatively constant over this period). Looking ahead to 2018, projects with commercial operation dates in 2017 could possibly record higher capacity factors than those built in 2016 on average, in light of an ongoing reduction in average specific power coupled with an uptick in average hub height. Counterbalancing those positives, however, is a deterioration in average site quality.

⁴⁸ As described earlier relating to Figure 27 (with further details found in the Appendix), estimates of wind resource quality are based on site estimates of gross capacity factor at 80 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. We index the values to those projects built in 1998–1999.

⁴⁹ The text immediately preceding Figure 27 lists several possible explanations for the buildout of less-energetic sites from 2009–2012.

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 are grouped into four different 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 one would expect, projects sited in higher wind speed areas generally realized higher capacity factors in 2017 than those in lower wind speed areas, regardless of specific power. Likewise, within each of the four wind resource categories along the x-axis, projects that fall into a lower specific power range realized significantly higher capacity factors in 2017 than those in a higher specific power range.



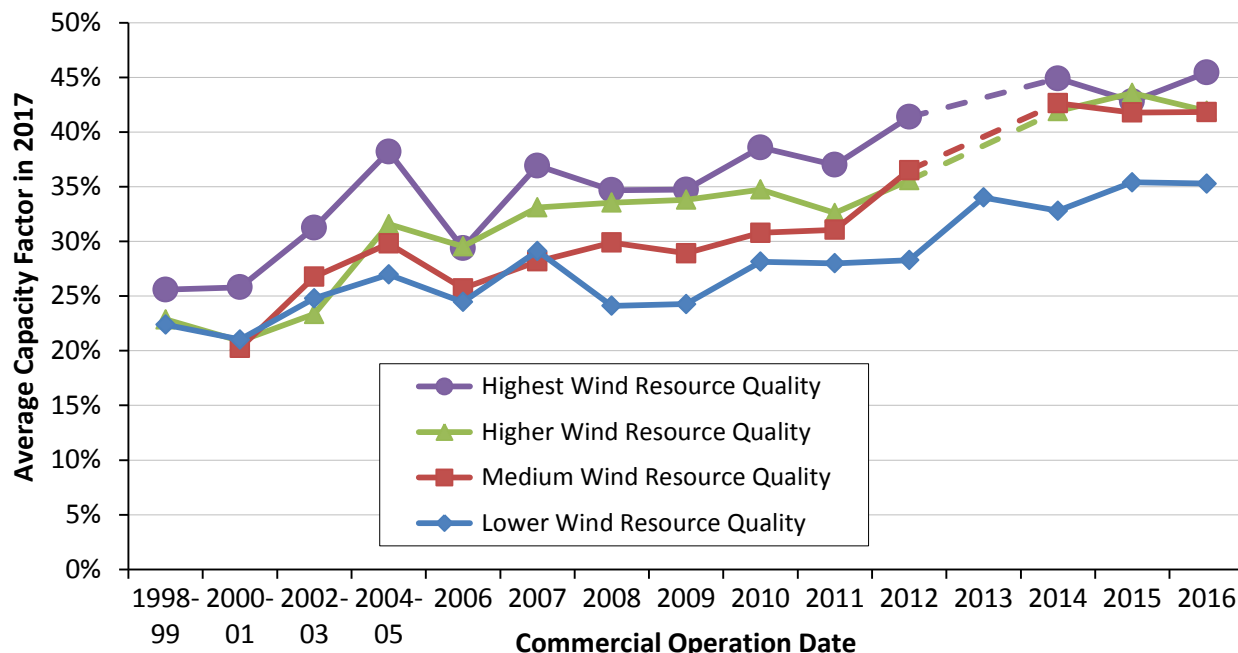
Note: See the Appendix for details on how the wind resource quality at each individual project site is estimated.

Source: Berkeley Lab

Figure 37. Calendar year 2017 capacity factors by wind resource quality and specific power: 1998-2016 projects

As a result, it is clear that turbine design changes (specifically, lower specific power, but also, to a lesser extent, higher hub heights) are driving realized capacity factors higher among projects located within a given wind resource regime. This finding is further illustrated in Figure 38, which again groups projects into the same four different categories of wind resource quality, and then reports average realized 2017 capacity factors by commercial operation date within each category.⁵⁰ As before, projects sited in higher wind speed areas have, on average, higher capacity factors. More importantly, although there is some variability in the year-to-year trends, it is clear that within each of the four wind resource categories there has been an improvement in capacity factors over time, by commercial operation date.

⁵⁰ The figure only includes those data points representing at least three projects in any single resource-year pair. Among projects built in 2013, only the “lower” wind resource quality grouping meets this sample size threshold. In years where insufficient sample size prohibits the inclusion of a data point, dashed lines are used to interpolate from the prior year to the subsequent year.

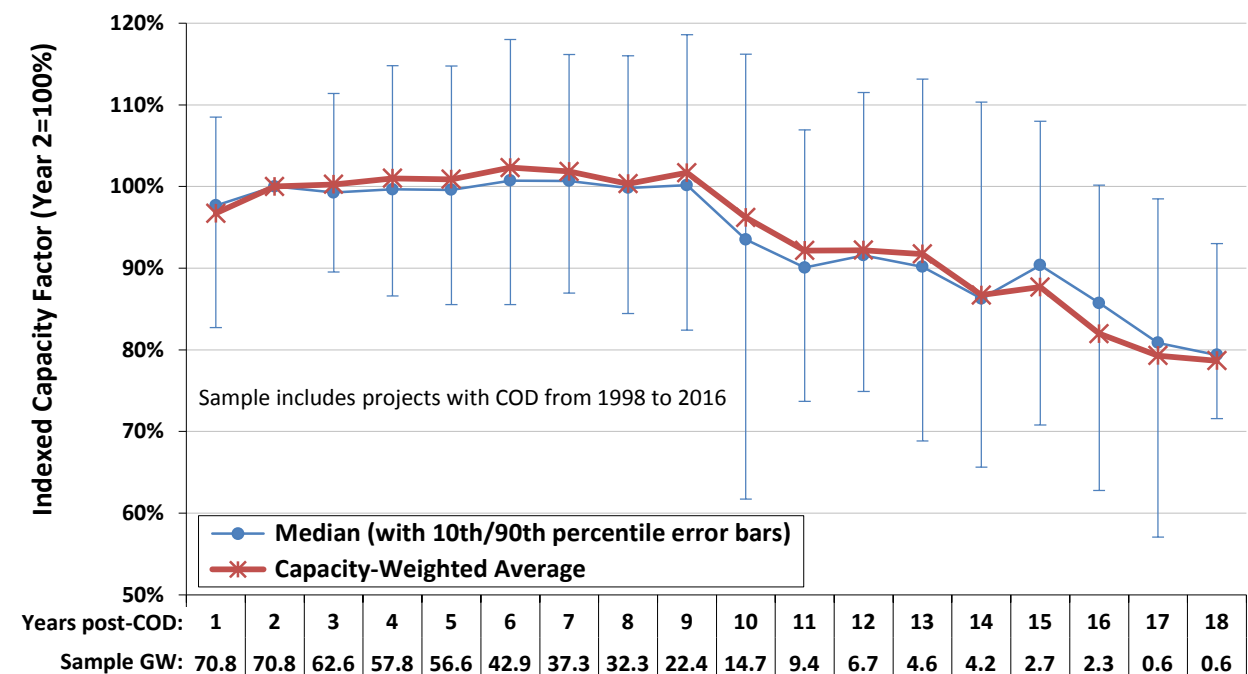


Source: Berkeley Lab

Figure 38. Calendar year 2017 capacity factors by commercial operation date and wind resource quality

One final variable that could be influencing the apparent improvement in capacity factors in 2017 among more recent projects is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998 to 2001—may have performed worse in 2017 than more recent projects simply due to their relative age. Figure 39 explores this question by graphing both median (with 10th and 90th percentile bars) and capacity-weighted average “weather-normalized” (i.e., to correct 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 (COD), and each project’s capacity factor is indexed to 100% in year two in order to focus solely on changes to each project’s capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base, rather than year 1, to reflect the initial production ramp-up period that is commonly experienced by wind projects as they work through and resolve initial “teething” issues during their first year of operations.

Figure 39 suggests some amount of performance degradation, though perhaps only once projects age beyond 9 years. Potential drivers of any such degradation might include a change in how projects are operated once they age beyond the 10-year PTC window, less-rigorous maintenance protocols following the expiration of warranties and initial service agreements, and/or more frequent component failures and downtime as equipment ages. Whatever the cause, the decline in capacity factors as projects age could partially explain why, for example, in Figure 33 the sample-wide capacity factors in 2000 and 2001 exceeded 31.5%, while in Figure 35 the projects built in 2000–2001 posted average capacity factors of just 23% in 2017.



Source: Berkeley Lab

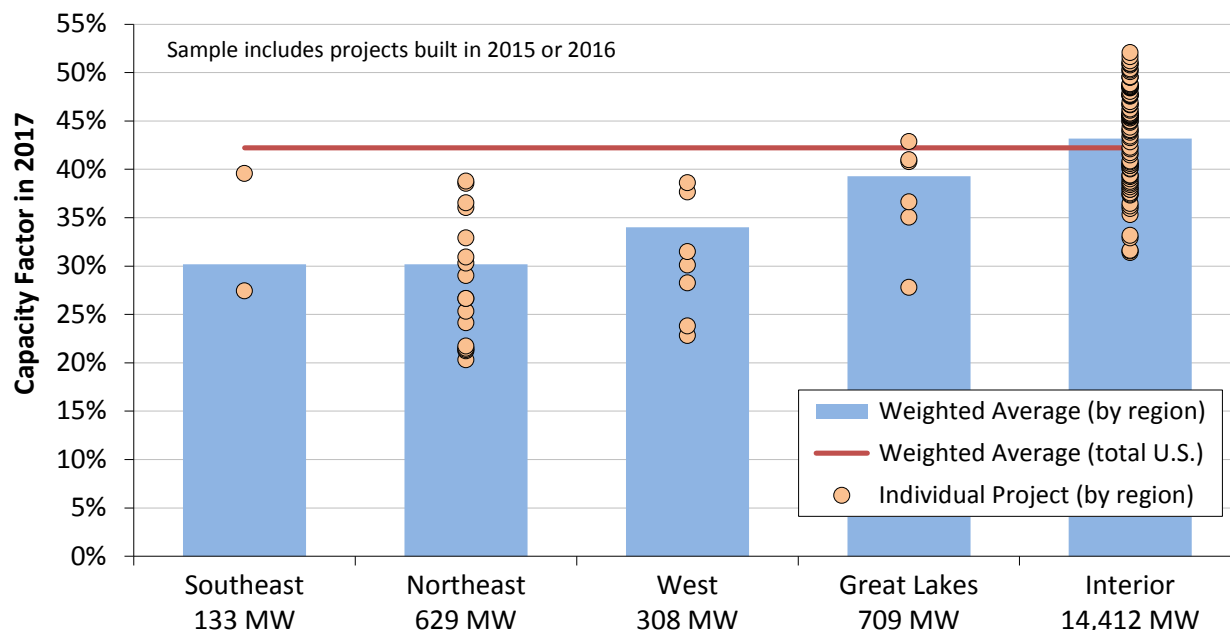
Figure 39. Post-COD changes in capacity factors over time suggest performance degradation

Although these suppositions surrounding Figure 39 are intriguing and worthy of further study, a number of caveats are in order. First, the sample is not the same in each year. The sample shrinks as the number of post-COD years increases, and is increasingly dominated by older projects using older turbine technology that may not be representative of today’s turbines.⁵¹ Second, as with all figures presented in this chapter, turbine decommissioning is accounted for by adjusting the nameplate project capacity as appropriate over time (all the way to zero if a project is fully decommissioned), such that each figure, including Figure 39, shows the performance of those turbines that are operating in each period, rather than relative to the original nameplate capacity of the overall project. Similarly, repowered projects are considered to be new projects in the year in which the repowered capacity comes online.

Regional variations in capacity factors reflect the strength of the wind resource and adoption of new turbine technology

The project-level spread in capacity factors shown in Figure 35 is enormous, with capacity factors in 2017 ranging from a minimum of 20% to a maximum of 52% among those projects built in 2016. (This spread is even wider for projects built in earlier years.) Some of the spread in project-level capacity factors—for projects built in 2016 and earlier—is attributable to regional variations in average wind resource quality. As such, Figure 40 shows the regional variation in capacity factors in 2017 (using the regional definitions shown in Figure 1, earlier) based on just the sample of wind power projects built in 2015 or 2016.

⁵¹ The trend shown in Figure 39 does not change appreciably if one focuses only on older projects. It remains to be seen whether newer projects using newer turbine technology will show a similar deterioration in capacity factors in their second decades of operations.



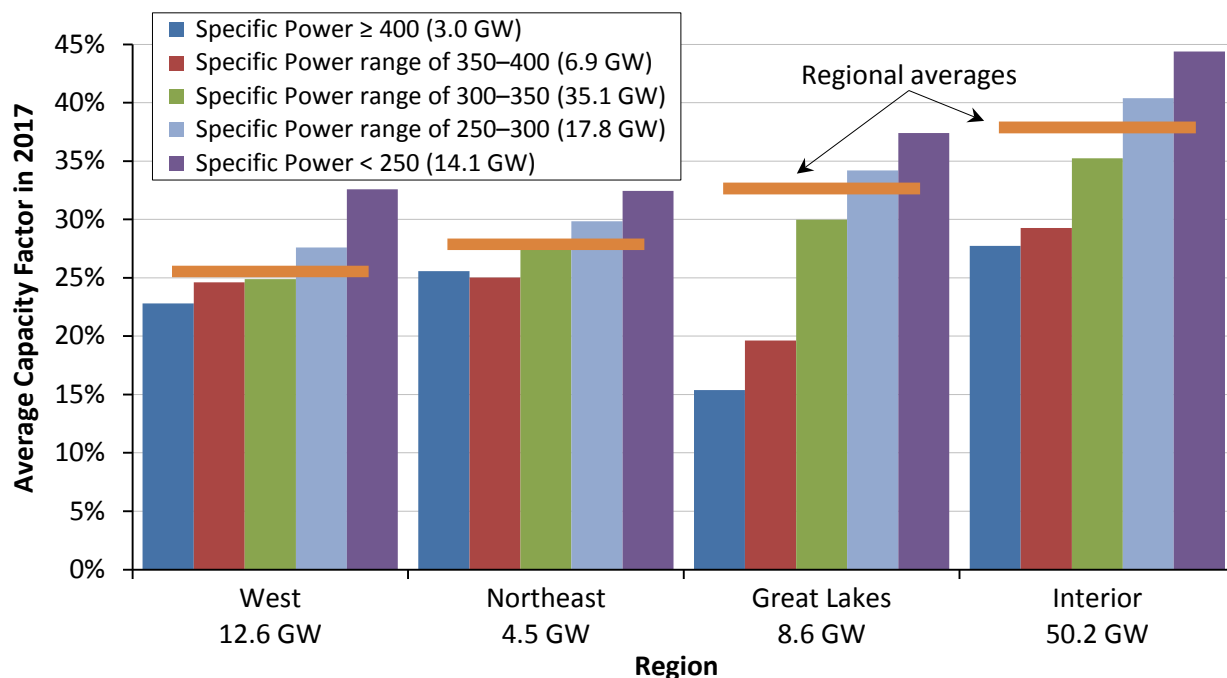
Source: Berkeley Lab

Figure 40. Calendar year 2017 capacity factors by region: 2015–2016 projects only

Four of the five regions have a limited sample, due to the fact that 89% of the total capacity installed in 2015 and 2016 was located in the Interior region. Nonetheless, generation-weighted average capacity factors appear to be highest in the Interior region (43.2%) and the lowest in the Southeast and Northeast (both at 30.2%), with the West and Great Lakes regions coming in at the mid- and upper-30% range, respectively.⁵² Even within these regions, however, there can still be considerable spread—e.g., 2017 capacity factors range from 31% up to 52% among projects installed in the Interior region in 2015 or 2016.

Some of this intra-regional variation can be explained by turbine technology. Figure 41 also provides a regional breakdown, although in this case it includes projects built from 1998 to 2016, which are further differentiated by average specific power. Including older projects (i.e., in this case, going back to 1998) in Figure 41 is necessary in order to have sufficient sample within each region to enable a specific power breakout. As one would expect, within each of the four regions shown (the Southeast is omitted due to insufficient sample), projects using turbines that fall into a lower specific power range generally have higher realized capacity factors than those in a higher specific power range.

⁵² Care should be taken in extrapolating these results, given the relatively small sample size in some regions, as well as the possibility that certain regions may have experienced a particularly good or bad wind resource year or different levels of wind energy curtailment in 2017.



Source: Berkeley Lab

Figure 41. Calendar year 2017 capacity factors by region and specific power: 1998-2016 projects

As shown earlier in Chapter 4, the rate of adoption of turbines with lower specific power ratings has varied by region. For example, Figure 28 (earlier) shows that 71% of all turbines installed in the Great Lakes region from 2015 to 2017 have a specific power rating of less than 250 W/m², while the comparable number in the Northeast is 17%. Similarly, 64% of all turbines installed in the Great Lakes region from 2015 to 2017 have tower heights of at least 90 meters, compared to 0% in the West. The relative degree to which projects in each region have employed these turbine design options (which is driven, in part, by the wind resource conditions in each region) influences, to some extent, their capacity factors shown in Figure 40 and Figure 41.

Taken together, Figure 33 through Figure 41 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of factors. 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.

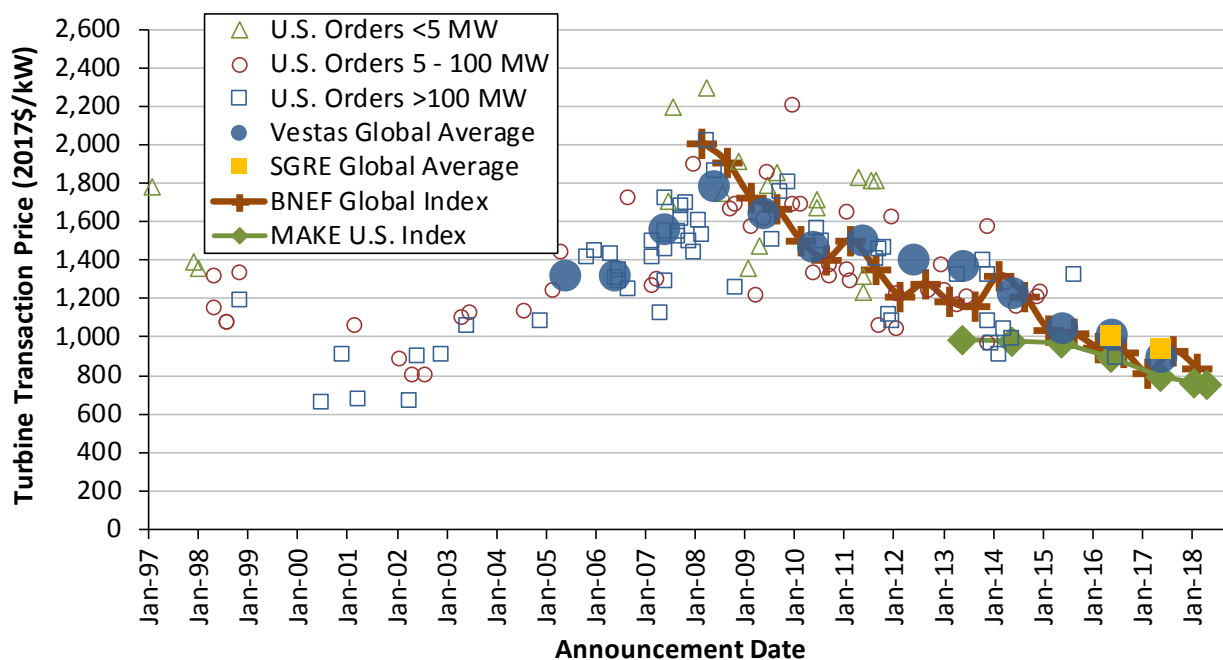
6 Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally operations and maintenance (O&M) costs. Sample size varies among these different datasets, and is therefore discussed in each section of this chapter.

Wind turbine prices remained well below levels seen a decade ago

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Further cost decreases occurred in 2017, with wind turbines sold at price points similar to the early 2000s.

Figure 42 depicts wind turbine transaction prices from a variety of sources: (1) Vestas and SGRE, on those companies’ global average turbine pricing, as reported in corporate financial reports; (2) BNEF (2018b) and MAKE (2018), on those companies’ turbine price indices by contract signing date; and (3) 122 U.S. wind turbine transactions totaling 30,780 MW announced from 1997 through 2016, as previously collected by Berkeley Lab.⁵³ 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, driving 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.



Sources: Berkeley Lab, Vestas, SGRE, BNEF, MAKE

Figure 42. Reported wind turbine transaction prices over time

⁵³ Sources of turbine price data for these 122 transactions vary, and include financial and regulatory filings, as well as press releases and news reports. Most of the transactions include turbines, towers, delivery to site, and limited warranty and service agreements, but the precise content of many of the individual transactions is not known.

After hitting a low of roughly \$800/kW from 2000 to 2002, average wind turbine prices increased by more than \$800/kW through 2008, rising to an average of greater than \$1,600/kW. 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 due in part to strong demand growth; and increased costs for turbine warranty provisions (Moné et al. 2017).

Since 2008, wind turbine prices have steeply declined, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher (Moné et al. 2017) as well as increased competition among manufacturers and significant cost-cutting measures on the part of turbine and component suppliers. As shown in Figure 42, data from Vestas, SGRE, BNEF, and MAKE signal average pricing in the range of \$750/kW to \$950/kW.

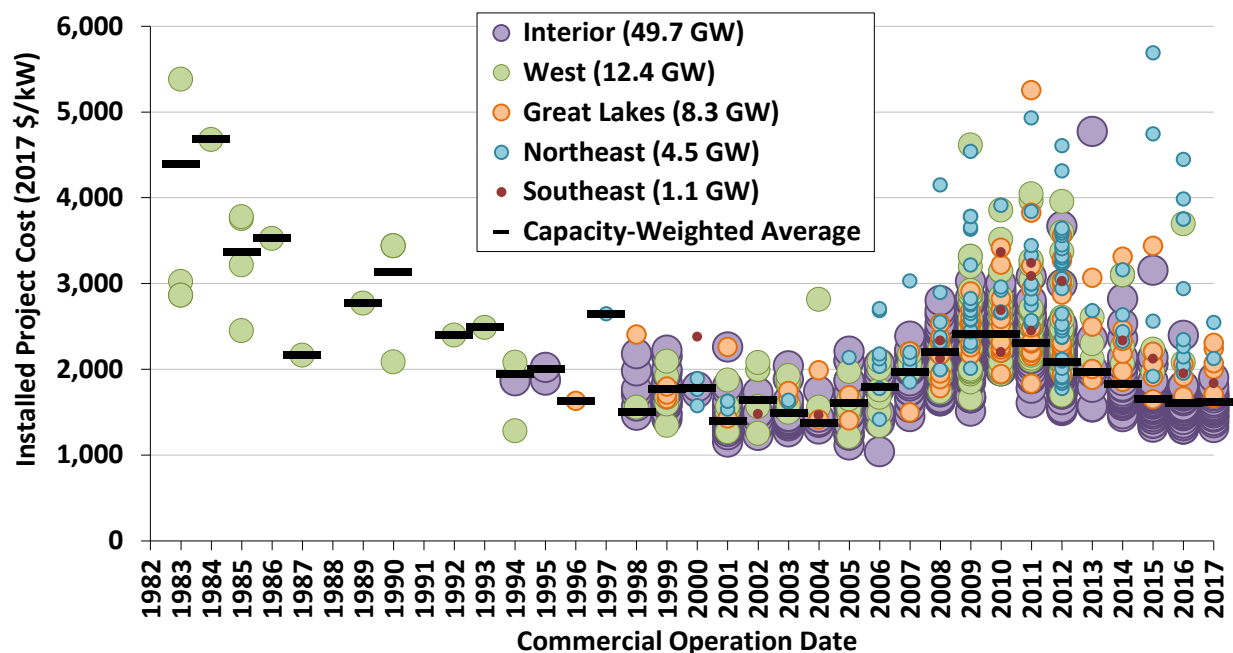
Overall, these figures suggest price declines of roughly 50% since late 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., the recent growth in average hub heights and rotor diameters shown in Chapter 4) and, in some cases, more favorable terms for turbine purchasers (e.g., more-stringent performance guarantees). These turbine price trends have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights are improving capacity factors and further reducing wind power prices. At the same time, it is important to acknowledge that this downward trend is compared to a 2008 peak in the market in terms of turbine pricing, and that looking back farther in time, turbine prices have only recently fallen back to where they were in the early 2000s.

Lower turbine prices have driven reductions in reported installed project costs

Berkeley Lab also compiles data on the total installed cost of wind projects in the United States, including data on 37 projects completed in 2017 totaling 5,275 MW, or 75% of the wind power capacity installed in that year. In aggregate, the dataset (through 2017) includes 917 completed wind power projects in the continental United States totaling 76,172 MW and equaling roughly 86% of all wind power capacity installed at the end of 2017. 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 43, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s,⁵⁴ and then increased—reflecting turbine price changes—through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010, with declines since that time. It is not surprising that changes in average installed project costs would lag behind changes in average turbine prices, as this reflects the normal passage of time between when a turbine supply agreement is signed (the announcement date in Figure 42) and when those turbines are actually installed and commissioned (the commercial operations date in Figure 43).

⁵⁴ Although our sample size in the 1980s and 1990s is relatively sparse compared to more recent years, for the most part, the individual project-level data and capacity-weighted averages for projects built in the 1980s and 1990s are consistent with average cost data for a subset of those years reported by the California Energy Commission (1988) and Gipe (1995).



Sources: Berkeley Lab (some data points suppressed to protect confidentiality), Energy Information Administration

Figure 43. Installed wind power project costs over time

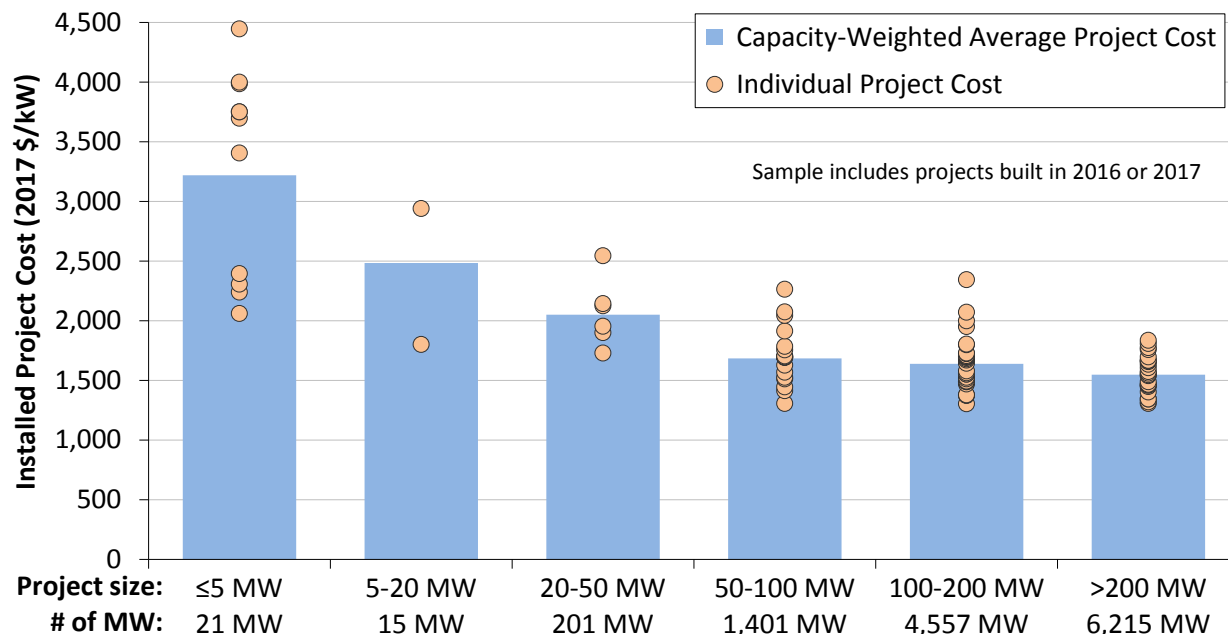
In 2017, the capacity-weighted average installed project cost within our sample stood at roughly \$1,610/kW. This is down \$795/kW or 33% from the apparent peak in average reported costs in 2009 and 2010, but is roughly on par with—or even somewhat higher than—the installed costs experienced in the early 2000s. All of the lowest-cost projects in recent years are located in the Interior region, which dominates the sample and where average costs have fallen by more than \$830/kW since 2010. Early indications from a limited sample of 11 projects (totaling 1.5 GW) currently under construction and anticipating completion in 2018 suggest that capacity-weighted average installed costs in 2018 will be slightly lower than in 2017.

Installed costs differed by project size, turbine size, and region

Average installed project costs exhibit economies of scale, which are especially evident when moving from small- to medium-sized projects. Figure 44 shows that among the sample of projects installed in 2016 and 2017, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 50–100 MW range. Economies of scale continue, though to a lesser degree, as project size increases beyond 100 MW.

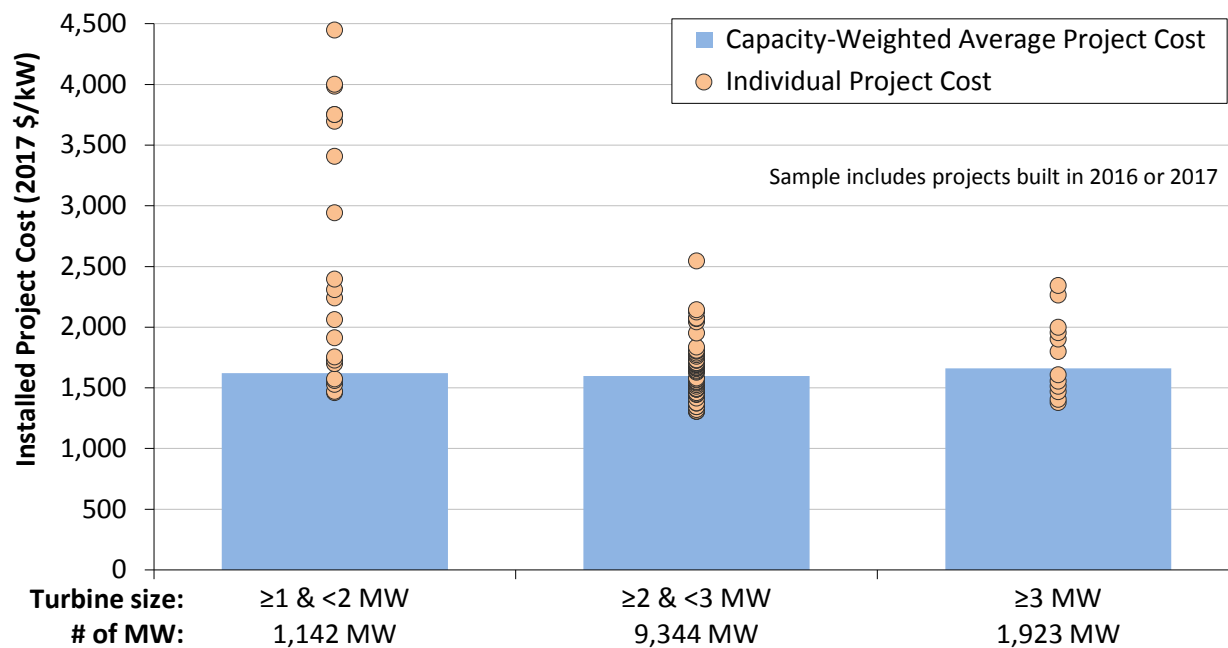
Another way to look for economies of scale is by turbine size (rather than by project size), on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines as opposed to more, smaller turbines. Figure 45 explores this relationship and finds mixed results. Although projects using smaller turbines (between 1 and 2 MW) exhibit significantly more cost variability, and in some cases are clearly more expensive than projects using larger turbines on a \$/kW basis, the capacity-weighted average costs do not vary significantly across the three turbine size bins.⁵⁵

⁵⁵ There is some correlation between turbine size and project size, at least at the low end of the range of each. As such, Figure 44 and Figure 45—both of which show a handful of high-cost projects in the smallest project or turbine size bin—could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.



Source: Berkeley Lab

Figure 44. Installed wind power project costs by project size: 2016–2017 projects

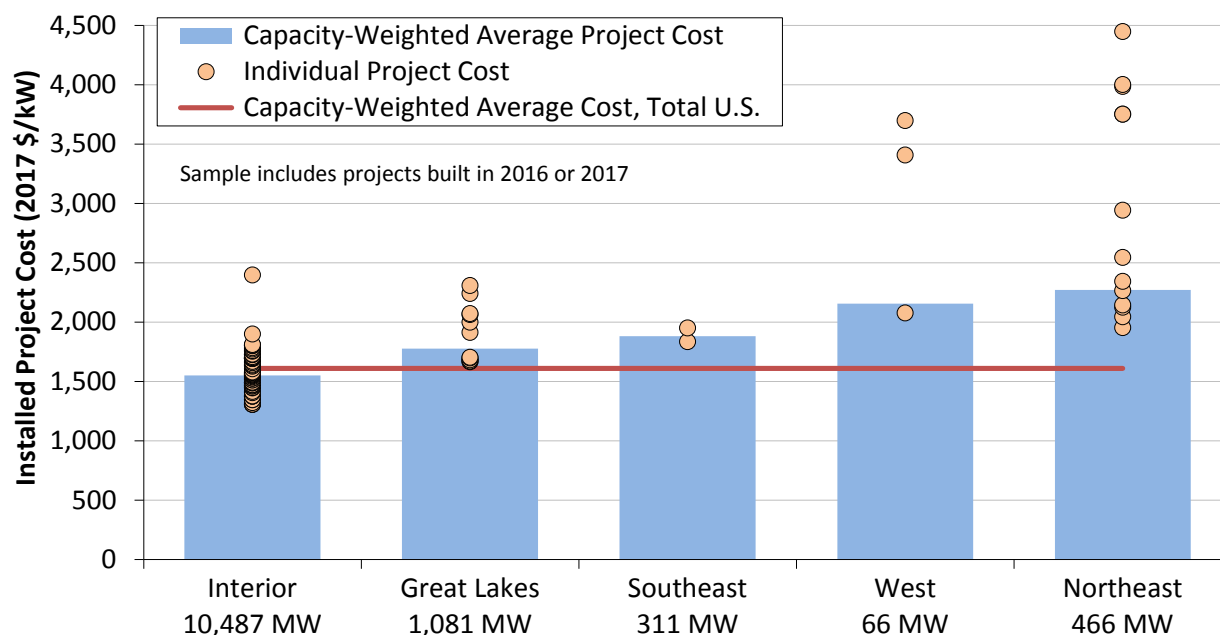


Source: Berkeley Lab

Figure 45. Installed wind power project costs by turbine size: 2016–2017 projects

As intimated earlier in Figure 43, regional differences in average project costs are also apparent and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2016 or 2017, Figure 46 breaks out project costs

among the five regions defined in Figure 1.⁵⁶ The Interior region—with by far the largest sample—was the lowest-cost region on average, with an average cost of \$1,550/kW, while the Northeast was the highest-cost region.⁵⁷ Two of the other three regions have very limited sample size.



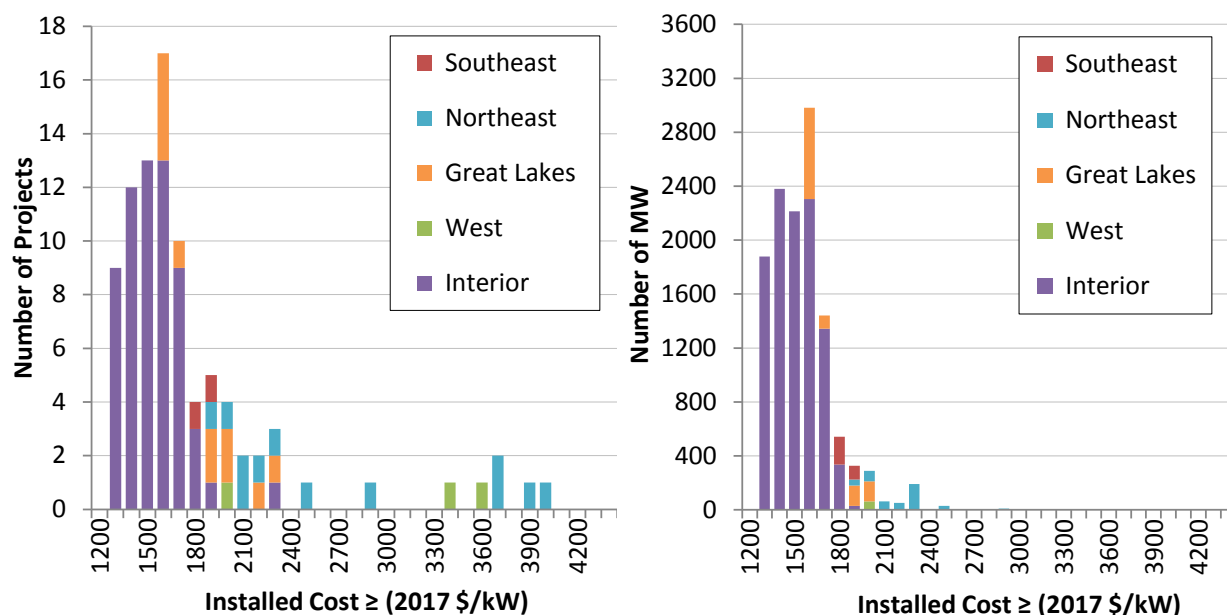
Source: Berkeley Lab

Figure 46. Installed wind power project costs by region: 2016–2017 projects

Finally, Figure 47 shows two histograms that present the distribution of installed project costs among 2016 and 2017 projects, in terms of both number of projects and capacity. Most of the projects—and most of the low-cost projects—are located in the Interior region, where the distribution is centered on the \$1,300–\$1,700/kW bins. Projects in other regions generally have higher costs (a number of the high-cost projects shown in the left half of the figure are not visible in the right half because their capacity is very small).

⁵⁶ For reference, the 88,973 MW of wind installed in the United States at the end of 2017 is apportioned among the five regions shown in Figure 1 as follows: Interior (66%), West (16%), Great Lakes (11%), Northeast (5%), and Southeast (1%). The remaining installed U.S. wind power capacity is located in Hawaii, Alaska, and Puerto Rico and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

⁵⁷ Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 46.



Source: Berkeley Lab

Figure 47. Histogram of installed costs by MW and projects: 2016–2017 projects

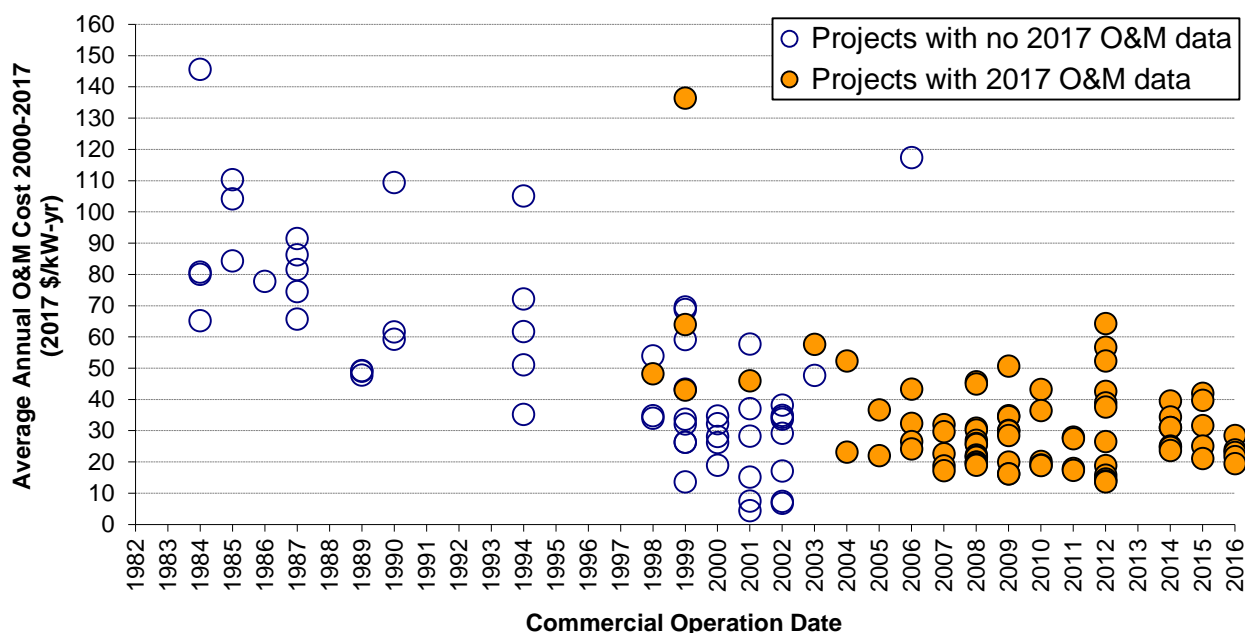
Operations and maintenance costs varied by project age and commercial operations date

Operations and maintenance costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available market 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 dramatic changes in wind turbine technology that have occurred over time (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 164 installed wind power projects in the United States, totaling 14,146 MW and with commercial operation dates of 1982 through 2016. 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 the data sources do not all 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.⁵⁸ Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, Figure 48 and Figure 49 are not representative of *total* operating expenses for wind power projects; the last paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow should be taken only as indicative of potential overall trends. Note finally that the available data are presented in \$/kW-year terms, as if O&M represents only a fixed cost. In fact, O&M costs are in part variable and in part fixed; expressing O&M costs in units of \$/MWh yields qualitatively similar results to those presented in this section.

⁵⁸ The vast majority 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.

Figure 48 shows project-level O&M costs by commercial operation date.⁵⁹ Here, each project’s O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2017, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2016, only year 2017 data are available, and that is what is shown.⁶⁰ Many other projects only have data for a subset of years during the 2000–2017 timeframe, so each data point in the chart may represent a different averaging period within the overall 2000–2017 timeframe. The chart highlights the 80 projects, totaling 10,506 MW, for which 2017 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 48. Average O&M costs for available data years from 2000 to 2017, by COD

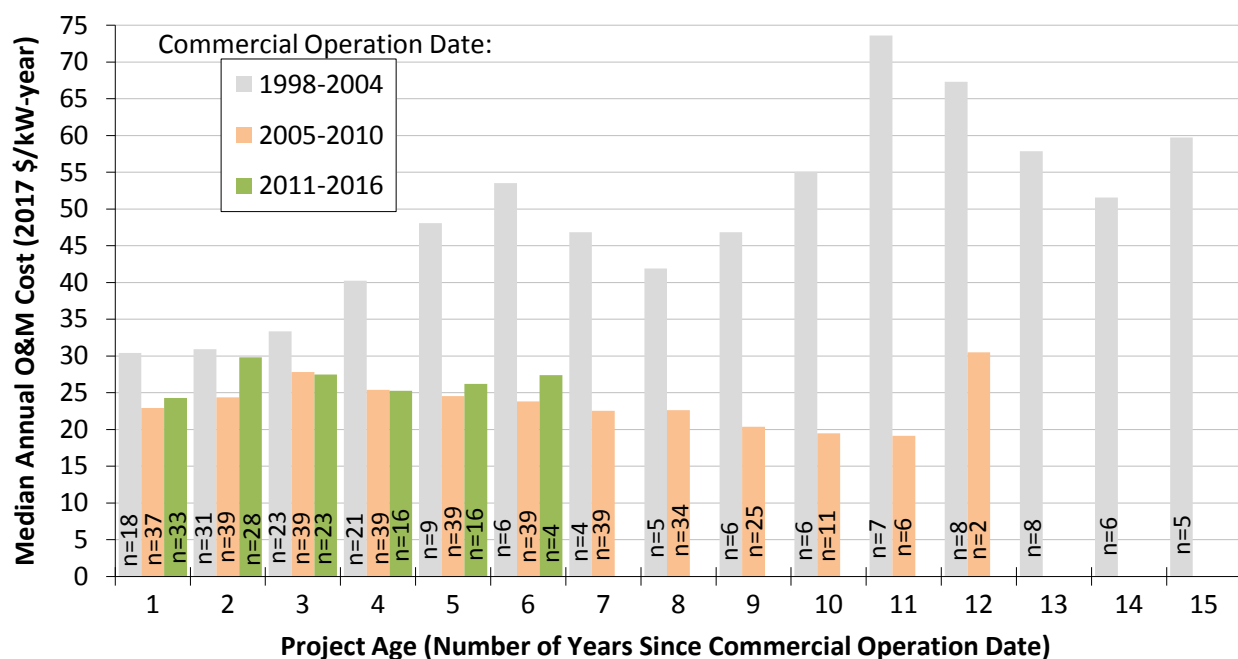
The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 48 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2017 O&M costs for the 24 projects in the sample constructed in the 1980s equal \$70/kW-year, dropping to \$58/kW-year for the 37 projects installed in the 1990s, to \$28/kW-year for the 65 projects installed in the 2000s, and staying at \$28/kW-year for the 38 projects installed

⁵⁹ For projects installed in multiple phases, the commercial operation date of the largest phase is used. For re-powered projects, the date at which re-powering was completed is used.

⁶⁰ Projects installed in 2017 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2017 would be year 2018.

since 2010.^{61,62} This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and manufacturer warranties expire;⁶³ and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a \$/kW-year basis.

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 49 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. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale, which reportedly can be significant (BNEF 2018c). Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially.



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

Figure 49. Median annual O&M costs by project age and commercial operation date

With these limitations in mind, Figure 49 shows an upward trend in project-level O&M costs as projects age, at least among the oldest projects in our sample—i.e., those built from 1998 to 2004—although the sample size

⁶¹ Somewhat consistent with these observed O&M cost magnitudes (if not necessarily time trends), BNEF (2018c) reports that, globally, the average cost from a sample of initial full-service O&M contracts was \$21.3/kW-year for those agreement signed in 2015, \$26.4/kW-year in 2016, and \$20.5/kW-year in 2017. North American contracts in 2017, meanwhile, had a reported average of just \$14/kW-yr. An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 5 GW of operating wind projects (with only about half that amount having been operable for longer than five years) also shows average levels of expenditure generally consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).

⁶² If the data in Figure 48 were expressed instead in terms of \$/MWh, capacity-weighted average 2000–2017 O&M costs were \$36/MWh for projects in the sample constructed in the 1980s, dropping to \$25/MWh for projects constructed in the 1990s, to \$11/MWh for projects constructed in the 2000s, and to \$9/MWh for projects constructed since 2010.

⁶³ Some of the projects installed most recently may still be within their turbine manufacturer warranty period, and/or may have partially capitalized O&M service contracts within their turbine supply agreement. In either case, reported O&M costs would be artificially low.

after year 4 is rather limited for these earliest projects. Those projects built in 2005 or after, on the other hand, do not show a consistent trend in costs with project age. Figure 49 also shows that projects installed more recently have had, in general, lower O&M costs than those installed in earlier years (1998-2004), at least for the first 12 years of operation, with little difference in observed costs between the sample of projects built from 2005 to 2010 and those built from 2011 to 2016.

As indicated previously, the data presented in Figure 48 and Figure 49 include only a subset of total operating expenses. In comparison, the financial statements of EDP Renováveis (EDPR), a public company that owned more than 4.9 GW of U.S. wind project assets at the end of 2017 (all of which have been installed since 2000), indicate markedly higher total operating costs. Specifically, EDPR (2018) reported total operating expenses of \$53/kW-year for its North American portfolio in 2017⁶⁴—roughly twice the ~\$28/kW-year average O&M cost reported above for the 103 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between EDPR and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, EDPR breaks out its total U.S. operating costs in 2017 (\$53/kW-year) into three categories: supplies and services, which “includes O&M costs” (\$33/kW-year); personnel costs (\$11/kW-year); and other operating costs, which “mainly includes operating taxes, leases, and rents” (\$9/kW-year). Among these three categories, the \$33/kW-year for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings (i.e., that turbine and balance-of-plant O&M costs make up only about half of total operating costs), NREL analysis based on data from the energy consultancy DNV KEMA on plants commissioned before 2009 shows total operating expenditures of \$40–\$60/kW-year (in 2011 dollars) depending on project age, with turbine and balance-of-plant O&M costs representing roughly half of those expenditures (Lantz 2013).

⁶⁴ Though not entirely clear, EDPR’s reported operating expenses may exclude any repair or replacement costs that have been capitalized rather than expensed. Also, at the end of 2017, EDPR’s North American portfolio consisted of 4,965 MW of wind and 90 MW of PV in the United States, along with 30 MW of wind in Canada and 200 MW of wind in Mexico. Hence, reported North American operating costs are neither entirely U.S.-based nor entirely for wind.

7 Wind Power Price Trends

Earlier sections documented trends in capacity factors, wind turbine prices, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices presented in this chapter. In general, higher-cost and/or lower-capacity-factor projects will require higher PPA prices, while lower-cost and/or higher-capacity-factor projects can have lower PPA prices.

Berkeley Lab collects data on wind PPA prices from the sources listed in the Appendix, resulting in a dataset that currently consists of 435 PPAs totaling 40,360 MW from wind projects that have either been built (from 1998 to the present) or are planned for installation later in 2018 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs), and most of them have a utility as the counterparty.⁶⁵

Except where noted, PPA prices are expressed throughout this chapter on a levelized basis over the full term of each contract, and are reported in real 2017 dollars.⁶⁶ Whenever individual PPA prices are averaged together (e.g., within a region or over time), the average is generation-weighted.⁶⁷ Whenever they are broken out by time, the date on (or year in) which the PPA was signed or executed is used, as that date provides the best indication (i.e., better than commercial operation date) of market conditions at the time. Finally, because the PPA prices in the Berkeley Lab sample are reduced by the receipt of state and federal incentives (e.g., the levelized PPA prices reported here would be at least \$15/MWh higher without the PTC, ITC, or Treasury Grant⁶⁸) and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. That said, we loosely estimate the levelized cost of energy for a large sample of U.S. wind projects in a later text box.

This chapter summarizes wind PPA prices in a number of different ways: by PPA execution date, by region, compared to past wholesale energy market value, and compared to future natural gas prices. In addition, REC prices are presented in a subsequent text box.

⁶⁵ Though we do have pricing details for some PPAs with corporate off-takers, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a “contract for differences” with the corporate off-taker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through traditional sources, like regulatory filings). Though only a minor omission at present, this distinction could limit our sample more severely in the future if corporate off-take agreements remain popular.

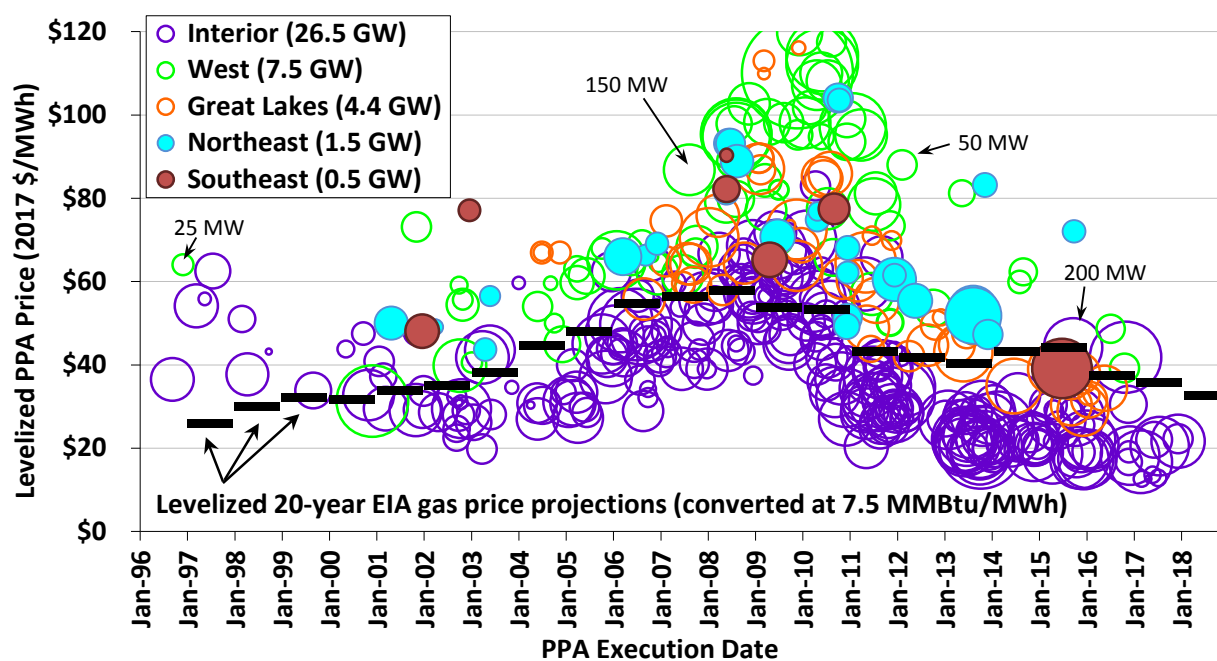
⁶⁶ Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 35 years, with 20 years being by far the most common (at 57% of the sample; 89% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 7% real discount rate.

⁶⁷ Generation weighting is based on the empirical project-level performance data analyzed earlier in this report and assumes that historical project performance (in terms of annual capacity factor as well as daily and/or seasonal production patterns where necessary) will hold into the future as well. In cases where there is not enough operational history to establish a “steady-state” pattern of performance, we used discretion in estimating appropriate weights (to be updated in the future as additional empirical data become available).

⁶⁸ The estimated levelized PPA price impact of \$15+/MWh is different from the PTC’s 2018 face value of \$24/MWh for several reasons. First, the PTC is a 10-year credit, whereas most PPAs are for longer terms (e.g., 20 years). Second, the PTC is a tax credit, and must be converted to pre-tax equivalent terms before being compared to PPA prices. Finally, the presence of the PTC constrains financing choices for many wind project owners and drives up the project’s weighted average cost of capital. In other words, if not for the PTC, projects could be financed more cheaply; this difference in the weighted average cost of capital with and without the PTC erodes some of the PTC’s value (for more information, see Bolinger (2014)).

Wind power purchase agreement prices remain very low

Figure 50 plots contract-level levelized wind power purchase agreement (PPA) prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region (see Figure 1 for regional definitions).⁶⁹ Because of the relatively larger sample of PPAs, this trend is particularly evident in the Interior region, which—as a result of its low average project costs and high average capacity factors shown earlier in this report—also tends to be the lowest-priced region over time. Prices generally have been higher in the rest of the United States.⁷⁰



Note: Area of “bubble” is proportional to contract nameplate capacity

Sources: Berkeley Lab, Energy Information Administration

Figure 50. Levelized wind PPA prices by PPA execution date and region

Figure 50 also shows that wind power PPA prices—particularly in the U.S. Interior region, but also in other regions in some cases—have been competitive with the projected fuel costs of gas-fired combined cycle generators over time. 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 MMBtu/MWh) from then-current EIA projections of natural gas prices delivered to electricity generators.⁷¹

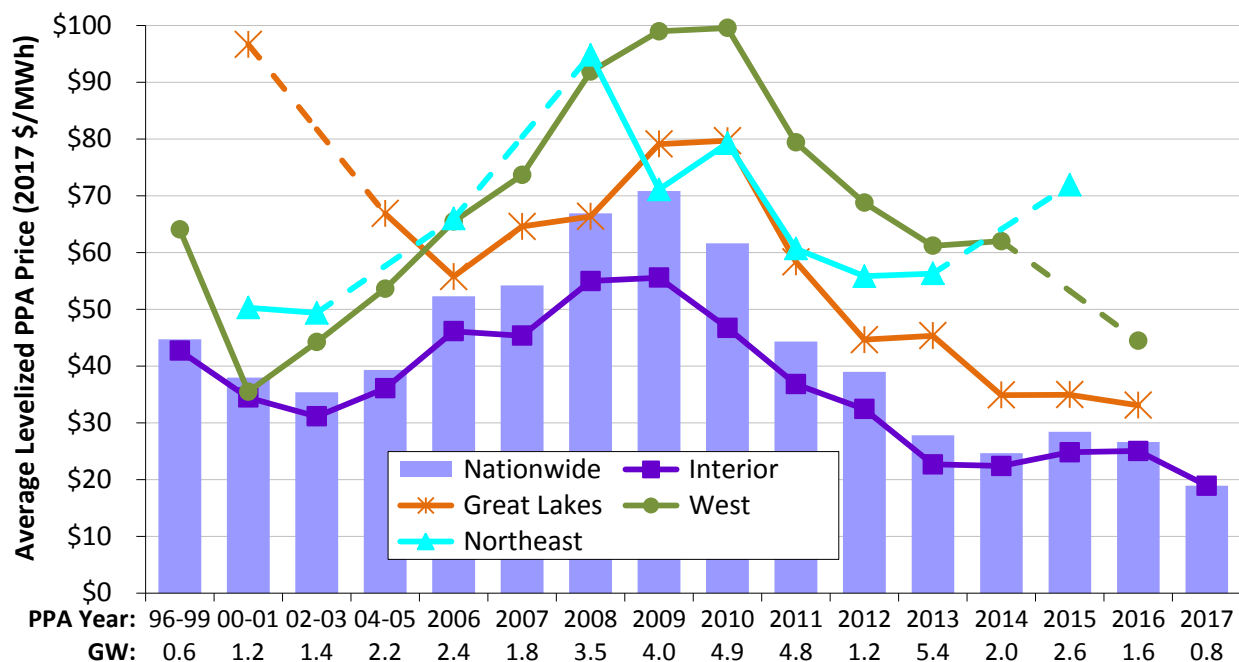
Figure 51 provides a smoother look at the time trend nationwide and regionally by averaging the individual levelized PPA prices shown in Figure 50 by year. After topping out at \$70/MWh for PPAs executed in 2009,

⁶⁹ Roughly 99% of the contracts that are depicted in Figure 48 are from projects that are already online. For the most part, only the most recent contracts in the sample are from projects that are not yet online.

⁷⁰ Regional differences can affect not only project capacity factors (depending on the strength of the wind resource in a given region), but also development and installation costs (depending on a region’s physical geography, population density, labor rates, or even regulatory processes). It is also possible that regions with higher wholesale electricity prices or with greater demand for renewable energy will, in general, yield higher wind energy contract prices due to market influences.

⁷¹ For example, the black dash marker in 1997 shows the 20-year levelized gas price projection from Annual Energy Outlook 1997, while the black dash in 2018 shows the same from Annual Energy Outlook 2018 (both converted to \$/MWh terms at a constant heat rate of 7.5 MMBtu/MWh).

the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped to around or even below \$20/MWh—though this nationwide average is admittedly focused on a sample of projects that largely hail from the lowest-priced Interior region of the country where most of the new capacity built in recent years is located. Focusing only on the Interior region, the PPA price decline has been more modest, from ~\$55/MWh among contracts executed in 2009 to below \$20/MWh in 2017.⁷² Prices declined especially rapidly from 2009 to 2013, and appear to have been stable or to have declined more modestly since that time.



Source: Berkeley Lab

Figure 51. Generation-weighted average levelized wind PPA prices by PPA execution date and region

The trend of rising PPA prices from 2003 to 2009 and then falling prices since then is directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent projects, as documented in Chapter 5. This combination of declining costs and improved performance—along with historically low (but rising) interest rates (as shown earlier in Figure 17) and natural gas prices (as shown in Figure 50)—has driven wind PPA prices to today’s record-low levels.

Figure 51 also shows trends in the generation-weighted average levelized PPA price over time among four of the five regions broken out in Figure 1 (the Southeast region is omitted from Figure 51 owing to its small sample size). Figure 50 and Figure 51 both demonstrate that, based on our contract sample, PPA prices are generally lower in the U.S. Interior, higher in the West, and moderate in the Great Lakes and Northeast regions. As shown by the close agreement between the two, the large Interior region—where much of U.S. wind project development occurs—dominates the nationwide sample, particularly in recent years.

⁷² Other sources (e.g., LevelTen Energy 2018) have noted recently signed PPAs that are priced significantly below \$20/MWh—in some cases in the low-to-mid teens per MWh. Although we have yet to see data on most of these contracts, within our current sample there are five projects totaling 819 MW that sell their output through nine different PPAs signed in either 2016 or 2017, all with levelized pricing below \$20/MWh. The levelized prices of these nine PPAs range from \$12.7/MWh to \$19.3/MWh, with an average of \$15.6/MWh (all in real 2017 dollars).

The economic competitiveness of wind power has been affected by low natural gas prices and by declines in the wholesale market value of wind energy

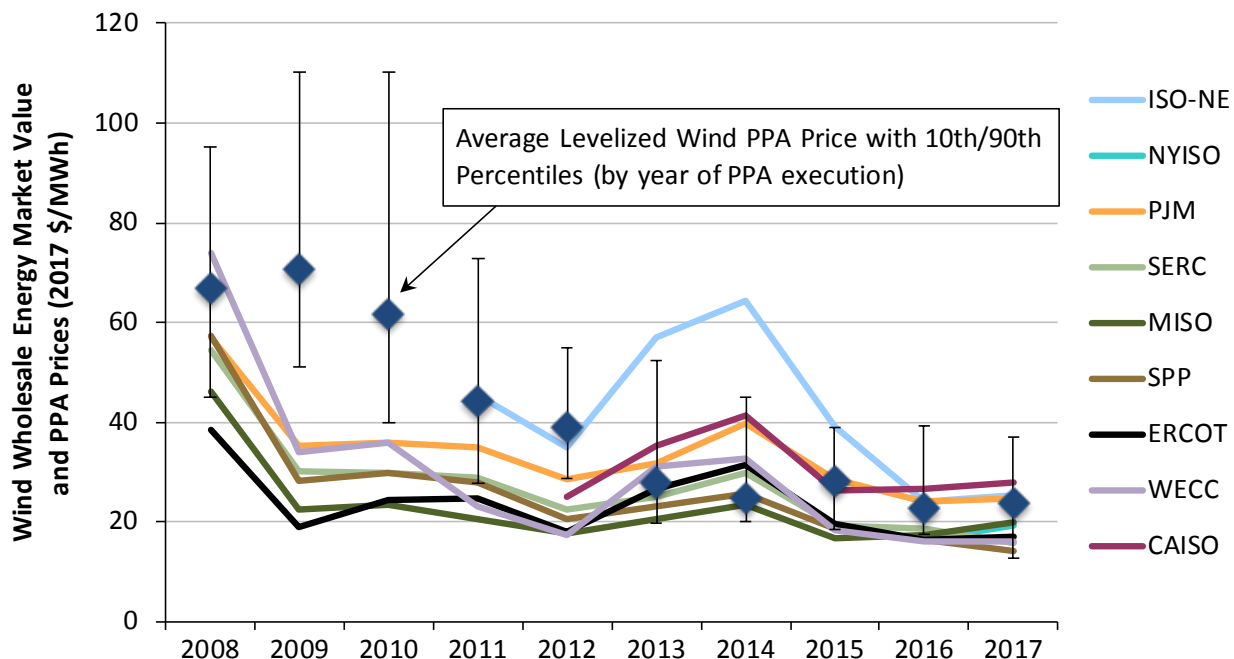
In many regions of the country, wind energy participates in organized wholesale electricity markets for energy and, where available, capacity. In some cases, wind projects directly bid into those markets, and earn the prevailing market price. In other cases—especially when a PPA is in place—the wind energy purchaser will sometimes 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.

In either instance, 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, the link is direct and affects the revenue of the plant. In the case of wind projects sold under a PPA, on the other hand, the pre-negotiated PPA price establishes plant revenue and, depending on the specifics of the PPA, pricing may or may not be linked to wholesale market prices. In this latter case, however, the revenue earned or 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 case, 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 were it 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. Overall, these prices have fallen over the last decade, in large measure due to the decline in the price of natural gas (Wiser et al. 2017). Moreover, 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 sometimes suppressed. Even absent transmission constraints, wind plants push local wholesale energy prices lower when wind output is high. Finally, the temporal profile of wind output is not always well aligned with system needs, potentially further reducing the energy market value of wind generation. These trends and tendencies suggest that the wholesale energy market value of wind may have declined over time, and may in general be somewhat lower than the energy market value of some other generation sources.

Figure 52 estimates the historical wholesale energy market value of wind across a number of different regions of the country. Specifically, we estimate the energy market value of wind using available region-wide hourly wind output profiles and real-time hourly wholesale energy pricing patterns at the nearest pricing node for each wind project (i.e., locational marginal prices, LMPs).⁷³ Prices for specific nodes are then weighted by the quantity of wind capacity at each node, in order to estimate region-wide averages. As a result, the analysis considers the output profile of wind (albeit on a regional average basis), the location of wind, and how those characteristics interact with local wholesale energy prices to estimate the revenue that would have been earned had wind sold its energy output at the hourly LMP price of the nearest pricing node. The figure then contrasts those wholesale energy 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 energy market value estimates and PPA prices is relevant in as much as PPA prices reflect the cost of wind, whereas wholesale energy market value reflects a portion of the value of that wind generation.

⁷³ The Appendix provides additional details on the methods used to estimate the wholesale energy value of wind.



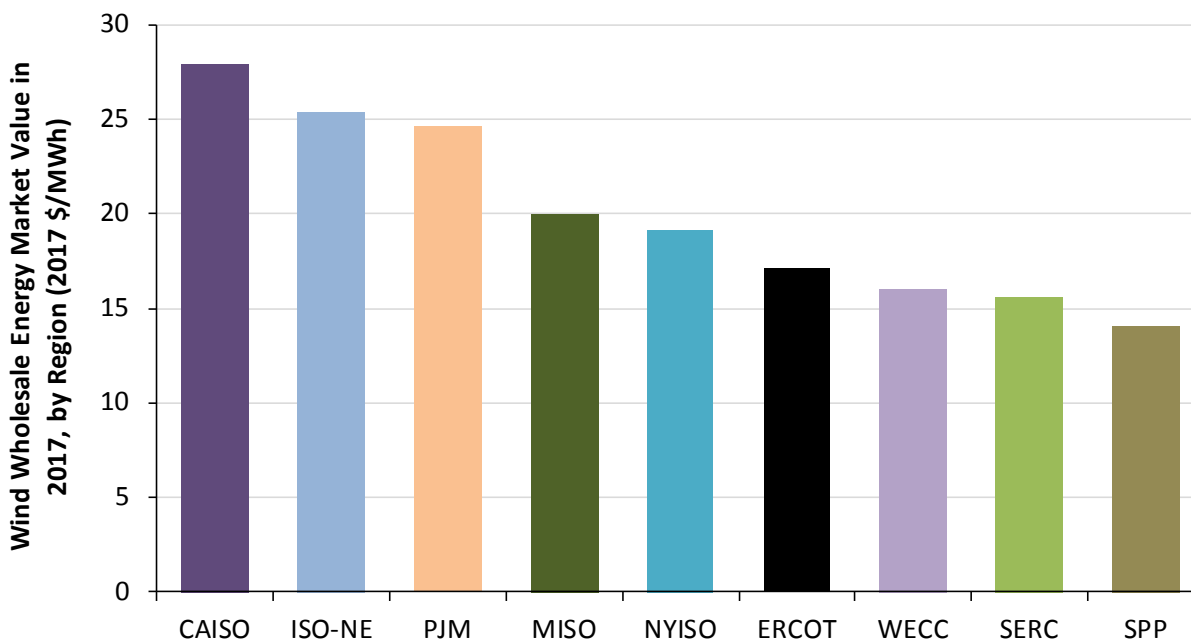
Note: Hourly wind output profiles are not available for all historical years for all regions; as such, estimates of the wholesale energy value of wind are not available for all years for all regions.

Sources: Berkeley Lab, ABB

Figure 52. Regional wholesale energy market value of wind and average levelized long-term wind PPA prices over time

These estimates show that the wholesale energy market value of wind has generally declined since 2008, and varies by region. With the sharp drop in wholesale electricity prices and therefore energy market value of wind in 2009, average wind PPA prices tended to exceed the wholesale energy market value of wind from 2009 to 2012. With continued declines in wind PPA prices, however, those prices reconnected with the energy market value of wind in 2013 and have remained generally in competitive territory in subsequent years, at least when focused on the lower-priced wind PPAs. This suggests that—with the help of the PTC, which reduces PPA prices—wind power developers and off-takers are successfully contracting at levels that are generally comparable in terms of both cost and value, at about two cents per kWh.

Because many of the regional wholesale energy market value estimates are in a similar range, it is difficult to discern individual regional estimates in Figure 52. Accordingly, Figure 53 presents these estimates of wind energy’s wholesale energy market value, by region, but only for the latest year—2017. The energy market value of wind in 2017 was the lowest in SPP, at \$14/MWh, whereas the highest-value market was CAISO at \$28/MWh.



Sources: Berkeley Lab, ABB

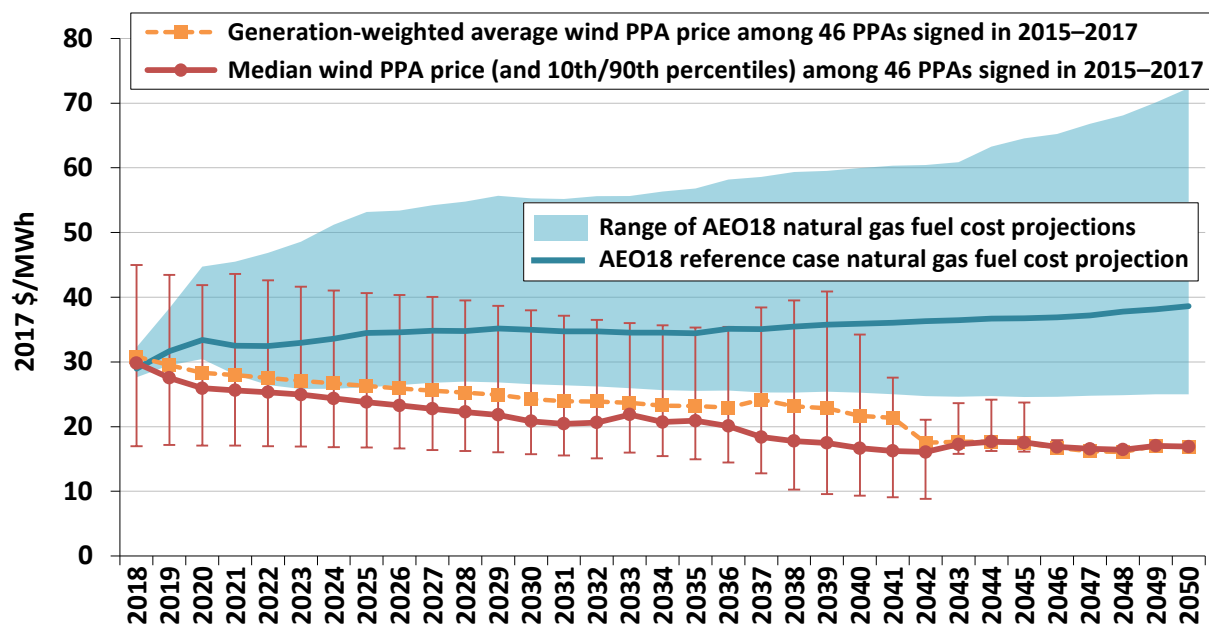
Figure 53. Regional wholesale energy market value of wind in 2017, by region

To be clear, these estimates only consider hourly wholesale energy (LMP) value. Wind power plants may also provide capacity (and perhaps ancillary services) value, either by participating in an explicit capacity market or by virtue of meeting a portion of a purchasers' capacity obligation. Given wind's generation profile during periods of electric system need, Mills et al. (2017) find that the capacity value of land-based wind in ISO-NE, NYISO, and PJM has averaged a little over \$3/MWh in recent years. This represents a roughly 15% boost in total wholesale market value when compared to energy value alone, and suggests that the value estimates presented in Figure 52 and Figure 53 understate wind's contribution to reducing electricity system costs.

The comparison between levelized wind PPA prices and wholesale wind energy values in Figure 52 is imperfect for another reason: levelized wind 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. Figure 54 attempts to remedy this temporal mismatch by presenting an alternative (yet still imperfect) way of looking at how wind stacks up relative to its competition.

Rather than leveling the wind PPA prices, Figure 54 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown, along with a generation-weighted average) from PPAs executed in 2015–2017 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.⁷⁴ As shown, the median and generation-weighted average wind PPA prices from contracts executed in the past three years are consistently below the low end of the projected natural gas fuel cost range, while the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall within the overall range by 2020.

⁷⁴ The fuel cost projections come from the EIA's *Annual Energy Outlook 2018* publication, and increase from around \$3.46/MMBtu in 2017 to \$5.41/MMBtu (both in 2017 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from \$/MMBtu into \$/MWh using the heat rates implied by the modeling output (which start at roughly 8.1 MMBtu/MWh in 2017 and gradually decline to roughly 7.2 MMBtu/MWh by 2050).



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 54 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 ultimately be lower or much 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 term of the forecast increases.

Important Note: Notwithstanding the above comparisons, 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 PPA prices with wholesale value and natural-gas cost estimates in this manner are the following:

- Wind PPA prices are reduced by virtue of federal and, in some cases, state tax and financial incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by virtue of any financial incentives provided to thermal generation and its fuel production. Wholesale electricity prices may also not fully account for the health and environmental costs of various generation technologies, and for other societal concerns such as fuel diversity, fuel security, and resilience.
- Wind 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 PPA prices—once established—are fixed and known, whereas the estimated wholesale market value of wind represent historical data and will change over time. As shown in Figure 54, EIA projects natural gas prices to rise from current levels which, all else being equal, will also result in an increase in wholesale electricity prices.

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

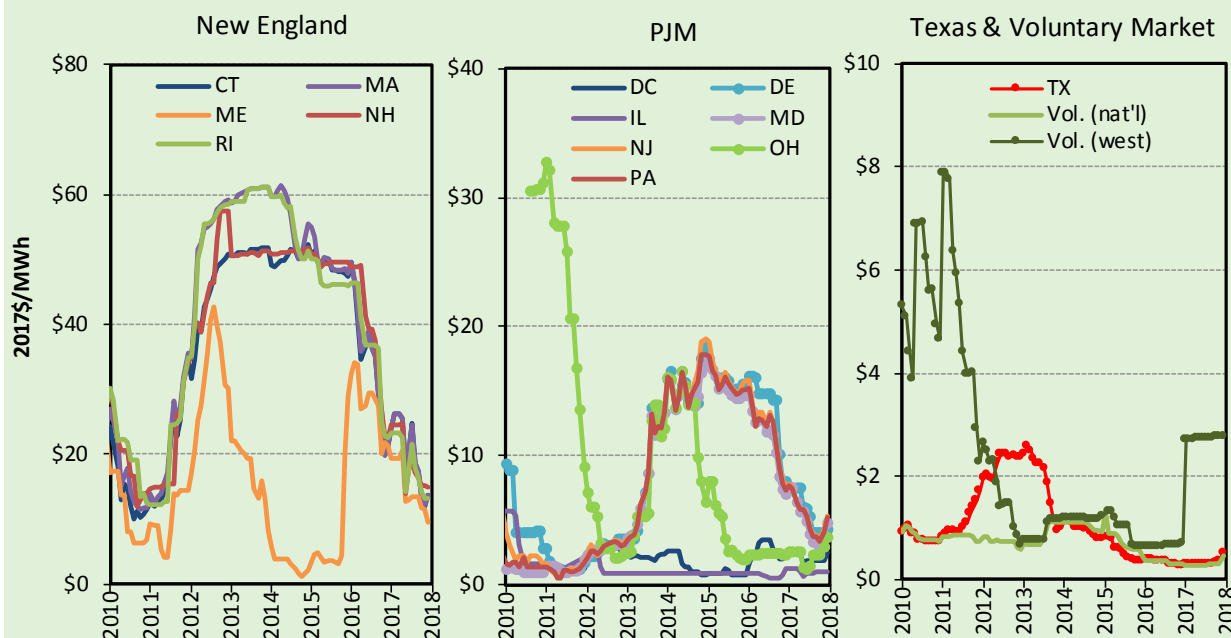
comparisons still provide some sense for the short-term competitive environment facing wind energy, and convey how those conditions have shifted over time.

REC Prices in Key RPS Compliance Markets Fell Significantly in 2017, Reflecting Growing Supplies

The wind power sales prices presented in this report reflect bundled sales of both electricity and RECs; excluded are projects that sell RECs separately from electricity, thereby generating two sources of revenue. REC markets are somewhat fragmented in the United States 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.

The figures below present indicative data of spot-market REC prices in both compliance and voluntary markets. Clearly, spot REC prices have varied substantially, both over time and across states, though prices within regional power markets (New England and PJM) are linked to varying degrees. In general, REC prices reflect the balance of available supply and demand within a given market.

REC prices in many compliance markets fell substantially over the course of 2017, as regional supplies grew faster than RPS demand. In particular, REC prices for most New England states fell from roughly \$25/MWh at the beginning of 2017 to \$15/MWh by year-end, while REC prices in some PJM states (DE, MD, NJ, and PA, which have more-restrictive eligibility rules and thus higher prices than other states in the region) fell from roughly \$8/MWh to \$5/MWh over the course of the year. In both regions, the REC price declines in 2017 followed substantial drops during the prior year as well. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas remained below \$1/MWh throughout the year, reflecting sustained over-supply, while prices for voluntary RECs sourced from the Western U.S. increased slightly to roughly \$3/MWh.



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.

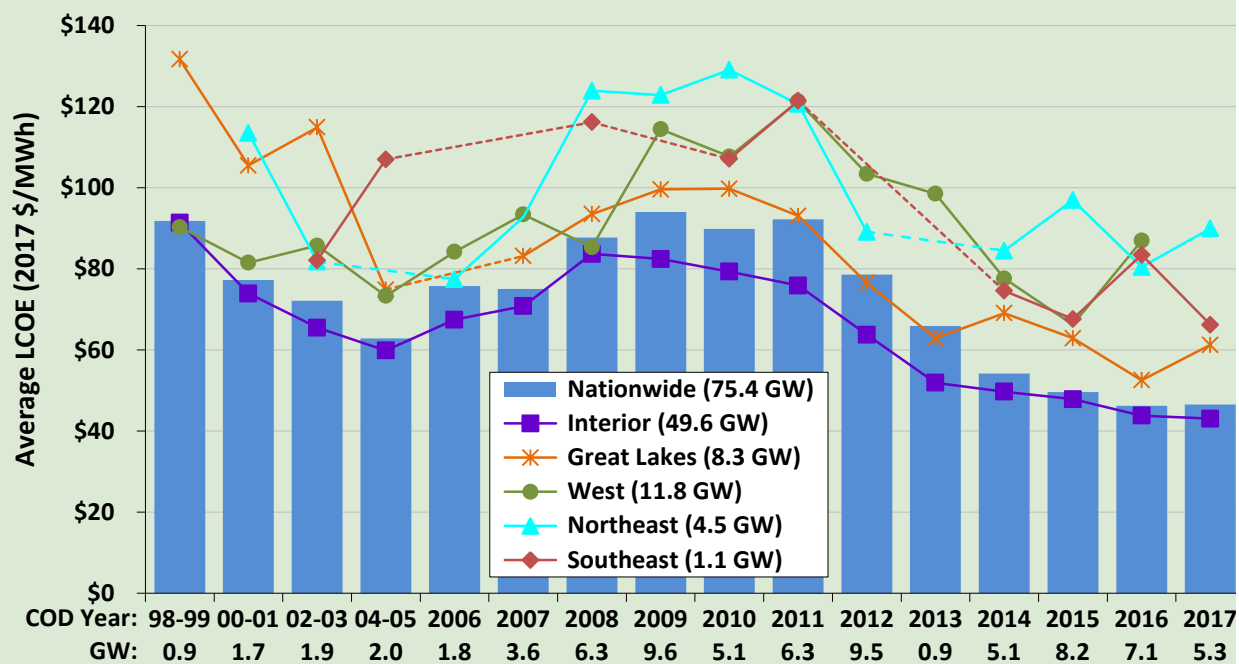
Source: Mares Spectron.

Estimating the Levelized Cost of Wind Energy

In a competitive market, bundled long-term PPA prices can be thought of as reflecting the levelized cost of energy (LCOE) reduced by the levelized 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, however, and Berkeley Lab has data on both the installed cost and capacity factor of more than 70 GW of wind power installed from 1998 through 2016, representing 86% of all capacity built over that period. Here we use those data, in conjunction with time-varying estimates of both operational and financing costs (the latter assuming no PTC), to estimate the LCOE of wind energy over time and by region, in real 2017 dollars. 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 Berkeley Lab PPA sample.

Based on a variety of data sources (including recent discussions with industry experts), total operational expenses are assumed to fall from a levelized cost of \$80/kW-year in 1998 to \$60/kW-year by 2003, \$51/kW-year by 2010, and \$44/kW-year by 2017. The weighted average cost of capital assumes a 65%:35% debt-to-equity ratio (possible in the absence of the PTC), with the cost of debt varying over time based on historical changes in the 20-year swap rate and bank spread, while the cost of equity holds steady at 12%. We assume standardized tax rates (40% combined state and federal tax for all projects built prior to 2018’s reduction in the corporate tax rate), project life (20 years), and 5-year accelerated depreciation, along with 2% annual inflation. For capacity factors, we use an average of available project-level data; as such, projects installed in 1998 may have 19 years of data to average, whereas projects installed in 2016 will have just one year. For projects built in 2017 (that have not yet been operating for a full year), we assume that capacity factors match the average capacity factor of projects built in the same region in 2015 or 2016.

The figure depicts the resulting generation-weighted average LCOE values over time, nationwide and by region (regional results are only shown for years in which we have at least 20 MW of project sample). Regional LCOE values span a wide range, but regional and nationwide trends closely follow the PPA price trends shown earlier—i.e., generally decreasing from 1998 to 2005, rising through 2009, and then declining through 2017. The lowest LCOEs are found in the Interior region, with a 2017 average of \$42/MWh and with some projects as low as \$38/MWh; looking back in time, these are the lowest wind LCOEs on record.



8 Policy and Market Drivers

The federal production tax credit remains one of the core motivators for wind power deployment

Various policies at both the federal and state levels, as well as federal investments in wind energy research and development (R&D), have contributed to the expansion of the wind power market in the United States. At the federal level, the most impactful policy incentives in recent years have been the PTC (or, if elected, the ITC) and accelerated tax depreciation.

Initially established in 1994 (via the Energy Policy Act of 1992—see Table 4), the PTC provides a 10-year, inflation-adjusted credit that stood at \$24/MWh in 2017. The historical impact of the PTC on the wind industry is illustrated by the pronounced lulls in wind additions in the years (2000, 2002, 2004, 2013) during which the PTC lapsed, as well as by the increased activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 2).

In December 2015, via the Consolidated Appropriations Act of 2016 (see Table 4), Congress passed a five-year extension of the PTC (as well as the ITC, which wind projects can elect to receive in lieu of the PTC). To qualify, projects must begin construction before January 1, 2020. Moreover, in 2016 the IRS issued Notice 2016-31, which allows four years for project completion after the start of construction, without the burden of proving continuous construction. This guidance lengthened the “safe harbor” completion period from the previous term of two years.

In extending the PTC, Congress also established a progressive reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC phases down in 20%-per-year increments for projects starting construction in 2017 (80% PTC value), 2018 (60%), and 2019 (40%). Under the current schedule, projects that commence construction in 2020 and after will no longer receive the PTC.

Developers reportedly qualified a significant amount of new wind turbine capacity for the full PTC by starting construction (as per the IRS safe harbor guidelines) prior to the end of 2016. Chadbourne & Parke (2017a) reported two such estimates of PTC-qualified capacity—30–58 GW and 40–70 GW—while consultant MAKE pegged the number at 45 GW (Recharge 2017). Notwithstanding this large volume of turbines that will be deployed through 2020 (within the four-year safe harbor window), an additional 10 GW of wind capacity was reportedly qualified for 80% of the PTC by the end of 2017.

A second form of federal tax support for wind is accelerated tax depreciation, which historically has enabled wind project owners to depreciate the vast majority of their investments over a five- to six-year period for tax purposes. Even shorter “bonus depreciation” schedules have been periodically available, since 2008, and the December 2017 tax reform legislation allows both new and used equipment to be fully expensed (i.e., equivalent to 100% bonus depreciation) in the year of purchase; historically, however, the wind industry has not opted to fully utilize such bonus depreciation measures.

The continued near-term availability of federal tax incentives underpins recent low-priced power purchase agreements for wind energy, and is a significant contributor to the ongoing surge in wind capacity additions. As discussed earlier, the tax reform legislation passed in December 2017 seems unlikely to substantially impact wind development during the current PTC cycle, though the impacts of that legislation in the longer-term are still being assessed. The PTC phase-out, on the other hand, imposes risks to the industry’s competitiveness in the mid- to long-term.

Table 4. History of Production Tax Credit Extensions

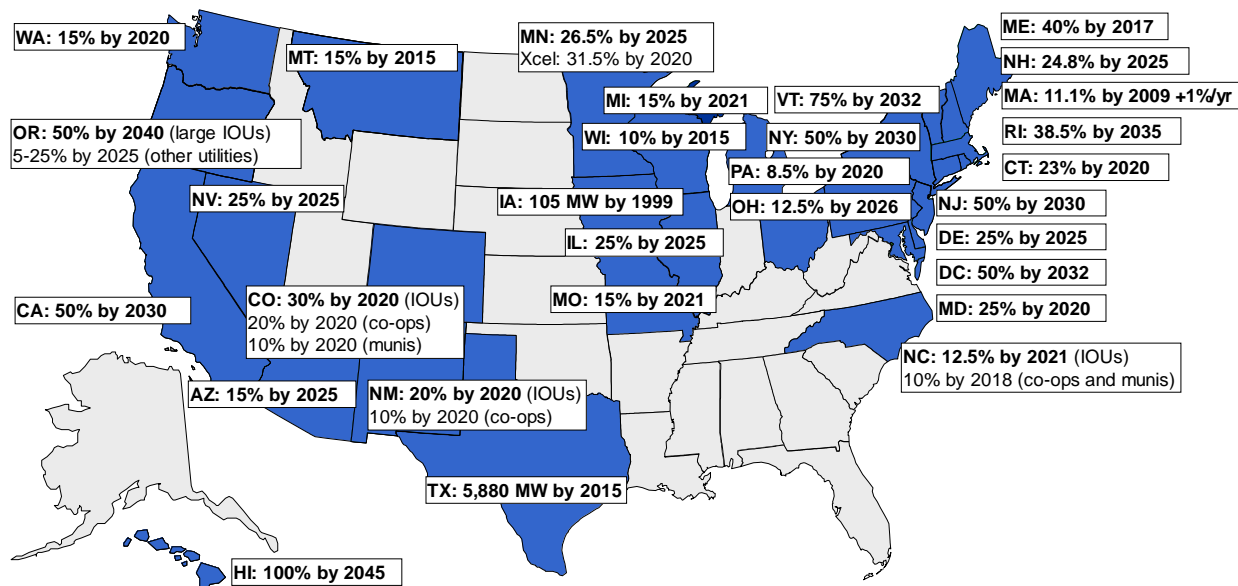
Legislation	Date Enacted	Start of PTC Window	End of PTC Window	Effective PTC Planning Window (considering lapses and early extensions)
Energy Policy Act of 1992	10/24/1992	1/1/1994	6/30/1999	80 months
				>5-month lapse before expired PTC was extended
Ticket to Work and Work Incentives Improvement Act of 1999	12/19/1999	7/1/1999	12/31/2001	24 months
				>2-month lapse before expired PTC was extended
Job Creation and Worker Assistance Act	3/9/2002	1/1/2002	12/31/2003	22 months
				>9-month lapse before expired PTC was extended
The Working Families Tax Relief Act	10/4/2004	1/1/2004	12/31/2005	15 months
Energy Policy Act of 2005	8/8/2005	1/1/2006	12/31/2007	29 months
Tax Relief and Healthcare Act of 2006	12/20/2006	1/1/2008	12/31/2008	24 months
Emergency Economic Stabilization Act of 2008	10/3/2008	1/1/2009	12/31/2009	15 months
The American Recovery and Reinvestment Act of 2009	2/17/2009	1/1/2010	12/31/2012	46 months
				2-day lapse before expired PTC was extended
American Taxpayer Relief Act of 2012	1/2/2013	1/1/2013	Start construction by 12/31/2013	12 months (in which to start construction)
				>11-month lapse before expired PTC was extended
Tax Increase Prevention Act of 2014	12/19/2014	1/1/2014	Start construction by 12/31/2014	2 weeks (in which to start construction)
				>11-month lapse before expired PTC was extended
Consolidated Appropriations Act of 2016	12/18/2015	1/1/2015	Start construction by 12/31/2016	12 months to start construction and receive 100% PTC value
			Start construction by 12/31/2017	24 months to start construction and receive 80% PTC value
			Start construction by 12/31/2018	36 months to start construction and receive 60% PTC value
			Start construction by 12/31/2019	48 months to start construction and receive 40% PTC value

Notes: Although the table pertains only to PTC eligibility, the American Recovery and Reinvestment Act of 2009 enabled wind projects to elect a 30% investment tax credit (ITC) in lieu of the PTC starting in 2009. While it is rarely used, this ITC option has been included in all subsequent PTC extensions (and will follow the same phase-out schedule as the PTC, as noted in the table: from 30% to 24% to 18% to 12%). Section 1603 of the same law enabled wind projects to elect a 30% cash grant in lieu of either the 30% ITC or the PTC; this option was only available to wind projects that were placed in service from 2009 to 2012 (and that had started construction prior to the end of 2011), and was widely used during that period. Finally, beginning with the American Taxpayer Relief Act of 2012, which extended the PTC window through 2013, the traditional “placed in service” deadline was changed to a more-lenient “construction start” deadline, which has persisted in the two subsequent extensions. The IRS initially issued safe harbor guidelines providing projects that meet the applicable construction start deadline up to two full years to be placed in service (without having to prove continuous effort) in order to qualify for the PTC. In May 2016, the IRS lengthened this safe harbor window to four full years.

Source: Berkeley Lab

State policies help direct the location and amount of wind power development, but wind power growth is outpacing state targets

As of June 2018, mandatory RPS programs existed in 29 states and Washington DC (Figure 55).^{75,76} Attempts to weaken RPS policies have been initiated in a number of states, and in limited cases—thus far only Ohio in 2014 and Kansas in 2015—have led to a temporary freeze or repeal of RPS requirements. In contrast, other states—including, most recently, California, Hawaii, Maryland, Michigan, New Jersey, New York, Oregon, Rhode Island, and Washington, DC—have increased their RPS targets. Vermont has created a new RPS.



Notes: The figure does not include mandatory RPS policies established in U.S. territories or non-binding renewable energy goals adopted in U.S. states and territories. Note also that many states have multiple sub-requirements or “tiers” within their RPS policies, though those details are not summarized in the figure.

Source: Berkeley Lab

Figure 55. State RPS policies as of June 2018

Of all wind power capacity built in the United States from 2000 through 2017, Berkeley Lab estimates that roughly 49% is delivered to load-serving entities with RPS obligations. In recent years, however, the role of state RPS programs in driving incremental wind power growth has diminished, at least on a national basis; 23% of U.S. wind capacity additions in 2017 is estimated to serve RPS requirements. Outside of the wind-rich Interior region, however, RPS requirements continue to form a strong driver for wind growth, with 79% of 2017 wind capacity additions in those regions serving RPS demand.

In aggregate, existing state RPS policies will require 520 terawatt-hours of RPS-eligible renewable electricity by 2030, at which point RPS requirements in most states will have reached their maximum percentage targets. Based on the mix and capacity factors of resources currently used or contracted for RPS compliance, this equates to a total of around 164 GW of RPS-eligible renewable generation capacity needed to meet RPS

⁷⁵ The data and analysis reported in this section largely derives from Barbose (2017), with some updates to include 2017 data.

⁷⁶ Although not shown in Figure 55, mandatory RPS policies also exist in a number of U.S. territories, and non-binding renewable energy goals exist in a number of U.S. states and territories.

demand in 2030.⁷⁷ Of that total, Berkeley Lab estimates that existing state RPS programs will require roughly 58 GW of renewable capacity additions by 2030, relative to the installed base at year-end 2017.⁷⁸ This equates to an average annual build-rate of roughly 4.5 GW per year, only a portion of which will be wind. By comparison, over the past decade, U.S. wind power capacity additions averaged 7.3 GW per year, and total U.S. renewable capacity additions averaged 12.3 GW per year.

In addition to state RPS policies, utility resource planning requirements—principally in Western and Midwestern states—have motivated wind power additions in recent years. So has voluntary customer demand for “green” power. State renewable energy funds provide support (both financial and technical) for wind power projects in some jurisdictions, as do a variety of state tax incentives—though one state, Oklahoma, recently eliminated its wind power production tax credit. Finally, some states and regions have enacted carbon reduction policies that may help to support wind power development. For example, the Northeast’s Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy has been operational for a number of years,⁷⁹ and California’s greenhouse gas cap-and-trade program commenced operation in 2012,⁸⁰ although carbon pricing in these programs has generally been too low to drive significant wind energy growth thus far.

System operators are implementing methods to accommodate increased penetrations of wind energy, but transmission and other barriers remain

Wind energy output is variable and often the areas with the greatest wind speeds are distant from electricity load centers. As a result, integration with the power system and provision of adequate transmission capacity are particularly important for wind energy. Concerns about, and solutions to, these issues impact the pace of wind power deployment. Experience in operating power systems with wind energy is also increasing worldwide, leading to an evolving set of best practices (e.g., Milligan et al. 2015, Jones 2017, Du et al. 2017).

Figure 56 provides a selective listing of estimated wind integration costs at various levels of wind capacity penetration, from studies completed from 2003 through 2017, and grouped by region of the United States. While studies differ in how they define integration costs, the impacts assessed typically include any additional balancing costs associated with managing increased forecast errors and balancing reserves. These integration costs were not included in the earlier analysis of the market value of wind, which only accounted for the time-varying generation profile and the location of wind in the system. Some of the integration cost studies reported in Figure 56 also include an estimate of the difference in the value of wind with a time-varying profile compared to a more conventional dispatch profile, thereby potentially overlapping with the market value results presented earlier. The wind integration costs in these studies do not, however, include any costs associated with incremental transmission or the lower capacity contribution of wind, costs that are sometimes included in other integration cost estimates (e.g., Heptonstall et al. 2017, BP 2018).

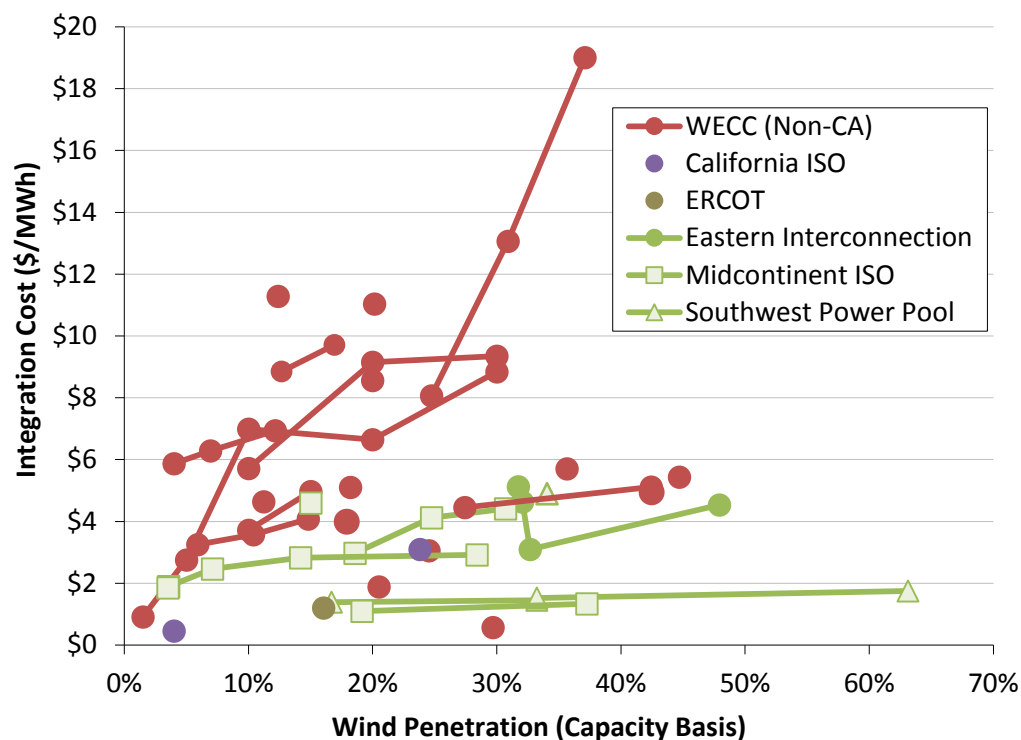
⁷⁷ Berkeley Lab’s projections of new renewable capacity required to meet each state’s RPS requirements assume different combinations of renewable resource types for each RPS state. Those assumptions are based, in large part, on the actual mix of resources currently used or under contract for RPS compliance in each state or region.

⁷⁸ Berkeley Lab’s estimate of required renewable capacity additions is derived by first estimating incremental renewable generation needed to meet RPS requirements in 2030, relative to available supplies as of year-end 2017. These estimates are performed on a utility-by-utility basis for regulated states, and on a regional basis for restructured states within regional REC markets. These estimates account for the ability of load-serving entities to bank excess RECs for compliance in future years, including any specific banking limitations in individual states. From the incremental renewable generation needs for each state, the corresponding capacity additions are estimated based on the mix and capacity factors of resources currently used or contracted for RPS compliance. This analysis ignores several complexities that could result in either higher or lower incremental capacity needs, including retirements of existing renewable capacity (which would result in higher incremental RPS needs) and the possibility that resources currently serving renewable energy demand outside of RPS requirements (e.g., voluntary corporate procurement) might become available for RPS demand in the future (which would result in lower incremental RPS needs).

⁷⁹ See, e.g., <https://www.rggi.org/>

⁸⁰ <https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>

Integration costs estimated by the studies reviewed vary widely, ranging near or below \$5/MWh in many of the regions shown, but rising close to \$20/MWh in the non-California portion of the Western Electricity Coordinating Council (WECC), for wind power capacity penetrations up to and even exceeding 40% of the peak load of the system in which the power is delivered. Studies in the non-California portion of WECC are all focused on individual utilities that also act as balancing authorities, with responsibility to maintain a balance between supply and demand at all times. These studies tend to find higher integration costs, though, with limited exceptions, integration costs estimated by the studies reviewed are still below \$10/MWh. Even in the non-California portion of WECC, however, some recent studies find relatively low integration costs. The integration study completed in 2016 as part of PacifiCorp’s 2017 Integrated Resource Plan (PacifiCorp 2017), for example, estimated an integration cost of \$0.57/MWh, which was lower than the costs in previous PacifiCorp assessments due to lower electricity prices and more resources being available to provide reserves. Overall, the results of these studies show that costs tend to increase with wind penetration levels, and tend in general to be lower when balancing areas are larger. Other variations in estimated costs are due, in part, to differences in methods, definitions of integration costs, power system and market characteristics, fuel price assumptions, wind output forecasting details, and the degree to which thermal plant cycling costs are included.



Notes: All studies categorized as WECC (Non-CA) are from individual utilities within WECC. Studies in California and ERCOT are all regional. Many of the studies in the Eastern Interconnect (inclusive of those in MISO and SPP) are regional, but some are from individual utilities. Studies that assessed multiple wind energy penetrations using a common methodology are depicted with connecting lines.

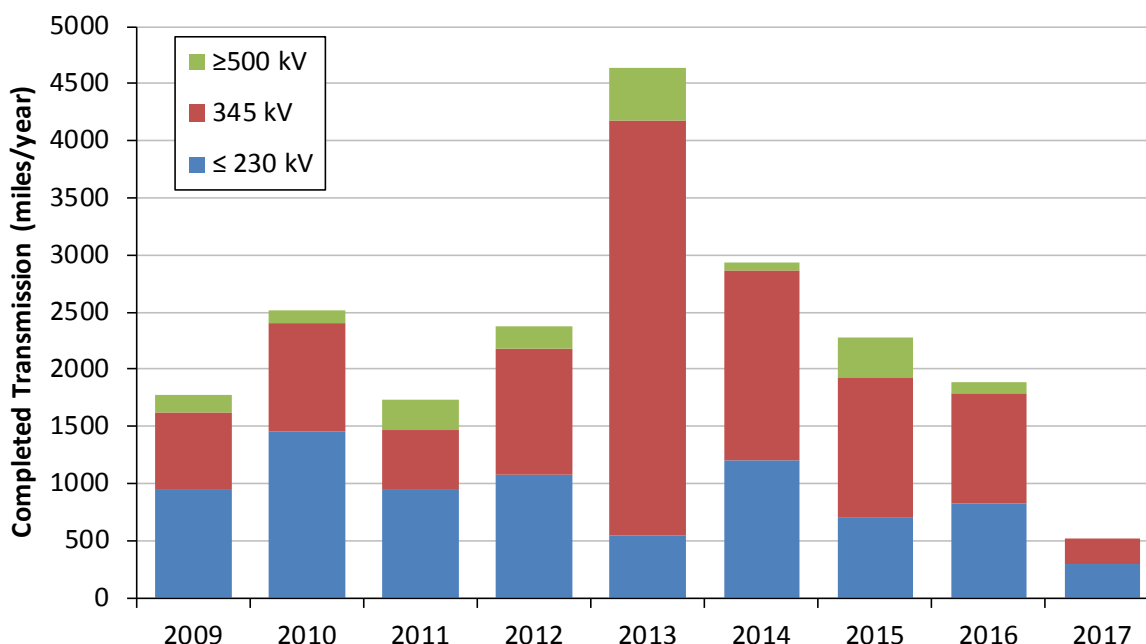
Sources: Additional details on the studies included in this review, and therefore represented in the figure, can be found in the data file associated with this report, downloadable from: <https://emp.lbl.gov/wind-technologies-market-report>

Figure 56. Integration costs at various levels of wind power capacity penetration

Beyond these studies, system operators and planners continue to make progress integrating wind into the power system, with new records for instantaneous wind penetration hit each year, including SPP reaching an instantaneous wind penetration of over 60% in March 2018. With wind power growth, wind energy is increasingly impacting wholesale power markets (Beiter et al. 2018). SPP, for example, attributes an increasing incidence of negative real-time prices to wind power, and recommends steps to increase the flexibility of the market, including improving market rules related to de-committing resources and developing a market to compensate generators that can quickly ramp up and down (SPP Market Monitoring Unit 2018).

More generally, this past year also saw a heightened conversation about the potential impacts of transformational changes in the power system, particularly associated with retirements of coal and nuclear plants, on grid reliability and resiliency (DOE 2017, National Academies of Sciences, Engineering, and Medicine 2017). As illustrated by the example of SPP, wind has impacted wholesale market prices, but over the past decade the decline in natural gas prices has been the dominant driver of average wholesale prices (Wiser et al. 2017). Moreover, the reasons for power plant retirements and the implications of those retirements are multifaceted and complex (DOE 2017). At the beginning of 2018, FERC opened a proceeding to inform what actions, if any, FERC and the markets need to take related to ensuring resilience of the bulk power system (FERC 2018a).

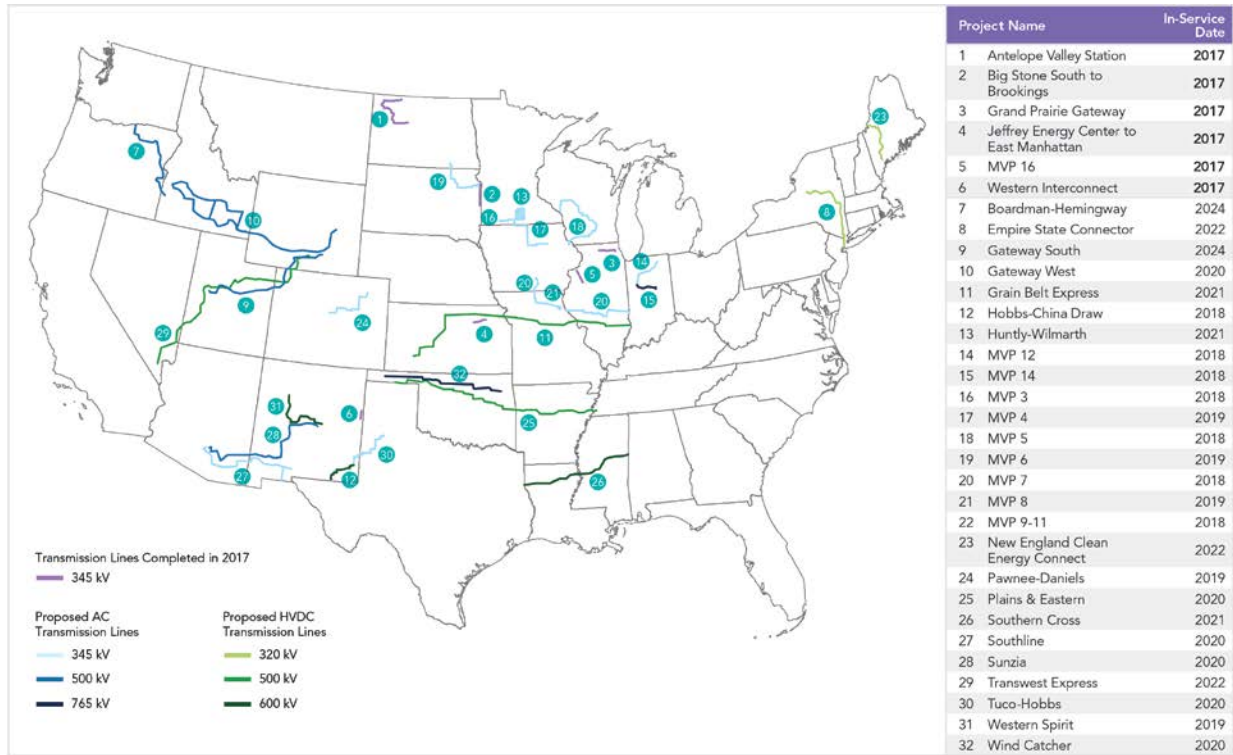
The best wind resources are often located far from load centers, and so transmission is also particularly important for wind power. Transmission additions were limited in 2017: just over 500 miles of transmission lines came online, the lowest amount since FERC began publishing these data in 2009 (see Figure 57). The decline since the peak in 2013 is, in part, due to the completion of the Texas CREZ lines in 2013. As of April 2018, FERC (2018b) finds that another 8,870 miles of new transmission (or upgrades) are proposed to come online by May 2020, with 4,280 miles of those lines having a higher probability of completion.



Source: FERC monthly infrastructure reports

Figure 57. Miles of transmission projects completed, by year and voltage

Six transmission projects that may support wind energy were completed in 2017. In addition, AWEA (2018a) has identified 26 additional near-term transmission projects that, if completed, could support considerable amounts of wind capacity (see Figure 58).



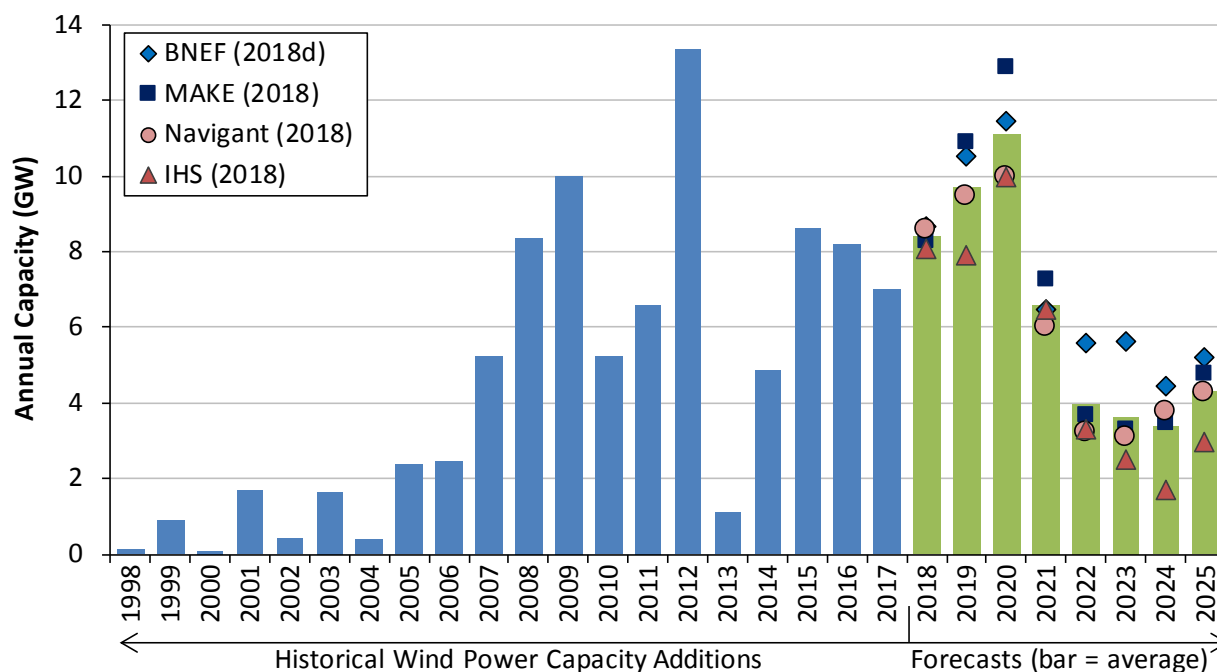
Source: AWEA (2018a)

Figure 58. Transmission Line Activity: Completed in 2017, and Planned for Near Future

9 Future Outlook

Energy analysts project that annual wind power capacity additions will continue at a rapid clip for the next several years, before declining, driven by the five-year extension of the PTC and the progressive reduction in the value of the credit over time. Additionally, near-term additions are impacted by improvements in the cost and performance of wind power technologies, which contribute to low power sales prices. Factors impacting wind energy demand also include corporate wind energy purchases and state-level renewable energy policies.

Among the forecasts for the domestic market presented in Figure 59, expected capacity additions increase from more than 8 GW in 2018 to 10–13 GW in 2020 (BNEF 2018d, MAKE 2018, Navigant 2018, IHS 2018). Forecasts for 2021 to 2025, on the other hand, show a downturn in additions in part due to the PTC phase-out. Expectations for continued low natural gas prices, modest growth in electricity demand, and lower near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do limited transmission infrastructure and competition from other resources (natural gas and solar, in particular) in certain regions of the country. At the same time, declines in the price of wind energy over the last decade have been substantial, helping to improve the economic position of wind even in the face of challenging competition. The potential for continued advancements and cost reductions enhance the prospects for longer-term growth, as does burgeoning corporate demand for wind energy and continued state RPS requirements. Moreover, new transmission in some regions is expected to open up high-quality wind resources to development. Given these diverse and contrasting underlying potential trends, wind additions, especially after 2020, remain uncertain.



Sources: AWEA WindIQ (historical additions), individual analyst forecasts

Figure 59. Wind power capacity additions: historical installations and projected growth

In 2015, the DOE published its *Wind Vision* report (DOE 2015), which analyzed a scenario in which wind energy reaches 10%, 20%, and 35% of U.S. electric demand in 2020, 2030, and 2050, respectively. Actual and projected wind additions from 2014 through 2020 (58 GW, in total) are slightly greater than the pathway envisioned in the DOE report (54 GW). Projected growth from 2021 through 2025 (22 GW), however, is well below the *Wind Vision* pathway (55 GW). As discussed in DOE (2015), and as further suggested by these comparisons, achieving 20% wind energy by 2030 and 35% by 2050 is likely to require efforts that go beyond business-as-usual expectations. Mai et al. (2017) specifically explore the role of wind technology

advancement, finding that aggressive continued cost reductions will be necessary to achieve the *Wind Vision* deployment pathway absent substantial changes in policy or market conditions.

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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 power projects) are sourced largely from AWEA (2018a). 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 ABB's Velocity database, except that solar data come from GTM Research.

Global cumulative (and 2017 annual) wind power capacity data are sourced from GWEC (2018) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Wind energy as a percentage of country-specific electricity consumption is based on year-end wind power capacity data and country-specific assumed capacity factors that come from Navigant (2016), as revised based on a review of EIA country-specific wind power data. For the United States, the performance data presented in this report are used to estimate wind energy production. Country-specific projected wind generation is then divided by country-specific electricity consumption. The latter is estimated based on actual past consumption as well as forecasts for future consumption based on recent growth trends (these data come from EIA).

The wind project installation map was created by NREL, based (in part) on AWEA's WindIQ 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 2017.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO, RTO, or utility. Only projects that were active in the queue, but not yet built, at the end of 2017 are included. Suspended projects are not included.

Industry Trends

Turbine manufacturer market share data are derived from the AWEA WindIQ project database, with some processing by Berkeley Lab.

Information on wind turbine and component manufacturing comes from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on recent U.S. nacelle assembly capability come from AWEA (2018a), as do data on U.S. tower and blade manufacturing capability. The listings of manufacturing and supply-chain facilities are not intended to be exhaustive. OEM profitability data come from a Berkeley Lab review of turbine OEM annual reports (where necessary, focusing only on the wind energy portion of each company's business).

Data on U.S. imports and exports of selected wind turbine equipment come primarily from the Department of Commerce, accessed through the U.S. International Trade Commission (USITC), and obtained from the USITC's DataWeb (<http://dataweb.usitc.gov/>). The analysis of USITC 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.

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	2005–2017	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	2011–2017	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	2012–2017	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	2012–2017	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	2012–2017	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014–2017	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category ⁸¹

Some trade 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 USITC and wind industry experts; USITC trade cases; and import patterns in the larger HTS trade categories. The assumptions reflect the rapidly increasing imports of wind equipment from 2006 to 2008, the subsequent decline in imports from 2008 to 2010, and the slight increase from 2010 to 2012. To account for uncertainty in these proportions, a $\pm 10\%$ variation is applied to the larger trade categories that include wind turbine components for all HTS codes considered, except for nacelles and other wind equipment shipped under 8503.00.9560—a range of $\pm 50\%$ of the total estimated wind import value is applied for HTS code 8503.00.9560.

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from AWEA and Norton Rose Fulbright. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of AWEA’s WindIQ project database.

Wind Turbine Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, specific power, and IEC Class was compiled by Berkeley Lab based on information provided by AWEA, 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 2017. Some turbines have not been rated within a formal numerical IEC Class, but are instead designated as Class “S-2,” “S-2/3,” or “S-3” for special. These turbines were recoded to their respective numerical class for purposes of analysis but are also reported

⁸¹ This was effective in 2014 as a result 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.

separately where appropriate. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA “Obstacle Evaluation / Airport Airspace Analysis (OE/AAA)” data containing prospective turbine locations and total proposed heights were used to estimate future technology trends. Any data with expiration dates between March 31, 2018 and September 30, 2019 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). For Figure 30, no distinction regarding either expiration dates or hazard evaluations was made—instead, all permit applications in the OE/AAA file were used and were binned based on their submission year.

Performance, Cost, and Pricing Trends

Wind project performance data were compiled overwhelmingly from two main sources: FERC’s *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), PJM, NYISO, SPP (for the Great Plains states), ISO-New England, and CAISO (for California).

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, 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 OE/AAA files, combined with Berkeley Lab and AWEA WindIQ 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 80-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. 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% assigned in that period. 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 includes all projects or turbines with an estimated gross capacity factor of less than 40%; the “medium” category corresponds to $\geq 40\%$ –45%; the “higher” category corresponds to $\geq 45\%$ –50%; and the “highest” category corresponds to $\geq 50\%$. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 49,070 turbines of the 49,748 installed from 1998 through 2017 in the continental United States (i.e., nearly 99%). Roughly 75% of the 678 turbines that are *not* mapped are more than ten years old.

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 1998–2017). Site-level available wind resources are calculated for each hour of each year based on downscaled MERRA reanalysis wind speed data to each particular plant’s location. MERRA (horizontal resolution $\sim 50 \text{ km} \times 50 \text{ km}$) wind speeds are downscaled to the higher-resolution gridded WIND Toolkit data (resolution $2 \text{ km} \times 2 \text{ km}$) following the methods developed in Mills et al. (2018). Hourly wind speeds at each project are converted to wind power by applying project-specific power curves. Power curves are based on the set of turbine-specific power curves reported by *thewindpower.net*, which provides power curves for more than 750 separate turbines. Although many projects contain only a single type of turbine, for projects that contain multiple turbine types, a turbine power curve is selected that most closely matches the average turbine capacity, rotor diameter, and specific power across the project. The wind indices are calculated without accounting for wake, electrical, or other losses, and are based only on the

downscaled MERRA wind speeds, and thus represent the strength of the total potential wind resource given the types of turbines that are deployed at each site.

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 data come from Vestas and SGRE corporate reports, BNEF, and MAKE.

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 2015, 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 POU's, and FERC Form 1 data for IOU-owned projects. A small number of data points are suppressed in the figures to protect data confidentiality.

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.

To calculate the historical wholesale energy market value of wind in various regions of the country, we start with data on hourly wholesale electricity prices and on hourly regional wind output profiles, both from ABB's Velocity Suite database (which derives data in many cases from ISOs). For each wind power plant, we identify the nearest or most-representative pricing node, and multiply regional hourly wind output profiles by the real-time hourly LMP at that pricing node. Then, we weight the resulting project-level results by the quantity of wind capacity at each node, in order to estimate region-wide capacity-weighted averages by year. Several important notes on our methods deserve mention. First, public data do not broadly exist for hourly wind output profiles at the plant level; as such, our use of regional hourly wind output profiles for all plants in the region is, by necessity, an approximation. For some regions of the country, we lack even regional hourly wind output profiles. In those cases, we use data from nearby regions. Second, for some regions, hourly wind output profiles are only available for a subset of the relevant years of our analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions. Third, we adjust the wind energy value estimates to account for regional wind curtailment volumes. The resulting \$/MWh energy values can, in effect, be thought of as \$/MWh-potential estimates, with MWhs grossed up to represent the amount of wind generation that would have occurred absent curtailment.

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 2018* is converted from \$/MMBtu into \$/MWh using heat rates derived from the modeling output. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.

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DOE/EE-1798 • August 2018

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