



# 2011 WIND TECHNOLOGIES MARKET REPORT

AUGUST 2012



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# 2011 Wind Technologies Market Report

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## List of Acronyms

AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCGT	combined cycle gas turbine
COD	commercial operation date
CREZ	competitive renewable energy zone
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
MISO	Midwest Independent System Operator
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OEM	original equipment manufacturer
O&M	operations and maintenance
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement
PTC	Production Tax Credit
PUC	public utility commission
REC	renewable energy certificate
RFI	request for information
RPS	renewables portfolio standard
RTO	regional transmission organization
SPP	Southwest Power Pool
WAPA	Western Area Power Administration



## Executive Summary

The U.S. wind power industry is facing uncertain times. With 2011 capacity additions having risen from 2010 levels and with a further sizable increase expected in 2012, there are – on the surface – grounds for optimism. Key factors driving growth in 2011 included continued state and federal incentives for wind energy, recent improvements in the cost and performance of wind power technology, and the need to meet an end-of-year construction start deadline in order to qualify for the Section 1603 Treasury grant program. At the same time, the currently-slated expiration of key federal tax incentives for wind energy at the end of 2012 – in concert with continued low natural gas prices and modest electricity demand growth – threatens to dramatically slow new builds in 2013.

Key findings from this year’s “Wind Technologies Market Report” include:

- **Wind Power Additions Increased in 2011, with Roughly 6.8 GW of New Capacity Added in the United States and \$14 Billion Invested.** Wind power installations in 2011 were 31% higher than in 2010, but still well below the levels seen in 2008 and 2009. Cumulative wind power capacity grew by 16% in 2011, bringing the total to nearly 47 GW.
- **Wind Power Comprised 32% of U.S. Electric Generating Capacity Additions in 2011.** This is up from 25% in 2010, but below its historic peak of 42-43% in 2008 and 2009. In 2011, for the sixth time in the past seven years, wind power was the second-largest new resource (behind natural gas) added to the U.S. electrical grid in terms of gross capacity.
- **The United States Remained the Second Largest Market in Annual and Cumulative Wind Power Capacity Additions, but Was Well Behind the Market Leaders in Wind Energy Penetration.** After leading the world in annual wind power capacity additions from 2005 through 2008, the U.S. has now – for three years – been second to China, comprising roughly 16% of global installed capacity in 2011, up slightly from 13% in 2010, but down substantially from 26-30% from 2007 through 2009. In terms of cumulative capacity, the U.S. also remained the second leading market, with nearly 20% of total global wind power capacity. A number of countries are beginning to achieve relatively high levels of wind energy penetration in their electricity grids: end-of-2011 wind power capacity is estimated to supply the equivalent of roughly 29% of Denmark’s electricity demand, 19% of Portugal’s, 19% of Spain’s, 18% of Ireland’s, and 11% of Germany’s. In the United States, the cumulative wind power capacity installed at the end of 2011 is estimated, in an average year, to equate to roughly 3.3% of the nation’s electricity demand.
- **California Added More New Wind Power Capacity than Any Other State, While Six States Are Estimated to Exceed 10% Wind Energy Penetration.** With 921 MW added, California led the 29 other states in which new large-scale wind turbines were installed in 2011, ending Texas’ six-year reign (Texas fell to ninth place in 2011). Other states with more than 500 MW added in 2011 included Illinois, Iowa, Minnesota, Oklahoma, and Colorado. On a cumulative basis, Texas remained the clear leader. Notably, the wind power capacity installed in South Dakota and Iowa as of the end of 2011 is estimated, in an average year, to supply approximately 22% and 20%, respectively, of all in-state electricity generation. Four other states are also estimated to exceed 10% penetration by this metric: Minnesota, North Dakota, Colorado, and Oregon.



- **No Offshore Turbines Have Been Commissioned in the United States, but Offshore Project and Policy Developments Continued in 2011.** At the end of 2011, global offshore wind power capacity stood at roughly 4,000 MW, with the vast majority located in Europe. To date, no offshore projects have been installed in the United States. Nonetheless, significant strides have been made recently in the federal arena, through both the Department of the Interior's responsibilities with regard to regulatory approvals and the Department of Energy's investments in offshore wind R&D. Interest exists in developing offshore wind energy in several parts of the country – e.g., Navigant finds that ten projects totaling 3,800 MW are somewhat more advanced in the development process. Of these, two have signed power purchase agreements (a third offshore wind PPA was recently canceled).
- **Data from Interconnection Queues Demonstrate that an Enormous Amount of Wind Power Capacity Is Under Consideration.** At the end of 2011, there were 219 GW of wind power capacity within the transmission interconnection queues administered by independent system operators, regional transmission organizations, and utilities reviewed for this report. This wind power capacity represented 45% of all generating capacity within these queues at that time, and was 1.5 times as much capacity as the next-largest resource (natural gas). Of note, however, is that the absolute amount of wind and coal power capacity in the sampled interconnection queues has declined in recent years, whereas natural gas and solar capacity has increased. Most (96%) of the wind power capacity is planned for the Midwest, PJM Interconnection, Texas, Mountain, Northwest, Southwest Power Pool, and California regions. Projects currently in interconnection queues are often very early in the development process, so much of this capacity is unlikely to be built as planned; nonetheless, these data demonstrate the continued high level of developer interest in wind power.
- **Despite the Ongoing Proliferation of New Entrants, the “Big Three” Turbine Suppliers Have Gained U.S. Market Share Since 2009.** GE and Vestas both secured roughly 29% of U.S. market share (by capacity installed) in 2011, followed by Siemens (18%), Suzlon and Mitsubishi (both at 5%), Nordex and Clipper (both at 4%), REpower (3%), and Gamesa (2%). There has been a notable increase in the number of wind turbine manufacturers serving the U.S. market – those installing more than 1 MW has increased from just 5 in 2005 to 20 manufacturers in 2011. Recently, however, there is evidence of gains in the aggregate market share of the three leading manufacturers: GE, Vestas, and Siemens. On a worldwide basis, Chinese turbine manufacturers continue to occupy positions of prominence: four of the top ten, and seven of the top 15, leading global suppliers of wind turbines in 2011 hail from China. To date, that growth has been based almost entirely on sales to the Chinese market. However, 2011 installations by Chinese and South Korean manufacturers in the U.S. include those from Sany Electric (10 MW), Samsung (5 MW), Goldwind (4.5 MW), Hyundai (3.3 MW), Sinovel (1.5 MW), and Unison (1.5 MW).
- **Domestic Wind Turbine and Component Manufacturing Capacity Has Increased, but Uncertainty in Future Demand Has Put the Wind Turbine Supply Chain Under Severe Pressure.** Eight of the ten wind turbine manufacturers with the largest share of the U.S. market in 2011 had one or more manufacturing facilities in the United States at the end of 2011. In contrast, in 2004 there was only one active utility-scale wind turbine manufacturer assembling nacelles in the United States (GE). In addition, a number of new wind turbine and component manufacturing facilities were either announced or opened in 2011, by both foreign and domestic firms. The American Wind Energy Association (AWEA) estimates that the *entire* wind energy sector directly and indirectly employed 75,000 full-time workers



in the United States at the end of 2011 – equal to the jobs reported in 2010 but fewer than in 2008 and 2009. Though domestic manufacturing capabilities have grown, uncertain prospects after 2012 – due primarily to the scheduled expiration of federal incentives – are pressuring the wind industry’s domestic supply chain as margins drop and concerns about manufacturing overcapacity deepen, potentially setting the stage for significant layoffs. The growth in U.S. wind turbine manufacturing capability and the drop in wind power plant installations since 2009 led to an estimated *over-capacity* of U.S. turbine nacelle assembly capability of more than 5 GW in 2011, in comparison to 4 GW of *under-capacity* in 2009. Over-capacity relative to U.S. turbine demand is anticipated to be even more severe in 2013 and 2014. As a result of this over-supply, coupled with increasing competition, including from new entrants from China and Korea, a wide range of turbine manufacturers have reported weakened financial results, with companies throughout the U.S. wind industry’s supply chain announcing cuts to their U.S. workforce.

- **A Growing Percentage of the Equipment Used in U.S. Wind Power Projects Has Been Sourced Domestically in Recent Years.** U.S. trade data show that the United States remained a large importer of wind power equipment in 2011, but that growth in installed wind power capacity has outpaced the growth in imports in recent years. As a result, a growing percentage of the equipment used in wind power projects is being sourced domestically. When presented as a fraction of total equipment-related wind turbine costs, domestic content is estimated to have increased significantly from 35% in 2005-2006 to 67% in 2011. Exports of wind-powered generating sets from the United States have also increased, rising from \$15 million in 2007 to \$149 million in 2011.
- **The Average Nameplate Capacity, Hub Height, and Rotor Diameter of Installed Wind Turbines Increased.** The average nameplate capacity of wind turbines installed in the United States in 2011 increased to 1.97 MW, up from 1.80 MW in 2010 and the largest single-year increase in more than six years. Since 1998-99, average turbine nameplate capacity has increased by 174%. Average hub heights and rotor diameters have also scaled with time, to 81 and 89 meters, respectively, in 2011. Since 1998-99, the average turbine hub height has increased by 45%, while the average rotor diameter has increased by 86%. In large part, these increases have been driven by new turbines designed to serve lower-wind-speed sites. Industry expectations as well as new turbine announcements (mostly surrounding additional low-wind-speed turbines) suggest that significant further scaling, especially in average rotor diameter, is anticipated in the near term.
- **Project Finance Was a Mixed Bag in 2011, as Debt Terms Deteriorated While Tax Equity Held Steady.** After steady improvement in both the debt and tax equity markets throughout 2010, progress faltered somewhat in 2011 on the debt side as the latest Greek/European debt crisis drove a new round of retrenchment. At the same time, new banking regulations took hold, driving considerably shorter bank loan tenors (institutional lenders, meanwhile, continued to offer significantly longer products). In contrast to the weakened debt market, the market for tax equity improved somewhat in 2011, with pricing remaining fairly stable and a handful of new or returning investors entering the market. As the number of grandfathered Section 1603 grant deals begins to taper off in 2012, however, attrition in tax equity investors is possible, as some have indicated no interest in PTC deals.
- **IPPs Remain the Dominant Owners of Wind Projects, But Utility Ownership Increased Significantly in 2011, Largely On the Back of One Utility.** Independent power producers (IPPs) own 73% of all new wind power capacity installed in the United States in 2011, and



82% of the cumulative installed capacity. Utility ownership jumped to nearly 25% in 2011 (as MidAmerican Energy alone added nearly 600 MW in Iowa), up from 15% in the two previous years, and reached 17% on a cumulative basis.

- **Long-Term Contracted Sales to Utilities Remained the Most Common Off-Take Arrangement, but Scarcity of Power Purchase Agreements and Looming PTC Expiration Drove Continued Merchant Development.** Electric utilities continued to be the dominant purchasers (i.e., off-takers) of wind power in 2011, either owning (25%) or buying (51%) power from 76% of the new capacity installed last year. Merchant/quasi-merchant projects were less prevalent in 2011 than they have been in recent years, accounting for 21% of all new capacity. With power purchase agreements (PPAs) in relatively short supply in comparison to wind developer interest, wholesale power prices at low levels, and a scheduled PTC expiration looming, it is likely that many of the merchant/quasi-merchant projects built in 2011 are merchant by necessity rather than by choice – i.e., building projects on a merchant basis may, in some cases, simply have been the most expedient way to ensure the deployment of committed turbines in advance of the scheduled expiration of important federal incentives. Some of these projects are, therefore, likely still seeking long-term PPAs. On a cumulative basis, utilities own (17%) or buy (50%) power from 66% of all wind power capacity in the United States, with merchant/quasi-merchant projects accounting for 24% and power marketers 10%.
- **With Increased Competition among Manufacturers, Wind Turbine Prices Continued to Decline in 2011.** After hitting a low of roughly \$700/kW from 2000 to 2002, average wind turbine prices increased by approximately \$800/kW (>100%) through 2008, rising to an average of more than \$1,500/kW. Wind turbine prices have since dropped substantially, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. A number of turbine transactions announced in 2011 had pricing in the \$1,150-\$1,350/kW range and price quotes for recent transactions are reportedly in the range of \$900-\$1,270/kW, depending on the technology. These price reductions, coupled with improved turbine technology and more-favorable terms for turbine purchasers, should, over time, exert downward pressure on total project costs and wind power prices.
- **Though Slow to Reflect Declining Wind Turbine Prices, Reported Installed Project Costs Finally Turned the Corner in 2011.** Among a large sample of wind power projects installed in 2011, the capacity-weighted average installed project cost stood at nearly \$2,100/kW, down almost \$100/kW from the reported average cost in both 2009 and 2010. Moreover, a preliminary estimate of the average installed cost among a relatively small sample of projects that either have been or will be built in 2012 suggests that average installed costs may decline further in 2012, continuing to follow lower turbine prices.
- **Installed Costs Differ By Project Size, Turbine Size, and Region.** Installed project costs are found to exhibit some weak economies of scale, at least at the lower end of the project and turbine size range. Texas is found to be the lowest-cost region, while California and New England were the highest-cost regions.
- **Newer Projects Appear to Show Improvements in Operations and Maintenance Costs.** Despite limited data availability, it appears that projects installed more recently have, on average, incurred lower O&M costs than older projects in their first several years of operation, and that O&M costs increase as projects age.
- **Sample-Wide Wind Project Capacity Factors Have Generally Improved Over Time.** Boosted primarily by taller towers and larger rotor diameters (relative to nameplate capacity),



average sample-wide wind power project capacity factors have, in general, gradually increased over time, from 25% in 1999 (for projects installed through 1998) to a high of nearly 34% in 2008 (for projects installed through 2007). In 2009 and 2010, however, sample-wide capacity factors dropped to around 30%, before 2011 brought a resurgence back to 33% (for projects installed through 2010). The drop in 2009 and 2010 was likely due to a combination of lackluster wind speeds throughout much of the U.S. in both 2009 and 2010 as well as wind power curtailment (particularly severe in 2009).

- **Some Stagnation in Wind Project Capacity Factor Improvement Is Evident Among Projects Built from 2006 through 2010, Due in Part to a Build Out of Projects in Progressively Weaker Wind Resource Areas.** Focusing only on capacity factors in 2011 parsed by project vintage reveals that *average* capacity factors have been largely stagnant among projects built from 2006 through 2010 (though the *maximum* capacity factor attained by any individual project in 2011 increased noticeably among projects built in 2009 and 2010, and the fact that rotor scaling continued for projects built in 2011 suggests that further increases in capacity factors are likely in 2012, all else equal). Three main drivers appear to be behind this stagnation: the average hub height of wind power projects has only increased by a few meters since 2006 (after growing rapidly in earlier years), the average rotor swept area relative to turbine nameplate capacity (i.e., the inverse of “specific power”) also held steady during much of this period (though increased considerably in both 2010 and 2011), while the average quality of the wind resource among those projects built in each year has deteriorated significantly since 2008. This final trend of building projects in progressively less-energetic wind resource sites may be driven by the proliferation of low wind speed turbine designs (see above), siting challenges (including transmission constraints), and even policy design (the value of the Section 1603 cash grant does not depend on how energetic a given site is).
- **Regional Variations in Capacity Factor Reflect the Strength of the Wind Resource.** Based on a sub-sample of wind power projects built from 2004 through 2010, capacity-weighted average capacity factors were the highest in the Heartland (37%) and Mountain (36%) regions in 2011, and lowest in the East (25%) and in New England (28%). Not surprisingly, these regional rankings are roughly consistent with the relative quality of the wind resource in each region.
- **Unlike Turbine Prices and Installed Project Costs, Cumulative, Sample-Wide Wind Power Prices Continued to Move Higher in 2011.** After having declined through 2005, sample-wide average wind power prices have risen steadily, such that in 2011, the cumulative sample of 271 projects totaling 20,189 MW built from 1998 through 2011 had an average power sales price of \$54/MWh. This general temporal trend of falling and then rising prices is consistent with – but lags, due to the cumulative nature of the sample – the turbine price and installed project cost trends (at least through 2008 and 2010, respectively) described earlier.
- **Binning Wind Power Sales Prices by Project Vintage Also Fails to Show a Price Reversal.** The capacity-weighted average 2011 sales price, based on projects in the sample built in 2011, was roughly \$74/MWh – essentially unchanged from the average among projects built in 2010 (the spread of individual project prices is also similar among projects built in 2010 and 2011), and more than twice the average of \$32/MWh among projects built during the low point in 2002 and 2003. Although the similarity in pricing among 2010 and 2011 projects may actually portend a peak (with lower prices likely among 2012 projects),



the fact that neither calendar year prices (among a cumulative sample) nor 2011 prices (binned by project vintage) show any sort of price reversal is nevertheless surprising, particularly given the degree to which turbine prices have dropped since 2008, along with growing evidence of aggressive pricing in wind PPAs.

- **Binning Wind Power Sales Prices by PPA Execution Date Shows Steeply Falling Prices.** An abnormally long lag between when PPAs were signed and when projects were built appears to be largely responsible for the stubborn lack of a price reversal in 2011 when viewed by calendar year or project vintage. Only two projects within the sample that were built in 2011 actually signed PPAs in 2011. All other 2011 projects in the sample signed PPAs in 2010, 2009, or even back as far as 2008 – i.e., at the height of the market for turbines – thereby locking in prices that ended up being above market in 2011. Binning by PPA signing date reveals that the average price peaked in 2009 and then progressively fell in both 2010 and 2011. Among a sample of “full term” wind project PPAs signed in 2011, the capacity-weighted average levelized PPA price is \$35/MWh, down from \$59/MWh for PPAs signed in 2010 and \$72/MWh for PPAs signed in 2009.
- **Wind Power PPA Prices Vary Widely By Region.** Texas, the Heartland, and the Mountain regions appear to be among the lowest-price regions, on average, while California is, by far, the highest price region. California also accounts for nearly one quarter of the 2011 project sample, thereby disproportionately inflating the capacity-weighted average price in 2011 (as it also did in 2010, when it made up almost 20% of the sample).
- **Low Wholesale Electricity Prices Continued to Challenge the Relative Economics of Wind Power.** Average wind power prices compared favorably to wholesale electricity prices from 2003 through 2008. Starting in 2009, however, increasing wind power prices, combined with a sharp drop in wholesale electricity prices (driven by lower natural gas prices), pushed wind energy to the top of (and in 2011 above) the wholesale power price range. Although low wholesale electricity prices are, in part, attributable to the recession-induced drop in energy demand, the ongoing development of significant shale gas deposits has also resulted in reduced expectations for gas price increases going forward. While comparing wind and wholesale electricity prices in this manner is not appropriate if one’s goal is to fully account for the costs and benefits of wind energy relative to its competition, these developments may nonetheless put the near-term comparative economic position of wind energy at some risk absent further reductions in the price of wind power and absent supportive policies for wind energy. That said, levelized PPA prices in the \$30-\$40/MWh range (currently achievable, with the PTC, in many parts of the interior U.S.) are fully competitive with the range of wholesale power prices seen in 2011.
- **Uncertainty Reigns in Federal Incentives for Wind Energy Beyond 2012.** The Recovery Act enabled wind power projects placed in service prior to the end of 2012 to elect a 30% investment tax credit (ITC) in lieu of the production tax credit (PTC). More importantly, given the relative scarcity of tax equity in the immediate wake of the financial crisis, the Recovery Act also enabled wind power projects to elect a 30% cash grant from the Treasury in lieu of federal tax credits. More than 60% of the new wind capacity installed in 2011 elected the cash grant. However, in order to qualify for the grant, wind power projects must have been under construction by the end of 2011, must apply for a grant by October 1, 2012, and must be placed in service by the end of 2012. With the PTC, ITC, and bonus depreciation all also currently scheduled to expire at the end of 2012, the wind energy sector is currently facing serious federal policy uncertainty looking to 2013 and beyond.



- **State Policies Play a Role in Directing the Location and Amount of Wind Power Development, but Current Policies Cannot Support Continued Growth at the Levels Seen in the Recent Past.** From 1999 through 2011, 65% of the wind power capacity built in the United States was located in states with renewables portfolio standards (RPS); in 2011, this proportion was 78%. As of July 2012, mandatory RPS programs existed in 29 states and Washington D.C., and a number of states strengthened previously established programs in 2011. However, existing RPS programs are projected to drive average annual renewable energy additions of roughly 4-5 GW/year (not all of which will be wind) between 2012 and 2020, which is less than the amount of wind capacity added in recent years and demonstrates the limitations of relying exclusively on state RPS programs to drive future deployment.
- **Despite Progress on Overcoming Transmission Barriers, Constraints Remain.** Transmission development has continued to gain traction during recent years, with about 2,300 circuit miles of new transmission additions under construction near the end of 2011, and with an additional 17,800 circuit miles planned through 2015. The wind industry has identified near-term transmission projects that – if all were completed – could carry almost 45 GW of wind power capacity. In July 2011, the Federal Energy Regulatory Commission (FERC) issued an order that requires public utility transmission providers to improve transmission planning processes and to determine a cost allocation methodology for new transmission facilities. States, grid operators, utilities, regional organizations, and the Department of Energy also continue to take proactive steps to encourage transmission investment. Finally, construction and development progress was made in 2011 on a number of transmission projects designed, in part, to support wind power. Nonetheless, siting, planning, and cost allocation issues remain key barriers to transmission investment, and wind curtailment continues to be a problem in some areas.
- **Integrating Wind Energy into Power Systems Is Manageable, but Not Free of Costs, and System Operators Are Implementing Methods to Accommodate Increased Penetration.** Recent studies show that wind energy integration costs are below \$12/MWh – and often below \$5/MWh – for wind power capacity penetrations of up to or even exceeding 40% of the peak load of the system in which the wind power is delivered. The increase in balancing reserves with increased wind power penetration is projected, in most cases, to be below 15% of the nameplate capacity of wind power, and typically considerably less than this figure, particularly in studies that use intra-hour scheduling. Moreover, a number of strategies that can help to ease the integration of increasing amounts of wind energy – including the use of larger balancing areas, the use of wind forecasts, and intra-hour scheduling – are being implemented by grid operators across the United States.

With federal tax incentives for wind energy currently slated to expire at the end of 2012, new capacity additions in 2012 are anticipated to exceed 2011 levels and perhaps even the highs in 2009 as developers rush to commission projects. At the same time, despite the improved cost, performance, and price of wind energy, policy uncertainty – in concert with continued low natural gas prices, modest electricity demand growth, and the aforementioned slack in existing state policies – threatens to dramatically slow new builds in 2013 and beyond. Forecasts for 2013 and beyond therefore span a particularly wide range, depending in large measure on assumptions about the possible extension of federal incentives.



# 1. Introduction

The U.S. wind power industry is facing uncertain times. With 2011 capacity additions having risen from 2010 levels and with a further sizable increase expected in 2012, there are – on the surface – grounds for optimism. At the same time, the currently-slated expiration of key federal tax incentives for wind energy at the end of 2012 – in concert with continued low natural gas prices and modest electricity demand growth – threatens to dramatically slow new builds in 2013, despite recent improvements in the cost and performance of wind power technology. In combination with growing global competition within the sector, these trends have already negatively impacted the U.S. wind power industry’s supply chain.

The wind power sector is dynamic, making it difficult to keep up with evolving trends in the marketplace. This annual report – now in its sixth year – meets the need for timely, objective information on the industry and its progress by providing a detailed overview of developments and trends in the United States wind power market, with a particular focus on 2011. As with previous editions, this report begins with an overview of key installation-related trends: trends in wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual states; the status of offshore wind power development; and the quantity of proposed wind power capacity in various interconnection queues in the United States. Next, the report covers an array of wind power industry trends, including: developments in turbine manufacturer market share; manufacturing and supply-chain investments; wind turbine and component imports into and exports from the United States; wind turbine size, hub height, and rotor diameter; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a discussion of wind power cost, performance, and pricing trends. In so doing, it describes trends in wind turbine transaction prices, installed project costs, operations and maintenance expenses, and project performance. It also reviews the prices paid for wind power in the United States, and how those prices compare to short-term wholesale electricity prices. Next, the report examines policy and market factors impacting the domestic wind power market, including federal and state policy drivers, transmission issues, and grid integration. Finally, the report concludes with a preview of possible near-term market developments.

This sixth edition of the annual report updates data presented in previous editions, while highlighting key trends and important new developments from 2011. New to this edition is a summary of trends in the wind resource conditions in which wind power projects have been sited, as well as differences in how wind power sales prices are reported – including new data on full-term power purchase agreement (PPA) prices levelized over the full contract term. The report concentrates on larger-scale wind turbines, defined here as individual turbines that exceed 100 kW in size.<sup>1</sup> The U.S. wind power sector is multifaceted, however, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Data on these latter applications are not the focus of this report, though a brief discussion on *Small Wind*

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<sup>1</sup> This 100 kW threshold between ‘small’ and ‘large’ wind turbines is applied starting with 2011 projects (to better match AWEA’s historical methodology), and is justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, however, different cut-offs are used to (a) better match AWEA’s reported capacity numbers and (b) to ensure that older utility-scale wind power projects in California are not excluded from the sample.



*Turbines* is provided on page 4. Because this report has an historical focus and all wind power projects installed in the U.S. have been land-based, its treatment of trends in the offshore wind power sector is limited to a brief summary of recent developments. A companion report funded by the U.S. Department of Energy that focuses exclusively on offshore wind energy will be published later this year.

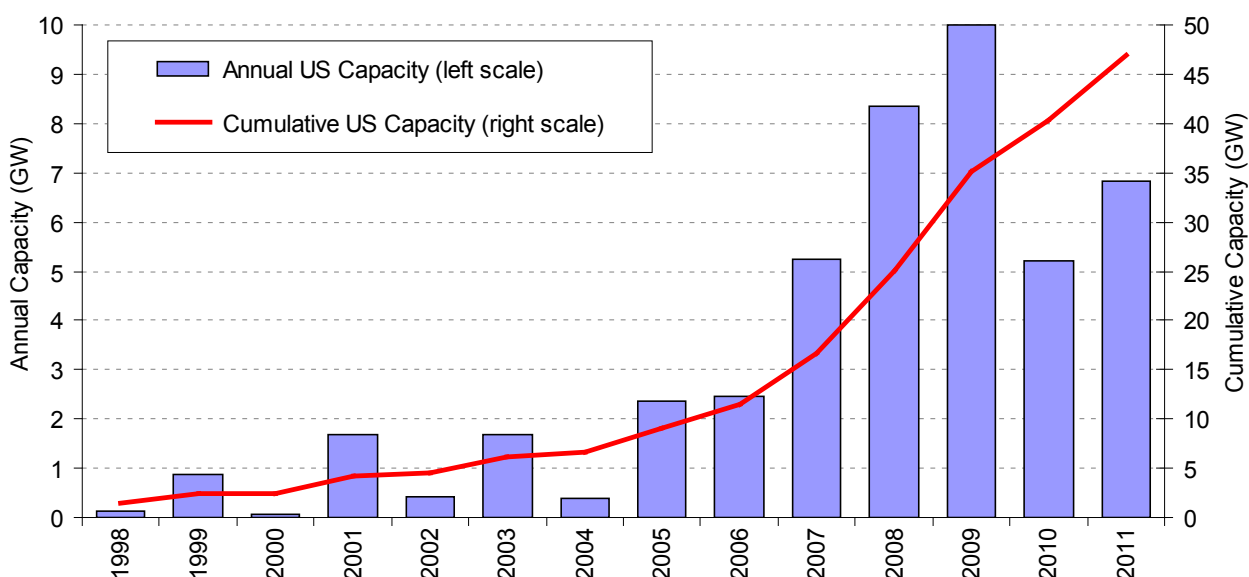
Much of the data included in this report were compiled by Berkeley Lab, and come from a variety of sources, including the American Wind Energy Association (AWEA), the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). The Appendix provides a summary of the many data sources used in the report, and a list of specific references follows the Appendix. Data on wind power capacity additions in the United States are based largely on information provided by AWEA, though minor methodological differences may yield slightly different numbers from AWEA (2012a) in some cases. In other cases, the data shown here represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market information, with an emphasis on 2011; with some limited exceptions (including the final section of the report), the report does not seek to forecast future trends.



## 2. Installation Trends

### Wind Power Additions Increased in 2011, with Roughly 6.8 GW of New Capacity Added in the United States and \$14 Billion Invested

The U.S. wind power market grew more rapidly in 2011 than in 2010, with 6,816 MW of new capacity added, bringing the cumulative total to nearly 47,000 MW (Figure 1).<sup>2</sup> This growth translates into \$14.3 billion (real 2011 dollars) invested in wind power project installation in 2011, for a cumulative investment total of \$95 billion since the beginning of the 1980s.<sup>3</sup> Wind power installations in 2011 were 31% higher than in 2010, but still well below the levels seen in 2008 and 2009. Cumulative wind power capacity grew by 16% in 2011.



Source: AWEA project database

**Figure 1. Annual and Cumulative Growth in U.S. Wind Power Capacity**

Key factors driving growth in 2011 included: continued state and federal incentives for wind energy, recent improvements in the cost and performance of wind power technology, and the need to meet an end-of-year construction start deadline in order to qualify for the Section 1603 Treasury grant program. With the Section 1603 grant and other federal tax incentives for wind energy scheduled to expire at the end of 2012, new capacity additions in 2012 are anticipated to substantially exceed 2011 levels as developers rush to commission projects. At the same time, this scheduled expiration – in concert with continued low natural gas prices, modest electricity demand growth, and existing state policies that are not sufficient to support continued capacity additions at the levels witnessed in recent years – threatens to dramatically slow new builds in 2013 and beyond.

<sup>2</sup> When reporting annual wind power capacity additions, this report focuses on gross capacity additions of large wind turbines. The net increase in capacity each year can be somewhat lower, reflecting turbine decommissioning.

<sup>3</sup> 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 & development expenditures, or operations and maintenance (O&M) costs.



## Small Wind Turbines

Small wind turbines can provide power directly to homes, farms, schools, businesses, and industrial facilities, offsetting the need to purchase some portion of the host's electricity from the grid; such wind turbines can also provide power to off-grid sites. Wind turbines used in these applications are often much smaller – generally ranging in size from a few hundred watts to 100 kW – than the larger-scale turbines that are the primary focus of this report.

The table below summarizes sales of small wind turbines, 100 kW and less in size, into the U.S. market from 2005 through 2011. Roughly 19 MW of small wind turbines were sold in the U.S. in 2011, most of which came from turbines manufactured by U.S. companies. These installation figures represent a 26% decline in annual sales – in capacity terms – relative to 2010, yielding a cumulative installed capacity of small wind turbines in the United States of 198 MW by the end of 2011 (AWEA 2012b).

Within this market segment, there has been a general trend towards larger, grid-tied systems. Sales of turbines <1 kW in size (often used off-grid) were flat or even declined from 2006-11, averaging roughly 2-3 MW per year. Sales of 1-10 kW turbines (often used in the grid-tied residential market), on the other hand, grew from less than 2 MW in 2006 to more than 8 MW in 2010, before dropping to approximately 6 MW in 2011. Sales of 11-100 kW turbines (often used in the grid-tied commercial / light industrial / government market) grew from around 3 MW in 2006 to more than 15 MW in 2010, before dropping to roughly 12 MW in 2011 (AWEA 2012b).

Year	Annual Sales of Small Wind Turbines (≤ 100 kW) into the United States		
	Number of Turbines	Capacity Additions	Sales Revenue
2005	4,324	3.3 MW	\$11 million
2006	8,330	8.6 MW	\$36 million
2007	9,102	9.7 MW	\$43 million
2008	10,386	17.4 MW	\$74 million
2009	9,820	20.4 MW	\$91 million
2010	7,811	25.6 MW	\$139 million
2011	7,303	19.0 MW	\$115 million

Source: AWEA (2012b)

Sales in this sector have historically been driven – at least in part – by a variety of state incentive programs. In addition, wind turbines equal to or under 100 kW in size are eligible for an uncapped 30% federal investment tax credit (in place through 2016). The Section 1603 Treasury Grant Program and programs administered by the USDA have also played a role in the recent growth of the sector. The decline in U.S. sales in 2011 is attributed by AWEA (2012b) in part to inconsistent state incentives, with several states suspending or defunding their small wind incentive programs in 2011, as well as the poor state of the U.S. economy.

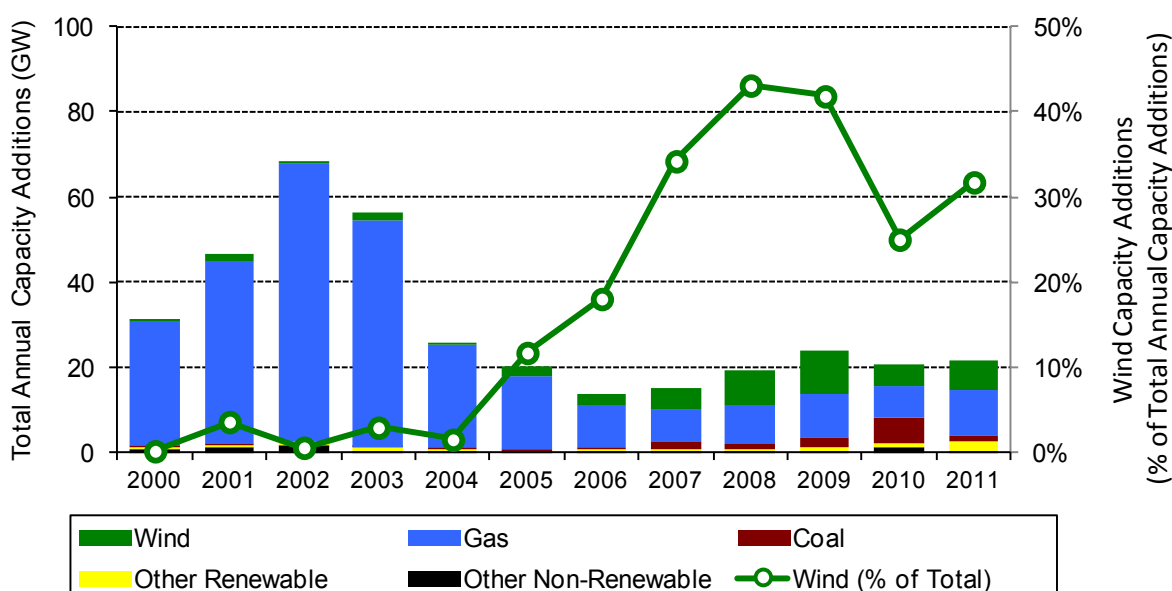
## Wind Power Comprised 32% of U.S. Electric Generating Capacity Additions in 2011

Wind power has represented one of the largest new sources of electric capacity additions in the United States in recent years. In 2011, wind power was again (for the sixth time in seven years) the second-largest new resource added to the U.S. electrical grid in terms of gross capacity additions, behind the 10,500 MW of new natural gas capacity.<sup>4</sup> New wind power projects

<sup>4</sup> Data presented here are based on gross capacity additions, not considering retirements.



contributed roughly 32% of the new nameplate capacity added to the U.S. electrical grid in 2011, compared to 25% in 2010, 42% in 2009, 43% in 2008, 34% in 2007, 18% in 2006, 12% in 2005, and less than 4% from 2000 through 2004 (Figure 2).



Source: EIA, Ventyx, AWEA, IREC, SEIA/GTM, Berkeley Lab

**Figure 2. Relative Contribution of Generation Types in Annual Capacity Additions**

EIA's (2012) reference-case forecast projects that total U.S. electricity supply will need to increase at an average pace of roughly 35 TWh (0.8%) per year from 2011 to 2035 in order to meet demand growth. On an energy basis, the annual amount of electricity expected to be generated by the new wind power capacity added in 2011 represents roughly 54% of this average annual projected growth in supply. By extension, if wind power additions continued through 2035 at the same pace as in 2011, then roughly 54% of the nation's projected increase in electricity generation from 2011 through 2035 would be met with wind electricity. Although future growth trends are hard to predict, it is clear that a significant portion of the country's new generation needs is already being met by wind energy.

## The United States Remained the Second Largest Market in Annual and Cumulative Wind Power Capacity Additions, but Was Well Behind the Market Leaders in Wind Energy Penetration

On a worldwide basis, a record of roughly 42,000 MW of wind power capacity was added in 2011, up 6% from the additions experienced in 2010 and bringing the cumulative total to 241,000 MW (BTM 2012; Table 1).<sup>5</sup> In terms of cumulative capacity, the United States ended

<sup>5</sup> Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from BTM (2012), but updated with the U.S. data presented here. Some disagreement exists among these data sources and others, e.g., *Windpower Monthly*, the Global Wind Energy Council, and AWEA.



the year with almost 20% of total global wind power capacity, but is now a distant second to China by this metric (Table 1).<sup>6</sup> Over the past 10 years, cumulative wind power capacity has grown by an average of 27% per year in the United States, somewhat higher than the 25% growth rate globally. Annual growth in cumulative capacity was down in 2011, however, at 16% for the U.S. and 21% globally.

After leading the world in annual wind power capacity additions from 2005 through 2008, the U.S. has now – for three years – been second to China (Table 1), representing roughly 16% of global installed capacity in 2011, up slightly from 13% in 2010, but down substantially from 26% in 2009, 30% in 2008, and 27% in 2007. China now dominates global wind power rankings, with an approximate 42% share of the global market for new wind power additions in 2011. India, Germany, and the U.K. rounded out the top five countries in 2011 for annual capacity additions.

**Table 1. International Rankings of Wind Power Capacity**

Annual Capacity (2011, MW)		Cumulative Capacity (end of 2011, MW)	
China	17,631	China	62,412
<b>U.S.</b>	<b>6,816</b>	<b>U.S.</b>	<b>46,916</b>
India	3,300	Germany	29,248
Germany	2,007	Spain	21,350
U.K.	1,293	India	16,266
Canada	1,267	U.K.	7,155
Spain	1,050	France	6,836
Italy	950	Italy	6,733
France	875	Canada	5,278
Sweden	763	Portugal	4,214
<i>Rest of World</i>	5,766	<i>Rest of World</i>	34,453
<b>TOTAL</b>	<b>41,718</b>	<b>TOTAL</b>	<b>240,861</b>

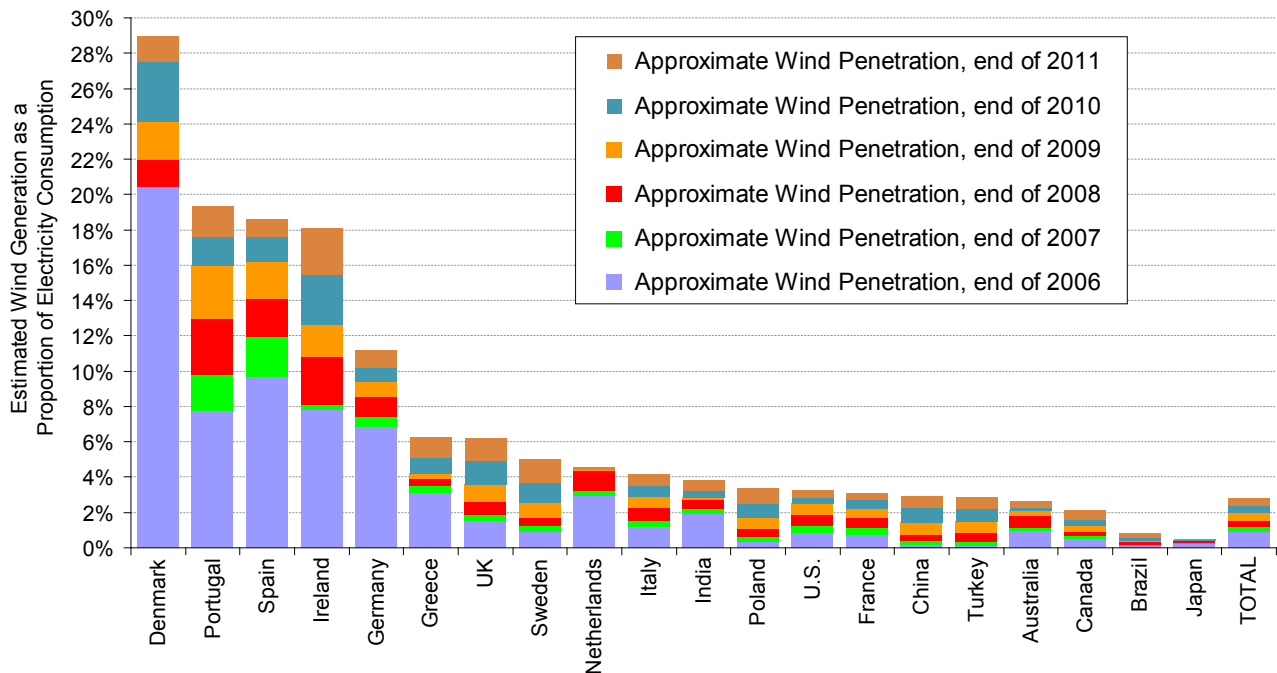
Source: BTM Consult; AWEA project database for U.S. capacity

A number of countries are beginning to achieve relatively high levels of wind energy penetration in their electricity grids. Figure 3 presents data on end-of-2011 (and end-of-2006/07/08/09/10) installed wind power capacity, translated into projected annual electricity supply based on assumed country-specific capacity factors, and divided by projected 2012 (and actual or projected 2007/08/09/10/11) electricity consumption. Using this approximation for the contribution of wind power to electricity consumption, and focusing only on the 20 countries with the greatest cumulative installed wind power capacity, end-of-2011 installed wind power is estimated to supply the equivalent of roughly 29% of Denmark's electricity demand, 19% of Portugal's, 19% of Spain's, 18% of Ireland's, and 11% of Germany's. In the United States, the cumulative wind power capacity installed at the end of 2011 is estimated, in an average year, to equate to roughly 3.3% of the nation's electricity demand (up from 2.9% at the end of 2010, and

<sup>6</sup> Wind power additions and cumulative capacity in China are from BTM (2012), and include a considerable amount of capacity that was installed but that had not yet begun to deliver electricity by the end of 2011, 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.



just 0.9% at the end of 2006).<sup>7</sup> On a global basis, wind energy's contribution at the end of 2011 is estimated to be 2.9%.



Source: Berkeley Lab estimates based on data from BTM Consult, EIA, and elsewhere

**Figure 3. Approximate Wind Energy Penetration in the Twenty Countries with the Greatest Installed Wind Power Capacity**

## California Added More New Wind Power Capacity than Any Other State, While Six States Are Estimated to Exceed 10% Wind Energy Penetration

New large-scale<sup>8</sup> wind turbines were installed in 30 states in 2011. With 921 MW installed, California added the most new wind capacity in 2011, ending Texas' six-year reign (Texas fell to ninth place in 2011, with 297 MW). As shown in Figure 4 and Table 2, other leading states in terms of new capacity (each with more than 500 MW) included Illinois, Iowa, Minnesota, Oklahoma, and Colorado. Nineteen states added more than 100 MW each in 2011.

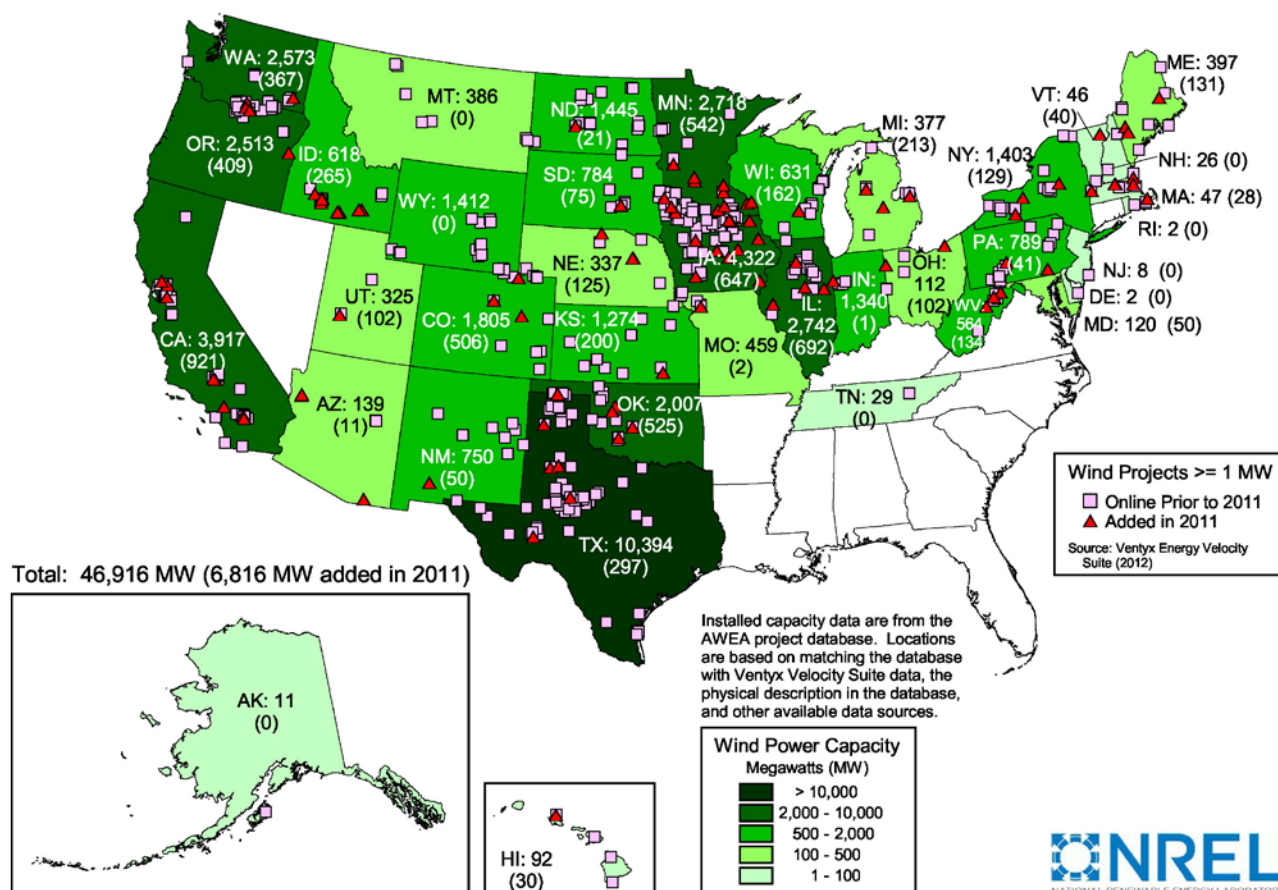
On a cumulative basis, Texas remained the clear leader among states, with 10,394 MW installed at the end of 2011 – *more than 6,000 MW more than the next-highest state* (Iowa, with 4,322 MW). In fact, Texas has more installed wind power capacity than all but five countries (including the U.S.) worldwide. States following (distantly) Texas in cumulative installed capacity include Iowa, California, Illinois, Minnesota, Washington, Oregon, and Oklahoma – all with more than 2,000 MW. Twenty-nine states had more than 100 MW of wind capacity installed as of the end of 2011, with twenty of these topping 500 MW, eight topping 2,000 MW,

<sup>7</sup> In terms of actual 2011 deliveries, EIA reports that wind energy represented 2.9% of net electricity generation and 3.2% of national electricity consumption in the United States. These figures are below the 3.3% figure provided above in part because 3.3% is a projection based on end-of-year 2011 wind power capacity.

<sup>8</sup> "Large-scale" turbines are defined consistently with the rest of this report – i.e., turbines over 100 kW.



and one (Texas) topping 10,000 MW. Although all wind power projects in the United States to date have been installed on land, offshore development activities continued in 2011, as discussed in the next section.



Note: Numbers within states represent cumulative installed wind capacity and, in parentheses, annual additions in 2011.

**Figure 4. Location of Wind Power Development in the United States**

Some states are beginning to realize relatively high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on both actual wind electricity generation in 2011 as well as estimated wind electricity generation from end-of-2011 wind power capacity, both divided by total in-state electricity generation in 2011.<sup>9</sup> Using either method, the same four upper Midwest states – North and South Dakota, Minnesota, and Iowa – lead the list (though in a slightly different order). Most notably, the wind power capacity installed in South Dakota and Iowa as of the end of 2011 is estimated, in an average year, to supply approximately 22% and

<sup>9</sup> Wind energy penetration can either be expressed as a percentage of in-state load or in-state generation. In-state generation is used here, primarily because wind energy (like other energy resources) is often sold across state lines, which tends to distort penetration levels expressed as a percentage of in-state load. The actual penetration of wind electricity generation in 2011 is based exclusively on preliminary EIA data for 2011, and matches what AWEA provides in its *U.S. Wind Industry Annual Market Report* (AWEA 2012a). For the estimated penetration – which captures the full, rather than partial, impact of new wind power capacity added in 2011 – end-of-2011 wind power capacity is translated into estimated annual wind generation based on estimated state-specific capacity factors that derive from the project performance data reported later in this report. The resulting state-specific wind electricity generation estimates are then divided by preliminary EIA data on total in-state electricity generation in 2011.



20%, respectively, of all in-state electricity generation. Four other states are also estimated to exceed 10% penetration by this metric: Minnesota (14.9%), North Dakota (14.1%), Colorado (10.7%), and Oregon (10.5%).

**Table 2. United States Wind Power Rankings: The Top 20 States**

Capacity (MW)				Percentage of In-State Generation			
Annual (2011)		Cumulative (end of 2011)		Actual (2011)*		Estimated (end of 2011)**	
California	921	Texas	10,394	South Dakota	22.3%	South Dakota	22.1%
Illinois	692	Iowa	4,322	Iowa	18.8%	Iowa	20.0%
Iowa	647	California	3,917	North Dakota	14.7%	Minnesota	14.9%
Minnesota	542	Illinois	2,742	Minnesota	12.7%	North Dakota	14.1%
Oklahoma	525	Minnesota	2,718	Wyoming	10.1%	Colorado	10.7%
Colorado	506	Washington	2,573	Colorado	9.2%	Oregon	10.5%
Oregon	409	Oregon	2,513	Kansas	8.2%	Idaho	9.7%
Washington	367	Oklahoma	2,007	Idaho	8.2%	Kansas	9.2%
Texas	297	Colorado	1,805	Oregon	8.2%	Oklahoma	9.1%
Idaho	265	North Dakota	1,445	Oklahoma	7.1%	Wyoming	8.8%
Michigan	213	Wyoming	1,412	Texas	6.9%	Texas	7.3%
Kansas	200	New York	1,403	New Mexico	5.4%	Maine	6.5%
Wisconsin	162	Indiana	1,340	Washington	5.3%	New Mexico	5.8%
West Virginia	134	Kansas	1,274	Maine	4.5%	Washington	5.5%
Maine	131	Pennsylvania	789	Montana	4.2%	California	4.7%
New York	129	South Dakota	784	California	4.0%	Montana	3.8%
Nebraska	125	New Mexico	750	Illinois	3.1%	Illinois	3.7%
Utah	102	Wisconsin	631	Hawaii	3.1%	Hawaii	3.7%
Ohio	102	Idaho	618	Nebraska	2.9%	Indiana	3.0%
South Dakota	75	West Virginia	564	Indiana	2.7%	Nebraska	2.9%
Rest of U.S.	274	Rest of U.S.	2,915	Rest of U.S.	0.4%	Rest of U.S.	0.5%
<b>TOTAL</b>	<b>6,816</b>	<b>TOTAL</b>	<b>46,916</b>	<b>TOTAL</b>	<b>2.9%</b>	<b>TOTAL</b>	<b>3.2%</b>

\* Based on 2011 wind and total generation by state from EIA's *Electric Power Monthly*.

\*\* Based on a projection of wind electricity generation from end-of-2011 wind power capacity, divided by total in-state electricity generation in 2011.

Source: AWEA project database, EIA, Berkeley Lab estimates

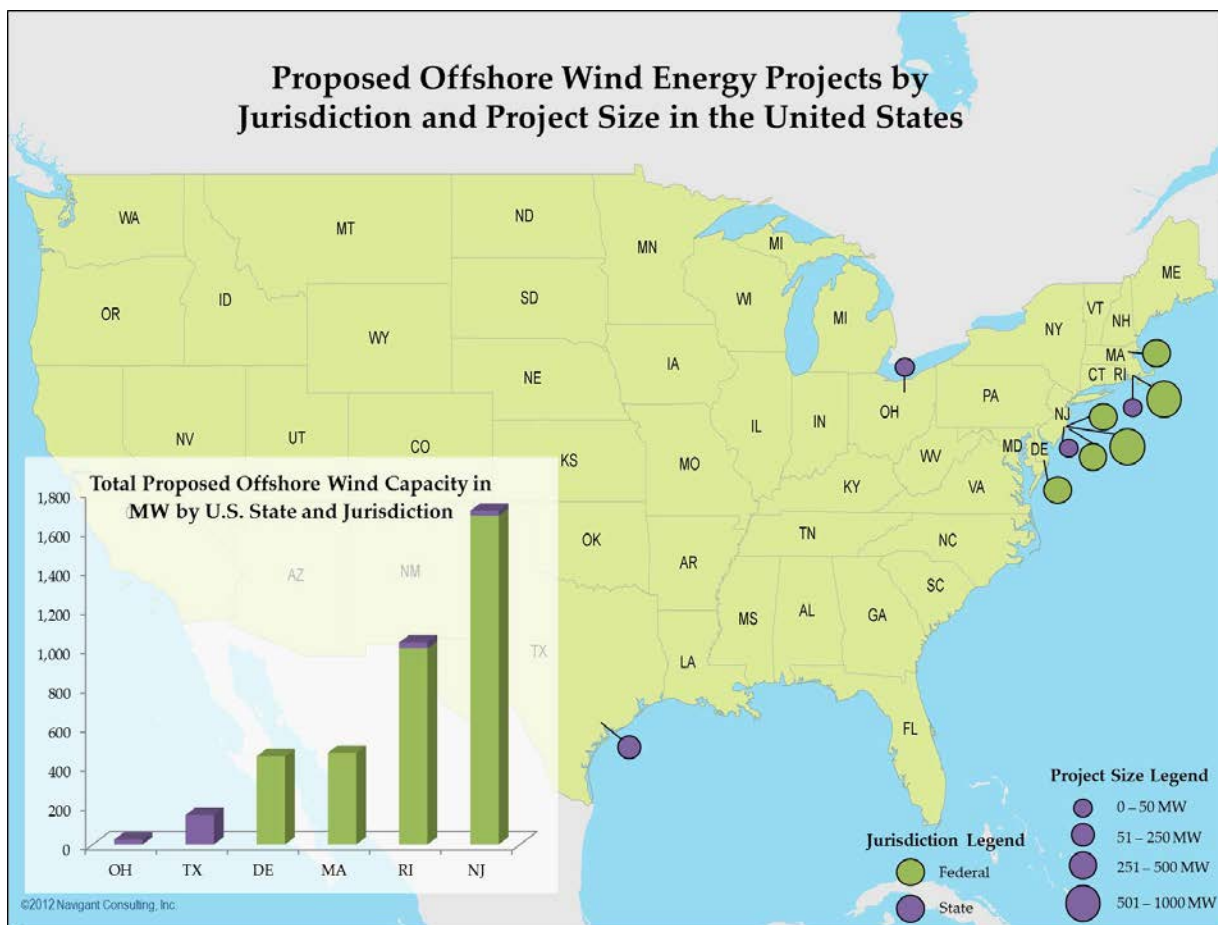
## **No Offshore Turbines Have Been Commissioned in the United States, but Offshore Project and Policy Developments Continued in 2011<sup>10</sup>**

At the end of 2011, global offshore wind power capacity stood at roughly 4,000 MW (BTM 2012), with the vast majority of 2011 additions and cumulative capacity located in Europe. Just 470 MW of new offshore wind power capacity was commissioned in 2011, a two-thirds decrease from 2010, though BTM (2012) reports that more than 1,500 MW are likely to be installed in 2012.

<sup>10</sup> A companion report funded by the U.S. Department of Energy that focuses exclusively on offshore wind energy will be published later this year, and will provide a detailed summary of the status of the offshore wind sector in the United States.



To date, no offshore projects have been installed in the United States, and the emergence of a U.S. offshore wind power market faces both challenges and opportunities. Perhaps most importantly, the projected near-term costs of offshore wind energy remain high. Additionally, planning, siting, and permitting can be challenging, as demonstrated in the long history of the Cape Wind project. At the same time, interest in developing offshore wind energy exists in several parts of the country. Driving this interest is the proximity of offshore wind resources to population centers, the potential for local economic development benefits, advances in technology, and superior capacity factors (and, in some instances, peak load coincidence) compared to the finite set of developable land-based wind power projects available in some regions. Moreover, significant strides relating to offshore wind energy have been made recently in the federal arena, both through the Department of the Interior's responsibilities with regards to regulatory approvals and the Department of Energy's investments in offshore R&D.



**Figure 5. Proposed Offshore Wind Power Projects in a Relatively Advanced State of Development**

Figure 5 identifies ten proposed offshore wind power projects in the United States that have been identified by Navigant Consulting as being more-advanced in development process: generally, this includes projects that have signed power purchase agreements, those with a partnership with a potential power offtaker, those that are pursuing detailed surveying/permitting efforts, and



those that are expecting to install demonstration or pilot-phase turbines in the relatively near future. In total, these proposed projects equal 3,800 MW, and are primarily located in the Northeast and Mid-Atlantic, though proposed projects also exist in the Great Lakes and Gulf of Mexico. It is not certain which of these projects will ultimately come to fruition, while many other proposed projects not listed in Figure 5 are in earlier planning phases.

Of the projects identified in Figure 5, two have signed power purchase agreements (PPAs): Cape Wind (Massachusetts) and Deepwater Wind (Rhode Island). The nation's first offshore wind PPA, for NRG Bluewater's project off the coast of Delaware, was canceled by the developer in 2011.

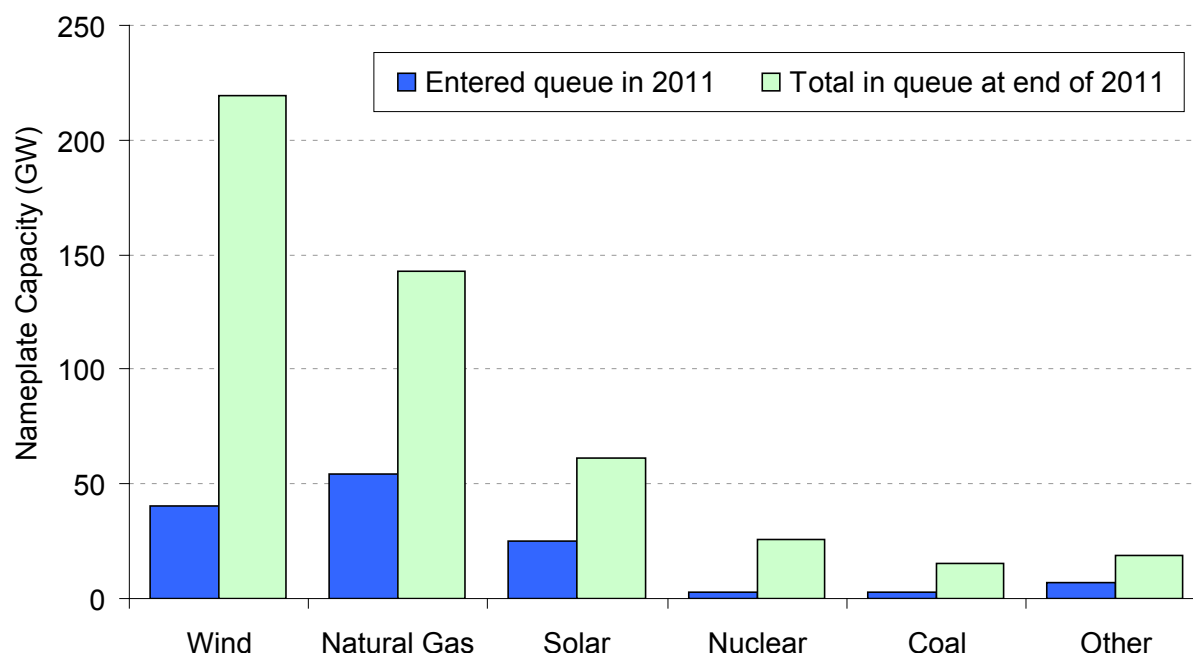
## **Data from Interconnection Queues Demonstrate that an Enormous Amount of Wind Power Capacity Is Under Consideration**

One testament to the continued interest in land-based wind energy is the amount of wind power capacity currently working its way through the major transmission interconnection queues across the country. Figure 6 provides this information for wind power and other resources aggregated across 41 different interconnection queues administered by independent system operators (ISOs), regional transmission organizations (RTOs), and utilities.<sup>11</sup> These data should be interpreted with caution: though placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually get built. In fact, projects currently in interconnection queues are often very early in the development process. As a result, efforts have been and are being taken by the Federal Energy Regulatory Commission (FERC), ISOs, RTOs, and utilities to reduce the number of speculative projects that have – in recent years – clogged these queues. One consequence of those efforts, as well as perhaps the uncertain magnitude of the future wind market in the U.S. given the impending scheduled expiration of federal tax incentives, is that the total amount of wind power capacity in the nation's interconnection queues has declined in recent years.

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<sup>11</sup> The queues surveyed include PJM Interconnection (PJM), Midwest Independent System Operator (MISO), New York ISO (NYISO), ISO-New England (ISO-NE), California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and 32 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 peak demand of almost 70% of the U.S. total. Figures 6 and 7 only include projects that were active in the queue at the end of 2011 but that had not yet been built; suspended projects are not included.





Source: Exeter Associates review of interconnection queues

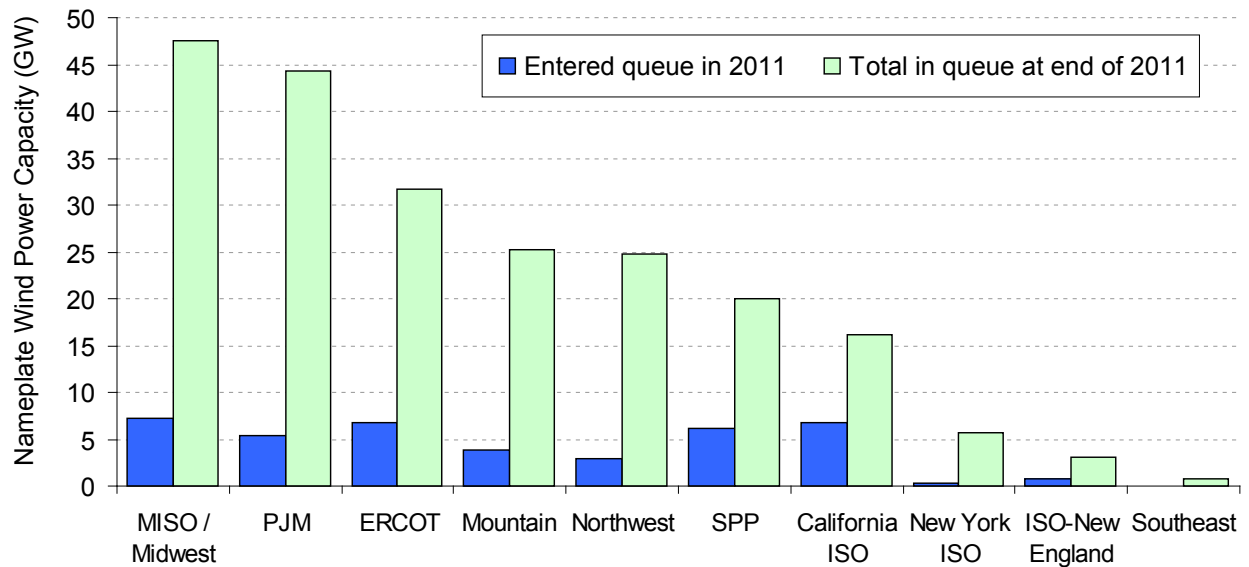
**Figure 6. Nameplate Resource Capacity in 41 Selected Interconnection Queues**

Even with this important caveat, the amount of capacity in the nation's interconnection queues still provides at least some indication of the amount of wind power development that is in the planning phase. At the end of 2011, even after reforms by a number of ISOs, RTOs, and utilities to reduce the number of projects in their queues, there were 219 GW of wind power capacity within the interconnection queues reviewed for this report – almost five times the installed wind power capacity in the United States.<sup>12</sup> This 219 GW represented 45% of all generating capacity within these selected queues at that time, and was 1.5 times as much capacity as the next-largest resource, natural gas. In 2011, 40 GW of gross wind power capacity entered the interconnection queues, compared to 54 GW of natural gas and 25 GW of solar; relatively little nuclear and coal capacity entered these queues in 2011. Of note, however, is that the absolute amount of wind and coal power in the sampled interconnection queues (considering gross additions and project drop-outs) has declined in recent years, whereas natural gas and solar capacity has increased.

Much of this wind power capacity is planned for the Midwest, PJM Interconnection, Texas, Mountain, Northwest, Southwest Power Pool, and California regions: wind power projects in the interconnection queues in these regions at the end of 2011 accounted for 96% of the aggregate 219 GW of wind power in the selected queues (Figure 7). Smaller amounts of wind power capacity were represented in the interconnection queues of the New York ISO (2.6%), ISO-New England (1.4%), and the Southeast (0.3%).

<sup>12</sup> As a rough benchmark, 300 GW of wind power capacity is the approximate amount of capacity required to reach 20% wind energy penetration in the United States in 2030, as estimated in DOE (2008).





Source: Exeter Associates review of interconnection queues

**Figure 7. Wind Power Capacity in 41 Selected Interconnection Queues**

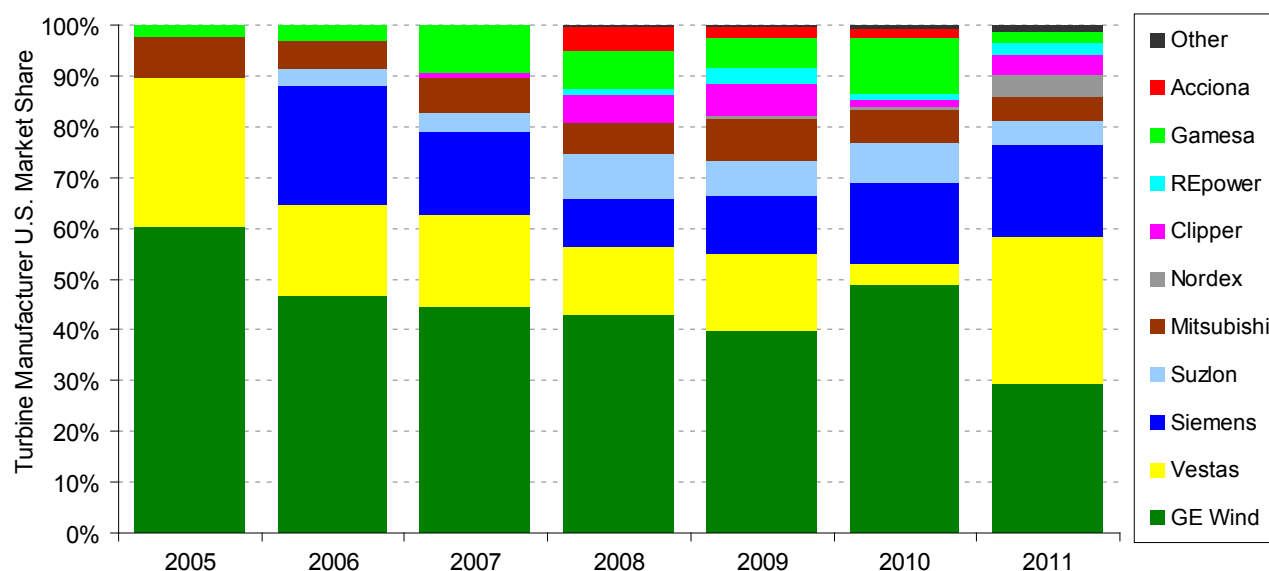
As a measure of the near-term development pipeline, Ventyx (2012) estimates that – as of mid-June 2012 – approximately 40 GW of wind power capacity was either under construction or in site preparation (11 GW of the 40 GW total), in-development and permitted (14 GW of the 40 GW), or in-development with pending permit and/or regulatory applications (the remaining 15 GW of the 40 GW total). This total is similar to the 38 GW that was in the development pipeline as of last year at approximately the same time (April 2011), indicating, potentially, that the development pipeline remains robust despite political uncertainty at the federal level. AWEA (2012c), meanwhile, reports 1,695 MW of wind power capacity installed in the first quarter of 2012, with another 8,900 MW under construction as of the end of March 2012.



### 3. Industry Trends

#### Despite the Ongoing Proliferation of New Entrants, the “Big Three” Turbine Suppliers Have Gained U.S. Market Share Since 2009

New U.S. wind projects built in 2011 deployed 2,006 MW of GE Wind turbines, compared to 1,969 MW of Vestas turbines, representing a roughly 29% market share for each manufacturer.<sup>13</sup> Following GE Wind and Vestas were Siemens (with an 18% market share), Suzlon and Mitsubishi (both at 5%), Nordex and Clipper (both at 4%), REpower (3%),<sup>14</sup> and Gamesa (2%). Other utility-scale (>100 kW) wind turbines installed in the U.S. in 2011 (and that fall into the “Other” category in Figure 8) were manufactured by Alstom (43 MW), Sany Electric (10 MW), Vensys (6 MW), Samsung (5 MW), Goldwind (4.5 MW), Hyundai (3.3 MW), Kenersys (2.5 MW), Northern Power Systems (2.3 MW), Sinovel (1.5 MW), Unison (1.5 MW), Nordic Windpower (1 MW), PowerWind (0.9 MW), and Aeronautica (0.75 MW). This list of turbine suppliers is increasingly global in nature, with manufacturers no longer hailing just from the United States, Europe, Japan, and India, but now also from China and South Korea.



Source: AWEA project database

**Figure 8. Annual U.S. Market Share of Wind Manufacturers by MW, 2005-2011**

Figure 8 and Table 3 depict a notable increase in the number of wind turbine manufacturers serving the U.S. market since 2005, when just five manufacturers (compared to twenty in 2011) installed more than 1 MW, and just four manufacturers captured 99% of the market (compared to the ten it took to reach 99% in 2011). Despite steady growth in the *number* of turbine manufacturers serving the U.S. market over time, however, the “big three” turbine suppliers – GE Wind, Vestas, and Siemens – have, in aggregate, actually *gained* market share since 2008/2009 (from 66% in both 2008 and 2009 up to 76% in 2011), reversing some of their earlier

<sup>13</sup> Market share reported here is in MW terms, and is based on project installations in the year in question, not turbine shipments or orders.

<sup>14</sup> As of October 2011, REpower became a wholly owned subsidiary of Suzlon.



losses through 2008. This recapture may, in part, reflect a legacy of the financial crisis (i.e., a heightened preference among investors for projects using “bankable” turbines), coupled with ample turbine supply (relative to demand), which reduces the need to consider less-bankable technology.

**Table 3. Annual U.S. Turbine Installation Capacity, by Manufacturer**

Manufacturer	Turbine Installations (MW)						
	2005	2006	2007	2008	2009	2010	2011
<b>GE Wind</b>	1,431	1,146	2,342	3,585	3,995	2,543	2,006
<b>Vestas</b>	699	439	948	1,120	1,488	221	1,969
<b>Siemens</b>	0	573	863	791	1,162	828	1,233
<b>Suzlon</b>	0	92	197	738	702	413	334
<b>Mitsubishi</b>	190	128	356	516	814	350	318
<b>Nordex</b>	0	0	3	0	63	20	288
<b>Clipper</b>	3	0	48	470	605	70	258
<b>REpower</b>	0	0	0	94	330	68	172
<b>Gamesa</b>	50	74	494	616	600	564	154
<b>Acciona</b>	0	0	0	410	204	99	0
<b>Other</b>	2	2	0	22	38	37	85
<b>TOTAL</b>	<b>2,375</b>	<b>2,454</b>	<b>5,249</b>	<b>8,361</b>	<b>10,000</b>	<b>5,214</b>	<b>6,816</b>

Source: AWEA project database

Globally, U.S.-owned GE remained the third-leading supplier of turbines worldwide in 2011, with an 8.8% market share (down from 9.3% in 2010), behind Vestas’ 12.9% and Goldwind’s 9.4% (BTM 2012). No other U.S.-owned manufacturer cracked the top-15.<sup>15</sup> On a worldwide basis, Chinese turbine manufacturers continue to occupy positions of prominence: four of the top ten, and seven of the top 15, leading global suppliers of wind turbines in 2011 hail from China.

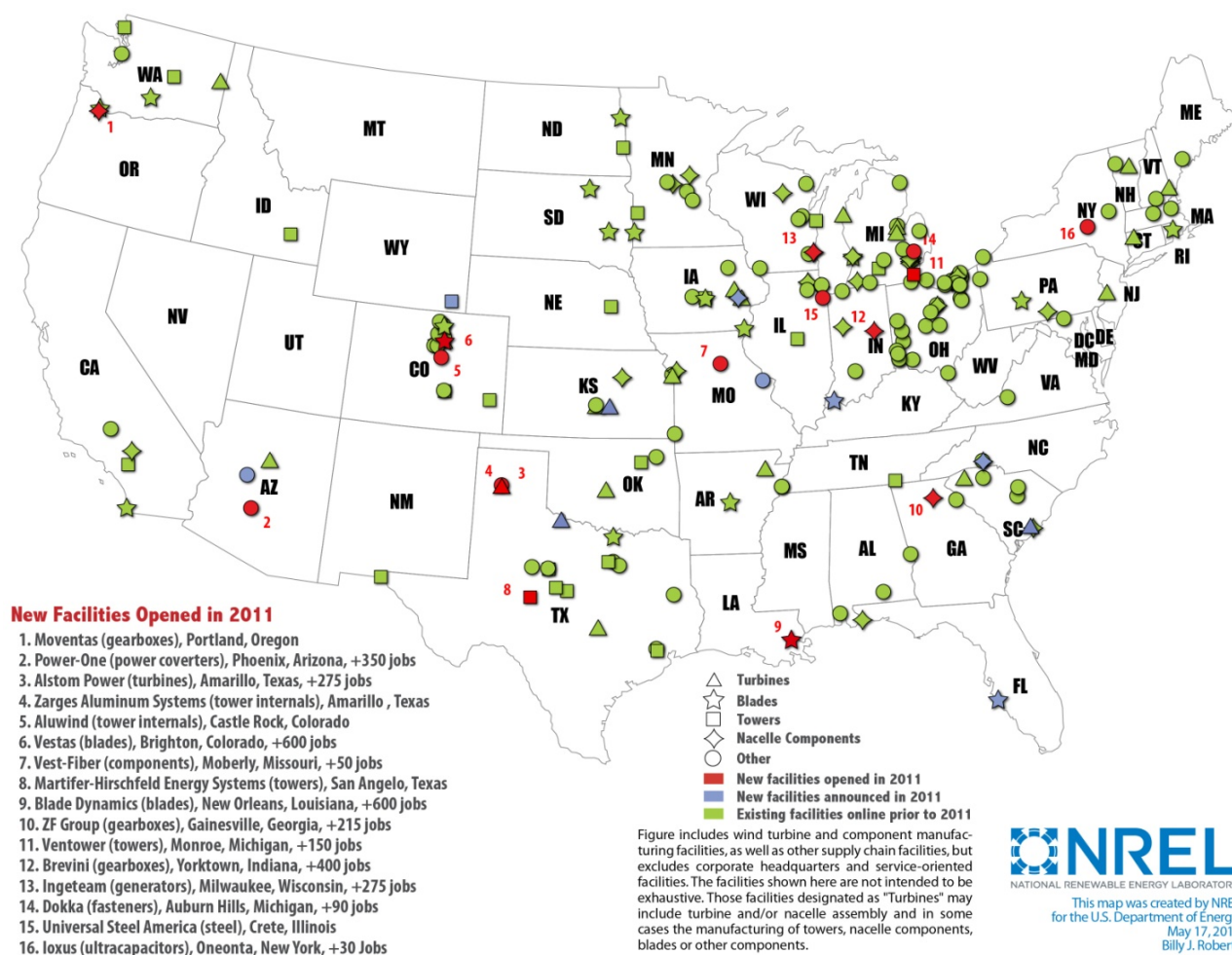
To date, the growth of Chinese turbine manufacturers has been based almost entirely on sales to the Chinese market. With the Chinese market beginning to show signs of cooling, however, Chinese (and South Korean) manufacturers have begun to look abroad and penetrate the international wind turbine market, including with limited sales into Europe and the United States. In the United States, for example, 2011 installations by Chinese and South Korean manufacturers included those from Sany Electric (10 MW), Samsung (5 MW), Goldwind (4.5 MW), Hyundai (3.3 MW), Sinoel (1.5 MW), and Unison (1.5 MW). Many of these early installations have been developed and financed by the turbine suppliers themselves, and until there is sufficient operating experience to mitigate uncertainty over turbine quality and bankability, widespread entry by Chinese suppliers into the U.S. market seems unlikely. Nevertheless, the historically-dominant wind turbine suppliers in the U.S. market are likely to face growing competition from new entrants in the coming years.

<sup>15</sup> These statements emphasize the sale of large wind turbines. U.S. manufacturers are major players in the global market for smaller-scale turbines (AWEA 2012b).



## Domestic Wind Turbine and Component Manufacturing Capacity Has Increased, but Uncertainty in Future Demand Has Put the Wind Turbine Supply Chain Under Severe Pressure

Faced with substantial expected growth in wind power capacity additions in 2012, but uncertain prospects after 2012, the wind industry's domestic supply chain faces conflicting pressures. As the cumulative capacity of wind power projects has grown, foreign and domestic turbine and component manufacturers have localized and expanded operations in the United States. In fact, despite the near-term demand uncertainty, a larger number of new turbine and component manufacturing facilities (16) opened in 2011 than in 2010 (13). Figure 9 presents a non-exhaustive list of the 16 wind turbine and component manufacturing and assembly facilities that opened in 2011, the 10 new manufacturing facilities announced (but not yet built) in 2011, and the more than 165 existing manufacturing facilities that were open prior to 2011.<sup>16</sup>



**Figure 9. Location of Existing and New Turbine and Component Manufacturing Facilities**

<sup>16</sup> The data on existing, new, and announced manufacturing facilities presented here differ somewhat from those presented in AWEA (2012a) due, in part, to methodological differences. In addition, AWEA (2012a) has access to data on smaller component suppliers that are not included here.



Of the new or announced facilities captured in Figure 9, two are owned by major international wind turbine original equipment manufacturers (OEMs): Vestas (blades in Brighton, Colorado) and Alstom (turbines in Amarillo, Texas). In addition, GE opened a new logistics center for renewable energy components in Mississippi (logistics and research centers are not included in Figure 9).<sup>17</sup>

Eight of the ten OEMs with the largest share of the U.S. market in 2011 (Alstom, Clipper, Gamesa, GE, Nordex, Siemens, Suzlon, and Vestas) had one or more operational manufacturing facilities in the United States in 2011 (Suzlon, however, announced the closure of its facility in 2012). Companies with multiple facilities include Gamesa, GE, Siemens, and Vestas. Other active domestic and foreign OEMs that have sold larger turbines in the U.S. market and that have established U.S. manufacturing facilities include Acciona, DeWind, Northern Power Systems, and Aeronautica, while still other companies have announced their interest in manufacturing but have not yet installed any utility-scale turbines in the United States. In contrast to the multiple OEMs operating in 2011, there was only one active utility-scale wind energy OEM assembling nacelles in the United States as late as 2004 (GE).<sup>18</sup>

The growth in U.S. wind turbine manufacturing capability and the drop in wind power plant installations since 2009 led to an estimated *over-capacity* of U.S. turbine nacelle assembly capability of more than 5 GW in 2011, in comparison to 4 GW of *under-capacity* in 2009 (Figure 10). Over-capacity is defined here as maximum turbine nacelle assembly capacity in the U.S. exceeding total turbine demand in the U.S. Because maximum factory utilization is uncommon, some level of over-capacity should not be considered problematic. On the other hand, actual over-capacity at U.S. nacelle assembly facilities likely exceeded these estimates because U.S. demand for wind turbines is also partially met with imports from other countries (see next section), leading to U.S. nacelle assembly facilities operating at well below their maximum capability in 2011.<sup>19</sup> With maximum domestic turbine nacelle assembly capacity predicted by Bloomberg NEF (2012a) to stabilize at approximately 13 GW in the near term, over-capacity relative to U.S. turbine demand (not considering imports or exports of turbines) is anticipated to be severe in 2013 and 2014 when wind power capacity additions are expected to decline (see Section 8, “Future Outlook”).

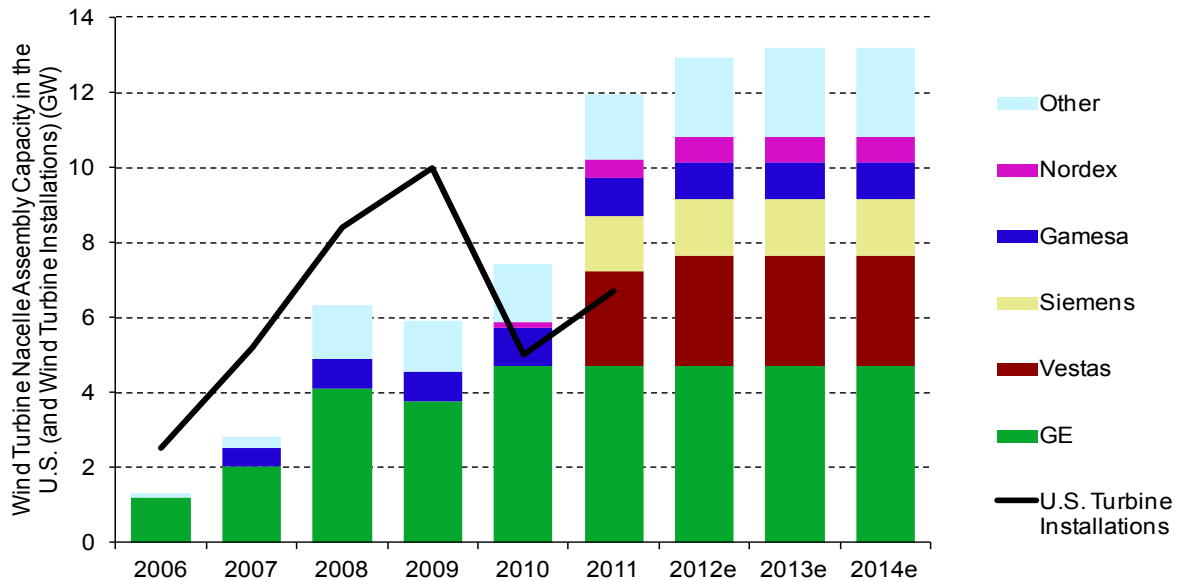
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<sup>17</sup> Vestas, however, announced the cancellation of its planned R&D facility in Massachusetts in early 2012.

<sup>18</sup> Nacelle assembly is defined here as the process of combining the multitude of components included in a turbine nacelle to produce a complete turbine nacelle unit.

<sup>19</sup> Exports of wind turbines from U.S. nacelle assembly facilities to other countries have the ability to reduce the estimated over-capacity, but as shown in the next section, U.S. exports have been relatively modest to date.

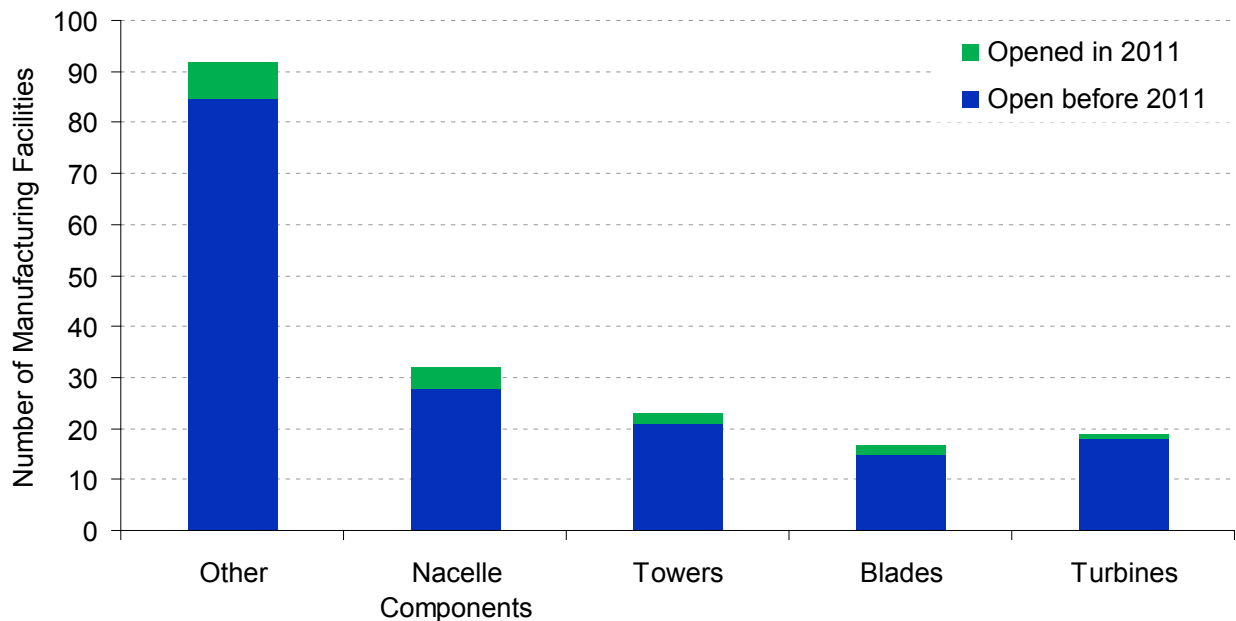




Source: Bloomberg New Energy Finance

**Figure 10. Domestic Wind Turbine Nacelle Assembly Capacity and Demand**

Beyond nacelle assembly, Figure 9 shows a good number of new component manufacturing facilities announced or opened in 2011. Figure 11 segments the manufacturing facilities operating in the U.S. by major component, including those that opened prior to and in 2011 (the figure excludes announced but not yet opened facilities).



Note: Manufacturing facilities that produce multiple components are included in multiple bars.

Source: National Renewable Energy Laboratory

**Figure 11. Number of Operating Wind Turbine and Component Manufacturing Facilities on U.S. Soil**



Though new and announced turbine and component manufacturing facilities are spread across the country, a number of component manufacturers are choosing to locate in markets with substantial wind power capacity or near already established large-scale OEMs. For example, in 2011, four component suppliers opened or announced facilities in Texas, a state with both substantial historical wind power additions and a strong wind turbine and component manufacturing base. Two new component manufacturing facilities were opened or announced in both Colorado and Michigan; both states are strategically positioned geographically near large wind power markets, therefore allowing for reduced transportation challenges and costs. Even states that are relatively far-removed from major wind power markets – including several states in the Southeast – have seen new wind turbine and component manufacturing facilities come online in recent years. Workforce considerations, transportation costs, and state and local incentives are among the factors that typically drive location decisions.

AWEA (2012a) estimates that the wind energy industry directly and indirectly employed 75,000 full-time<sup>20</sup> workers in the United States at the end of 2011 – equal to the jobs reported in 2010 but fewer than in 2008 and 2009. The 75,000 jobs include manufacturing (which accounts for 30,000 jobs), project development, construction and turbine installation, operations and maintenance, transportation and logistics, and financial, legal, and consulting services.

Notwithstanding these developments, policy uncertainty and unfavorable market conditions (e.g., low wholesale power prices and competition amount turbine and component suppliers) are straining the wind industry's manufacturing supply chain, as margins drop and concerns about manufacturing overcapacity deepen, potentially setting the stage for significant layoffs. As noted earlier, maximum nacelle assembly capacity in the U.S. (as well as component manufacturing in some cases) substantially exceeds post-2012 near-term expected demand for wind in the U.S., yielding relatively lower utilization of the production capacity of existing facilities, downward pressure on component and turbine pricing, and compressed manufacturer profit margins. Reportedly in part as a result, Mitsubishi – the OEM with the 5<sup>th</sup>-largest amount of U.S. installations in 2011 – announced in early 2012 that it would indefinitely delay the opening of its Fort Smith, Arkansas manufacturing facility. UTC, meanwhile, announced that it was seeking to sell Clipper, while a wide range of OEMs – including GE, Vestas, Siemens, Nordex, Gamesa, Goldwind, and Sinovel – have recently announced weakened financial results. Consequently, Vestas has indicated that it will lay off 182 people in the U.S. and is prepared to make further and more-substantial cuts if the PTC is not extended. Gamesa, NRG, Clipper, Iberdrola, EDP Renewables North America, and others have also recently announced cuts to their U.S. workforce, demonstrating that elements of the entire supply chain, from OEMs to developers, are at risk.

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<sup>20</sup> Jobs are reported as full-time equivalents. For example, two people working full-time for six months are equal to one full-time job in that year.



## A Growing Percentage of the Equipment Used in U.S. Wind Power Projects Has Been Sourced Domestically in Recent Years

As a result of the aforementioned developments in U.S.-based wind turbine and component manufacturing, the share of *domestically manufactured* wind turbines and components has grown in recent years, while the *import share* has witnessed a corresponding drop. These trends are supported by an analysis of data from the U.S. Department of Commerce.<sup>21</sup>

Figure 12 presents calendar-year data on *estimated* U.S. imports of wind-related equipment from 2005 through 2011.<sup>22</sup> Specifically, the figure shows imports of wind-powered generating sets (i.e., nacelles and, when imported with the nacelle, other turbine components) as well as imports of turbine components that are shipped *separately* from the generating sets.<sup>23</sup> The separate importation of selected wind turbine components includes towers as well as other wind turbine components (specifically, generators, blades and other components, and gearboxes). Estimates provided for these component-level imports in Figure 12 should be viewed with caution because the underlying data used to produce the figure are based on trade categories that are not exclusive to wind energy (e.g., they could include generators for non-wind applications). The component-level import estimates shown in Figure 12 therefore required assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. The error bars included in Figure 12, meanwhile, account for uncertainty in these assumed fractions.<sup>24</sup>

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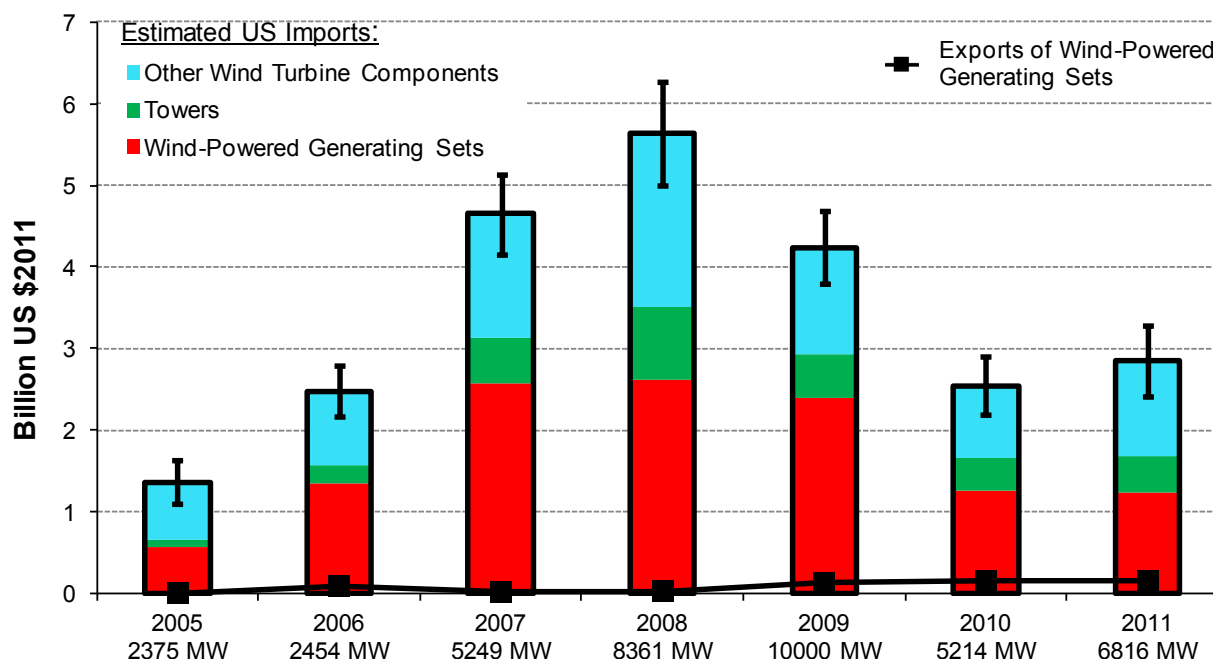
<sup>21</sup> The Department of Commerce trade data are accessed through the U.S. International Trade Commission's (USITC) DataWeb, which compiles statistics from the Department of Commerce on imports and exports. The statistics can be queried online at: <http://dataweb.usitc.gov/>. The analysis presented here relies on the 'customs value' of imports as opposed to the 'landed value.' For more information on these data and their application to wind energy, see David (2009, 2010, 2011).

<sup>22</sup> "Wind-powered generating sets" are in Harmonized Tariff Schedule (HTS) 8502.31.0000. This HTS provision includes both utility-scale and small wind turbines. Estimating separate wind turbine component imports is complicated by the fact that the HTS does not contain provisions that are exclusive to wind turbine components. Included in the analysis presented here are: HTS 7308.20.0000 – "towers and lattice masts" (available for years 2005-2010); HTS 7308.20.0020 – "towers and lattice masts - tubular" (available for 2011 only); HTS 8501.64.0020 – "AC generators (alternators) from 750 to 10,000 kVA"; HTS 8412.90.9080 – "other parts of engines and motors"; HTS 8503.00.9545 – "parts of generators (other than commutators, stators, and rotors)"; HTS 8483.40.5010 – "fixed ratio speed changers"; and HTS 8483.40.5050 – "multiple and variable ratio speed changers."

<sup>23</sup> Wind turbine components such as blades, towers, generators, and gearboxes are included in the data on wind-powered generating sets if shipped with the nacelle. Otherwise, these component imports are reported separately.

<sup>24</sup> Given the split of the "towers and lattice masts" HTS classification into "tubular" and "other" in 2011, we calculated the 2011 ratio of "tubular" tower imports (all of which are assumed to be wind-related) to the sum of "tubular" and "other" tower and lattice mast imports. Using this ratio and considering overall U.S. import levels of wind-related equipment, it is assumed that the proportion of towers and lattice masts imports from 2005-2010 that are related to towers used in U.S. wind power plants increases from 80% in 2005 to 90% in 2008, before decreasing to 80% in 2010. Based on a review of the countries of origin for the imports, personal communications with USITC and AWEA staff, David (2010), and Wyden (2010), the proportion of wind-related equipment in the five other relevant HTS provisions (i.e., wind turbine components other than towers) is assumed to increase from 40% in 2005 to 55% in 2008, before dropping back to 40% in 2010, and staying at 40% in 2011. These trends are intended to reflect, in part, the rapidly increasing imports of wind equipment from 2005-2008, and the subsequent decline in imports from 2008-2010, before steadying in 2011. To reflect uncertainty in these proportions, a  $\pm 15\%$  variation is applied to the trade categories that include wind turbine components other than towers, and a  $\pm 5\%$  variation is applied to the category that includes wind turbine towers.





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

**Figure 12. Estimated Imports of Wind-Powered Generating Sets, Towers, and Other Wind Turbine Components, as Well as Exports of Wind-Powered Generating Sets**

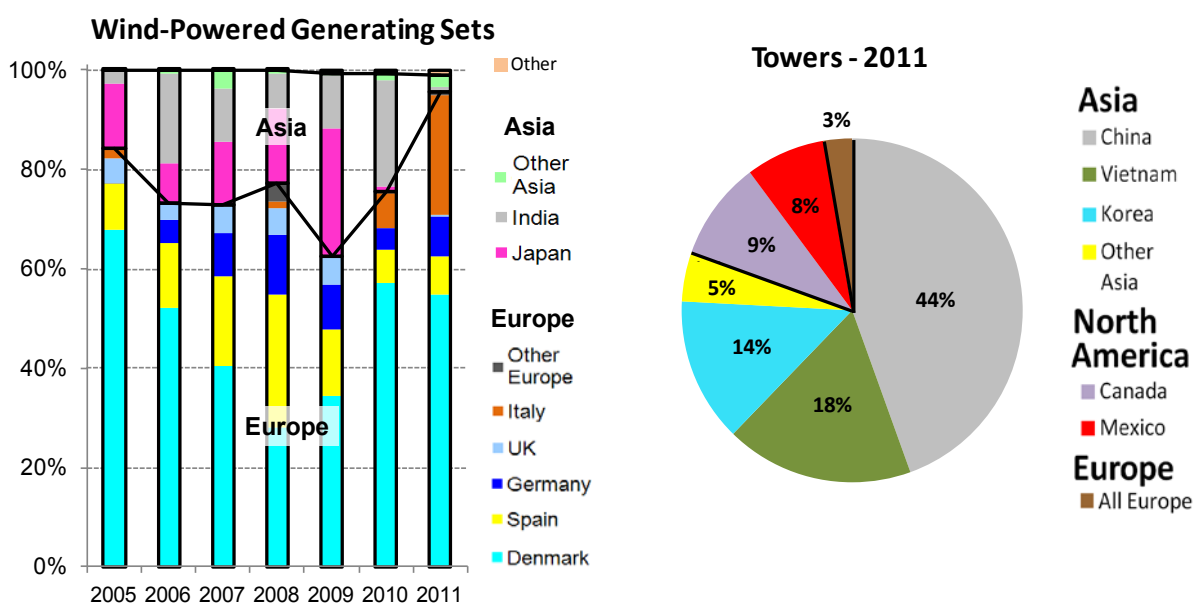
As shown, *estimated* imports of wind-related equipment into the United States substantially increased from 2005-2008, before falling dramatically through 2010 and then increasing somewhat in 2011. These overall trends are driven primarily by changes in the share of domestically manufactured wind turbines and components (versus imports) as well as changes in the annual rate of wind power capacity installations and wind turbine prices.

Figure 12 also shows that exports of wind-powered generating sets from the United States have increased, rising from \$15 million in 2007 to \$147 million in 2010, and staying relatively constant at \$149 million in 2011. The largest destination markets for these exports over the entire 2005-2011 timeframe have included Canada (54%), Brazil (19%), Mexico (10%), China (6%), and Honduras (4%), while 2011 exports were dominated by Brazil (67%), Honduras (16%), Mexico (8%), and Canada (8%). Wind turbine component exports (towers, blades, gearboxes, generators) are not shown in the figure because such exports are likely a small and/or uncertain fraction of the broader trade category totals.<sup>25</sup> Despite some long-term growth in exports, it is clear from these data that the U.S. remained a sizable net importer of wind turbine equipment over the entire 2005 to 2011 timeframe.

<sup>25</sup> U.S. exports of ‘towers and lattice masts’ in 2011 totaled \$102 million, however, with the largest destination markets being Canada (42%), Costa Rica (14%), and Mexico (11%). The U.S. ITC data for tower exports do not differentiate between tubular towers (used in wind power applications) and other types of towers, unlike the import classification for 2011. Though it is likely that most of these tower exports are wind-related, the exact proportion is not known and hence the \$102 million figure should be viewed with some caution.



Looking behind the import data presented in Figure 12 in more regional detail, Figure 13 shows a number of trends in the origin of the U.S. imports of wind-powered generating sets and towers.<sup>26</sup> The primary source markets for wind-powered generating sets during the 2005-2011 period have been the home countries of the major international turbine manufacturers: Denmark, Spain, Japan, India, and Germany. The obvious exception is Italy, which is not “home” to a major wind turbine manufacturer, though Vestas, at least, has blade and nacelle manufacturing facilities there. Offsetting the recent increase in Italy's share (as well as the lesser increase in Denmark's contribution from 2009-2011) has been a notable recent decline in the share of imports from Japan, Spain, and the India.<sup>27</sup> The countries of origin for tower imports are only reported for the year 2011, as the proportion of tower imports that were wind-related for each country is not known for years 2005-2010, before the HTS classification that contains towers was split into a tubular and “other” category. In 2011, the share of imports of tubular towers from Asia was over 80%, with a sizable proportion of the imports from China, Vietnam, and Korea, as well as from Canada and Mexico; unlike for wind-powered generating sets, the share of tower imports from Europe is minor. Responding to a case brought by a number of U.S. tower manufacturers, in May 2012 the U.S. Commerce Department issued a preliminary ruling that will impose additional duties on Chinese towers imported into the United States. Once finalized, this trade case may impact the magnitude and source countries of tower imports to the U.S. in years to come.



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

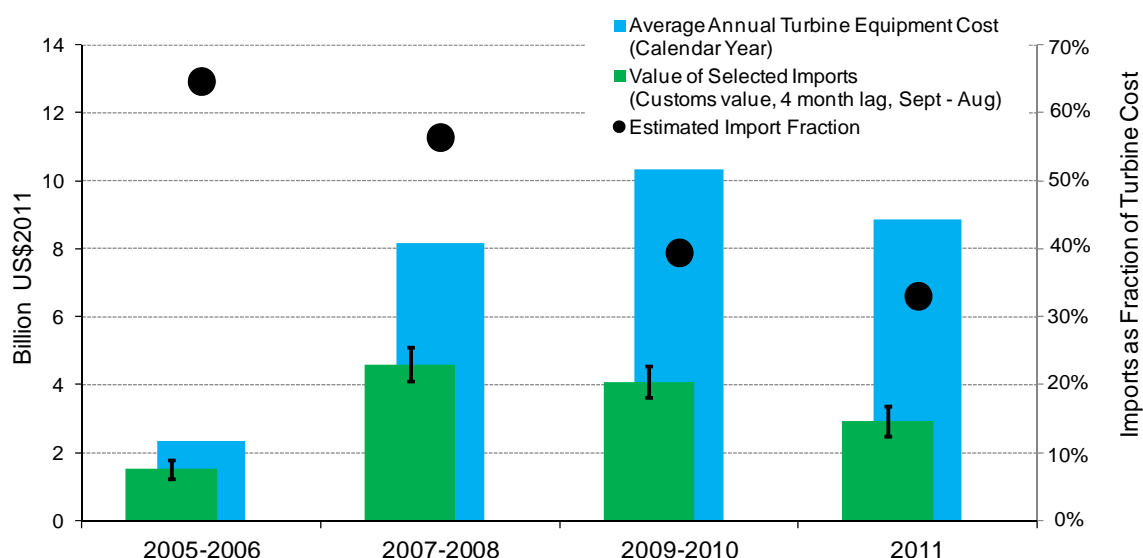
**Figure 13. Origins of Imports of Wind-Powered Generating Sets and Towers**

<sup>26</sup> Only the origin of imports for “wind-powered generating” sets and “towers” are presented in Figure 13 because the other five trade categories that sum to “other wind turbine components” in Figure 12 are assumed to have smaller proportions of wind-related equipment.

<sup>27</sup> Over the entire 2005-2011 timeframe, the largest source countries for wind-powered generating sets were: Denmark (42%), Spain (16%), Japan (13%), India (10%), and Germany (8%) (in 2011, the top three countries were Denmark (55%), Italy (24%), and Germany (8%)).



Though Figures 12 and 13 depict a U.S. market that remains reliant on imports of wind power equipment, that reliance has declined over time as growth in installed wind power capacity has outpaced wind turbine and component imports. To estimate the percentage share of imports and domestic manufacturing over time, one must account for the fact that turbines, towers, and other components imported at the end of one year may not be installed until the following year. As such, in Figure 14 the combined imports of wind-powered generating sets and selected turbine components are determined by using a 4-month lag (i.e., monthly import data from September of the previous year to August of the current year are used to estimate the value of imports in wind turbine installations in the current year). Those import figures are then compared to total wind turbine equipment-related costs on a calendar-year basis.<sup>28</sup> Data from 2005-2010 are averaged over two-year periods to further avoid “noise” in the resulting estimates. The error bars correspond to those in Figure 12, and represent the uncertainty in the proportion of wind-related equipment imports in certain larger trade categories.



**Figure 14. Estimated Wind Power Equipment Imports as a Fraction of Total Turbine Cost**

Ultimately, when presented as a fraction of total equipment-related turbine costs in this fashion, the overall import fraction is found to have declined considerably, from 65% in 2005-2006 to 33% in 2011 (conversely, domestic content has increased from 35% in 2005-2006 to 67% in 2011). Reporting these figures as a proportion of total wind project installed costs (not just wind turbine equipment-related costs) is also of interest, but is complicated by the fact that non-turbine balance-of-plant costs may also involve some level of imports. Nonetheless, if one simply assumes that 80% of non-turbine-equipment balance-of-plant costs derive from domestic sources with the remaining 20% from imports, then the import fraction for total wind project installed

<sup>28</sup> Total wind turbine costs (\$/kW) are assumed to equal approximately 75% of the average project-level costs reported later in this report in Figure 20, while wind turbine equipment-related costs are assumed to equal 85% of total wind turbine costs (with the remaining 15% consisting of transportation, project management, and other soft costs). To calculate total calendar-year wind turbine equipment-related costs, this wind turbine equipment-related cost figure in \$/kW is multiplied by annual wind power capacity installations.

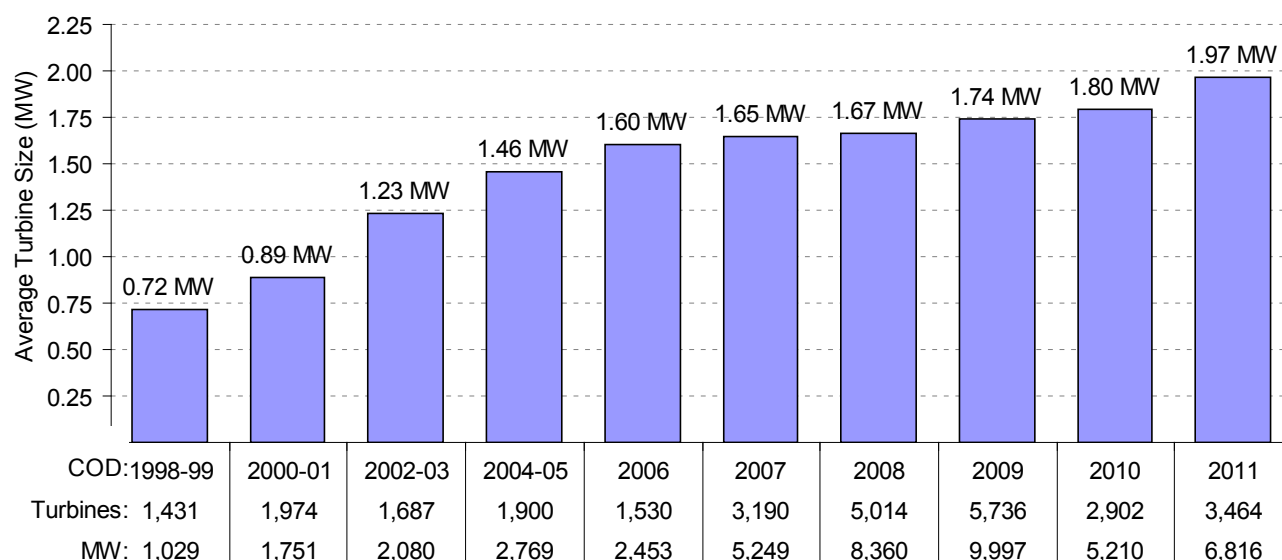


costs would equal 48% in 2005-2006 and 28% in 2011 (i.e., domestic content would equal 52% in 2005-2006 and 72% in 2011).

These figures should be considered rough approximations for the reasons stated earlier, and may understate the wind power industry's reliance on turbine and component imports because it is possible that imports of wind power equipment are occurring under other trade categories that are not captured here. Nonetheless, these figures demonstrate that a growing amount of the equipment used in wind power projects has been sourced domestically in recent years. Whether that trend continues in the future may depend on the size and stability of the U.S. wind power market as well as the manufacturing strategies of emerging turbine manufacturers from Asia and elsewhere.

## The Average Nameplate Capacity, Hub Height, and Rotor Diameter of Installed Wind Turbines Increased

The average nameplate capacity of wind turbines that were newly installed in the United States in 2011 increased to roughly 1.97 MW (Figure 15), up from 1.80 MW in 2010. This was the largest single-year increase in more than six years. Since 1998-99, average turbine nameplate capacity has increased by 174%.<sup>29</sup>



Source: AWEA project database

**Figure 15. Average Turbine Nameplate Capacity Installed During Period (only turbines > 100 kW)**

<sup>29</sup> Figure 15 (as well as a number of the other figures and tables included in this report) combines data into both one- or two-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; though not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects.



Table 4 shows how the distribution of turbine nameplate capacity has shifted over time: nearly 42% of all turbines installed in 2011 had a nameplate capacity larger than 2.0 MW, up significantly from 28% in 2010, 24% in 2009, 20% in 2008, 16% in both 2007 and 2006, and just 0.1% or less in years prior to 2006. GE's 1.5/1.6 MW wind turbine remained the nation's most-popular turbine in 2011, with 1,170 units installed (709 of the 1.5 MW version, and 461 of the 1.6 MW version), equating to 26% of all wind power capacity installed in 2011.<sup>30</sup>

**Table 4. Size Distribution of Number of Turbines over Time (only turbines > 100 kW)**

Years:		1998-99	2000-01	2002-03	2004-05	2006	2007	2008	2009	2010	2011
# MW:		1,029	1,751	2,080	2,769	2,453	5,249	8,360	9,997	5,210	6,816
# turbines:		1,431	1,974	1,687	1,900	1,530	3,190	5,014	5,736	2,902	3,464
Turbine Size Range (MW)	>0.1≤0.5	0.5%	0.2%	0.2%	0.1%	0.3%	0.0%	0.0%	0.2%	0.1%	0.2%
	>0.5≤1.0	99%	74%	42%	19%	11%	11%	11%	5%	0.2%	0.2%
	>1.0≤1.5	0.0%	26%	45%	56%	54%	49%	54%	49%	52%	21%
	>1.5≤2.0	1%	0.4%	13%	24%	18%	23%	16%	21%	20%	37%
	>2.0≤2.5	0.0%	0.0%	0.0%	0.1%	16%	15%	17%	23%	25%	35%
	>2.5≤3.0	0.0%	0.0%	0.1%	0.0%	0.0%	1%	2%	1%	2%	7%

Source: AWEA project database

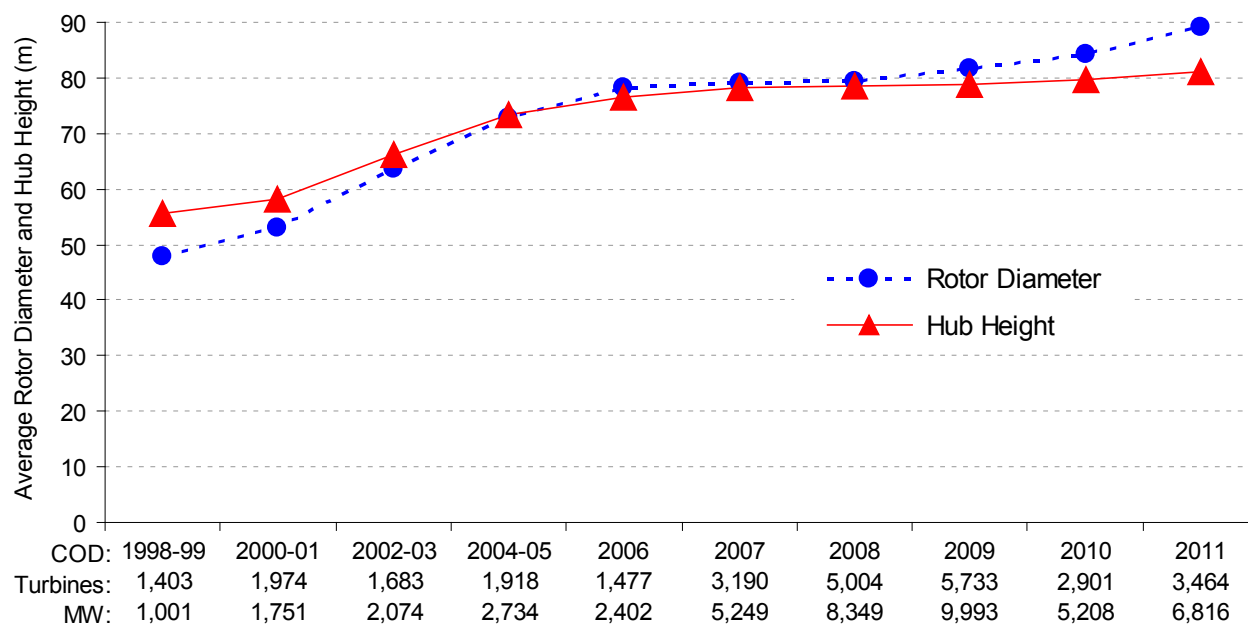
In addition to nameplate capacity ratings, average hub heights and rotor diameters have also scaled with time. The average hub height of wind turbines installed in the United States in 2011 was 81 meters (Figure 16), up from 79.8 meters in 2010 and 78.9 meters in 2009. Since 1998-99, the average turbine hub height has increased by 45% (or 25.3 meters), though growth has slowed in the more recent years. At the upper extreme, 128 turbines installed in 2011 (totaling 239 MW) had hub heights of 100 meters, up from 17 turbines (38.5 MW) in 2010. Not surprisingly, most of these taller towers have been installed in areas with less-energetic wind regimes, such as the East and Great Lakes regions (see Figure 30, later, for regional definitions).

Average rotor diameters have increased at a more rapid pace, especially in the last two years: the average rotor diameter of wind turbines installed in the United States in 2011 was 89 meters (Figure 16), up from 84.3 meters in 2010 and 81.6 meters in 2009. Since 1998-99, the average rotor diameter has increased by 86% (or 41.2 meters). At the upper extreme, 810 turbines installed in 2011 (totaling 1,803 MW) featured rotor diameters of 100 meters or larger, up from 222 turbines (512 MW) in 2010.

These trends in hub height and rotor scaling are one of several factors impacting the project-level capacity factors highlighted later in this report. Moreover, industry expectations as well as new turbine announcements (especially to serve lower-wind-speed sites) suggest that significant further scaling, especially in average rotor diameter, is anticipated in the near term.

<sup>30</sup> A number of *pre-existing* GE 1.5 MW turbines installed in earlier years have been upgraded to 1.6 MW, but data on how many or which turbines have been upgraded are not publicly available, and so this change in nameplate capacity is not reflected in the data presented in this report.





Source: Berkeley Lab

**Figure 16. Average Rotor Diameter and Hub Height Installed During Period**

Apart from (but related to) turbine size, turbine configuration is also changing somewhat. In particular, there were 17 direct drive (as opposed to geared) turbines installed in the U.S. in 2011 (totaling 35.3 MW), up from no more than three (totaling no more than 4.5 MW) in any of the previous three years.<sup>31</sup> Five turbine manufacturers supplied direct drive units in 2011, up from two in previous years, with the new entrant Siemens accounting for the largest share (7 turbines totaling 21 MW).<sup>32</sup> The number of direct drive turbines installed in the U.S. is expected to grow further in 2012, as Goldwind has acquired a number of projects (totaling more than 100 MW) to showcase its 1.5 MW (and 2.5 MW) direct drive turbine, while Siemens will install more than 200 MW of its 3 MW direct drive units at the Bison II and III projects in North Dakota alone.

## Project Finance Was a Mixed Bag in 2011, as Debt Terms Deteriorated While Tax Equity Held Steady

After steady improvement in both the debt and tax equity markets throughout 2010, progress faltered somewhat in 2011 on the debt side, as the latest Greek/European debt crisis drove a new round of retrenchment.

AWEA (2012a) reports that roughly 4,000 MW of new wind capacity raised \$5.9 billion in debt in 2011 – down 30% from the \$8.4 billion of debt raised by nearly 5,600 MW in 2010. Though

<sup>31</sup> Direct drive technology has been relatively slow to enter the U.S. market – e.g., BTM (2012) reports that as much as 21% of *global* wind installations in 2011 featured direct drive turbines – in part because Enercon, a German leader in direct drive technology, has not entered the U.S. market, while Chinese sales of direct-drive turbines into the U.S. has been limited.

<sup>32</sup> Other manufacturers supplying direct drive turbines to the U.S. in 2011 include Vensys (4 x 1.5 MW), Goldwind (3 x 1.5 MW), Northern Power Systems (1 x 2.3 MW), and Unison (2 x 750 kW).



AWEA attributes this decline to several rather innocuous factors,<sup>33</sup> it is also the case that debt terms – and in particular bank loan tenors – deteriorated in the latter part of 2011, in response to the unfolding Greek drama and some of the new banking regulations taking hold (e.g., Basel III). Though 2010 was characterized by a steady lengthening of loan tenors throughout the year – with 7- to 10-year “mini-perms” stretching to longer maturities (e.g., 10-12 years) and eventually even to 15- to 18-year fully amortizing deals – by the end of 2011, 10- to 12-year mini-perms were once again the norm (AWEA 2012d).<sup>34</sup> In addition, a number of European banks – which historically have been familiar lenders to U.S. wind projects – dropped out of the market in response to the financial turmoil emanating from Greece. As a result, bank loan pricing ratcheted up a bit, with spreads over the London Interbank Offered Rate (LIBOR) reportedly starting at around 275 basis points (+/- 50 basis points depending on the particulars of the deal) with a 25 basis point step-up every 3-4 years (AWEA 2012d). With LIBOR trading at around 0.5%, however, and 10-year interest rate swaps priced at roughly 2.25% in 4Q11, all-in interest rates starting below 6% were, and still are, achievable.

While banks have pulled back somewhat, institutional lenders (e.g., insurance companies) continue to offer long-term products – e.g., as long as 20 years with full amortization, and also at all-in interest rates of 6% or less. Some wind project developers have split up their debt financing in response to this divergence – using banks for their shorter-term borrowing needs (e.g., construction and cash grant bridge financing) and institutional lenders (or even the bond market) for long-term permanent debt financing.

In contrast to the weakened debt market, the market for tax equity improved somewhat in 2011. The total amount of tax equity committed to both wind and solar projects in 2011 increased to \$6 billion (up 20% from \$5 billion in 2010), but virtually all of this growth came from solar investments – perhaps a harbinger of the growing competition for tax equity that the wind sector will increasingly face – while wind investments held steady at around \$3.5 billion (Eber 2012). There were reportedly 19 wind tax equity deals done in 2011: 18 partnership flip structures (five with project-level debt) and one sale-leaseback (Chadbourn & Parke 2012). Tax equity pricing has remained fairly stable since late 2009, with yields on “best-in-market” deals reportedly hovering around 8% on an after-tax, unleveraged basis (Chadbourn & Parke 2012). The pool of active tax equity investors increased to as many as twenty-two in 2011 (up from around 16 in 2010), but this swelling of the ranks was comprised mostly of returning investors who had temporarily dropped out of the market, rather than of entirely new investors (Chadbourn & Parke 2012, Eber 2012). Moreover, one high-profile investor – Google – that had entered the market in 2010 and made several tax equity investments in wind projects in 2010 and 2011 has reportedly shifted its investment focus away from tax equity and towards private equity, where it

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<sup>33</sup> These factors include a growing preference for the PTC over the Section 1603 cash grant (PTC deals are mostly financed with tax equity rather than debt), lower PPA prices (which cannot support as much leverage), and two very large debt-financed projects (including the 845 MW Shepherds Flat project, which closed on a partial DOE guarantee of \$1.3 billion in debt in December 2010) that happened to fall in 2010 rather than 2011 (AWEA 2012a).

<sup>34</sup> 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 10-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 10 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).



can earn higher returns and also feel more like a sponsor than a passive investor (Eber 2012). As the number of grandfathered Section 1603 grant deals begins to taper off, further attrition of tax equity investors is possible, as some have indicated that they are not interested in deals that involve the PTC.

Looking ahead to the remainder of 2012, the looming end-of-year expiration of both the PTC and the Section 1603 cash grant (for those wind projects that met the end-of-2011 construction start deadline) dominate the picture. As developers rush to complete projects in advance of these policy deadlines, the competition for financing will likely increase, as will the cost of capital. Demand for tax equity could increase disproportionately (relative to debt) as projects increasingly choose the PTC over the Section 1603 cash grant.<sup>35</sup> Meanwhile, the ongoing implementation of more stringent capital adequacy and leverage requirements under the Basel III Accord likely means that shorter bank loan tenors are here to stay – this could have a particularly detrimental impact on wind project finance beyond 2012 if the PTC is ultimately not extended or renewed, which would then make term debt financing more the norm.

## **IPPs Remain the Dominant Owners of Wind Projects, But Utility Ownership Increased Significantly in 2011, Largely On the Back of One Utility**

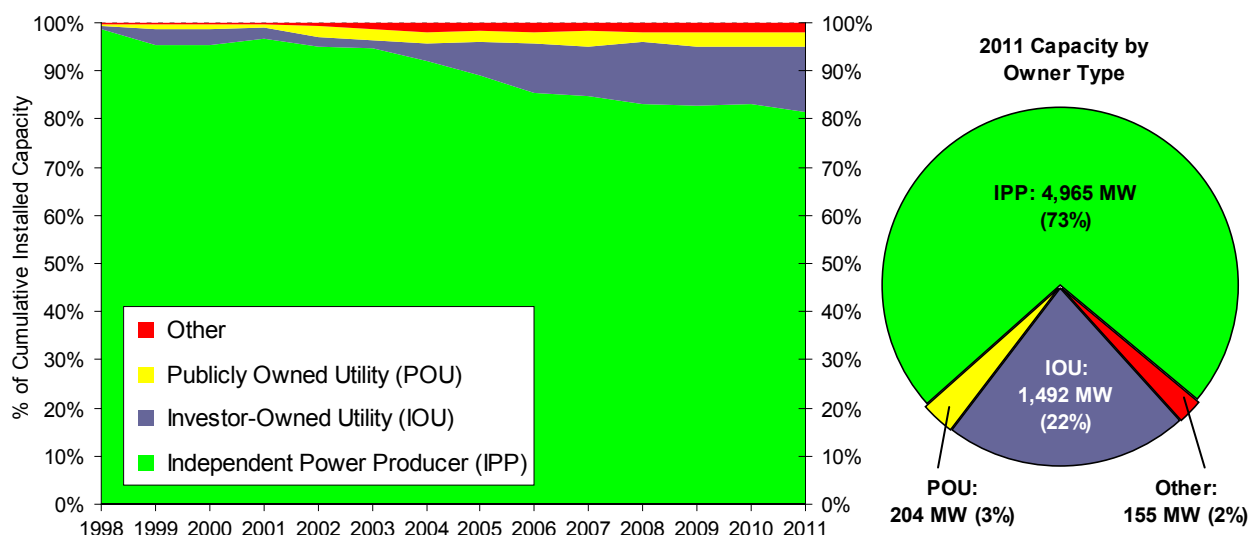
Independent power producers (IPPs) continued to dominate the ownership of wind power projects, owning 73% (4,965 MW) of all new capacity additions in 2011 (Figure 17). On the back of nearly 600 MW of new capacity built by MidAmerican Energy, however, utility ownership jumped to nearly 25% – up from roughly 15% in the two previous years – with investor-owned utilities (IOUs) owning 1,492 MW and publicly owned utilities (POUs) owning another 204 MW. The remaining 2% (155 MW) of new 2011 wind capacity is owned by “other” entities that are neither IPPs nor utilities (e.g., towns, schools, commercial customers, farmers).<sup>36</sup> Of the cumulative installed wind power capacity at the end of 2011, IPPs owned 82% (38,407 MW) and utilities owned 17% (6,357 MW for IOUs and 1,424 MW for POUs), with the remaining 2% (904 MW) falling into the “other” category.

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<sup>35</sup> Some 2012 projects might not have met the end-of-2011 construction start milestone for the grant, and so have no choice but to take the PTC. More likely, though, most wind projects will willingly choose the PTC because recent trends in installed project costs and capacity factors have made the PTC more valuable than the grant, at least in terms of face value. This is likely why AWEA (2012a) finds that 56% of tax equity raised in 2011 went to PTC deals, compared to just 22% in 2010. This preference for the PTC could further exacerbate any shortage of tax equity in 2012, as some tax equity investors are only interested in cash grant deals.

<sup>36</sup> Most of these “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. One example of a 2011 project that is classified in Figure 17 as IPP-owned, yet might also be considered a community wind project, is the 40.5 MW Petersburg project in Nebraska – a C-BED (Community-Based Energy Development) project that is owned by Gestamp (a Spanish IPP). According to AWEA (2012a), 6.7% of 2011 capacity additions qualified as community wind projects.





Source: Berkeley Lab estimates based on AWEA project database

**Figure 17. Cumulative and 2011 Wind Power Capacity Categorized by Owner Type**

The dominance of IPP ownership, and the trend towards increasing utility ownership since the mid 2000s, has been driven by several factors. When wind energy was a small part of the generation mix, some utilities felt that buying wind power from IPPs was less risky than owning wind power projects themselves. As utilities have gained comfort with wind power over the years, however, their interest in ownership has increased for several reasons: IOUs are typically allowed to earn a regulated return on project ownership (i.e., by adding it to their rate base) but not on power purchases; some credit rating agencies consider long-term power purchase agreements to be debt-like instruments, thereby potentially negatively impacting a utility's credit rating; and ownership places the utility in a position of greater control over project development, operations, and eventually repowering. More recently, as the tax equity market dried up in the wake of the financial crisis of 2008/2009, IOUs were left as one of the few natural wind project investors with a steady and sizable tax liability<sup>37</sup> – some of the utility-owned wind projects built in 2011 were conceived at that time. With most of these drivers still in place, utility ownership may continue to increase in the coming years.

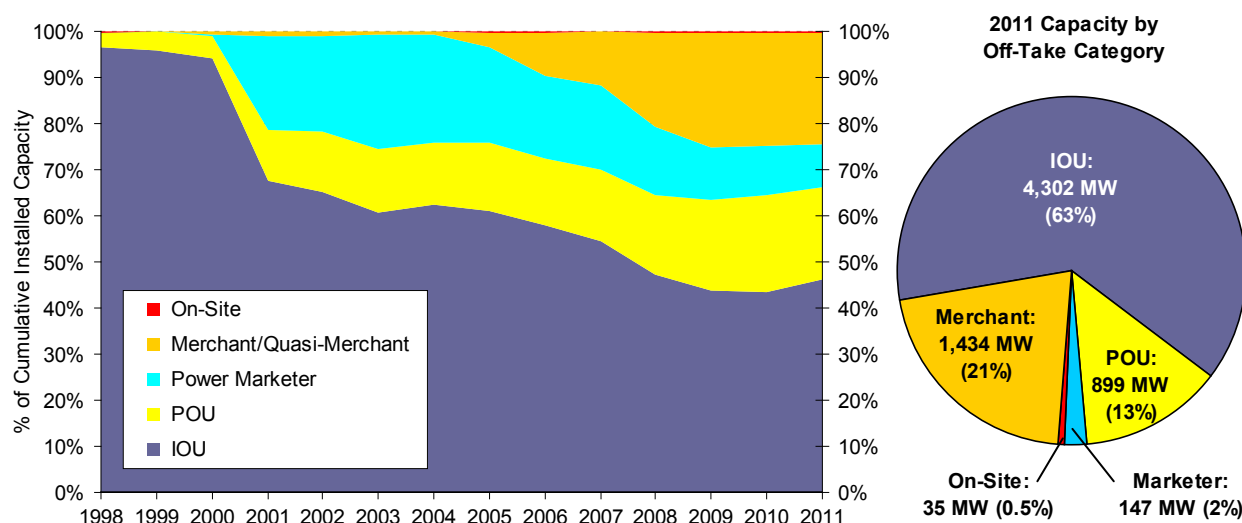
### **Long-Term Contracted Sales to Utilities Remained the Most Common Off-Take Arrangement, but Scarcity of Power Purchase Agreements and Looming PTC Expiration Drove Continued Merchant Development**

Electric utilities continued to be the dominant off-takers of wind power in 2011 (Figure 18), either owning (25%) or buying (51%) power from 76% of the new capacity installed last year (with the 76% split between 63% IOU and 13% POU). On a cumulative basis, utilities own

<sup>37</sup> Earlier, in 2005, the internal revenue service (IRS) clarified that a utility's customers are "unrelated" for the purposes of satisfying the requirement in Section 45 of the tax code that power must be sold to an unrelated party in order to qualify for the PTC. As such, utilities that own wind projects and sell the wind generation to their ratepayers (rather than on the wholesale power market) are entitled to claim the PTC on that wind generation.



(17%) or buy (50%) power from 66% of all wind power capacity installed in the United States (with the 66% split between 46% IOU and 20% POU), a slight increase over the past two years.



Source: Berkeley Lab estimates based on AWEA project database

**Figure 18. Cumulative and 2011 Wind Power Capacity Categorized by Power Off-Take Arrangement**

The role of power marketers – defined here as corporate intermediaries that purchase power under contract and then re-sell that power to others, sometimes taking some merchant risk<sup>38</sup> – in the wind power market has waned somewhat in recent years. In 2011, power marketers purchased the output of just 2% of the new wind power capacity, with 10% of the cumulative wind power capacity being sold to these entities.

Merchant/quasi-merchant projects were less prevalent in 2011 than they have been in recent years, accounting for 21% of all new capacity (compared to 23% in 2010 and 36%-38% in 2009 and 2008) and 24% of cumulative capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracted and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 5- to 10-year period<sup>39</sup>) rather than being locked in through a long-term PPA. With PPAs in relatively short supply compared to wind developer interest, wholesale power prices at low levels, and a scheduled PTC expiration looming, it is likely that many of the merchant/quasi-merchant projects built in 2011 are merchant by necessity rather than by desire. In other words, in the absence of a PPA, building a

<sup>38</sup> Power marketers are defined here to include not only traditional marketers such as PPM Energy (now part of Iberdrola), but also the wholesale power marketing affiliates of large investor-owned utilities (e.g., PPL Energy Plus or FirstEnergy Solutions), which may buy wind power on behalf of their load-serving affiliates. Direct sales to end users (e.g., the University of Maryland buys wind power from both the Pinnacle project in West Virginia and the Roth Rock project in Maryland) are also included in this category, because in these few limited cases the end-user is effectively acting as a power marketer.

<sup>39</sup> 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 (especially where natural gas is virtually always the marginal supply unit), the hedge is structured in the natural gas market rather than the power market, in order to take advantage of the greater liquidity and longer terms available in the forward gas market.



project on a merchant basis may, in some cases, simply have been the most expedient way to ensure the deployment of committed turbines (perhaps ordered several years ago under framework agreements) in advance of the scheduled expiration of important federal incentives like the Section 1603 Treasury cash grant and the PTC. Given relatively low wholesale power prices, and despite improvements in the cost, performance, and price of wind energy, some of these projects are likely still seeking long-term PPAs, and may therefore not remain merchant for long.

Finally, roughly 35 MW of the wind power additions in 2011 that used turbines over 100 kW in size were interconnected on the customer side of the utility meter, with the power being consumed on site rather than sold.



## 4. Cost Trends

This section 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 operation and maintenance (O&M) costs. Later sections present data on wind project performance, and then the price at which wind energy is being sold.

### **With Increased Competition among Manufacturers, Wind Turbine Prices Continued to Decline in 2011**

Wind turbine prices have dropped substantially in recent years, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters.

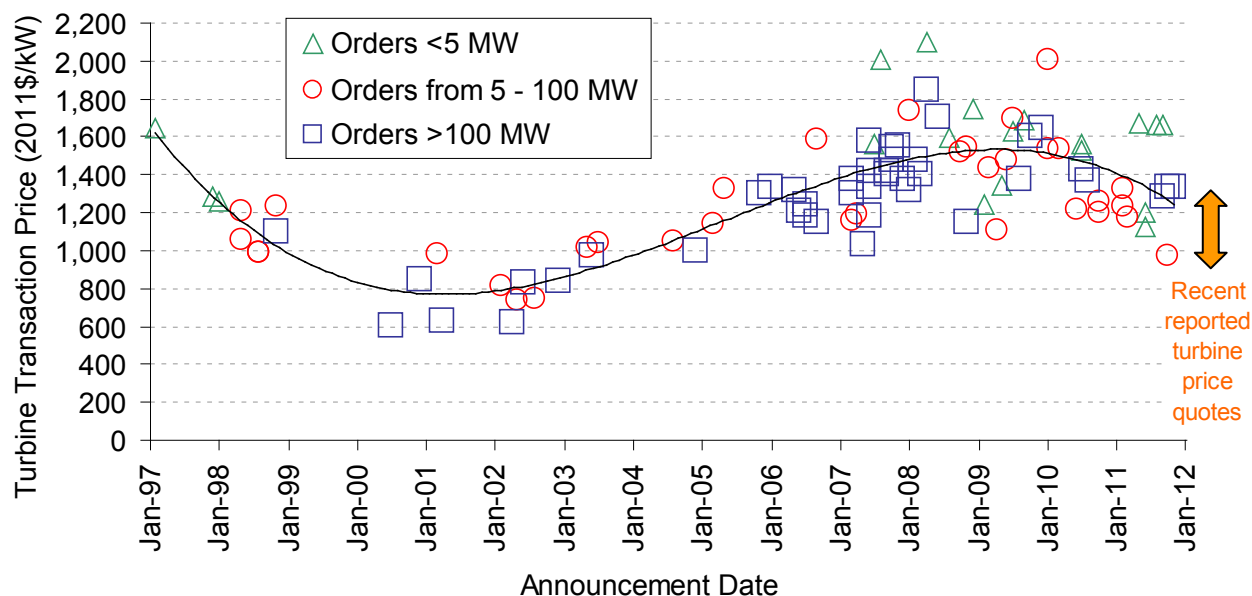
Berkeley Lab has gathered price data for 96 U.S. wind turbine transactions totaling 26,600 MW announced from 1997 through 2011, including 12 transactions summing to 2,630 MW announced in 2011. Sources of turbine price data vary, but many derive from press releases and news reports. Wind turbine transactions differ in the services included (e.g., whether towers and installation are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and on the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices. Nonetheless, most of the transactions included in the Berkeley Lab dataset likely include turbines, towers, delivery, and limited warranty and service agreements.<sup>40</sup> Unfortunately, collecting data on wind turbine transaction prices is a challenge – e.g., the sample of turbine transactions announced in 2011 for which price data were identified represents just 30% of the 8,750 MW of new turbine orders reported by AWEA (2012a). In part as a result, Figure 19 – which depicts these wind turbine transaction prices – also presents a range of 2012 wind turbine price quotes, as reported by Bloomberg NEF (2012a).

After hitting a low of roughly \$700/kW from 2000 to 2002, average wind turbine prices increased by approximately \$800/kW (>100%) through 2008, rising to an average of more than \$1,500/kW. The increase in turbine prices over this period 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 turbine and component supply shortages; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter (Bolinger and Wiser 2011).

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<sup>40</sup> Because of data limitations, the precise content of many of the individual transactions is not known.





Source: Berkeley Lab

**Figure 19. Reported U.S. Wind Turbine Transaction Prices over Time**

Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher, as well as increased competition among manufacturers and a shift to a buyer's market (Bloomberg NEF 2012b). As shown in Figure 19, a number of turbine transactions announced in 2011 had pricing in the \$1,150-\$1,350/kW range, while typical turbine prices in the U.S. in the first half of 2012 were reported by Bloomberg NEF (2012a) to be in the range of \$900-\$1,270/kW depending on the technology. These figures suggest price declines of as much as 33% or more since late 2008, with an average decline closer to perhaps 20% for orders announced in 2011. Moreover, these declines have been coupled with: (1) improved turbine technology (e.g., witness the recent and continued growth in average hub heights and rotor diameters shown earlier in Figure 16), and (2) more-favorable terms for turbine purchasers (e.g., reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial operations and maintenance (O&M) contract durations, improved warranty terms, and more-stringent performance guarantees). These price reductions and improved terms would be expected, over time, to exert downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights would be expected to improve capacity factors and further reduce wind power prices.

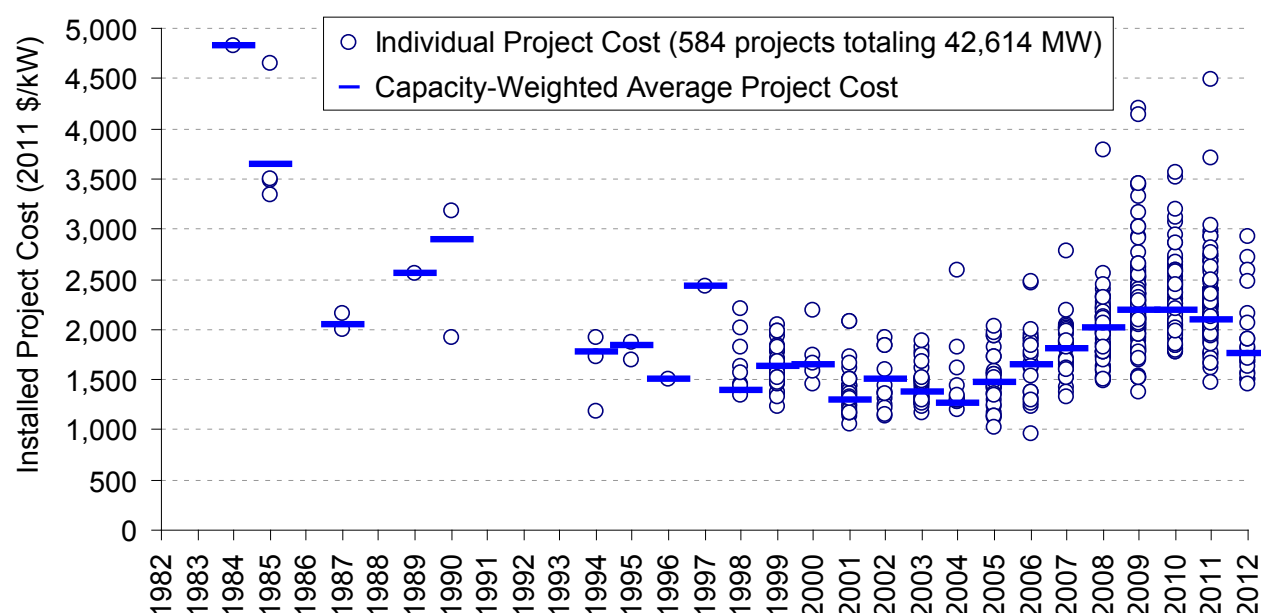
### **Though Slow to Reflect Declining Wind Turbine Prices, Reported Installed Project Costs Finally Turned the Corner in 2011**

Berkeley Lab compiles data on the installed cost of wind power projects in the United States, including data on 90 projects completed in 2011 totaling 6,402 MW, or 94% of the wind power capacity installed in that year. In aggregate, the dataset (through 2011) includes 564 completed wind power projects in the continental United States totaling 40,022 MW, and equaling roughly 85% of all wind power capacity installed in the United States at the end of 2011. Also reported



here are data on a small sample of projects already installed or soon to be installed in 2012 (20 projects totaling 2,592 MW). 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 20, the average installed costs of wind power projects declined dramatically from the beginning of the U.S. wind industry in California in the 1980s through the early 2000s, before following turbine prices higher through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, installed costs only started to turn the corner in 2011, suggesting 2009/2010 as a likely peak. That average installed project costs would lag average turbine prices is not surprising, and reflects the normal passage of time between when a turbine supply agreement is signed (the time stamp for Figure 19) and when those turbines are actually installed and commissioned (the time stamp for Figure 20).<sup>41</sup>



Note: 2012 data represent preliminary cost estimates for a sample of 20 projects totaling 2.6 GW that have either already been or will be built in 2012, and for which substantive cost estimates were available.

Source: Berkeley Lab (some data points suppressed to protect confidentiality)

**Figure 20. Installed Wind Power Project Costs over Time (including preliminary sample of 2012 project costs)**

In 2011, the capacity-weighted average installed project cost stood at nearly \$2,100/kW, down almost \$100/kW from the reported average cost in both 2009 and 2010. Moreover, a preliminary estimate of the average installed cost among a relatively small sample of 20 projects totaling 2.6

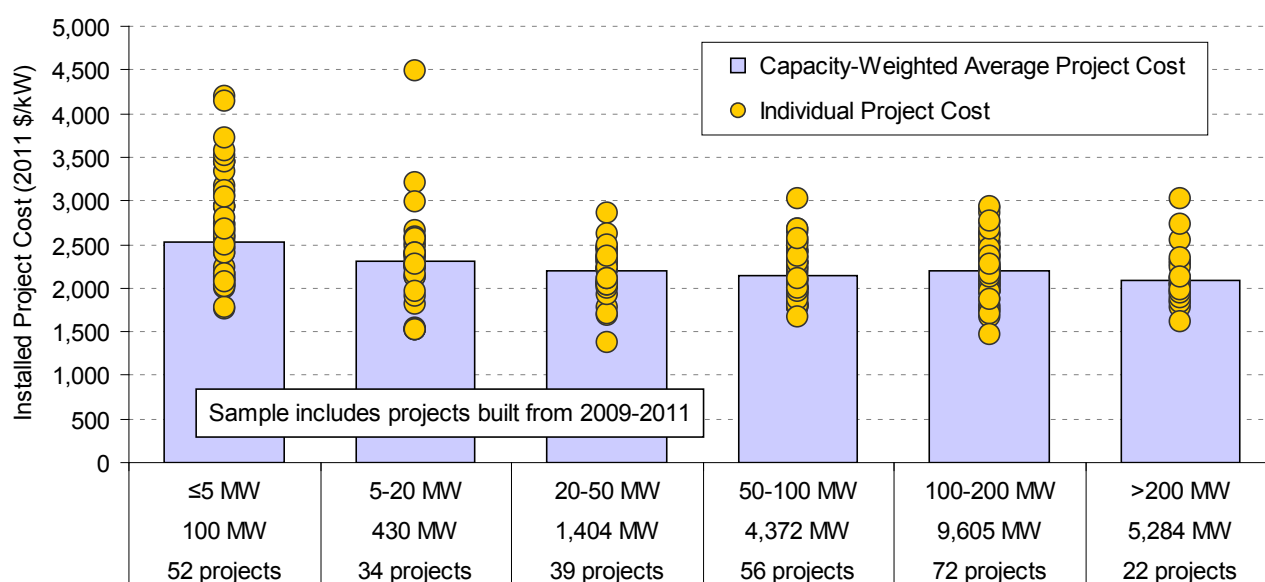
<sup>41</sup> On the other hand, since 2009, Figure 20 partly reflects installed cost estimates derived from publicly available data from the Section 1603 cash grant program. In some cases (though exactly which is unknown), the Section 1603 grant data likely reflect the fair market value rather than the installed cost of wind power projects; in such cases the installed cost estimates shown in Figure 20 will be artificially inflated.



GW of capacity that either have been or will be built in 2012 suggests that average installed costs may decline further in 2012, continuing to follow lower turbine prices.<sup>42</sup>

## Installed Costs Differ By Project Size, Turbine Size, and Region

Average installed wind power project costs exhibit weak economies of scale, at least at the low end of the project size range. Figure 21 shows that – among the sample of projects installed from 2009 through 2011 – there is a steady drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 20-50 MW range. As project size increases beyond 50 MW, however, these data do not show strong evidence of continued economies of scale.



Source: Berkeley Lab

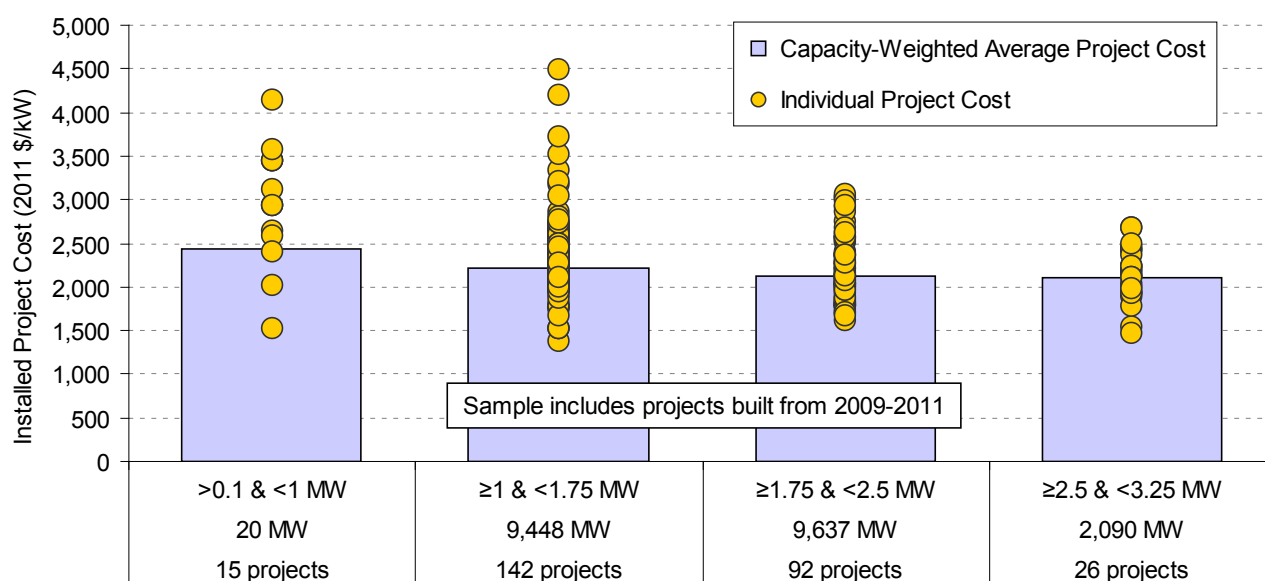
**Figure 21. Installed Wind Power Project Costs by Project Size: 2009-2011 Projects**

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 a larger number of smaller turbines. Figure 22 explores this relationship, breaking down turbine size into 0.75 MW bins. Here too some economies of scale are evident as turbine size increases, at least at the lower end of the turbine size range.<sup>43</sup>

<sup>42</sup> Learning curves have been used extensively to understand past cost trends and to forecast future cost reductions for a variety of energy technologies, including wind energy. Learning curves start with the premise that increases in the cumulative production or installation of a given technology leads to a reduction in its costs. The principal parameter calculated by learning curve studies is the learning rate: for every doubling of cumulative production/installation, the learning rate specifies the associated percentage reduction in costs. Based on the installed cost data presented in Figure 20 and global cumulative wind power installations, learning rates can be calculated as follows: 7.5% (using data from 1982 through 2011) or 14.4% (using data only during the period of cost reduction, 1982-2004).

<sup>43</sup> It should be noted that there is likely some correlation between turbine size and project size, at least at the low end of the range of each. In other words, projects of 5 MW or less are more likely than larger projects to use individual





Source: Berkeley Lab

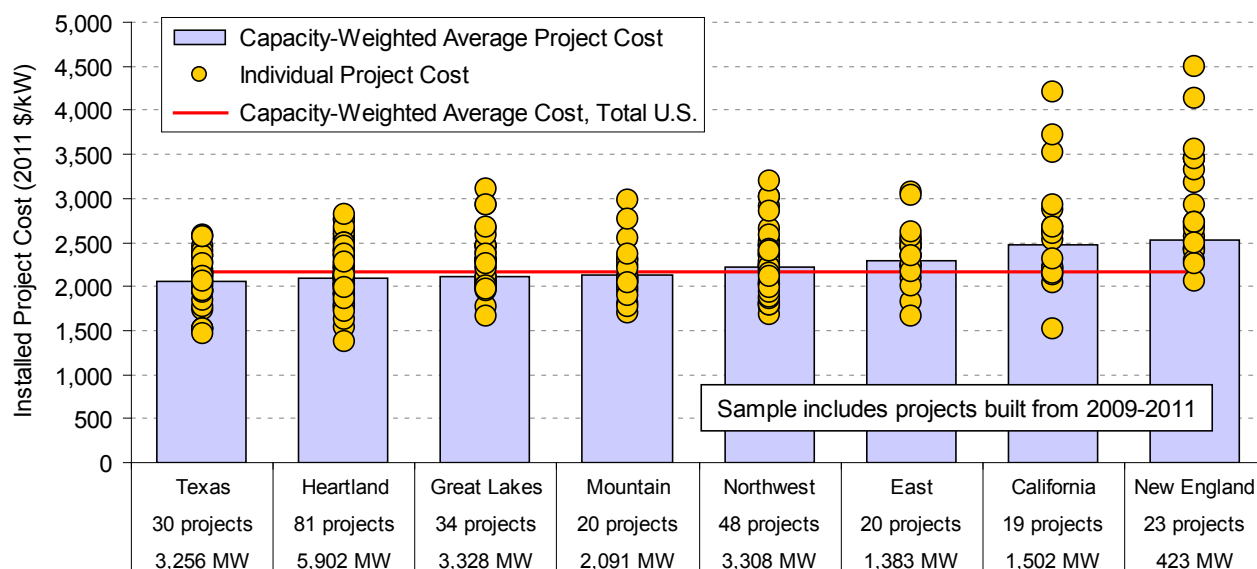
**Figure 22. Installed Wind Power Project Costs by Turbine Size: 2009-2011 Projects**

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. Considering only projects in the sample that were installed from 2009 through 2011, Figure 23 shows that the capacity-weighted average cost equaled \$2,160/kW nationwide over this period. Texas was the lowest-cost region, while California and New England were the highest-cost regions; all other regions came in close to the nationwide average (see Figure 30, later, for regional definitions).<sup>44</sup>

turbines of less than 1 MW. As such, Figures 21 and 22 – both of which show scale economies at small project or turbine sizes, but diminishing as project or turbine size increases – could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.

<sup>44</sup> Permitting and regulatory compliance costs presumably play a role at both ends of the spectrum: Texas is reputed to be one of the easiest locations in which to develop and build a wind power project, while California and New England are two of the hardest. Graphical presentation of the data in this way, however, should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 23.





Source: Berkeley Lab

**Figure 23. Installed Wind Power Project Costs by Region: 2009-2011 Projects**

## Newer Projects Appear to Show Improvements in Operations and Maintenance Costs

Operations and maintenance (O&M) costs are a significant component of the overall cost of wind energy, but can vary substantially among projects, and market data on actual project-level O&M costs are not readily 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 the last two decades, not least of which has been the up-scaling of turbine size (see Figures 15 and 16, earlier). Anecdotal evidence suggests that O&M costs and premature component failures continue to be key challenges for the wind power industry.

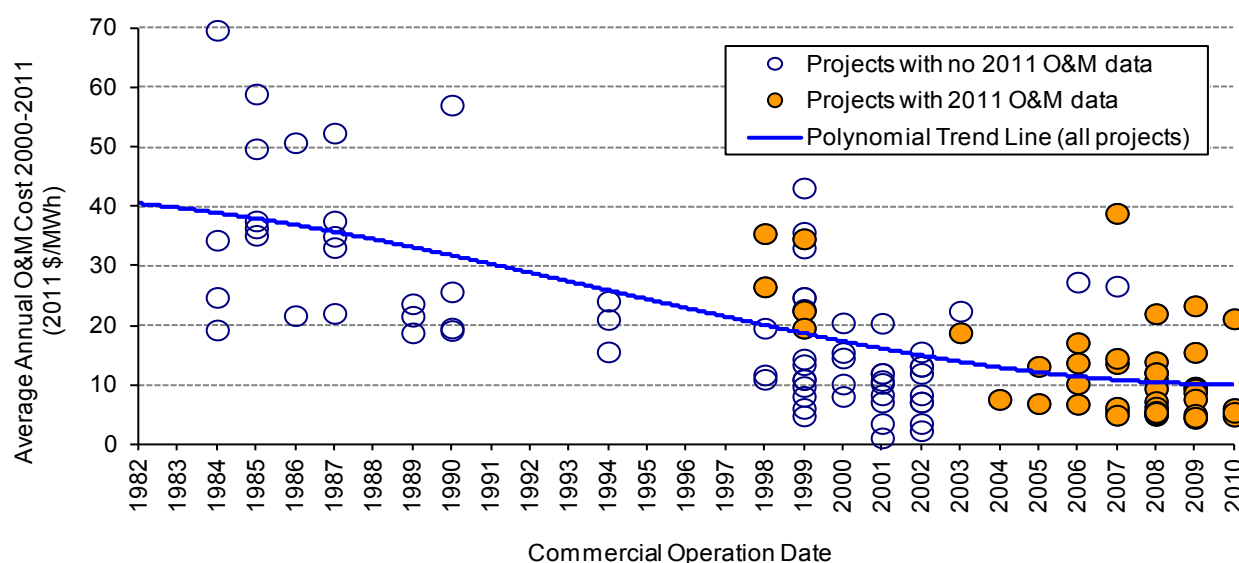
Berkeley Lab has compiled O&M cost data for 133 installed wind power projects in the United States, totaling 7,965 MW of capacity, with commercial operation dates of 1982 through 2010. These data cover facilities owned by both independent power producers and utilities, though data since 2004 are exclusively from utility-owned projects. 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 cost 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 facility, as well as rent.<sup>45</sup> Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, the following figures are not representative of *total* operating expenses for wind power projects; the final paragraph in this section cites data from the financial reports of two public

<sup>45</sup> The vast majority of the recent data derive from FERC Form 1, which uses Uniform System of Accounts definitions.



companies with U.S wind assets suggesting higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow therefore may not fully depict the industry's challenges with O&M issues and expenditures; instead, these results should only be taken as illustrative of overall trends. Note finally that the available data are presented in \$/MWh terms, as if O&M represents a variable cost; in fact, O&M costs are in part variable and in part fixed. Although not presented here, expressing O&M costs in units of \$/kW-year yields qualitatively similar results to those presented in this section.

Figure 24 shows project-level O&M costs according to the commercial operation date.<sup>46</sup> Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2011, based on however many years of data are available for that time period. For example, for projects that reached commercial operations in 2010, only year 2011 data are available, and that is what is shown in the figure.<sup>47</sup> Many other projects only have data for a subset of years during the 2000-11 timeframe, either because they were installed after 2000 or because a full time series is not available, so each data point in the chart may represent a different averaging period over 2000-11. The chart highlights the 47 projects, totaling 4,339 MW, for which 2011 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; seven data points suppressed to protect confidentiality

**Figure 24. Average O&M Costs for Available Data Years from 2000-2011, by Commercial Operation Date**

The data exhibit considerable spread, demonstrating that O&M costs are far from uniform across projects. However, Figure 24 suggests that projects installed more recently have, on average, incurred lower O&M costs. Specifically, capacity-weighted average 2000-11 O&M costs for the

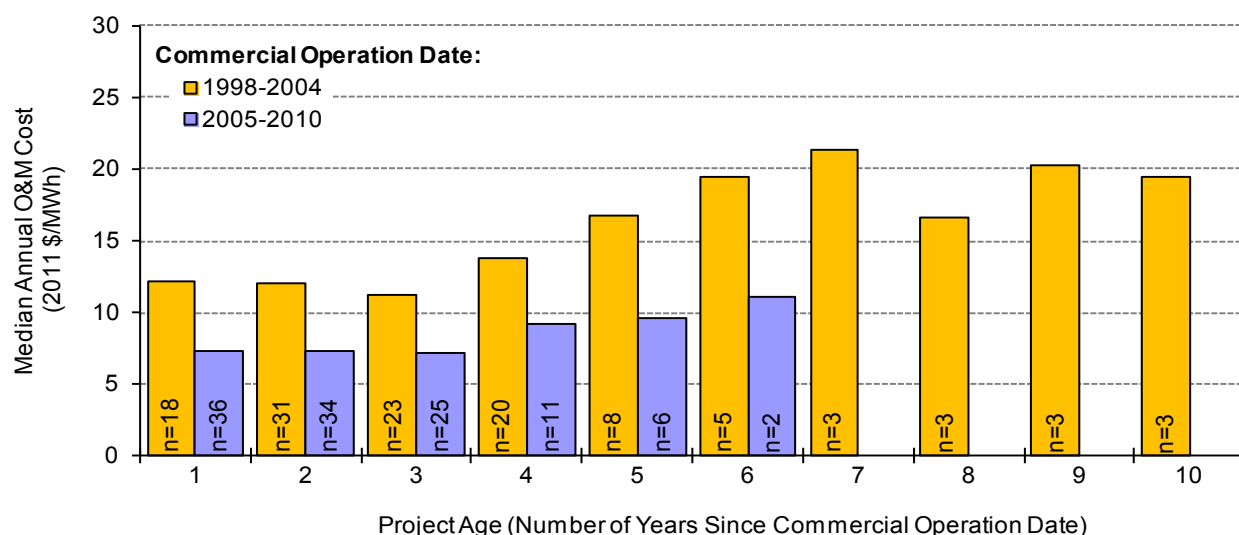
<sup>46</sup> For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.

<sup>47</sup> Projects installed in 2011 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 2011 would be year 2012 (for which data are not yet available).



24 projects in the sample constructed in the 1980s equal \$33/MWh, dropping to \$23/MWh for the 37 projects installed in the 1990s, and to \$10/MWh for the 69 projects installed since 2000.<sup>48</sup> 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<sup>49</sup>; and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a per-MWh basis. Limitations in the underlying data, however, do not permit the influence of these two factors to be unambiguously distinguished.

To help illustrate the possible influence of these two factors, however, Figure 25 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 two project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale. Note that, at each project age increment and for each of the two project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially (from 3 to 31 data points per project-year for projects installed from 1998 through 2004 and from 2 to 36 data points per project-year for projects installed from 2005 through 2010). With this limitation in mind, the figure shows that projects installed more recently (2005-2010) have had, in general, lower O&M costs than those installed in earlier years (1998-2004), at least for the first six years of operation. In addition, projects show an upward trend in project-level O&M costs as they age, though the sample size after year four is limited.



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

**Figure 25. Median Annual O&M Costs by Project Age and Commercial Operation Date**

<sup>48</sup> If expressed instead in terms of \$/kW-yr, capacity-weighted average 2000-2011 O&M costs were \$65/kW-yr for projects in the sample constructed in the 1980s, dropping to \$54/kW-yr for projects constructed in the 1990s, and to \$28/kW-yr for projects constructed since 2000. Somewhat consistent with these observed O&M costs, Bloomberg New Energy Finance (2011) reports the cost of 5-year full-service O&M contracts at \$30-\$48/kW-yr.

<sup>49</sup> Many of the projects installed more-recently may still be within their turbine manufacturer warranty period.



As indicated previously, the data presented in Figures 24 and 25 are derived from a variety of sources, and in most cases include only a subset of total operating expenses. In comparison, the financial statements of public companies with sizable U.S. wind project assets indicate markedly higher total operating costs. Specifically, two companies – Infigen and EDP Renováveis (EDPR), which together represent approximately 4,511 MW of installed capacity, nearly all of which has been installed since 2000 – report total operating expenses of \$21.5/MWh and \$22.1/MWh, respectively, for their U.S. wind project portfolios in 2011 (EDPR 2012; Infigen 2011, 2012). These operating expenses are more than twice the \$10/MWh reported above, for the 69 projects in the Berkeley Lab data sample installed since 2000. These differences are likely due, in large measure, to the scope of expenses included, as the company financial reports include items such as general and administrative expenses, local taxes, property insurance, and workers’ compensation insurance, which are generally not included within the data comprising the Berkeley Lab sample.

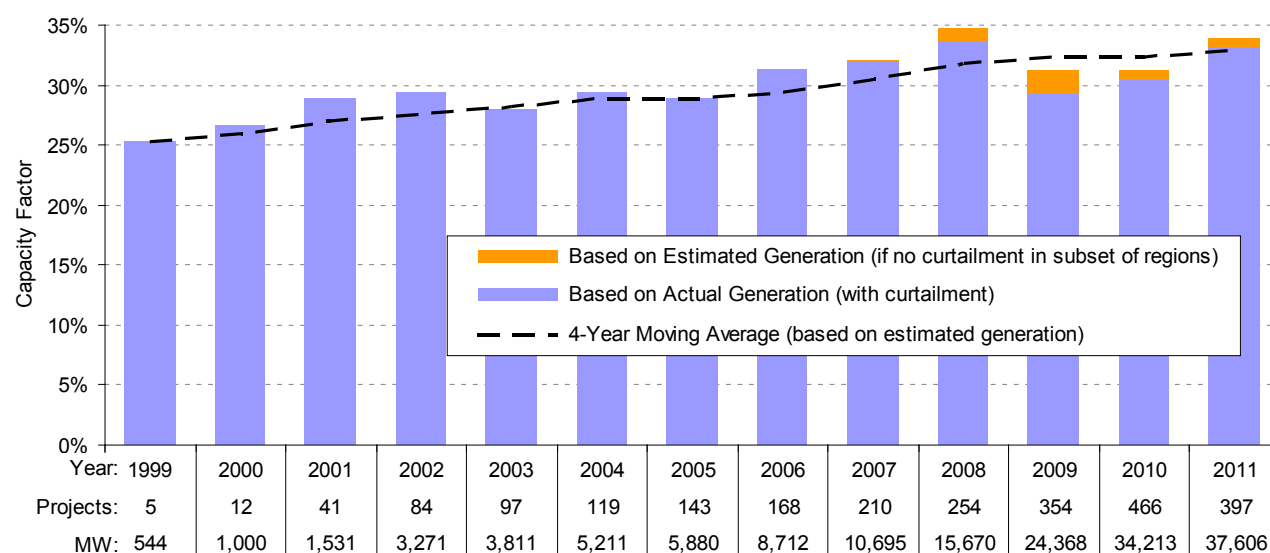


## 5. Performance Trends

This section presents data from a Berkeley Lab compilation of project-level capacity factors. The full data sample consists of 397 wind power projects built between 1983 and 2010, and totaling 37,606 MW (94% of nationwide installed wind power capacity at the end of 2010).<sup>50</sup> The followed discussion of performance trends is broken up into three sub-sections: the first analyzes trends in sample-wide capacity factor over time; the second looks at variations in capacity factor by project vintage; and the third focuses on regional variations in capacity factor.

### Sample-Wide Wind Project Capacity Factors Have Generally Improved Over Time

Focusing on a progressively larger cumulative sample of projects in each calendar year,<sup>51</sup> the blue bars in Figure 26 demonstrate that average sample-wide wind power project capacity factors have, in general, gradually increased over time, from 25% in 1999 (for projects installed through 1998) to a high of nearly 34% in 2008 (for projects installed through 2007). In 2009 and 2010, however, sample-wide capacity factors dropped to around 30%, before 2011 brought a resurgence back to 33% (for projects installed through 2010).



Source: Berkeley Lab

**Figure 26. Average Cumulative Sample-Wide Capacity Factor by Calendar Year**

<sup>50</sup> Though some performance data for wind power projects installed in 2011 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 in 2010 and earlier.

<sup>51</sup> There are fewer individual projects – though more capacity – in the cumulative sample for 2011 than there are for 2010. This is due to the sampling method used by the EIA, which focuses on a subset of larger projects throughout the year, before eventually capturing the entire sample some months after the year has ended. As a result, it might be late 2012 before the EIA reports 2011 performance data for all of the wind power projects that it tracks, and in the mean time, this report is left with a smaller sample consisting mostly of the larger projects in each state.



The relatively steady improvement in average sample-wide capacity factors through 2008 can be attributed largely to the substantial increase in average hub height and rotor diameter (particularly in relation to rated capacity) shown earlier in Figure 16. The drop in 2009 and 2010, however, followed by a rebound in 2011, warrants further investigation. At least two factors likely played a role in this more recent volatility in average project performance: annual wind resource variation and wind power curtailment.

**Annual Wind Resource Variation:** The strength of the wind resource varies from year to year, in part in response to significant persistent weather patterns such as El Niño/La Niña. In 2011, the U.S. reportedly enjoyed above-average wind speeds throughout much of the nation, and in particular across much of the country's interior – where most installed wind power capacity resides (AWS Truepower 2012, 3TIER 2012). An above-normal 2011 follows what were considered to be lackluster wind years in 2010 and 2009, preceded by a strong wind year in 2008. This same pattern is evident in the average sample-wide capacity factors shown in Figure 26, highlighting the influence of natural yearly variations in average wind resource conditions on sample-wide average wind power capacity factors.

**Wind Power Curtailment:** Curtailment of wind project output due to transmission inadequacy and/or minimum generation limits (and, as a consequence, low or negative wholesale electricity prices) has become common, principally in Texas, but also to a lesser degree in other markets. For example, Table 5 (which focuses on forced, rather than economic, curtailment) shows that 8.5% of potential wind energy generation within ERCOT was curtailed in 2011 – up slightly from 7.7% in 2010, but down sharply from 17% in 2009.<sup>52</sup> Outside of Texas, forced curtailment increased significantly on the Bonneville Power Administration's (BPA) system in 2011, due to unusually heavy spring runoff that resulted in above-normal hydropower generation.<sup>53</sup> In aggregate, assuming a 33% average capacity factor, the total amount of wind generation curtailed in 2011 within just the six utility/ISO/RTO service territories shown in Table 5 equates to the annual output of roughly 1,220 MW of wind power capacity.

Looked at another way, wind power curtailment has reduced sample-wide average capacity factors in recent years, and particularly in 2009. While the blue bars in Figure 26 reflect actual capacity factors – i.e., including the negative impact of curtailment events – the orange bars add back in the estimated amount of wind generation that has been forced to curtail in recent years within the six territories shown in Table 5, to estimate what the sample-wide capacity factors would have been absent this forced curtailment. As shown, sample-wide capacity factors would have been on the order of 1-2 percentage points higher nationwide from 2008 through 2011 absent curtailment in just this *subset* of regions. Estimated capacity factors would have been even higher if comprehensive forced and economic curtailment data were available for *all* regions.

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<sup>52</sup> The significant reduction in ERCOT curtailment since 2009 is, in part, attributable to a private 229-mile transmission line built by NextEra Energy in late 2009 to move power from its 735.5 MW Horse Hollow project out of the congested West zone and into the uncongested South zone. As a result, Horse Hollow's capacity factor increased from just 20% in 2009 to 29% in both 2010 and 2011. Several transmission line upgrades related to the Texas competitive renewable energy zone (CREZ) effort have also helped reduce curtailment in ERCOT (see later section on transmission).

<sup>53</sup> BPA again curtailed some wind generation for similar reasons in the spring of 2012, but the magnitude and duration was nowhere near that seen in 2011.



**Table 5. Estimated Wind Curtailment in Various Areas, in GWh (and as a % of potential wind generation)**

	2007	2008	2009	2010	2011
Electric Reliability Council of Texas (ERCOT)	109 (1.2%)	1,417 (8.4%)	3,872 (17.1%)	2,067 (7.7%)	2,622 (8.5%)
Southwestern Public Service Company (SPS)	N/A	0 (0.0%)	0 (0.0%)	0.9 (0.0%)	0.5 (0.0%)
Public Service Company of Colorado (PSCo)	N/A	2.5 (0.1%)	19.0 (0.6%)	81.5 (2.2%)	63.9 (1.4%)
Northern States Power Company (NSP)	N/A	25.4 (0.8%)	42.4 (1.2%)	42.6 (1.2%)	54.4 (1.2%)
Midwest Independent System Operator (MISO), less NSP	N/A	N/A	250 (2.2%)	781 (4.4%)	657 (3.0%)
Bonneville Power Administration (BPA)	N/A	N/A	N/A	4.6* (0.1%)	128.7* (1.4%)
<b>Total Across These Six Areas:</b>	<b>109 (1.2%)</b>	<b>1,445 (5.6%)</b>	<b>4,183 (9.6%)</b>	<b>2,978 (4.8%)</b>	<b>3,526 (4.8%)</b>

\*A portion of BPA's curtailment is estimated assuming that each curtailment event lasts for half of the maximum possible hour for each event.

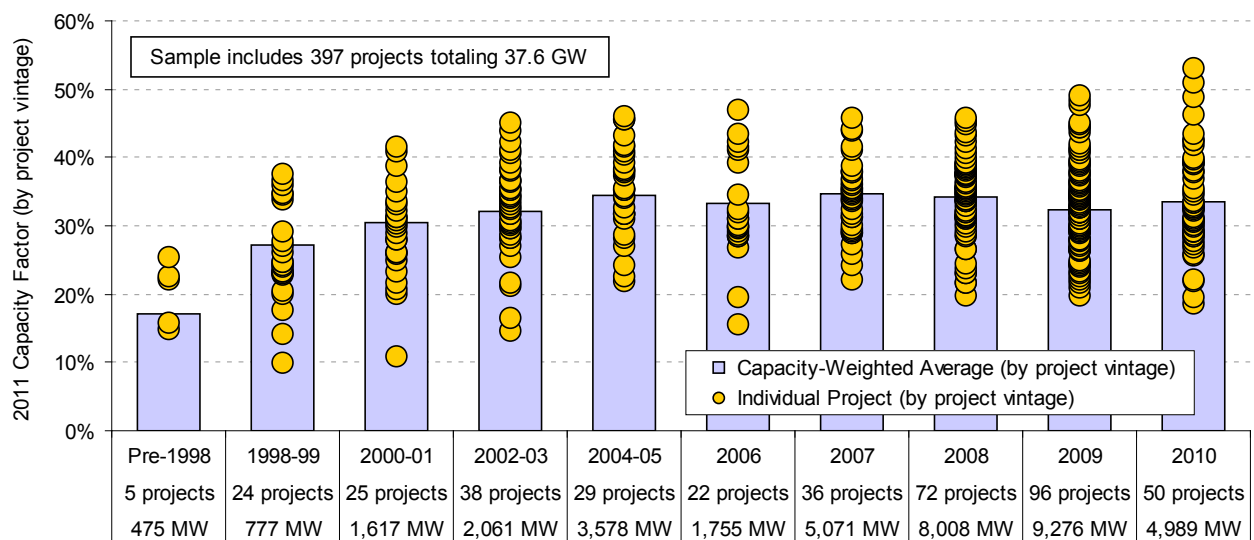
Source: ERCOT, Xcel Energy, MISO, BPA

## Some Stagnation in Wind Project Capacity Factor Improvement Is Evident Among Projects Built from 2006 through 2010, Due in Part to a Build Out of Projects in Progressively Weaker Wind Resource Areas

One way to control for the time-varying influences described in the previous section (e.g., annual wind resource variations and a particularly bad curtailment year in 2009) is to focus exclusively on capacity factors in 2011.<sup>54</sup> As such, whereas Figure 26 presents capacity factors in each calendar year, Figure 27 instead shows only capacity factors in 2011, broken out by project vintage. In general, Figure 27 indicates that projects built more recently generated higher capacity factors in 2011 – this is particularly true among those projects built up through 2005. Average 2011 capacity factors for projects built from 2006 through 2010, however, were largely stagnant, ranging from 33%-35% on a weighted-average basis (on the other hand, the *maximum* capacity factor attained by any individual project in 2011 increased noticeably among those projects built in 2009 and 2010).

<sup>54</sup> Although focusing just on 2011 does control (at least loosely) for some of these known time-varying impacts, it also means that the *absolute* capacity factors shown in Figure 27 may not be representative over longer terms if 2011 was not a representative year in terms of the strength of the wind resource or wind power curtailment. As noted earlier, 2011 was generally an above-average wind year in much of the U.S., suggesting that the capacity factors shown in Figure 27 may be biased upwards to some degree due to this factor.





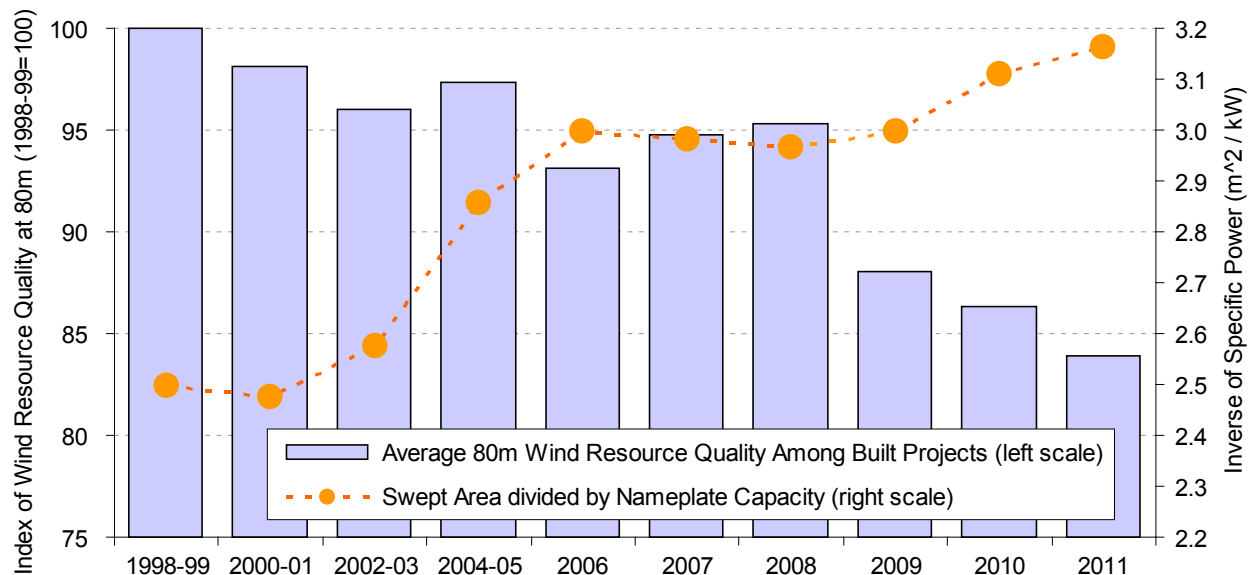
Source: Berkeley Lab

**Figure 27. 2011 Project Capacity Factors by Commercial Operation Date**

This pattern of improving performance by project vintage through 2005 followed by relative stagnation for projects built from 2006-2010 is broadly consistent with trends over this same period in both average hub height (shown earlier in Figure 16) *and* average swept rotor area relative to turbine nameplate capacity – i.e., the inverse of “specific power” (shown below in Figure 28).<sup>55</sup> Specifically, scaling in both hub height and the inverse of “specific power” was most pronounced among turbines installed from 1998 through 2006, which roughly coincides with the vintages that show the largest increases in 2011 capacity factor in Figure 27. Since 2006, however, average hub height has increased by only a few meters (see Figure 16), which in part explains the stagnation in average capacity factors among more recently built wind power projects. Swept area relative to rated capacity also held steady from 2006 through 2009, before increasing again in 2010 and 2011 – this recent increase is perhaps reflected in the higher *maximum* capacity factors achieved by 2010 vintage projects in Figure 27. The fact that rotor scaling (relative to nameplate capacity) continued for projects built in 2011 (and now 2012) suggests that further increases in capacity factors are likely in the coming years, all else equal.

<sup>55</sup> A wind turbine’s “specific power” is a measure of its rated capacity relative to its swept rotor area ( $\text{W/m}^2$ ). As rotor diameter (and therefore swept area) increases relative to nameplate capacity – e.g., as with low wind speed turbine designs – more of the wind’s energy is captured, resulting in greater utilization of the generator’s rated capacity, and therefore a higher overall capacity factor. Thus, all else equal, as specific power declines, capacity factor should increase. Figure 28 plots the *inverse* of specific power ( $\text{m}^2/\text{kW}$ ) in order to better portray its influence on capacity factor.





**Figure 28. Index of Wind Resource Quality at 80 Meters vs. Inverse of Specific Power**

Though trends in hub height and “specific power” explain a portion of the results presented in Figure 27, another large influence relates to the quality of the wind resource in which projects are located. In particular, as depicted in Figure 28, the average estimated quality of the wind resource at 80 meters among those projects built in each period has declined over time, and that decline is particularly sizable since 2008.<sup>56</sup> Specifically, wind power projects built in 2008 were, on average, located in estimated 80-meter wind resource conditions that are 4.7% worse than those projects built in 1998-99. Projects built in 2011, meanwhile, were – on average – located in estimated 80-meter wind resource conditions that are 16.1% worse than those projects built in 1998-99. Moreover, the sharp decline in average estimated wind resource quality at 80 meters for projects built since 2008 *has not* – unlike in earlier periods – been offset by significant growth in average hub heights (though swept area relative to rated capacity has increased over this period). This decline in the average estimated wind resource quality of recently built wind power projects is therefore also a key contributor to the recent stagnation in average capacity factors and, without this decline, project-level average capacity factors would likely have continued their improvement from 2006 through 2010.

This apparent trend of building wind power projects in lower quality wind resource areas in recent years may come as a surprise, given that the United States still has an abundance of undeveloped high-quality wind resource areas. Several different factors could be driving this trend:

- Technology Change:** The increased availability of low-wind speed turbines that feature higher hub heights and a lower “specific power” (i.e., a larger rotor diameter relative to rated capacity) may have enabled the economical build out of lower wind speed sites.

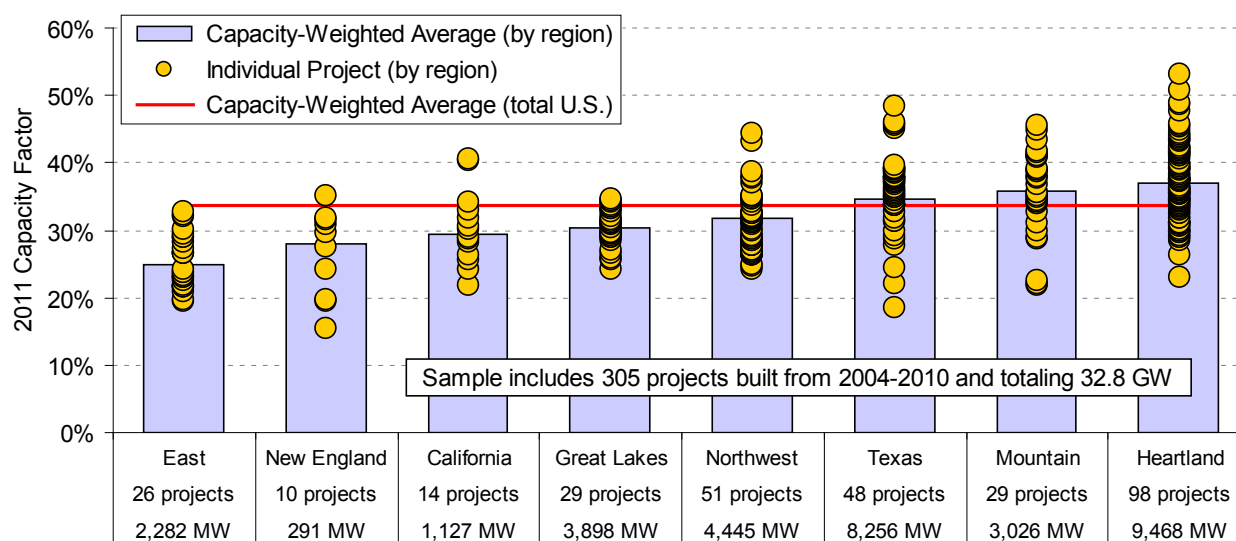
<sup>56</sup> The procedures used for estimating the quality of the wind resource in which wind projects are located, over time, is described in the Appendix.



- **Siting Impacts:** Developers may have reacted to increasing transmission constraints (or other siting constraints, or even just regionally differentiated wholesale electricity prices) by focusing on those projects in their pipeline that may not be located in the best wind resource areas, but that do have access to transmission (or higher-priced markets, or readily available sites without long permitting times).
- **Policy Influence:** Projects built in the four-year period from 2009 through 2012 have been able to access a 30% ITC or cash grant in lieu of the PTC. Because the dollar amount of the ITC or grant is not dependent on how much electricity a project generates, it is possible that developers have seized this limited opportunity to build out the less-energetic sites in their development pipelines. Additionally, state RPS requirements sometimes require or motivate in-state or in-region wind development in lower wind resource regimes.

## Regional Variations in Capacity Factor Reflect the Strength of the Wind Resource

The project-level spread in capacity factors shown earlier in Figure 27 is enormous, with 2011 capacity factors ranging from 18% to 53% among just those projects built in 2010. Some of this spread is attributable to regional variations in average wind resource quality.



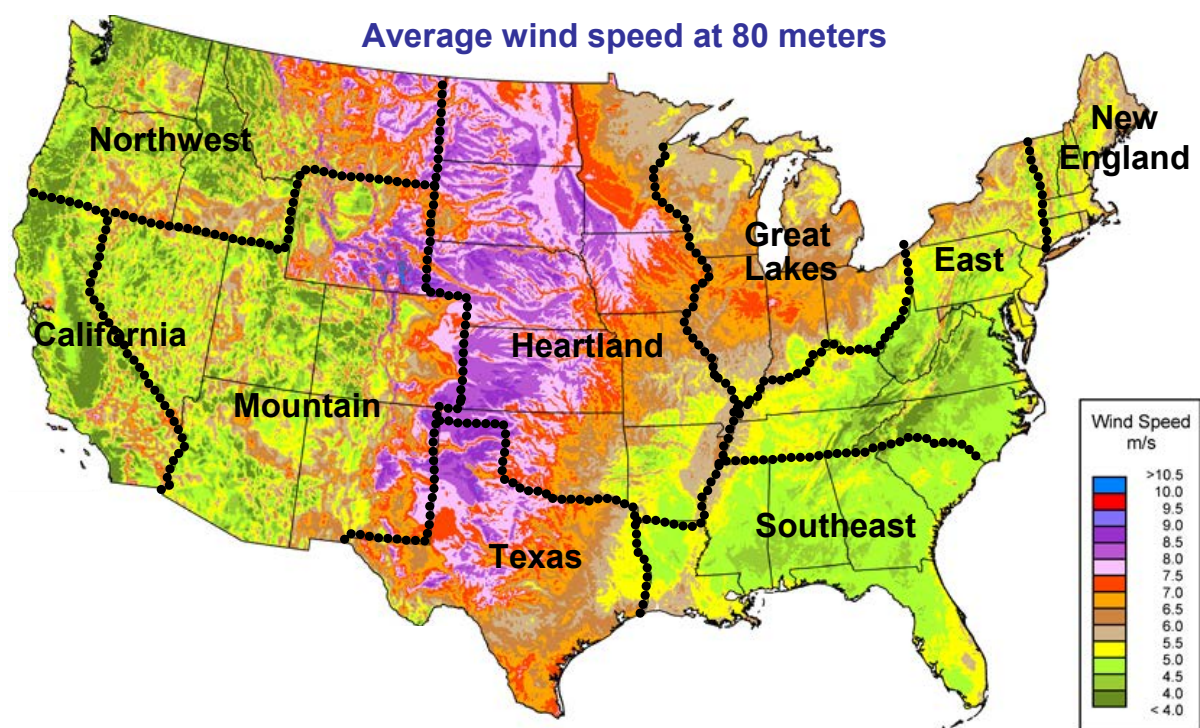
Source: Berkeley Lab

**Figure 29. 2011 Project Capacity Factors by Region: 2004-2010 Projects Only**

Figure 29 shows the regional variation in 2011 capacity factors (using the regional definitions shown in Figure 30), based on a sub-sample of wind power projects built from 2004 through 2010 (i.e., a period of relative stability in 2011 capacity factors, per Figure 27). For this sample of projects, capacity-weighted average capacity factors are the highest in the Heartland (37%) and Mountain (36%) regions, and lowest in the East (25%) and New England (28%) regions.



Not surprisingly, these regional rankings are roughly consistent with relative average wind speed within each region, as shown in Figure 30.<sup>57</sup>



Source: AWS Truepower, NREL

**Figure 30. Average Wind Speed at 80 Meters (with regional boundaries)**

<sup>57</sup> 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 2011, care should be taken in extrapolating these results. For example, the average 2011 capacity factor in Texas of 34.4% was depressed by the forced curtailment of wind generation, and would have been closer to 38% – an absolute increase of 3.3% – had there been no curtailment.



## 6. Wind Power Price Trends

Earlier sections documented trends in wind turbine prices, installed project costs, O&M costs, and capacity factors – all of which are determinants of the wind power sales prices presented in this section. In general, higher cost and/or lower capacity factor projects will require higher wind power prices, while lower cost and/or higher capacity factor projects can get by with lower wind power prices.

Berkeley Lab collects data on wind power sales prices from the sources listed in the Appendix, resulting in a dataset that consists of historical price data for 271 wind power projects installed between 1998 and the end of 2011. These projects total 20,189 MW, or 44% of the wind power capacity brought on line in the United States over the 1998-2011 timeframe.<sup>58</sup> The dataset excludes merchant plants and projects that sell renewable energy certificates (RECs) separately. The prices in the dataset therefore reflect the bundled price of electricity and RECs as sold by a project owner under a power purchase agreement (PPA). Because these prices are suppressed by the receipt of available state and federal incentives (e.g., the prices reported here would be at least \$20/MWh higher without the PTC / ITC / Treasury Grant), and are also influenced by various local policies and market characteristics, they do not represent wind energy generation costs.

This section summarizes wind power sales prices in a number of different ways: by calendar year, by project vintage, by PPA execution date, by region, and compared to wholesale power prices both nationwide and regionally. In addition, REC prices are presented in a text box on page 53.

### Unlike Turbine Prices and Installed Project Costs, Cumulative, Sample-Wide Wind Power Prices Continued to Move Higher in 2011

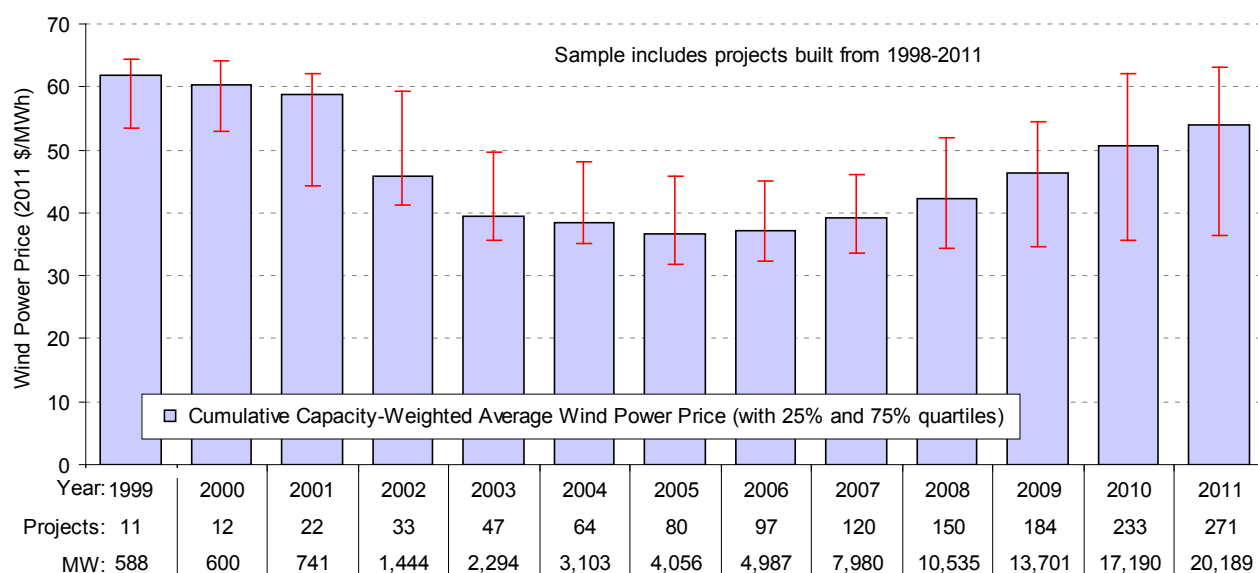
Figure 31 shows the cumulative capacity-weighted average wind power price (along with the range of individual project prices falling between the 25<sup>th</sup> and 75<sup>th</sup> percentiles) in each calendar year from 1999 through 2011. Based on the limited sample of 11 projects built in 1998 or 1999 and totaling 588 MW, the weighted-average price of wind energy in 1999 was roughly \$62/MWh (expressed in 2011 dollars). This weighted-average price progressively declined in subsequent years until reaching a low of \$37/MWh in 2005 (among a sample of 80 projects totaling 4,056 MW). Since then, sample-wide average prices have risen steadily, such that in 2011, the cumulative sample of projects built from 1998 through 2011 had grown to 271 projects totaling 20,189 MW, with an average price of \$54/MWh (with 50% of individual project prices

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<sup>58</sup> Three primary factors significantly restrict the size of this sample: (1) projects located within ERCOT (in Texas) fall outside of FERC's jurisdiction, and are therefore not required to report prices (reduces sample by roughly 9,600 MW); (2) the increasing number of utility-owned projects are not included, since these projects do not sell their power at an observable price (reduces sample by about 6,400 MW); and (3) the increasing number of merchant (or quasi-merchant) projects that sell power and RECs separately are not included in the sample, because the power price reported by these projects only represents a portion of total revenue received (reduces sample by roughly another 6,000 MW). In addition, certain "qualifying facilities" are not required to report their power sales to FERC.



falling between \$36/MWh and \$63/MWh).<sup>59</sup> This general temporal trend of falling and then rising prices is consistent with the turbine price and installed project cost trends shown in earlier sections, though the cumulative nature of Figure 31 results in a smoother, less-responsive curve that lags the directional changes in turbine and project cost trends.<sup>60</sup>



Source: Berkeley Lab

**Figure 31. Cumulative Capacity-Weighted Average Wind Power Prices over Time**

## Binning Wind Power Sales Prices by Project Vintage Also Fails to Show a Price Reversal

To better illustrate changes in the price of power from newly built wind power projects, Figure 32 shows average wind power sales prices in 2011, grouped by project vintage (i.e., by each project's initial commercial operation date, COD).<sup>61</sup> Although the limited project sample and the considerable variability in prices across projects installed in a given time period complicate analysis of national price trends (with averages subject to regional and other factors), the general trend exhibited by the capacity-weighted-average prices (i.e., the blue columns) nevertheless shows that prices bottomed out for projects built from 2002 through 2005, and have since risen

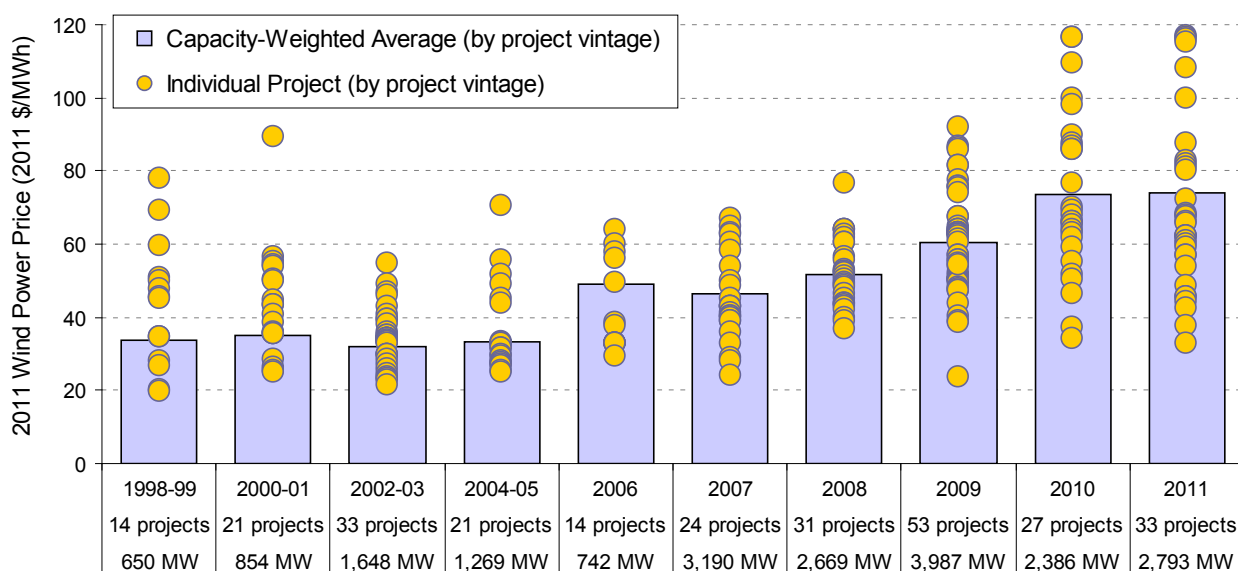
<sup>59</sup> All wind power pricing data presented in this report exclude the few projects located in Hawaii. Those projects are considered outliers in that they are significantly more expensive to build than projects in the continental United States, and have received power sales prices that are significantly higher-than-normal, in part because those prices have historically been linked to the price of oil.

<sup>60</sup> For example, Figure 31 shows wind power sales prices bottoming in 2005 – i.e., several years after turbine prices and installed project costs bottomed – and potentially not yet peaking in 2011, even though turbine prices peaked in 2008/2009 and installed costs peaked in 2009/2010.

<sup>61</sup> Prices from two individual projects – one built during the 2000-2001 period, and the other built in 2008 – are not shown in Figure 32 (due to the scale of the y-axis), but are included in the capacity-weighted averages for those periods. The omitted prices are roughly \$150/MWh and \$126/MWh, respectively.



significantly.<sup>62</sup> Specifically, the capacity-weighted average 2011 sales price, based on projects in the sample built in 2011, was roughly \$74/MWh. This price is essentially unchanged from the average among projects built in 2010 (the spread of individual project prices is also similar among projects built in 2010 and 2011), and is more than twice the average of \$32/MWh among projects built during the low point in 2002 and 2003.



Source: Berkeley Lab database

**Figure 32. 2011 Wind Power Prices by Project Commercial Operation Date**

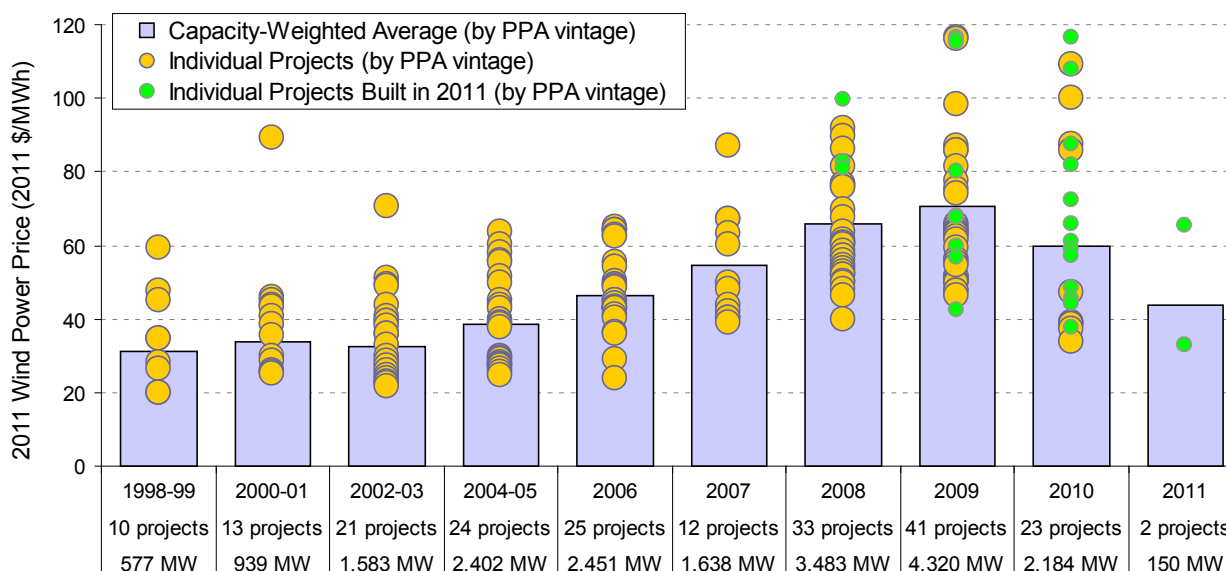
Although the similarity in pricing among 2010 and 2011 projects shown in Figure 32 may actually portend a peak (with lower prices likely among 2012 projects), the fact that neither Figure 31 nor (especially) Figure 32 show any sort of price reversal is nevertheless surprising, particularly given the degree to which turbine prices have dropped since 2008, along with growing anecdotal evidence of aggressive pricing in wind PPAs. The next section parses the data in a different way, by PPA execution date, to try and understand these findings.

<sup>62</sup> Although it may seem counterintuitive, the weighted-average price in 1999 for projects built in 1998 and 1999 (shown in Figure 31 to be about \$62/MWh) is significantly higher than the weighted-average price in 2011 for projects built in 1998 and 1999 (shown in Figure 32 to be about \$34/MWh) for three reasons: (1) the sample size is larger in Figure 32, due to the fact that 2011 prices are presented, rather than 1999 prices as in Figure 31 (i.e., early-year pricing for some of the projects built in 1998-1999 were unavailable); (2) two of the larger projects built in 1998 and 1999 (for which both 1999 and 2011 prices are available, meaning that these projects are represented within both figures) have nominal PPA prices that actually *decline*, rather than remaining flat or escalating, over time; and (3) inflating all prices to constant 2011 dollar terms impacts older (i.e., 1999) prices more than it does more-recent (i.e., 2011) prices.



## Binning Wind Power Sales Prices by PPA Execution Date Shows Steeply Falling Prices

Figure 33 shows essentially the very same data as Figure 32, but this time binned by PPA execution date rather than commercial operation date.<sup>63</sup> Viewed this way, 2011 and 2010 wind power prices tell a very different story – one of falling prices since 2009. The green individual project markers in Figure 33 represent those wind power projects built in 2011, and demonstrate that only two such projects (within our sample) actually signed PPAs in 2011. All other 2011 projects in our sample signed PPAs in 2010, 2009, or even back as far as 2008 – i.e., at the height of the market for turbines – thereby locking in prices that ended up being above market in 2011. Overall, the weighted-average PPA execution date among all 2011 projects in our sample was December 2009 – more than a full year before the start of 2011. This lag is considerable – particularly in a fast-moving market – and is roughly a year longer than the average lag seen in previous years (i.e., prior to 2011, the average PPA execution date for projects built in a given year most often fell somewhere in the fourth quarter of the *immediately* preceding year).



**Figure 33. 2011 Wind Power Prices by PPA Execution Date**

Figure 34 also breaks out wind power pricing by PPA execution date, but this time among a slightly smaller sample of projects for which we have *full-term* (rather than just historical) PPA price data.<sup>64</sup> Having full-term price data (i.e., pricing data for the full duration of each PPA, not just historical PPA prices) enables us to present these PPA prices on a levelized basis (levelized over the full contract term), which provides a more complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Consistent with Figure 33, Figure 34 shows a clear downward trend in wind power prices since 2009, particularly among those

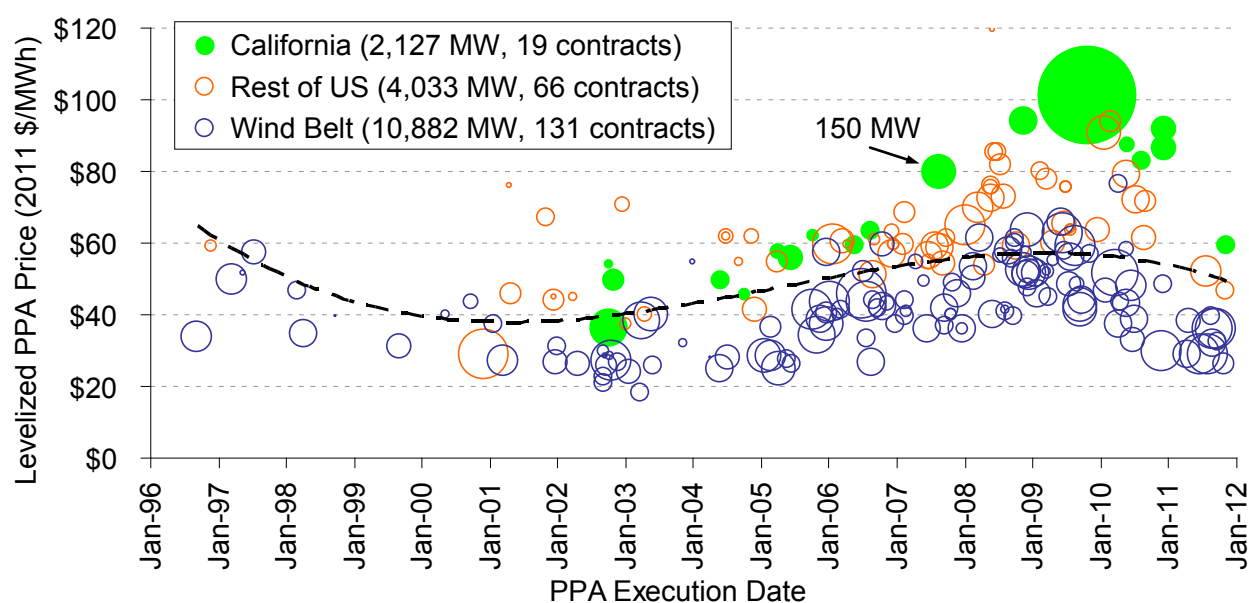
<sup>63</sup> The sample in Figure 33 is slightly smaller than in Figure 32 (19,727 MW vs. 20,189 MW, respectively) because we were not able to ascertain PPA execution dates for all projects included in Figure 32.

<sup>64</sup> Many of the recent levelized PPA prices shown in Figure 34 are from projects that will be built in 2012; these projects do not show up in Figure 33, because they were not operational in 2011.



projects located within the mid-continent “wind belt.”<sup>65</sup> Prices are generally higher in the rest of the U.S., where the wind resource is not as strong (the dashed “best fit” curve almost perfectly divides the “wind belt” from the rest of the U.S.), and have been particularly high in California in recent years.<sup>66</sup>

Among the full sample of wind power projects with PPAs signed in 2011 depicted in Figure 34, the capacity-weighted average levelized PPA price is \$35/MWh, down from \$59/MWh for PPAs signed in 2010 and \$72/MWh for PPAs signed in 2009. For just the “wind belt,” the corresponding levelized PPA prices are \$32/MWh, \$44/MWh, and \$53/MWh respectively. Either way, it is apparent that wind pricing – when parsed by PPA execution date – has come down significantly in recent years, and is currently more competitive than what is implied by Figures 31 and 32, earlier. In fact, levelized PPA prices in the \$30-\$40/MWh range – currently achievable (at least with the PTC) in many parts of the interior U.S. – are fully competitive with the range of wholesale power prices seen in 2011, as shown later in Figure 36.



Note: Size of “bubble” is proportional to project nameplate capacity.

**Figure 34. Levelized Wind PPA Prices by PPA Execution Date**

<sup>65</sup> The “wind belt” is defined here to consist of 13 states located within the interior U.S. where the wind resource is generally the strongest (see Figure 30, earlier). Wind belt states include Colorado, Iowa, Kansas, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

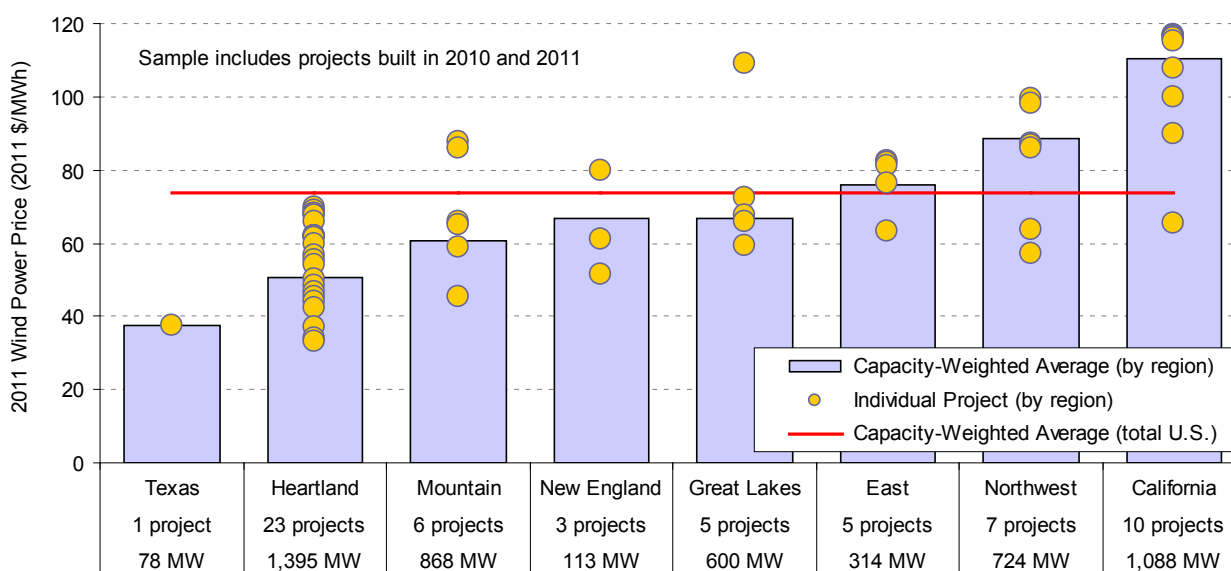
<sup>66</sup> Recent high prices in California may be due, in part, to aggressive renewable energy policies (along with certain elements of policy design) that give developers a strong negotiating position. Relatively stringent permitting and regulatory requirements may also make California a particularly expensive state in which to build wind power projects, as suggested by the installed cost data presented earlier in this report.



## Wind Power PPA Prices Vary Widely By Region

As suggested by Figure 34, regional factors can influence wind power pricing. Regional differences, for example, 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 factors.

Figure 35 shows individual project and average 2011 wind power prices by region for just those wind power projects installed in 2010 and 2011 (which, at least per Figure 32, was a period of stable pricing), with regions as defined earlier in Figure 30. Although sample size is quite small and therefore problematic in several regions,<sup>67</sup> Texas, the Heartland, and the Mountain regions appear to be among the lowest price areas, on average, while California is, by far, the highest price region.



Source: Berkeley Lab

**Figure 35. 2011 Wind Power Prices by Region: 2010-2011 Projects Only**

Abnormally high pricing in California, coupled with an unusually high proportion of California projects in the 2011 project sample, is another reason why Figure 32 fails to show a price reversal. Specifically, California accounts for nearly one quarter of the 2011 project sample, thereby disproportionately inflating the capacity-weighted average price among *all* 2011 projects (as it also did in 2010, when it made up almost 20% of the 2010 project sample).

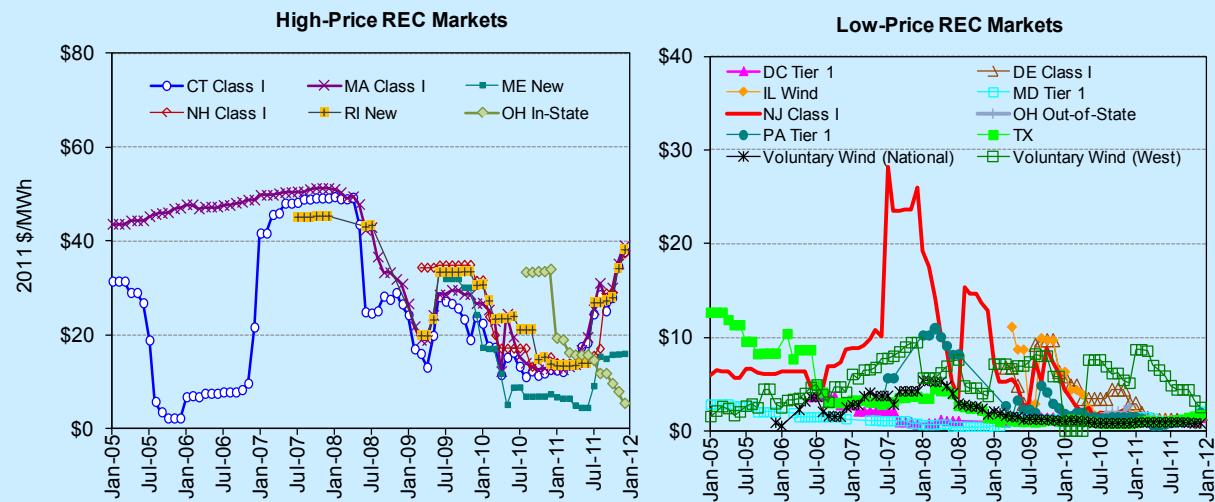
<sup>67</sup> Average prices in Texas and New England, in particular, may not be representative as those averages include just one and three projects, respectively. Once again, sample size in Texas is severely limited (despite the enormous growth of wind power capacity in that state) because generators located within ERCOT are not required to file pricing information with FERC. As such, the pricing information for Texas provided in this report comes primarily from projects located in the Texas panhandle, which is within the SPP rather than ERCOT.



## REC Prices Rise in the Northeast, Remain Depressed Elsewhere

The wind power sales prices presented in this report reflect only the bundled sale of both electricity and RECs; excluded are projects that sell RECs separately from electricity, thereby generating two sources of revenue. REC markets are 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 monthly data of spot-market REC prices in both compliance and voluntary markets, grouped into High-Price and Low-Price markets; data for compliance markets focus on the “Class I” or “Main Tier” of the RPS policies. Clearly, spot REC prices have varied substantially, both across states and over time within individual states, though prices across states within common regions (New England and PJM) are linked to varying degrees. Over the course of 2011, REC spot-market prices rose substantially among Northeastern markets, after having steadily declined over several preceding years, and ended the year above \$35/MWh in Connecticut, Massachusetts, New Hampshire, and Rhode Island. Elsewhere, however, REC prices for compliance markets fell (e.g., for Ohio’s in-state RPS requirements) or remained below \$5/MWh, due to a continued surplus of eligible renewable energy supply relative to RPS-driven demand. Prices for RECs offered in the national voluntary market remained below \$1/MWh, while voluntary wind RECs in the West declined to below \$5/MWh over the course of the year.



Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last monthly trade (if available) or the mid-point of monthly Bid and Offer prices, for the earliest compliance year traded in each month (compliance markets) or for the current or nearest year traded in each month (voluntary markets).

## Low Wholesale Electricity Prices Continued to Challenge the Relative Economics of Wind Power

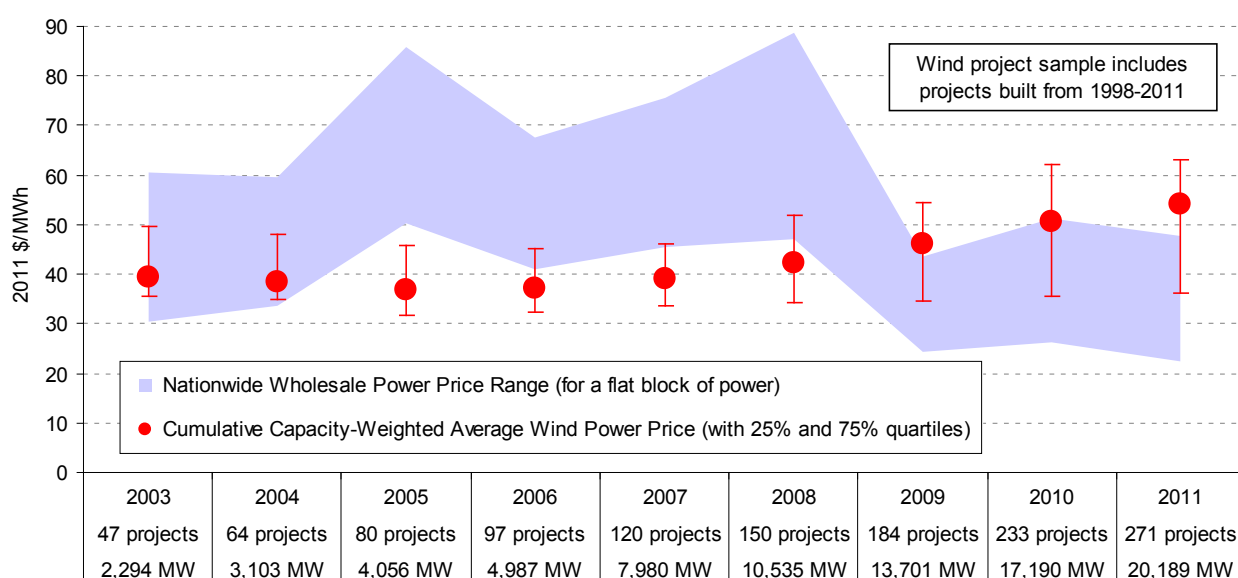
Figure 36 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power<sup>68</sup> going back to 2003 at twenty-three different pricing nodes located throughout the country (refer to the Appendix for the names and approximate locations

<sup>68</sup> A flat block of power is defined as a constant amount of electricity generated and sold over a specified time period. Though wind power projects do not provide a flat block of power, as a common point of comparison, a flat block is not an unreasonable starting point. In other words, the time-variability of wind energy is often such that its wholesale market value is somewhat lower than, but not too dissimilar from, that of a flat block of (non-firm) power.



of the twenty-three pricing nodes represented by the blue-shaded area). The red dots show the cumulative capacity-weighted average price received by wind power projects in each year among those projects in the sample with commercial operation dates of 1998 through 2011 (consistent with the data first presented in Figure 31).

At least on a cumulative basis within the sample of projects reported here, average wind power prices compared favorably to wholesale electricity prices from 2003 through 2008. Starting in 2009, however, increasing wind power prices, combined with a sharp drop in wholesale electricity prices (driven by lower natural gas prices), pushed average wind energy prices to the top of (and in 2011 above) the wholesale power price range. Although low natural gas prices are, in part, attributable to a slow economic recovery, gas prices may not ultimately rebound to earlier levels as the economy recovers, due to the ongoing development of significant shale gas deposits. Reduced expectations for natural gas price levels going forward puts the near-term comparative economic position of wind energy at some risk, absent further reductions in the price of wind power (and absent supportive policies for wind energy). That said, as shown earlier in Figures 33 and 34, pricing among recently signed wind PPAs – in some cases for projects that will be built in 2012 – is already largely competitive with the wholesale power price range for 2011 shown in Figure 36.



Source: Berkeley Lab, FERC, Ventyx, ICE

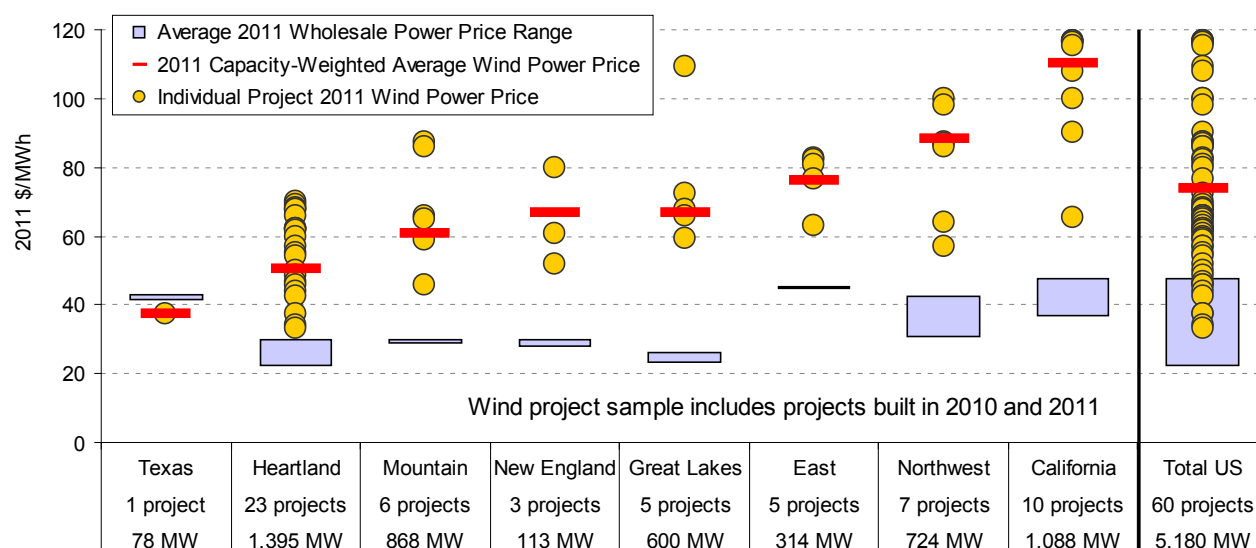
**Figure 36. Average Cumulative Wind and Wholesale Electricity Prices over Time**

Though Figure 36 portrays a national comparison, there are clearly regional differences in wholesale electricity prices and in the average price of wind power. Figure 37 focuses on 2011 wind and wholesale electricity prices in the same regions as shown earlier, based only on the sample of wind power projects installed in 2010 and 2011.<sup>69</sup> Although there is quite a bit of variability within some regions, and several regions again have limited sample size, the spread between average wind power and wholesale electricity prices (i.e., the wind power premium) in

<sup>69</sup> As discussed in footnote 67, the average wind power prices presented here for Texas and New England in particular should be viewed with caution.



each region in 2011 is fairly consistent across much of the United States. Again, though, recently signed wind PPAs – particularly in Texas, and the Heartland and Mountain regions (e.g., see the “wind belt” in Figure 34) – are more competitive than shown in Figure 37.



Source: Berkeley Lab, Ventyx, ICE

**Figure 37. Wind and Wholesale Electricity Prices by Region: 2010-2011 Projects Only**

**Important Note:** Notwithstanding the comparisons made in Figures 36 and 37, it should be recognized that neither the wind nor wholesale electricity prices presented in this section reflect the full social costs of power generation and delivery. Specifically, the wind power prices are suppressed by virtue of federal and, in some cases, state tax and financial incentives. Furthermore, these prices do not fully reflect integration, resource adequacy, or transmission costs. At the same time, wholesale electricity prices do not fully reflect transmission costs, may not fully reflect capital and fixed operating costs, and are suppressed by virtue of any financial incentives provided to fossil-fueled generation and by not fully accounting for the environmental and social costs of that generation. In addition, wind power prices – once established – are typically fixed and known (because wind energy is often sold through long-term, fixed-price power purchase agreements), whereas wholesale electricity prices are short-term and therefore subject to change over time. Moreover, as discussed earlier, the *historical* wind power prices presented here are not necessarily representative of PPAs being negotiated today based on the lower turbine pricing environment that now prevails. Finally, the location of the wholesale electricity nodes and the assumption of a flat-block of power are not perfectly consistent with the location and output profile of the sample of wind power projects.

**In short, comparing wind and wholesale electricity prices in this manner is not appropriate if one’s goal is to fully account for the costs and benefits of wind energy relative to its competition.** Another way to think of Figures 36 and 37, however, is as loosely representing the decision facing wholesale electricity purchasers that are otherwise under no obligation to purchase additional amounts of wind energy – i.e., whether to contract long-term for wind power or to buy a flat block of (non-firm) spot power on the wholesale electricity market. In this sense, the costs represented in Figures 36 and 37 are reasonably comparable, in that they represent (to some degree, at least) what the power purchaser would actually pay.



## 7. Policy and Market Drivers

### Uncertainty Reigns in Federal Incentives for Wind Energy Beyond 2012

A variety of policy drivers at both the federal and state levels have been important to the expansion of the wind power market in the United States. At the federal level, the most important policy incentives in recent years have been the PTC, accelerated tax depreciation, and two Recovery Act provisions that enabled wind power projects to elect, for a limited time only, either a 30% investment tax credit (ITC) or a 30% cash grant in lieu of the PTC. Also of more-limited import to wind development has been the Department of Energy's loan guarantee program.

- First established by the *Energy Policy Act of 1992*, the PTC provides a 10-year, inflation-adjusted credit that stood at 2.2¢/kWh in 2011. The historical importance of the PTC to the U.S. wind power industry is illustrated by the pronounced lulls in wind power capacity additions in the three years (2000, 2002, and 2004) in which the PTC lapsed, as well as the increased development activity often seen during the year in which the PTC is otherwise scheduled to expire (see Figure 1). Wind power projects are currently eligible for the PTC if they achieve commercial operations by the end of 2012.
- Accelerated tax depreciation enables wind project owners to depreciate the vast majority of their investments over a five- to six-year period for tax purposes. An even-more-attractive 50% first-year “bonus depreciation” schedule was in place during 2008-2010. The *Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010* that was signed into law in mid-December 2010 increased first-year bonus depreciation to 100% for those projects placed in service between September 8, 2010 and the end of 2011, after which the first-year bonus reverted to 50% for projects placed in service during 2012.
- The Recovery Act enabled wind power projects placed in service prior to the end of 2012 to elect a 30% ITC in lieu of the PTC. More importantly, given the relative scarcity of tax equity in the wake of the financial crisis, Section 1603 of the Recovery Act also enabled wind power projects to elect a 30% cash grant from the Treasury in lieu of either the ITC or the PTC. More than 60% of the new wind capacity installed in 2011 elected the Section 1603 grant. In order to qualify for the grant, wind power projects must have been under construction by the end of 2011, must apply for a grant by October 1, 2012, and must be placed in service by the end of 2012.
- Another Recovery Act program, the Section 1705 loan guarantee program for commercial projects, has also wound down, as projects had to be under construction by September 30, 2011 in order to qualify. In total, this program closed on four loan guarantees to wind power projects totaling 1,024 MW of capacity, 285 MW of which were online by the end of 2011.

With the PTC, 30% ITC, 30% cash grant, and bonus depreciation all currently scheduled to expire at the end of 2012 for new wind projects,<sup>70</sup> the wind energy sector is currently experiencing serious federal policy uncertainty, and therefore rushing to complete projects by the

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<sup>70</sup> Although eligibility for the Treasury grant does hinge on construction having begun by the end of 2011, complying with this interim start-of-construction deadline is unlikely to have been particularly onerous for most wind power projects, based on safe harbor guidance published by the Treasury.



end of the year. Moreover, 2011 saw another year pass without any concrete Congressional action on what are seemingly the wind power industry's two highest priorities – a longer-term extension of federal tax (or cash) incentives and passage of a federal renewable or clean energy portfolio standard.

Though the lack of long-term federal incentives for wind energy has been a drag on the industry, new and accelerated federal activity in wind project siting and permitting has been viewed as a net positive. In March 2012, for example, the Department of Interior released voluntary guidelines designed to help wind power projects avoid and minimize impacts to wildlife, reducing the perceived risk and uncertainty that preceded the release. Progress also continued to be made on streamlining the process of developing wind power projects on public lands.

### **State Policies Play a Role in Directing the Location and Amount of Wind Power Development, but Current Policies Cannot Support Continued Growth at the Levels Seen in the Recent Past**

From 1999 through 2011, 65% of the wind power capacity built in the United States was located in states with RPS policies; in 2011, this proportion was 78%.<sup>71</sup> As of July 2012, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 38). Although no new state RPS policies were passed in 2011, a number of states strengthened previously established RPS programs.<sup>72</sup> In aggregate, existing state RPS policies are estimated to require roughly 100 GW of new renewable capacity by 2035, beyond what was already installed in each RPS state at the time that its RPS policy was established.<sup>73</sup> This required additional renewable capacity is equivalent to roughly 7% of total projected U.S. retail electricity sales in 2035 and 34% of projected load growth between 2000 and 2035.

Given the size of the RPS targets and the amount of new renewable energy capacity already built, existing state RPS programs are projected to drive average annual renewable energy additions of roughly 4-5 GW/year (not all of which will be wind) between 2012 and 2020.<sup>74</sup> This is well below the amount of wind power capacity added in 2011, and even further below the 9 GW of total renewable capacity added in 2011 (which included roughly 2 GW of solar capacity), demonstrating the limitations of relying exclusively on state RPS programs to drive future wind power development.

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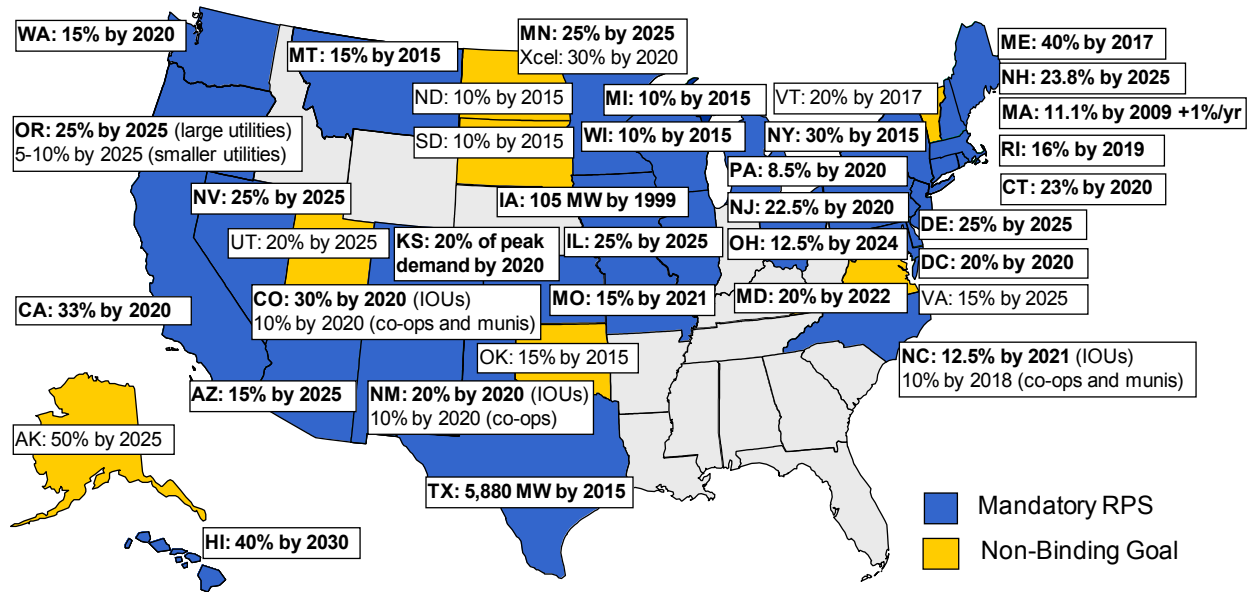
<sup>71</sup> Such statistics provide only a rough indication of the impact of RPS policies on wind power development, and could either overstate or understate the actual policy effect to-date.

<sup>72</sup> Attempts to weaken RPS programs have also been initiated in some states, though those efforts have not thus far led to meaningful changes in RPS design.

<sup>73</sup> 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, though they do not assume any biomass co-firing at existing thermal plants. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis or with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.

<sup>74</sup> Again, varying combinations of renewable resource types for each RPS state were assumed in estimating the 4-5 GW/year of average annual renewable capacity additions required to meet RPS obligations through 2020.





Source: Berkeley Lab

Note: The figure does not include West Virginia's mandatory "alternative and renewable energy portfolio standard" or Indiana's voluntary "clean energy standard." Under these two states' policies, both renewable and non-renewable energy resources may qualify, but neither state specifies any minimum contribution from renewable energy. Thus, for the purposes of the present report, these two states are not considered to have enacted mandatory RPS policies or non-binding renewable energy goals.

**Figure 38. State RPS Policies and Non-Binding Renewable Energy Goals (as of July 2012)**

In addition to state RPS policies, utility resource planning requirements, principally in Western and Midwestern states, have also helped spur wind power additions in recent years, as has voluntary customer demand for "green" power. State renewable energy funds provide support for wind power projects (both financial and technical) in some jurisdictions, as do a variety of state tax incentives. Finally, concerns about the possible impacts of global climate change continue to fuel interest in some states and regions to implement and enforce carbon reduction policies. The Northeast's Regional Greenhouse Gas Initiative (RGGI) cap-and-trade policy, for example, has been operational for several years, and California's greenhouse gas cap-and-trade program commenced operation in 2012, though carbon pricing seen to date under RGGI has been too low to drive significant wind energy growth. At the same time, other states have expressed growing skepticism of these efforts, and a number of states have withdrawn, or undertaken steps toward withdrawal, from regional greenhouse gas reduction initiatives, including RGGI and the Western Climate Initiative.

## Despite Progress on Overcoming Transmission Barriers, Constraints Remain

Transmission development has continued to gain traction during recent years. The North American Electric Reliability Corporation (NERC), for example, reported that about 2,300 circuit miles of new transmission additions were under construction in the United States near the end of 2011, with an additional 17,800 circuit miles planned through 2015 (NERC 2011). The Brattle Group, meanwhile, has estimated that planned and proposed transmission projects represent around \$60-80 billion in potential investments from 2011 through 2015 (Pfeifenberger



2012). Finally, AWEA has identified near-term transmission projects that – if all were completed – could carry almost 45 GW of wind power capacity (AWEA 2012a).

Lack of transmission can be a barrier to new wind power development, and insufficient transmission capacity in areas where wind projects are already built can lead to curtailment, as illustrated by the data on wind energy curtailment reported earlier. New transmission is particularly important for wind energy because wind power projects are constrained to areas with adequate wind speeds, which are often located at a distance from load centers. There is also a mismatch between the relatively short timeframe often needed to develop a wind power project compared to the longer timeframe typically required to build new transmission. Uncertainty over transmission siting and cost allocation, particularly for multi-state transmission lines, further complicates transmission development.

In July 2011, FERC issued Order No. 1000, which requires public utility transmission providers to improve transmission planning processes and to determine a cost allocation methodology for new transmission facilities. The transmission planning requirements established in the new rule include development of regional transmission plans, mandatory participation in regional transmission planning, consideration of transmission needs driven by public policy requirements established by state and federal regulations (such as RPS programs), and coordination between neighboring transmission planning regions. In addition, each public utility transmission provider is now required to develop a common regional methodology for allocating the costs for new transmission facilities consistent with six principles for both intra-regional and inter-regional facilities. The methodology can include different cost allocation schemes for projects driven by different needs, i.e., reliability, economic, and public policy (FERC 2011a). Initial compliance filings under Order No. 1000 are due in October 2012.

States, grid operators, utilities, regional organizations, and DOE continue to take proactive steps to encourage transmission investment and improve access to renewable resources. A non-exhaustive list of these initiatives is presented below:

- **Bonneville Power Administration (BPA):** As a result of the Network Open Season initiative, BPA processed 263 transmission service requests from 2008-2010, including 7,105 MW associated with wind power. However, due to uncertainty regarding proposed wind projects and that the success of the Network Open Season was more than BPA anticipated, plans for future Network Open Seasons have been put on hold until BPA conducts a review of transmission planning and wind energy integration issues. In February 2012, BPA completed the 79-mile 500-kV McNary-John Day transmission project, which can support up to 575 MW of wind power capacity. The Network Open Season initiative also prompted the development of the 28-mile Big Eddy-Knight transmission project; completion is expected in 2013. Separately, in January 2012, BPA signed a Memorandum of Understanding with NorthWestern Energy to explore the possibility of participating in the development of the Mountain States Transmission Intertie that would extend from Montana to Idaho.
- **Southwest Power Pool (SPP):** In October 2011, FERC denied requests for rehearing, and thereby upheld, its 2010 order accepting SPP's "Highway/Byway" transmission cost allocation methodology (FERC 2011b). In early 2012, the SPP Board of Directors approved a near-term transmission expansion plan that will result in the construction of \$251 million in new transmission projects over the next five years. SPP's board also approved a 10-year



transmission expansion plan, with projects representing an additional \$1.5 billion in transmission investment.

- **Midwest Independent Transmission System Operator (MISO):** In late October 2011, FERC upheld its December 2010 acceptance of MISO's regional cost allocation methodology for multi-value projects (MVP), subject to a FERC requirement that MISO monitor the cumulative costs and benefits of all approved MVP projects (FERC 2011c). In December 2011, the MISO Board of Directors approved the MISO Transmission Expansion Plan, which includes 215 projects, representing 3,665 circuit-miles of new or upgraded transmission lines, and requires about \$6.5 billion in potential transmission investment over the next 5 to 7 years. The plan includes 17 MVPs, representing about \$5.1 billion. Together with the previously approved MVPs, the 17 MVPs could connect as much as 14,000 MW of wind power capacity (AWEA 2012a). Also in MISO, the CapX2020 Monticello to St. Cloud 345-kV transmission line in Minnesota was energized in late December 2011, the first CapX2020 project to be completed and placed in service.
- **Texas Competitive Renewable Energy Zones (CREZ):** The 2,300 circuit-miles of Texas CREZ lines are largely on track to be completed by the end of 2013, and are expected to accommodate a total of 18,500 MW of wind power capacity. Since 2008, the initial cost estimate of about \$4.9 billion has increased by over 40%, to almost \$7 billion (PUCT 2012). It is also now estimated that it may take several years or more for developers to build enough wind power capacity to fully utilize the CREZ lines planned for West Texas and the Texas Panhandle area because of lower natural gas prices, slower load growth, and the difficulty of securing project financing for wind power development. Nevertheless, the potential for wind energy development along the Texas Gulf Coast has spurred recent discussions regarding a second phase of CREZ.
- **Western Area Power Administration (WAPA):** WAPA received \$3.25 billion in borrowing authority under the Recovery Act for developing new transmission. In September 2011, WAPA and TransWest Express (TWE) agreed to fund the development phase of the TransWest Express transmission project, a proposed 725-mile, 600-kV transmission line that could deliver up to 3,000 MW of renewable energy from Wyoming to the Marketplace Hub, near Las Vegas. If WAPA continues its participation in the project into the construction phase – a decision that will be made when the environmental analysis is completed – additional borrowing authority would be used to help fund the project. Meanwhile, a DOE Inspector General report released in November 2011 criticized WAPA for failing to implement safeguards for protecting the \$161 million WAPA has committed towards the construction of the Montana-Alberta Transmission Line, a controversial project that is currently facing legal challenges. Should it be completed, the 214-mile, 230-kV line would deliver up to 300 MW in either direction.
- **California ISO (CAISO):** According to the CAISO's 2011-2012 Transmission Plan, enough transmission capacity to meet California's 33% RPS goal by 2020 is either under development or in planning. Of the \$7.1 billion in transmission projects included in the plan, a number of them have already been approved and permitted, including: the Sunrise Powerlink, the Tehachapi Transmission project, the Colorado River-Valley line, the Eldorado-Ivanpah line, and the Carrizo-Midway reconductoring (CAISO 2012b). The Sunrise Powerlink transmission line was completed in June 2012, and will be capable of transmitting up to 1,000 MW of renewable energy. SDG&E, the developer of the Sunrise Powerlink, recently signed long-term PPAs with Pattern Wind Energy and Manzana Wind



for 315 MW and an additional 100 MW of wind energy to flow across the line. The Tehachapi Transmission project, which is being developed by Southern California Edison (SCE), is expected to accommodate up to 4,500 MW of new generation, much of it potentially wind, once completed in 2015. In late 2011, however, the California Public Utilities Commission ordered SCE to stop construction on a segment of the project that runs through Chino Hill, California. The City of Chino Hills and SCE have yet to come to a mutual agreement on an alternative route, which may push back the in-service date of the project.

Three RTOs are also in various stages of reforming their interconnection queue processes. In early 2012, FERC accepted a set of revisions to CAISO's generator interconnection procedures that: allow power plants to request partial deliverability status, which could reduce the cost of network upgrades; provide for reimbursement of network upgrades for projects built in phases; divide the cost of financial security for network upgrades into separate components to align with construction phases; and allow customers to cut generation capacity by up to 5% for any reason between the effective date of an interconnection agreement and the commercial operation date. In May 2012, CAISO proposed further revisions to its interconnection queue process, which are currently being evaluated at FERC. In February 2012, PJM Interconnection filed a petition to FERC to make three modifications to its Open Access Transmission Tariff: a six-month queue cycle to replace the current three-month planning cycle; allowing a project to decrease in size during the study process; and establishing an alternate queue for projects smaller than 20 MW that connect to distribution level facilities and do not cause the need for upgrades to the PJM transmission system. Finally, in March 2012, FERC conditionally approved a proposal from MISO that addresses backlogs and late-stage terminations of generation interconnection agreements. In addition to revised timelines and new study procedures, the reforms require interconnection customers to put more money at risk earlier in the process with the justification being that the projects that remain in the queue are those that are more likely to reach commercial operations.

Progress was also reported under interconnection-wide planning supported by previous grants from the DOE. In December 2011, the Eastern Interconnection Planning Collaborative submitted its phase one report to DOE, which focused on the integration of regional plans and long-term macroeconomic analysis. Phase two of the project will focus on conducting transmission studies based on three scenarios, which will include reliability studies as well as various options for transmission expansion plans. In the Western Interconnection, the Western Electricity Coordinating Council completed its first 10-Year Regional Transmission Plan in September 2011. Also in 2011, the Texas Interconnection's Long-Term Study Task Force submitted to DOE its interim status report for the ERCOT Long-Term Transmission Analysis. ERCOT's Task Force will submit its final report to DOE by June 2013. In addition, the Obama Administration is attempting to expedite the construction of seven backbone transmission projects with the formation of the Rapid Response Team for Transmission which seeks to streamline federal permitting and improve cooperation among federal, state, and tribal governments. The proposed projects include over 3,100 miles of new transmission lines spread across 12 states.

Finally, numerous transmission projects have been planned, in part, to accommodate the growth of wind energy throughout the country. Examples of some of these projects are described below.



- Construction began on the first segment of the Michigan Thumb Loop Transmission Project in early 2012. Once completed in 2015, the 140-mile transmission project will transport wind energy to load centers in Michigan.
- Duke-American Transmission Company, a joint venture between Duke Energy and American Transmission Company, announced plans to invest about \$4 billion in seven transmission projects in five Midwestern states. Also, in late 2011, DATC acquired the 500-kV Zephyr transmission line project, which could transmit 3,000 MW of renewable energy between Wyoming and southern Nevada if completed in 2020, four years later than the original planned in-service date.
- Los Angeles Department of Water and Power's proposed Barren Ridge Renewable Transmission Project is expected to provide 1,100 MW of transmission capacity to transport wind and solar resources from the Tehachapi Mountains and Mojave Desert to the San Fernando Valley. The draft environmental analysis documents were released for public review in August 2011. Assuming the project proceeds, construction will begin in 2013, with a target in-service date of 2016.

Though a number of transmission projects have progressed, others have been delayed or scaled back. Due to a lowered demand forecast, for example, Xcel Energy dropped a transmission project that would have allowed up to 1,500 MW of renewable energy to be transported from the San Luis Valley to the Denver metropolitan area. In 2012, PacifiCorp announced plans to scale back the Energy Gateway Transmission Project.

### **Integrating Wind Energy into Power Systems Is Manageable, but Not Free of Costs, and System Operators Are Implementing Methods to Accommodate Increased Penetration**

There has been a considerable amount of attention paid to the potential impacts of wind energy on power systems in recent years. Concerns about, and solutions to, these issues have affected, and continue to impact, the pace of wind power deployment in the United States. Experience in operating power systems with wind energy is also increasing worldwide (Jones 2011).

Figure 39 provides a selective listing of estimated wind integration costs<sup>75</sup> and Figure 40 summarizes the estimated increase in balancing reserves<sup>76</sup> associated with increased wind energy from integration studies completed from 2003 through 2011 at various levels of wind power

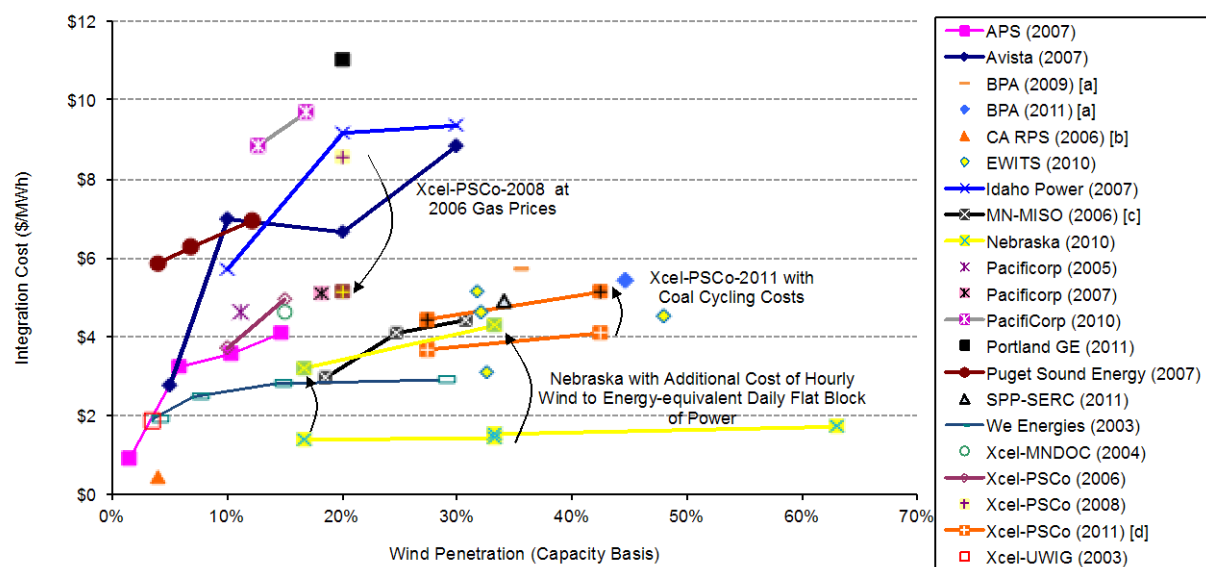
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<sup>75</sup> The integration costs considered in these studies typically refer to the costs associated with accommodating the variability and uncertainty associated with wind energy. Generally, these costs are associated with three different time frames: *regulation* – from seconds to a few minutes; *load-following* – tens of minutes to a few hours; and *unit commitment* – out to the next day or two. Studies often, but not always, estimate these costs as the difference in overall electric system production costs between a scenario that captures the variability and unpredictability of wind energy and a scenario with an energy-equivalent block of power having no variability or uncertainty.

<sup>76</sup> In general, these balancing reserves reflect the resources required to maintain system balance between schedules. Often studies have balancing reserve requirements that change depending on the level of wind electricity generation or the time of day (Ela et al. 2011). The balancing reserves in the figure represent either the average reserves or the maximum increase in reserves depending on which statistics are reported by the study authors.



capacity penetration.<sup>77,78</sup> System operators use reserves to balance variability and uncertainty between scheduling periods, and scheduling periods vary, so Figure 40 separates balancing reserves by the duration of the scheduling period assumed in the study. Regions with fast energy markets, for example, change the schedule of dispatchable generators over 5-minute periods while other regions often use hourly schedules.<sup>79</sup> Because methods vary and a consistent set of operational impacts has not been included in each study, results from the different analyses of integration costs (Figure 39) and balancing reserves (Figure 40) are not fully comparable. Note also that the rigor with which the various studies have been conducted varies, as does the degree of peer review. Finally, there has been some recent literature questioning the methods used to estimate wind integration costs and the ability to explicitly disentangle those costs, while also highlighting potential integration costs associated with other generation options (Milligan et al., 2011).



- [a] Costs in \$/MWh assume 31% capacity factor.  
 [b] Costs represent 3-year average.  
 [c] Highest over 3-year evaluation period.  
 [d] Higher cost line adds the coal cycling costs found in Xcel Energy (2011).

Sources: Acker (2007) [APS (2007)]; EnerNex Corp. (2007) [Avista (2007)]; BPA (2009); BPA (2011c); Shiu et al. (2006) [CA RPS (2006)]; EnerNex Corp. (2010) [EWITS (2010)]; EnerNex Corp. and Idaho Power Co. (2007) [Idaho Power (2007)]; EnerNex Corp. and WindLogics Inc. (2006) [MN-MISO (2006)]; EnerNex et al. (2010) [Nebraska (2010)]; PacifiCorp (2005); PacifiCorp (2007); PacifiCorp (2010); PGE and EnerNex Corp. (2011) [Portland GE (2011)]; Puget Sound Energy (2007); EPRI (2011) [SPP-SERC (2011)]; Electrotek Concepts, Inc. (2003) [We Energies (2003)]; EnerNex Corp. and WindLogics, Inc. (2004) [Xcel-MNDOC (2004)]; EnerNex Corp. (2006) [Xcel-PSCo (2006)]; EnerNex Corp. (2008) [Xcel-PSCo (2008)]; Xcel Energy and EnerNex Corp. (2011) [Xcel-PSCo (2011)]; Brooks et al. (2003) [Xcel-UWIG (2003)]

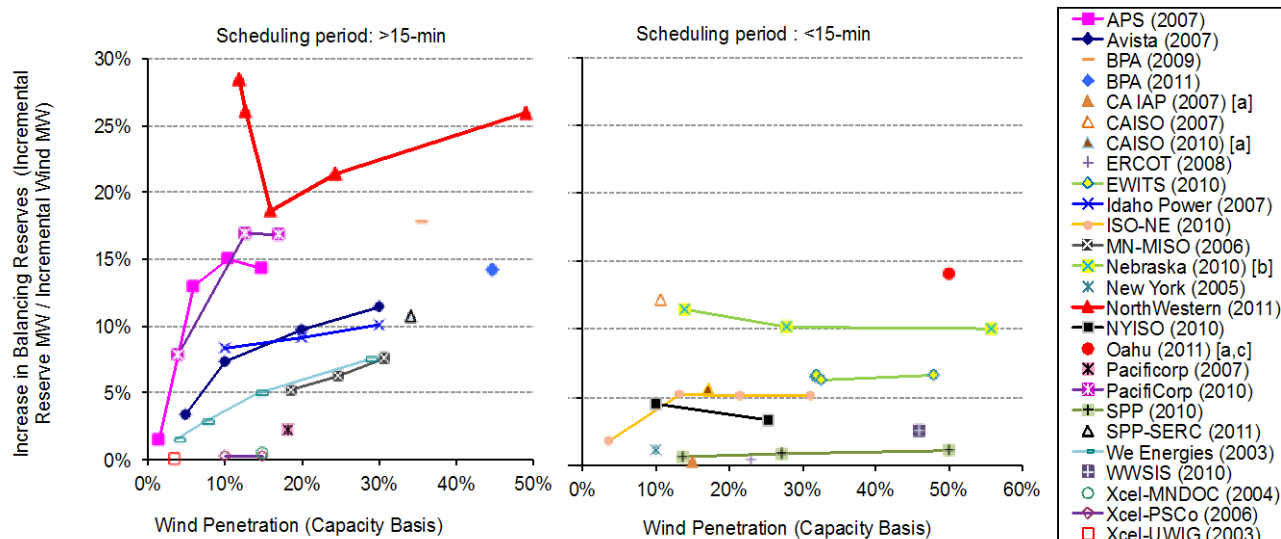
**Figure 39. Integration Costs at Various Levels of Wind Power Capacity Penetration**

<sup>77</sup> Wind power penetration on a capacity basis (defined as nameplate wind power capacity serving a region divided by that region's peak electricity demand) was frequently used in earlier integration studies. For a given amount of wind power capacity, penetration on a capacity basis is typically higher than the comparable wind penetration in energy terms (because, over the course of a year, wind power projects generally operate at a lower percentage of their rated capacity, on average, than does aggregate load).

<sup>78</sup> Some studies address capacity valuation for resource adequacy purposes; those results are not presented here.

<sup>79</sup> Over half the load in the U.S. is now in regions with 5-minute scheduling: PJM, MISO, ERCOT, NYISO, ISO-NE, and CAISO.





[a] Includes some solar energy in addition to wind energy.

[b] 3-year average.

[c] Small, isolated island system.

Sources: See Figure 39; GE (2007) [CA IAP (2007)]; CAISO (2007); CAISO (2010); GE (2008) [ERCOT (2008)]; GE (2010a) [ISO-NE (2010)]; GE (2005) [New York (2005)]; NYISO (2010); Shoucri (2011) [Northwestern (2011)]; GE (2011a) [Oahu (2011)]; Charles River Associates (2010) [SPP(2010)]; GE (2010b) [WWSIS (2010)]

**Figure 40. Incremental Balancing Reserves at Various Levels of Wind Power Capacity Penetration**

In addition to balancing reserve requirements and wind integration costs, these and other studies have also focused on identifying the required changes to existing practices in power system operations, the role of forecasting, and the capability of thermal and hydropower generators to provide the needed flexibility to integrate wind power. A sizable portion of these studies have been conducted by or commissioned by RTOs and ISOs (e.g. CAISO, ERCOT, SPP, New York Independent System Operator (NYISO), and Independent System Operator – New England (ISO-NE); PJM is currently conducting an integration study that is expected to be complete in 2013). Key conclusions that continue to emerge from the growing body of integration literature include the following:

- Wind integration costs estimated by all studies reviewed are below \$12/MWh – and often below \$5/MWh – for wind power capacity penetrations of up to and even exceeding 40% of the peak load of the system in which the wind power is delivered.<sup>80</sup> Variations in estimated costs across studies are due, in part, to differences in methodologies, definitions of

<sup>80</sup> These integration cost estimates compare to levelized wind PPA prices that ranged from \$25/MWh to \$60/MWh among contracts signed in 2011 (as shown earlier in Figure 34). The relatively low integration cost estimates in the 2006 Minnesota study and the 2010 Nebraska study, despite aggressive levels of wind power penetration, are partly a result of relying on the broader regional electricity market to accommodate certain elements of integrating wind energy into system operations. Conversely, the higher integration costs found by Avista, Idaho Power, and PacifiCorp, and Portland General Electric are, in part, caused by the relatively smaller markets in which the wind energy is being absorbed and by those utilities' operating practices. Specifically, the Northwest currently uses hourly scheduling intervals rather than the sub-hourly markets common in ISOs and RTOs. A sensitivity case in the Avista Utilities study demonstrates that the use of a 10-minute transaction scheduling interval would decrease the cost of integrating wind energy by 40-60%.



integration costs, power system and market characteristics, wind energy penetration levels, fuel price assumptions, and the degree to which thermal power plant cycling costs are included.

- Larger balancing areas, such as those found in RTOs and ISOs, make it possible to integrate wind energy more easily and at lower cost than is the case in smaller balancing areas. Coordination among smaller balancing areas can reduce the cost of wind integration.
- The successful use of wind power forecasts by system operators can significantly reduce integration challenges and costs. Intra-hour transmission scheduling and generator dispatch (e.g., 5-minute scheduling and dispatch) provides access to flexibility in conventional power plants that, among other benefits, lowers the costs of integrating wind energy.
- Thermal plant cycling costs are increasingly being highlighted and may contribute to the costs and challenges associated with integrating wind. Among other studies of cycling costs, the Western Wind and Solar Integration Study Phase II and the PJM wind integration study, both due to be completed within the next year, will include an assessment of cycling costs. Strategies for mitigating thermal plant damages associated with cycling should be investigated further.
- The increase in balancing reserves with increased wind power penetration is projected to be typically less than 15% of the nameplate capacity of wind power and often considerably less than this figure, particularly in studies that use intra-hour scheduling. The high balancing reserve finding in the NorthWestern study (Shoucri 2011) reflects the issues with hourly scheduling and small balancing areas. A number of studies indicate that the amount of balancing reserves needed at any particular time changes with different wind and load conditions. Setting dynamic balancing reserve requirements that respond to these changes in conditions can lower integration costs.

ISOs and utilities are continuing to take important steps to mitigate the challenges faced with integrating larger quantities of wind energy.

- Centralized wind energy forecasting systems are currently in place in all ISO/RTOs except ISO-NE where it is scheduled to become operational by the start of 2013. A large number of electric utilities are also now using centralized wind forecasting in their operations (Rogers and Porter, 2011; Porter and Rogers, 2012). Wind forecasting was identified to be a key prerequisite to successful integration of wind into power system operations in a worldwide survey of grid operators that together currently manage over 141 GW of wind (Jones 2011).
- In 2011, FERC conditionally approved a Midwest ISO proposal to implement Look Ahead Commitment that every 15-minutes automatically evaluates the need to commit additional quick-start power plants over the next few hours based on current conditions and near-term forecasts of load, wind, and scheduled interchanges (FERC 2012a).
- CAISO also sought FERC approval to include a Flexible Ramp Constraint in its tariff and is further developing a Flexible Ramping Product (FERC 2011d). CAISO is proposing to commit a certain amount of additional generation capability during early stages of the market, based on estimates of potential short-term variability and uncertainty, to then be used to balance the system in later stages of the market. For example, some additional generation capability will be committed in the day-ahead market so that the additional generation capability will be available for balancing in the real-time market. Similarly, the CAISO will set aside generation in one real-time dispatch interval in order to ensure that adequate



resources will be available to be dispatched in subsequent dispatch intervals. The ramping product differs from standard reserves in that the additional generation that is set aside in one energy market interval is then released to be dispatched in a later energy market interval, whereas reserves are not generally meant to be dispatched as part of the energy market (CAISO 2012a).

- Intra-hour scheduling pilots began for several balancing authorities in the West, and intra-hour scheduling changes (primarily half-hour changes) are increasingly being used, though practices are not yet fully standardized among balancing areas. A platform to enable faster bilateral transactions, the Intra-hour Transaction Accelerator Platform (I-TAP), also launched in 2011. Inter-regional interchange scheduling on a sub-hourly basis between different organized markets is similarly under investigation within the Eastern Interconnection.
- An energy imbalance market for the Western Interconnection, with many similarities to the SPP imbalance market, was proposed and, if developed, would provide a sub-hourly, real-time energy imbalance market providing centralized, automated, interconnection-wide generation dispatch within the Western Interconnection (WECC 2010). Studies show benefits – due in part to a reduction in balancing reserves – and costs that depend on the way that the energy imbalance market is implemented (WECC 2011). Two low-cost options would leverage the existing structure and expertise of either SPP or the CAISO to implement and operate parts of the energy imbalance market.

Some utilities are now directly charging wind power projects for balancing services.<sup>81</sup> BPA, for example, includes a wind energy balancing charge in its transmission tariff equivalent to about \$5.40/MWh. The charge for wind energy that participates in BPA's Committed Intra-hour Scheduling Pilot program in which wind generators submit schedules every half-hour rather than every hour is reduced to about \$3.60/MWh. More frequent scheduling by wind resources in the pilot program allows BPA to reduce its balancing reserve requirement and the savings are passed on as a decreased wind balancing rate (BPA 2011). FERC has also approved a higher generator regulation and frequency response services charge for wind energy in the Westar Energy balancing area, equivalent to about \$0.7/MWh; this interim tariff will be in place until it is rendered unnecessary through the anticipated implementation of an ancillary services market and balancing authority area consolidation in SPP (FERC 2010).<sup>82</sup> Puget Sound Energy (PSE) proposed an increase in Regulation and Frequency Response Service that charges a higher rate for wind energy exporting from the PSE balancing area: the resulting charge would be about \$9.5/MWh and is based on an hourly scheduling assumption. The general changes to the rate schedule were conditionally accepted by FERC, although the methodology and resulting charge are still being sorted out through a settlement hearing at FERC (FERC 2011f).

Similar charges to recover costs associated with regulation will continue to be evaluated on a case-by-case basis by FERC according to the decision on integrating variable energy resources in Order 764 (FERC 2012b). The decision does require that scheduling at 15-min intervals be

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<sup>81</sup> In addition, Idaho Power, Avista, and PacifiCorp all discount their published avoided cost payments for qualifying wind power projects in Idaho by an integration rate that ranges from 7-9% of the avoided cost rate, up to \$6.50/MWh (IPUC 2010). In early 2011, however, the Idaho PUC reduced the maximum size of a qualifying wind power facility from 10 MW to 100 kW. Projects larger than 100 kW will need to directly negotiate individual project PPA prices rather than obtaining the published avoided cost rate.

<sup>82</sup> The rate was revised from about \$0.8/MWh in 2010 to \$0.7/MWh in 2011 based on an error in the methodology Westar used in its 2010 estimate of the cost of providing the service (FERC 2011e).



offered to transmission customers and that variable energy resources provide data to be used in production forecasting to the transmission provider. FERC therefore provided guidance that the design of any generator regulation charges should account for the use of intra-hour scheduling and production forecasts when determining quantities of regulation service. Furthermore, any regulation charge that differs across customer classes must take into account any diversity benefits from aggregating several customer classes with different variability patterns. The transmission provider must demonstrate that any difference in regulating reserve responsibilities across customer classes is due to differences in their operating characteristics.

Finally, a study of the frequency response implications of high renewable penetrations in the California ISO was completed in 2011 (GE 2011b), following an earlier broad assessment of frequency response issues for FERC (Eto et al. 2010). The CAISO study found that as long as adequate secondary reserves (regulation and load following) were available to balance wind and solar, then even in situations with high instantaneous penetrations of variable generation (50% of load in California and 25% in the rest of WECC), none of the credible conditions examined lead to stability problems. The results of the CAISO study were generally in agreement with the earlier frequency response study for FERC.



## 8. Future Outlook

Wind power capacity additions in 2011 – at 6,816 MW – fell within the range of market forecasts (4,450-8,000 MW) presented in last year’s edition of the *Wind Technologies Market Report*. Key factors driving growth in 2011 included: continued state and federal incentives for wind energy, recent improvements in the cost and performance of wind power technology, and the need to meet an end-of-year construction start deadline in order to qualify for the Section 1603 Treasury grant program.

With the Section 1603 grant and federal tax incentives for wind energy currently scheduled to expire at the end of the year, 2012 is widely expected to be a strong year for new capacity growth, as wind energy purchasers take advantage of this potentially “limited time only” buying opportunity that combines federal incentive availability with lower PPA prices (from lower turbine costs and improved performance), and as developers rush to commission projects before the expiration of incentives. As a result, with the exception of the EIA (2012) “no sunset” projection, the remaining forecasts presented in Table 6 predict 2012 additions to range from 7,280 MW to 12,000 MW – i.e., in excess of 2011 additions, and perhaps even surpassing the previous record set back in 2009. With AWEA (2012c) reporting 1,695 MW installed in the first quarter of 2012, and another 8,900 MW under construction as of the end of the first quarter, the industry appears to be on track to fall within that forecast range.

**Table 6. Forecasts for Annual U.S. Wind Capacity Additions (MW)**

Source	Assumed Status of Federal Tax Incentives After 2012	2012	2013	2014	Cumulative Additions 2012-2014
EIA (2012)	Expired	7,280	1,430	600	9,310
Bloomberg NEF (2012a)	Expired	11,200	1,000	3,000	15,200
Navigant (2011)	Expired	8,500	2,400	2,400	13,300
EIA (2012)	Extended Indefinitely	3,230	3,320	580	7,130
BTM (2012)	Presumably Extended	8,250	7,500	9,000	24,750
Bloomberg NEF (2012a)*	Extended – 3 year	11,200	3,100	5,500	19,800
IHS EER (2012)	Extended – 3+ year	12,000	1,200	6,050	19,250
MAKE (2012)	Extended – details n/a	10,700	3,800	4,600	19,100
Navigant (2011)	Extended – 4 year	8,500	7,500	8,000	24,000

\*Assumes extension occurs in Q1 2013

Projections for 2013 and beyond are much less certain, but generally show lower wind power capacity additions. Besides the possible expiration of federal incentives at the end of 2012, other challenges include: continued low natural gas and wholesale electricity prices; inadequate transmission infrastructure in some areas; modest electricity demand growth; existing state policies that are insufficient to support future wind power capacity additions at the levels



witnessed in recent years,<sup>83</sup> and growing competition from solar energy in certain regions of the country. Industry hopes for a federal renewable or clean energy standard, or climate legislation, have also dimmed in the near term.

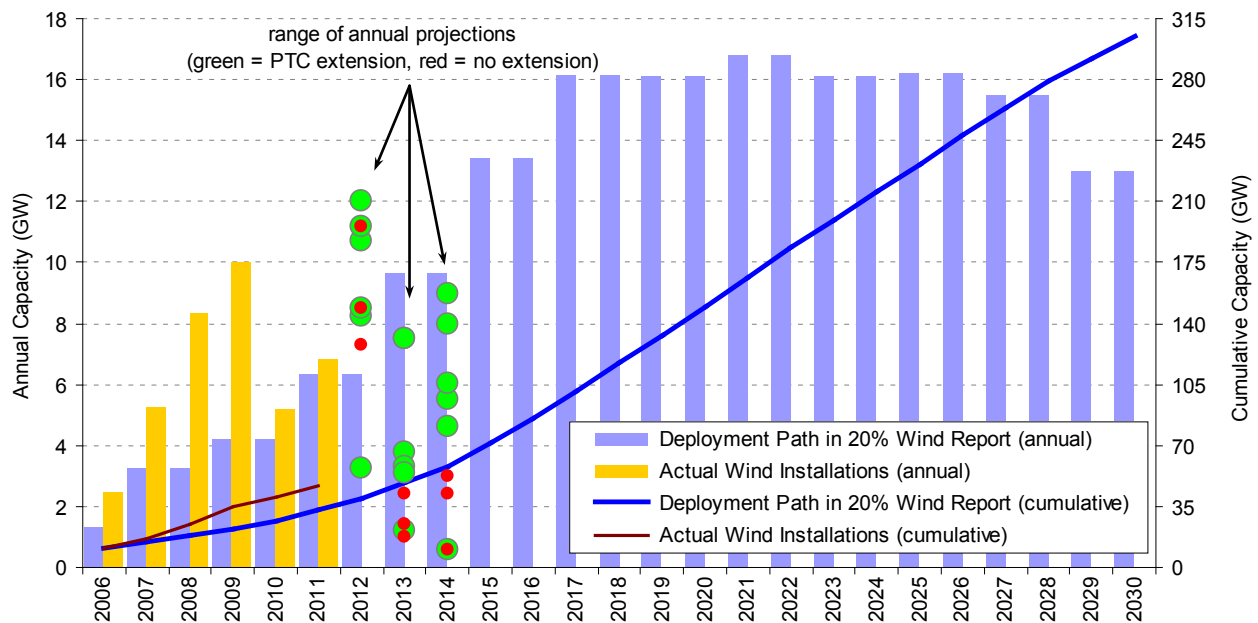
Given this challenging, but also uncertain, outlook, it is not surprising that forecasts for 2013 and beyond – as shown in Table 6 – span a particularly wide range, depending in large measure on assumptions about the possible extension of federal incentives. In a scenario with no PTC extension, for example, Bloomberg NEF (2012a) predicts a precipitous drop in wind power installations, with perhaps only 1,000 MW installed in 2013. BTM (2012), on the other hand, presumably assumes an extension of federal support, leading to relatively stable wind power additions from 2012 to 2014. Even with a PTC extension, however, most predictions are for more-modest wind power additions in the near term as the development pipeline takes time to recharge and considering the other challenges impacting the wind industry; this may be especially true if a longer term extension is achieved, as industry participants will then not need to rush to meet yet-another near-term expiration threat.

Regardless of future uncertainties, wind power capacity additions over the past several years, as well as the additions predicted for 2012, have put the United States on a trajectory that may lead to 20% of the nation's electricity demand coming from wind energy by 2030 (see Figure 41). In May 2008, the U.S. Department of Energy, in collaboration with its national laboratories, the wind power industry, and others, published a report that analyzed the technical and economic feasibility of achieving 20% wind energy penetration by 2030 (DOE 2008). In addition to finding no insurmountable barriers to reaching 20% wind energy penetration, the report also laid out a potential wind power deployment path that started at 3.3 GW/year in 2007, increasing to 4.2 GW/year by 2009, 6.4 GW/year by 2011, 9.6 GW/year by 2013, 13.4 GW/year by 2015, and roughly 16 GW/year by 2017 and thereafter, yielding cumulative wind power capacity of 305 GW by 2030. Historical growth over the last six years puts the United States on a trajectory exceeding this deployment path, a trend that is anticipated to continue in 2012. Nonetheless, all of the projections for annual capacity additions in 2013 and 2014 – even those that assume PTC extension (as denoted by the green, rather than red, circles in Figure 41) – fall short of the annual growth envisioned in the 20% wind energy report for those years, suggesting that there is a very-real risk that the market will not grow rapidly enough to maintain a long-term trajectory consistent with a 20% wind energy penetration level by 2030.

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<sup>83</sup> Utilities have signed numerous PPAs with projects expecting 2012 online dates – in some cases for more wind energy than is strictly needed to comply with near-term RPS targets – while PPA availability for projects to be built in 2013 and later has all but dried up as purchasers await federal tax clarity (Bloomberg NEF 2012c).





Source: DOE (20% wind scenario); AWEA (historical additions): Table 6 (projected additions)

**Figure 41. Wind Power Capacity Growth: 20% Wind Report, Actual Installations, Projected Growth**

Ramping up to the annual installation rate of roughly 16 GW per year needed for wind power to contribute 20% of the nation's electricity by 2030, and maintaining that rate for a decade, would be a challenging task. This rate of deployment has not yet been witnessed in the U.S. market, and is not expected to be achieved in the near term, due to uncertainty in federal policy towards wind energy after 2012, market expectations for continued low natural gas prices, slow growth in electricity demand, and uncertainty surrounding future environmental regulations to limit carbon emissions.

In addition to stable long-term promotional policies, the DOE (2008) report suggests four other areas where supportive actions may be needed in order to reach such annual installation rates. First, the nation will need to invest in significant amounts of new transmission infrastructure designed to access remote wind resources. Second, to more-effectively integrate wind power into electricity markets, larger power control regions, better wind forecasting, and increased investment in fast-responding generating plants will be required. Third, siting and permitting procedures will need to be designed to allow wind power developers to identify appropriate project locations and move from wind resource prospecting to construction quickly. Finally, enhanced research and development efforts in both the public and private sector will be required to lower the cost of offshore wind power, and incrementally improve conventional land-based wind energy technology.



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

### ***Installation Trends***

Data on wind power additions in the United States come from AWEA, though methodological differences noted throughout this report result in some discrepancies in the data presented here relative to AWEA (2012a). Annual wind power capital investment estimates derive from multiplying these wind power capacity data by weighted-average capital cost data, provided elsewhere in the report. Data on non-wind electric capacity additions come primarily from EIA (for years prior to 2011) and Ventyx's Velocity database (for 2011), except that solar data come from the Interstate Renewable Energy Council (IREC) and SEIA/GTM (Solar Energy Industries Association / GTM Research). Information on offshore wind power development activity in the United States was compiled by Navigant.

Global cumulative (and 2011 annual) wind power capacity data come from BTM (2012), but are revised 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 primarily from BTM (2012), 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 consumption in 2009 and earlier, escalated at a country-specific growth rate (assumed to be the same as the rate of growth from 2007 through 2009) to estimate 2010-2012 consumption (these data come from EIA).

The wind power project installation map was created by NREL, based in part on AWEA's database of projects and in part on data from Ventyx's Velocity database on the location of individual projects. Estimated wind energy as a percentage contribution to statewide electricity generation is based on AWEA installed capacity data for the end of 2011 and the underlying wind power project performance data presented in this report. Where necessary, judgment was used to estimate state-specific capacity factors. The resulting state wind generation is then divided by in-state total electricity generation in 2011, based on EIA data. Actual state-level wind energy penetration figures for 2011 are derived from EIA data.

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 at the end of 2011, but that had not yet been built, are included. Suspended projects are not included in these listings. Data on projects that are in the nearer-term development pipeline come from Ventyx (2012) and other sources.

### ***Industry Trends***

Turbine manufacturer market share and average turbine size are derived from the AWEA wind power project database, with some processing by Berkeley Lab. Information on turbine hub heights and rotor diameters were compiled by Berkeley Lab based on information provided by turbine manufacturers, standard turbine specifications, Federal Aviation Administration data, web searches, and other sources.



Information on wind turbine and component manufacturing come from NREL, AWEA, and Berkeley Lab, based on a review of press reports, personal communications, and other sources. Data on U.S. nacelle assembly capacity came from Bloomberg NEF (2012a). The listings of manufacturing and supply chain facilities are not intended to be exhaustive. Data on aggregate U.S. imports and exports of wind power equipment come primarily from the U.S. International Trade Commission (USITC), and can be obtained from the USITC's DataWeb (<http://dataweb.usitc.gov/>).

Information on wind power financing trends was compiled by Berkeley Lab. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of the AWEA project database.

### **Cost, Performance and Pricing Trends**

Wind turbine transaction prices were compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission filings. In part because wind turbine transactions vary in the services offered, a good deal of intra-year variability in the cost data is apparent.

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 power projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include: EIA Form 412, FERC Form 1, various Securities and Exchange Commission filings, various filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, DOE/EPRI's Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009-2011 projects, data from the Section 1603 Treasury Grant program were used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not equally credible, little emphasis should be placed on individual project-level data; instead, it is the trends in those underlying data that offer insight. Only wind power cost data from the contiguous lower-48 states are included.

Wind project operations and maintenance costs come primarily from two sources: EIA Form 412 data from 2001-2003 for private power projects and projects owned by POU's, and FERC Form 1 data for IOU-owned projects. Some data points are suppressed in the figures to protect data confidentiality.

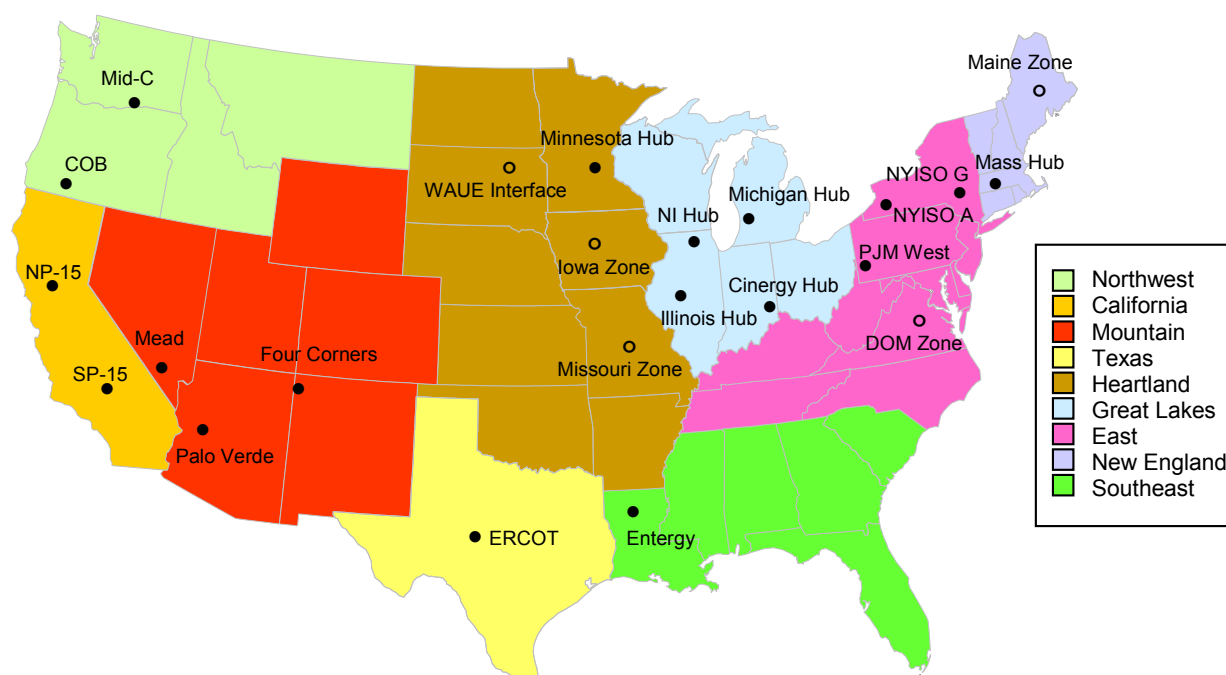
Wind power project performance data are compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT (for Texas), MISO (for the Midwest), Xcel Energy (for its Northern States Power, Public Service Company of Colorado, and Southwestern Public Service Company subsidiaries), and from BPA (for the Northwest).

The following procedure was used to estimate the quality of the wind resource in which wind projects are located. First, the location of individual wind turbines and the year in which those



turbines were installed were identified using FAA Digital Obstacle (i.e., obstruction) files (accessed via Ventyx' Intelligent Map) and LBNL data on individual wind projects. Second, NREL used data from AWS Truepower – specifically, gross capacity factor estimates with a 200-meter resolution – to estimate the quality of the local wind resource at an 80 meter hub height for each of those turbines. These gross capacity factors are derived from average mapped 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). Third, using the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998-99 period as the benchmark, and assigning that period an index value of 100 percent, comparative percentage changes in average wind resource quality for turbines installed after 1998-99 are calculated. Not all turbines could be mapped by LBNL for this purpose: the final sample included 25,413 turbines totaling 41,230 MW of capacity installed from 1998 through 2011, or 90% of all wind power capacity installed in the continental United States over that period.

Wind power 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 power purchase agreements. Wholesale electricity price data were compiled by Berkeley Lab from the IntercontinentalExchange (ICE) as well as Ventyx's Velocity database (which itself derives wholesale price data from the ICE and the various ISOs). Earlier years' wholesale electricity price data come from FERC (2007, 2005). Pricing hubs included in the analysis, and within each region, are identified in the map below. REC price data were compiled by Berkeley Lab based on information provided by Evolution Markets and Spectron.



Note: The pricing nodes represented by an open, rather than closed, bullet do not have complete pricing history back through 2003.

### Map of Regions and Wholesale Electricity Price Hubs Used in Analysis



### ***Policy and Market Drivers***

The wind energy integration, transmission, and policy sections were written by staff at Berkeley Lab and Exeter Associates, based on publicly available information.

### ***Future Outlook***

This section was written by staff at Berkeley Lab, based largely on publicly available information.



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## Wind Energy Web Sites

**U.S. Department of Energy Wind Program**  
[wind.energy.gov](http://wind.energy.gov)

**Wind Powering America**  
[www.windpoweringamerica.gov](http://www.windpoweringamerica.gov)

**Lawrence Berkeley National Laboratory**  
<http://eetd.lbl.gov/EA/EMP/re-pubs.html>

**National Renewable Energy Laboratory**  
[www.nrel.gov/wind](http://www.nrel.gov/wind)

**Sandia National Laboratories**  
[www.sandia.gov/wind](http://www.sandia.gov/wind)

**Pacific Northwest National Laboratory**  
[www.pnl.gov](http://www.pnl.gov)

**Lawrence Livermore National Laboratory**  
[www.llnl.gov](http://www.llnl.gov)

**Oak Ridge National Laboratory**  
[www.ornl.gov](http://www.ornl.gov)

**Argonne National Laboratory**  
[www.anl.gov](http://www.anl.gov)

**Idaho National Laboratory**  
[www.inl.gov](http://www.inl.gov)

**Ames Laboratory**  
[www.ameslab.gov](http://www.ameslab.gov)

**Los Alamos National Laboratory**  
[www.lanl.gov](http://www.lanl.gov)

**Savannah River National Laboratory**  
<http://srnl.doe.gov>

**Brookhaven National Laboratory**  
[www.bnl.gov](http://www.bnl.gov)

**American Wind Energy Association**  
[www.awea.org](http://www.awea.org)

**Database of State Incentives for  
Renewables & Efficiency**  
[www.dsireusa.org](http://www.dsireusa.org)

**International Energy Agency – Wind Agreement**  
[www.ieawind.org](http://www.ieawind.org)

**National Wind Coordinating Collaborative**  
[www.nationalwind.org](http://www.nationalwind.org)

**Utility Wind Integration Group**  
[www.uwig.org](http://www.uwig.org)

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## On the Cover

The 3-MW Alstom ECO 100 wind turbine installed at the National Renewable Energy Laboratory's National Wind Technology Center near Boulder, Colorado, is part of a long-term research and development agreement between NREL and Alstom.

*Photo by Dennis Schroeder, NREL/PIX 18891*

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