Wind Vision:

A New Era for Wind Power in the United States

U.S. DEPARTMENT OF ENERGY

This page is intentionally left blank

Table of Contents

This page is intentionally left blank

This page is intentionally left blank

Appendix A: Glossary

Term	Definition
Advanced stage of development	An offshore wind project is in an advanced stage of development when it has achieved at least one of the following: (1) received approval for an interim limited lease or a commercial lease, (2) conducted baseline or geophysical studies at the proposed site with a meteorological tower erected and collecting data, boreholes drilled, or geological and geophysical data acquisition system in use, or (3) signed a power purchase agreement with a power off-taker.
Balance of system	Infrastructure elements of a wind plant other than the turbines; e.g., substation hardware, cabling, wiring, access roads, and crane pads.
Balancing area (balancing authority area)	A predefined area within an interconnected transmission grid where a utility, an independent system operator, or a transmission system operator must balance load (electrical demand) and electrical generation, while maintaining system reliability and continuing interchanges with adjoining balancing areas.
Baseline Scenario	The *Baseline Scenario* applies a constraint of no additional wind capacity after 2013 (wind capacity fixed at 61 GW through 2050). It is the primary reference case to support comparisons of costs, benefits, and impacts against the *Study Scenario.*
Blade pitch regulation or control	Changing the orientation of the blades to vary a wind turbine's output.
Business-as-Usual (BAU) Scenario	The *Business-as-Usual (BAU) Scenario* does not prescribe a wind future trajectory, but instead models wind deployment under policy conditions current on January 1, 2014. The *BAU Scenario* uses demand and cost inputs from the Energy Information Administration's *Annual Energy Outlook 2014.*
Capacity	The amount of delivered or required electrical power, for which manufacturers rate a generator, turbine, transformer, transmission circuit, station, or system.
Capacity factor	A measure of the productivity of a power plant, calculated as the amount of energy that the power plant produces over a set time period, divided by the amount of energy that would have been produced if the plant had been running at full capacity during that same time interval. Most wind power plants operate at a capacity factor of 25% to 40%.
Capacity value	The probability of a power plant being available during high-demand situations.
Capital costs	The total investment cost for a power plant, including balance of system costs.
Carbon dioxide (CO_2)	A colorless, odorless, noncombustible gas present in the atmosphere. It is formed by the combustion of carbon and carbon compounds (such as fossil fuels and biomass); by respiration, which is a slow form of combustion in animals and plants; and by the gradual oxidation of organic matter in the soil. CO_2 is a greenhouse gas that contributes to global climate change.

Term	Definition
Competitive Renewable Energy Zones (CREZ)	A mechanism of the renewable portfolio standard in Texas designed to ensure that the electricity grid is extended to prime wind energy areas. The designation of these areas directs the Electric Reliability Council of Texas to develop plans for transmission lines to these areas that will connect them with the grid. See also “Electric Reliability Council of Texas” and “renewable portfolio standard.”
Complex flow	The wind conditions and dynamics—and how these interact with wind turbine arrays in terms of structural load and power production. The spatially and temporally dynamic interactions are known as “complex flow.”
Condition-based monitoring	Sensors that measure key operating characteristics of gearboxes, generators, blades, and related equipment to alert operators when nonstandard operating conditions occur. It is a major component of predictive maintenance.
Conventional fuel	Coal, oil, and natural gas (fossil fuels); also nuclear fuel.
Curtailment	When the dispatch order from the transmission system operator to the wind plant is to reduce or stop generation, even though the wind resource is available.
Direct-drive generators	Generators that eliminate the need for a gearbox.
Dispatch	The physical inclusion of a generator’s output onto the transmission grid by an authorized scheduling utility; the real-time centralized control of the on-line generation fleet to reliably and economically serve net system load.
Distributed wind/ generation	Wind turbines that are connected either physically or virtually on the customer side of the meter to offset all or a portion of the energy consumption at or near the location of the project, or that are connected directly to the local grid to support grid operations.
Distribution	The process of distributing electricity. Distribution usually refers to the series of power poles, wires, and transformers that run between a high-voltage transmission substation and a customer’s point of connection.
Drive train	Converts a rotor’s rotational power into electrical power, generally includes a main shaft, gearbox (unless a direct-drive configuration is used), generator, and power converter. It is part of the nacelle assembly.
Economically efficient	Denotes the most cost-effective way of achieving the goal of operating the power system reliability with a given level of wind energy.
Electricity generation	The process of producing electricity by transforming other forms or sources of energy into electrical energy. Electricity is measured in kilowatt-hours.
Energy	The capacity for work. Energy can be converted into different forms, but the total amount of energy remains the same.

Term	Definition
ERCOT (Electric Reliability Council of Texas)	One of the 10 regional reliability councils of the North American Electric Reliability Council, ERCOT is a membership-based 501(c)(6) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. See also "North American Electric Reliability Council."
Feathering the blades	Changing the orientation of the blades to vary a wind turbine's output.
Flexibility	The ability of the power system to respond to variations in supply and/or demand.
Full-time employee (FTE)	An FTE job is the equivalent of one person working full time (40 hours per week) for one year or two people working half time for one year.
Gearbox	A system of gears in a protective casing used to increase or decrease shaft rotational speed.
Generator	A device for converting mechanical energy to electrical energy.
Gigawatt (GW)	A unit of power, which is instantaneous capability, equal to one million kilowatts.
Gigawatt-hour (GWh)	A unit or measure of electricity supply or consumption of one million kilowatts over a period of one hour.
Global warming	A term used to describe the increase in average global temperatures caused by the greenhouse effect.
Greenhouse gases (GHGs)	Gases such as water vapor, CO_2, methane, and low-level ozone that are transparent to solar radiation, but opaque to long-wave radiation. These gases contribute to the greenhouse effect.
Grid	A common term that refers to an electricity transmission and distribution system. See also "power grid" and "utility grid."
Hub height and tower height	Hub height and tower height are generally synonymous. The tips of the rotor blades extend above the hub height by the length of the blades, reaching an even better wind resource.
Impacts	The significant or major effects caused by wind power development. They can be positive (benefits), negative (costs), or neutral.
Inflow	The wind encountering the rotor, including many characteristics (velocity, angle, etc.).
Instantaneous penetration	The ratio of the wind plant output to load at a specific point in time, or over a short period of time.
Investment tax credit (ITC)	A tax credit that can be applied for the purchase of equipment, such as renewable energy systems.

Term	Definition
Kilowatt (kW)	A standard unit of electrical power, which is instantaneous capability, equal to 1,000 watts.
Kilowatt-hour (kWh)	A unit or measure of electricity supply or consumption of 1,000 watts over a period of one hour.
Levelized cost of electricity (LCOE)	The present value of total costs divided by the present value of energy production over a defined duration.
Lidar or Doppler lidar	Uses atmospheric scattering of beams of laser light to measure profiles of the wind at a distance.
Load (electricity)	The amount of electrical power delivered or required at any specific point or points on a system. The requirement originates at the consumer's energy-consuming equipment.
Megawatt (MW)	The standard measure of electrical power plant generating capacity. One megawatt is equal to 1,000 kilowatts or 1 million watts.
Megawatt-hour (MWh)	A unit of energy or work equal to 1, 000 kilowatt-hours or 1 million watt-hours.
Met tower	A meteorological tower erected to verify the wind resource found over a certain area of land.
Metric ton (tonne)	1,000 kilograms or approximately 2,204.6 lb.
Micro-siting	Careful placement of turbines within a wind project.
Modified Accelerated Cost Recovery System (MACRS)	A U.S. federal system through which businesses can recover investments in certain property through depreciation deductions over an abbreviated asset lifetime. For solar, wind, and geothermal property placed in service after 1986, the current MACRS property class is five years. With the passage of the Energy Policy Act of 2005, fuel cells, micro turbines, and solar-hybrid lighting technologies became classified as five-year property as well.
Nacelle assembly	The protective shell (nacelle) on top of the tower and its contents: generator, gearbox, and control systems that make up a wind turbine.
Nitrogen oxides (NO_x)	The products of all combustion processes formed by the combination of nitrogen and oxygen. NO_x and sulfur dioxide (SO_2) are the two primary causes of acid rain.
Particulate matter	Air pollutant particulate matter (PM); coarse particles (PM_{10}) and fine particles ($PM_{2.5}$).
Penetration of wind energy	The share of total wind generation relative to total end-use energy demand, expressed as a percentage.
Permanent magnet generators	Synchronous generators with permanent magnets often based on rare-earth materials.

Term	Definition
Power	The rate of production or consumption of energy.
Power grid	A common term that refers to an electricity transmission and distribution system. See also "utility grid."
Power purchase agreement (PPA)	A long-term agreement to buy power from a company that produces electricity.
Power quality	Stability of frequency and voltage and lack of electrical noise on the power grid.
Production tax credit (PTC)	A U.S. federal, per-kilowatt-hour tax credit for electricity generated by qualified energy resources. Originally enacted as part of the Energy Policy Act of 1992, the credit expired at the end of 2001, was extended in March 2002, expired at the end of 2003, was renewed on October 4, 2004, extended through December 31, 2008, extended through 2009, extended through 2012, expired December 2012, extended for projects starting construction prior to January 1, 2014.
Public Utility Commission (PUC)	A governing body that regulates the rates and services of a utility.
Ramp rate (ramping)	The rate at which load on a power plant is increased or decreased. The rate of change in output from a power plant.
Rated wind speed	The wind speed at which the amount of electrical power delivered by a wind turbine equals the manufacturer's rating of the turbine.
Renewable energy	Energy derived from resources that are regenerative or that cannot be depleted. Types of renewable energy resources include wind, solar, biomass, geothermal, and moving water.
Renewable energy credit (REC) or certificate	A mechanism created by a state statute or regulatory action to make it easier to track and trade renewable energy. A single REC represents a tradable credit for each unit of energy produced from qualified renewable energy facilities, thus separating the renewable energy's environmental attributes from its value as a commodity unit of energy. Under a REC regime, each qualified renewable energy producer has two income streams—one from the sale of the energy produced, and one from the sale of the RECs. The RECs can be sold and traded and their owners can legally claim to have purchased renewable energy.
Renewable portfolio standard (RPS)	Under such a standard, a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources (e.g., 1% of electric sales must be from renewable energy in the year 20xx). An RPS most commonly refers to electricity sales measured in megawatt-hours, as opposed to electrical capacity measured in megawatts.
Reserve generating capacity	Reserve generating capacity is equipment that is ready to add power to the grid to compensate for increased load or reduced generation from other units (such as wind or solar).

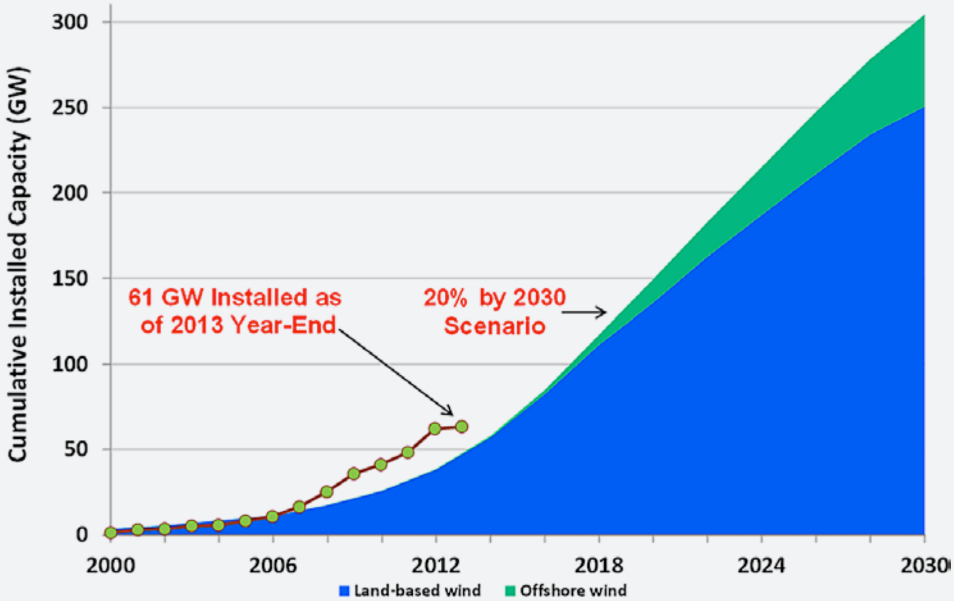
Term	Definition
Rotor	The blades and other rotating components of a wind turbine.
Solar energy	Electromagnetic energy transmitted from the sun (solar radiation).
Specific power	The ratio of generator nameplate capacity (in watts) to the rotor-swept area (in meters^2).
Spinning reserve	Generation that is on-line but not part of the load and can respond within 10 minutes to compensate for generation or transmission outages.
Sulfur dioxide (SO_2)	A colorless gas released as a by-product of combusted fossil fuels containing sulfur. The two primary sources of acid rain are SO_2 and NO_x.
Synoptic scale	The spatial scale of the migratory high- and low-pressure systems of the lower troposphere, with wavelengths of 1,000-2,500 km.
Turbine	A term used for a wind energy conversion device that produces electricity. See also "wind turbine."
Turbulence	A swirling motion of the atmosphere that interrupts the flow of wind.
Utility grid	A common term that refers to an electricity transmission and distribution system. See also "power grid."
Utility-scale wind	Turbines and projects sized at 1 MW or greater.
Variable-speed wind turbines	Turbines in which the rotor speed increases and decreases with changing wind speeds. Sophisticated power control systems ensure that their power maintains a constant frequency, compatible with the grid.
Volt (V)	A unit of electrical force.
Voltage	The amount of electromotive force, measured in volts, between two points.
Wake	Intra-plant wind flows altered by the presence of other wind turbines or topographical features.
watt (W)	A unit of power.
watt-hour (Wh)	A unit of electrical consumption of one watt over the period of one hour.
Wind	Moving air. The wind's movement is caused by the sun's heat, the earth, and the oceans, which force air to rise and fall in cycles.
Wind energy	Energy generated by using a wind turbine to convert the mechanical energy of the wind into electrical energy. See also "wind power."
Wind generator	A wind energy conversion system designed to produce electricity.

Term	Definition
Wind plant, windplant, or wind power plant	Arrays of wind turbines and other components including foundations, towers, and underground cables to collect the power from the individual turbines, step-up transformers, and switchgear connected through a single point to the transmission grid. A group of wind turbines interconnected to a common utility system. Also known as a wind farm.
Wind power	Power generated by using a wind turbine to convert the mechanical power of the wind into electrical power. See also "wind energy."
Wind power class	A scale for classifying wind power density. The seven wind power classes range from 1 (lowest wind power density) to 7 (highest wind power density). In general, sites with a wind power class rating of 4 or higher are now preferred for large-scale wind plants.
Wind power density	Measured in watts per square meter, indicates the amount of wind energy available at a site for conversion by a wind turbine.
Wind resource assessment	The process of characterizing the wind resource and its energy potential for a specific site or geographical area.
Wind shear	Different wind speeds at different heights mean the blades nearest to the ground level experience different wind than those at the top of blade travel.
Wind speed	The rate of flow of wind when it blows undisturbed by obstacles.
Wind turbine	A term used for a device that converts wind energy to electricity.
Wind turbine rated capacity	The amount of power a wind turbine can produce at its rated wind speed.
Wind Vision Study Scenario	The *Wind Vision Study Scenario* applies a trajectory of 10% of the nation's end-use demand served by wind by 2020, 20% by 2030, and 35% by 2050. It is the primary analysis scenario for which costs, benefits, and impacts are assessed.

This page is intentionally left blank

Appendix B: Summary of *20% Wind Energy by 2030*

The *20% Wind Energy by 2030* report [1] examined one scenario for supplying 20% of the nation's electricity from wind energy by 2030 (Figure B-1). The report contrasted the 20% Wind Energy by 2030 scenario with one in which no new wind was installed. These scenarios were not a prediction of the future, but provided a basis for estimating prospective impacts in terms of costs and benefits to the nation. The assessment was the work of more than 100 individuals from major stakeholder sectors (government, industry, electric utilities, and non-governmental organizations), conducted over a two-year period from 2006–2008. The study analyzed wind energy's potential contributions to economic prosperity, environmental sustainability, and energy security.



Sources: American Wind Energy Association 2014 [2]; DOE 2008 [1]

Figure B–1. The 20% Wind Energy by 2030 installation scenario and actual installation history since 2000

Primary Assumptions and Findings of the 20% Wind Energy by 2030 Scenario

Electricity demand growth, fuel prices, and financing assumptions in the *20% Wind Energy by 2030* report were based on the Energy Information Administration's 2007 *Annual Energy Outlook* [3]. Specifically, U.S. electricity consumption was projected to increase by 39% over consumption in 2005, to 5,800 terawatt-hours per year in 2030. No major breakthroughs in wind technology were assumed. By 2030, wind turbine energy production was projected to increase by about 15% on a relative basis, and wind project costs were assumed to drop by about 10%.

The study found that it would take about 300 gigawatts of wind generating capacity to produce 20% of U.S. electricity in 2030. It concluded that ample, affordable, and accessible wind resources are available throughout the country and in coastal waters to support this amount of wind generation. Substantial reductions in greenhouse gas emissions would result from this amount of wind energy, as would significant water savings. Based on studies and experience through 2007, power system cost impacts arising from the variable and uncertain nature of wind were projected to be modest. Ensuring the availability of sufficient electrical transmission capability, however, was identified as a major challenge.

Annual wind installation rates would need to increase to about 15–17 gigawatts per year after 2016 to reach 300 gigawatts by 2030. This was found to be well within the possible manufacturing capability of the domestic industry. No limitations from the availability of raw materials or financing were identified. An estimate of the gross workforce needed to support realization of the 20% Wind Energy by 2030 scenario was included in the report, as well as an estimate of the indirect and induced jobs that would occur in communities with wind manufacturing and deployment. The economic impacts to local communities, in the form of lease payments to landowners and property taxes, were also quantified. These estimated revenues arising from the 20% Wind Energy by 2030 scenario would reach about $2 billion per year in 2030.

Costs of the 20% Wind Energy by 2030 Scenario

The study estimated that, no matter how the future unfolds, the electric power sector was likely to invest more than $2 trillion in generation, transmission and distribution infrastructure from 2007–2030, expressed as a 2007 net present value. It also estimated that the cost of the 20% Wind Energy by 2030 scenario (expressed as a 2007 net present value), would be $43 billion greater than the cost of a scenario in which no new wind was installed after 2006. This is a difference of 2% in relative terms, which would lead to an increase in the average household electricity bill of about 50¢ per month.

Impacts of the 20% Wind Energy by 2030 Scenario

The study also estimated the impacts of providing 20% of the nation's electricity from wind, most of which would be viewed as desirable from the standpoint of those pursuing a clean energy future for the nation. Coal consumption in the electric sector would be reduced by 18%, and construction of 80 gigawatts of new coal plants could be avoided. Natural gas consumption in the U.S. electric sector would be reduced by 50%, corresponding to a reduction in overall domestic natural gas consumption of 11%. Because of natural gas price elasticity, natural gas prices would be reduced relative to the scenario with no new wind capacity. Although not described in *20% Wind Energy by 2030*, the impact on consumer prices for natural gas was estimated by the project analysts and is described in a related report from the National Renewable Energy Laboratory [4]. That report estimated related consumer benefits from *20% Wind Energy by 2030* ranging from $86–214 billion. These savings would result in a corresponding revenue loss to natural gas producers.

Under the 20% Wind Energy by 2030 scenario, greenhouse gas emissions would be substantially reduced. Carbon dioxide, or CO_2, emissions from the electric power sector would drop by 825 million metric tonnes annually in 2030. This drop represents about one-third of that needed within the nation's power sector to support the International Energy Agency's worldwide goal for greenhouse gas emissions in 2050 to be 80% below the level in 2005. These reductions, if monetized at $18 per metric tonne of CO_2, correspond to savings in regulatory costs of about $98 billion [3]. Although not quantified in *20% Wind Energy by 2030*, reductions in atmospheric criteria pollutants and heavy metals regulated by the U.S. Environmental Protection Agency, including mercury, may be realized. Displacing energy generation from conventional electric power sources with wind power would also reduce pollution from extracting and transporting fossil fuels for the power sector.

The 20% Wind Energy by 2030 scenario also projected avoided consumption of four trillion gallons of water through 2030; with electric-power-sector water consumption reduced 17% by 2030. Nearly one-third of this reduction would occur in the relatively arid western states.

The deployment of 300 gigawatts of wind power would impact land area roughly equivalent to the size of West Virginia. Only about 4% of that land would be occupied by turbines, access roads, and electricity collection and interconnection equipment. For perspective, this area occupied by turbines, roads, and equipment would be roughly equivalent to that occupied by the U.S. Interstate Highway System (estimated to comprise about 1% of the nation's roads), also equivalent to half the area of the city of Anchorage, Alaska.

The workforce needed to support the realization of the 20% Wind Energy by 2030 scenario was estimated in the report. It was projected that 46 states would have wind deployment in excess of 100 megawatts, with more than 20 of these expected to have more than five gigawatts. Most states were projected to have manufacturing facilities directly supporting the wind equipment supply chain. The study estimated that, over the decade from 2020–2030, about 180,000 jobs would be directly supported by the wind industry. This includes jobs in manufacturing, construction and operations. An additional 100,000 indirect jobs would be supported at suppliers of components and services needed to support manufacturing, construction and operations (e.g., materials like steel and concrete, electrical components, and financial services).

Wind power plants also produce local revenue streams that can be important to communities, including lease payments to landowners and property taxes. Estimated revenues of these types arising from the 20% Wind Energy by 2030 scenario would reach about $2 billion per year in 2030.

Primary Challenges of the 20% Wind Energy by 2030 Scenario

The 2008 report identifies several significant challenges to achieving the 20% Wind Energy by 2030 scenario. Increased investment in electrical transmission would be needed, both to access remote regions with good wind resources and to relieve congestion on existing transmission infrastructure. Siting, permitting and financing new transmission is generally a difficult process, regardless of the intended use of the new lines. Developing the transmission needed to support wind power expansion could present a major challenge.

Accommodating wind's natural variability and uncertainty would also require increased flexibility in the electric power system. While substantial related progress has already been made in this area, continued expansion of both supply and demand flexibility would be needed.

The siting and permitting of wind power generation could also be challenging. In some cases, environmental concerns, such as visual and sound impacts and potential impacts on wildlife, have led to local opposition. The 20% Wind Energy by 2030 study recognized that these concerns need to be addressed with sensitivity and sincerity.

In addition, achieving the 20% Wind Energy by 2030 scenario with its estimated costs and benefits would require steady, continued advancement of wind technology. As indicated above, however, no technology breakthroughs would be required.

Finally, since the cost of the 20% Wind Energy by 2030 scenario exceeded the cost of no new wind, some policy measure would be needed to encourage continued wind growth.

Conclusion

The assessment overall concluded that achievement of the 20% Wind Energy by 2030 scenario was feasible. Although significant challenges would need to be overcome, no major barrier was identified. On balance, the impacts of achieving the scenario would be primarily positive and beneficial to the nation.

Appendix B References

[1] *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*. DOE/GO-102008-2567. Washington, DC: U.S. Department of Energy, 2008. Accessed Dec. 13, 2014: *http://energy.gov/eere/wind/20-wind-energy-2030-increasing-wind-energys-contribution-us-electricity-supply*.

[2] *AWEA U.S. Wind Industry Annual Market Report.* American Wind Energy Association. Washington, DC: AWEA, 2014a. Accessed Dec. 13, 2014: *http://www.awea.org/AMR2013*.

[3] *Annual Energy Outlook 2007 with Projections to 2030.* DOE/EIA-0383 (2007). Washington, DC: U.S. Department of Energy, Energy Information Administration, 2007. Accessed Feb. 3, 2015: *http://www.eia.gov/oiaf/archive/aeo07/*.

[4] Hand, M.; Blair, N.; Bolinger, M.; Wiser, R.; O'Connell, R.; Hern, T.; Miller, B. "Power System Modeling of 20% Wind-Generated Electricity by 2030." Preprint. Prepared for the Power Engineering Society 2008 General Meeting, July 20–24, 2008. NREL/CP-500-42794. Golden, CO: National Renewable Energy Laboratory, June 2008. Accessed Feb. 2, 2015: *http://www.nrel.gov*.

This page is intentionally left blank

Appendix C: Regulatory Agencies

Various federal agencies have authority over the siting and permitting of wind plants, depending on the specific locations being considered, nearby existing uses, and potential for undesired impacts. The following is a summary list of key federal agencies and their statutory authorities (Stanton 2012):

- **Federal Aviation Administration (FAA):** (a) Determination of No Hazard to Air Navigation; (b) Notice of proposed construction (form FAA 7460-1); (c) Lighting plan; (d) Post construction form (form FAA 7460-2); (e) 49 U.S. Code (U.S.C.) § 44718 (Notice of Proposed Construction for projects near airports or structures 200 ft. above ground level).
- **U.S. Military (Department of Defense [DoD]):** Determination of non-interference with flight operations, military practice areas, and radar.
- **U.S. Army Corps of Engineers:** (a) Clean Water Act: Section 404 (33 U.S.C. § 1251 *et seq.*); —Dredge or fill activities in waterways or wetlands; (b) Rivers and Harbors Act: Section 10 (33 U.S.C. § 403)—Obstructions in navigable waters.
- **Department of Commerce—National Oceanic and Atmospheric Administration:**
  - **National Ocean Service:** For offshore wind—National Marine Sanctuaries Act (16 U.S.C. § 1431 *et seq.*); Coastal Zone Management Act (16 U.S.C. § 1451 *et seq.*).
  - **Fisheries, the National Marine Fisheries Service:** For offshore wind—Threatened and Endangered Species Act, Section 7 (16 U.S.C. § 1531 *et seq.*); Marine Mammal Protection Act (16 U.S.C. § 1362 *et seq.*); Magnuson-Stevens Fisheries Conservation and Management Act (16 U.S.C. § 1801 *et seq.*).
- **The U.S. Department of the Interior**—Leasing and siting lead on federal lands (States 2012):
  - **The Bureau of Ocean Energy Management:** Outer Continental Shelf Lands Act (42 U.S.C. § 1331 *et seq.*). Leasing authority and NEPA lead agency in federal waters.
  - **U.S. Fish and Wildlife Service (USFWS):** Threatened and Endangered Species Act (16 U.S.C. § 1531 et seq.), Section 7; Consultation Migratory Bird Treaty Act (16 U.S.C. § 730); and Bald and Golden Eagle Protection Act (16 U.S.C. § 668).
- **Federal Communications Commission:** Microwave studies.
- **U.S. Environmental Protection Agency:** Spill Prevention, Control and Countermeasures Plan (SPCC Plan, 40 CFR 112). These requirements are often delegated to state or local government agencies (Stanton 2012).
- **Advisory Council on Historic Preservation:** Authority delegated to Tribal and/or State Historic Preservation Offices under the National Historic Preservation Act of 1966 (16 U.S.C. § 470).

The following provides details of some wind-related federal agency activities, including updated processes:

- Before issuing a "Determination of No Hazard to Air Navigation," the FAA conducts aeronautical studies for potential conflicts with navigable airspace and radar, and ensures proper marking and lighting under 49 U.S.C. § 44718.
- DoD created a formal and informal review process for wind energy plants through the DoD Siting Clearinghouse. The FY11 National Defense Authorization Act, Section 358, called for an integrated review process, "Study of Effects of New Construction of Obstructions on Military Installations and Operations." This was followed by establishment of the DoD Siting Clearinghouse and the Mission Compatibility Evaluation Process,[1] which provides the formal process for parallel multi-service review and comment on applications filed pursuant to 49 U.S.C. § 44718. It also provides information on how developers, local officials, or members of the public can engage the Clearinghouse in a non-formal process for early consultation on projects.

1 CFR 2011.

- In March 2012, USFWS issued voluntary "Land-Based Wind Energy Guidelines"[2] to help wind energy project developers avoid and minimize impacts of land-based wind plants on wildlife and their habitats. As a supplement to the guidelines, USFWS issued the "Eagle Conservation Plan Guidance Module 1—Land-based Wind Energy Version 2"[3] in April of 2013. This document provides guidance for adaptive management and conservation practices for siting, construction, and operations of wind energy plants. It also explains the approach for issuing eagle "take" permits—approval to kill or significantly impact an animal—in compliance with the Bald and Golden Eagle Protection Act (16 U.S.C. §§ 668–668c). The USFWS acknowledges community and distributed wind projects separately in its guidelines, and notes that impacts from distributed wind projects can be lower than those from utility-scale development because distributed wind systems are normally installed on previously developed land.
- In October 2011, the USFWS developed "Indiana Bat Section 7 and Section 10 Guidance for Wind Energy Projects"[4] (USFWS 2011b) to help its biologists assess the impacts of wind energy plants on Indiana bats.

2. *http://www.fws.gov/windenergy/docs/weg_final.pdf*
3. *http://www.fws.gov/migratorybirds/Eagle_Conservation_Plan_Guidance-Module%201.pdf*
4. *http://www.fws.gov/midwest/endangered/mammals/inba/pdf/inbaS7and10WindGuidanceFinal26Oct2011.pdf*

This page is intentionally left blank

Appendix D: Wind Project Development Process and Cost

To obtain a current understanding of the development process and associated costs for land-based wind facilities in the United States, the U.S. Department of Energy funded research on wind development starting in 2012. In this study, researchers from U.S. Department of Energy's National Renewable Energy Laboratory interviewed wind developers to gain insight into their decision-making processes, from the early stage of land prospecting through to the construction phase of the plant. Developers also provided direct and indirect cost data for typical U.S. plants. Combined, these data show ranges of costs for different phases of project development; costs related to mitigating issues related to radar, sensitive wildlife species, and public engagement. This work is ongoing and will be published at a later date, but preliminary findings are presented here.

Through interviews with major developers, researchers aggregated data received from wind siting and permitting representatives and created a summary and flow chart of the wind development or "deployment" process. All interview respondents cautioned that there is no "typical" project, but basic project phases can be summarized in a flow chart (Figure D-1).

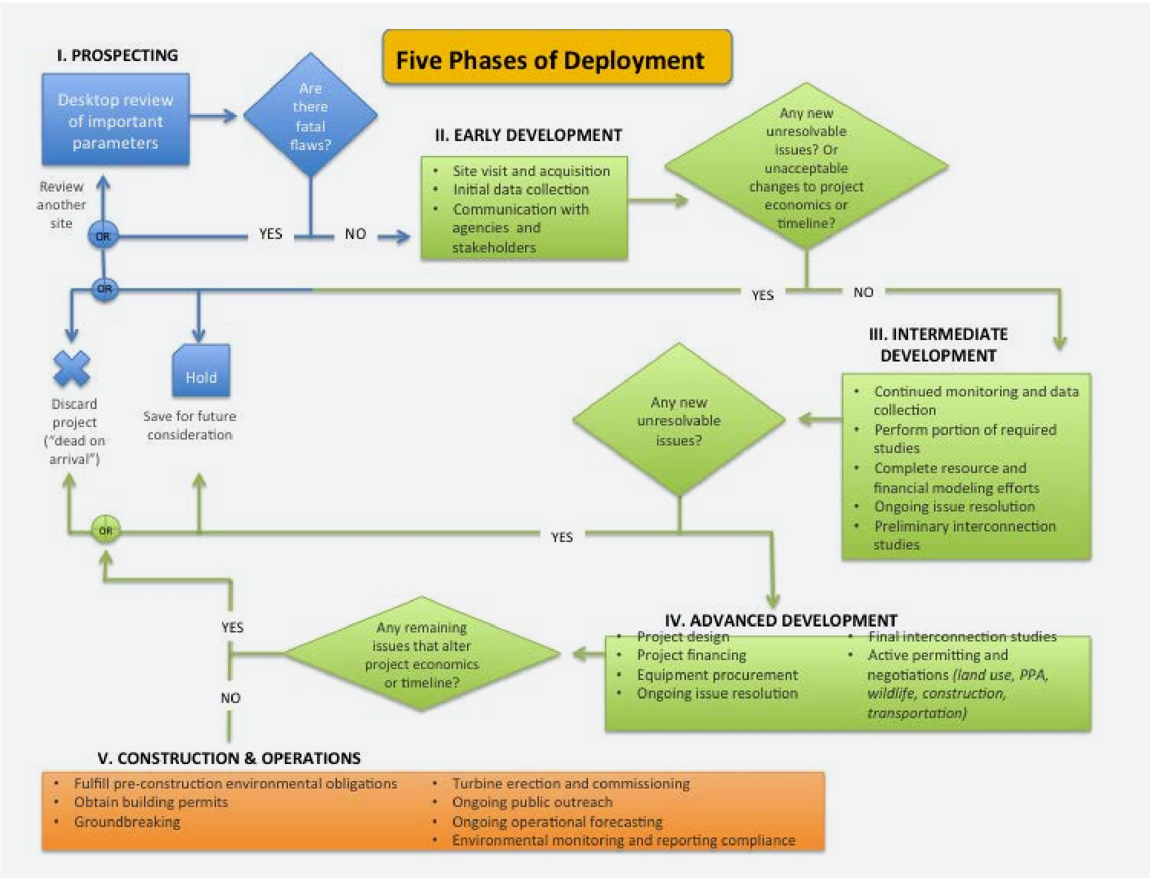


Figure D–1. Wind project development flow chart

Sorting and aggregating the submitted direct cost data allowed researchers at the National Renewable Energy Laboratory to calculate an average plant development cost profile. The range and average of typical costs (rounded to the nearest $100,000) for a 100-megawatt wind plant are shown Table D-1.

Table D–1. Cost Estimates by Cost Category for Approval of a Typical Land-Based 100-Megawatt Wind Power Project

Category	Range of Cost Estimates from Three Firms	Average
Environmental review and permit	$900,000–$2,700,000	$1,600,000
Interconnection	$200,000–$2,000,000	$1,000,000
Land	$300,000–$700,000	$500,000
Land use permitting	$200,000–$1,200,000	$600,000
Navigation and communications	$5,000–$70,000	$30,000
Off-take	$200,000–$2,200,000	$1,000,000
Public relations	$100,000–$400,000	$200,000
Resource evaluation	$400,000	$400,000
Total costs for 100 MW	$4,100,000–$6,500,000	$5,000,000

Note: Totals may not sum due to rounding.

Indirect development costs, such as the cost to redo studies because of project delays or sunk costs from stalled or failed projects, are more difficult to estimate and were instead aggregated by project phase. Indirect issues have a significant impact on the profitability and viability of the industry, given that they may prevent or substantially slow the completion of successful projects. Indirect costs vary widely but can, in some cases, be higher than direct development costs.

Based on reported developer experience, the study estimated a success rate of between 25% and 50%—significant improvements from previous rates in the early 2000s, which developers indicate were closer to 10%. Data from the consulting firm that supported this effort generally confirmed success rates of 25% to 50%. These success rates mean that, with respect to development costs, it takes two to four times the cost of one project to deliver a single, completed and commissioned plant. Focusing on data for existing plants that utilized consulting services (i.e., those that have advanced into early development, at a minimum) between 2009 and 2011, 21% are in service, an additional 32% are in active development, and the remaining 47% are delayed (38%), canceled (8%), or unknown (1%).

Since the early to mid-2000s, the development market has also evolved. The trend used to be a more diversified developer process in which individual, smaller developers would work on projects from start to finish. The market in 2013 had become more liquid, with several large development firms and smaller development organizations working on projects and selling them to even larger organizations that may complete development or flip the project again after the next stage of development has been completed.

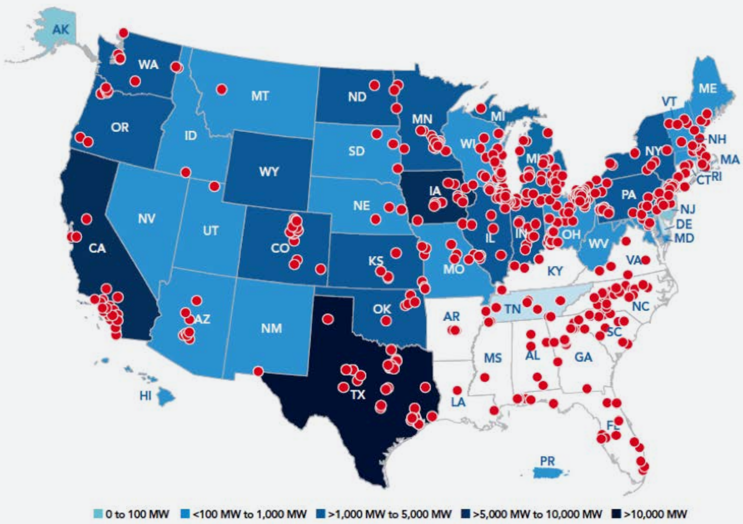
This page is intentionally left blank

Appendix E: Domestic Supply Chain Capacity

This appendix supplements the information in Chapter 2, Section 2.6 about the U.S. supply chain for the wind industry. Information about the U.S. supply chain available through year-end 2013 was used.

E.1 Domestic Manufacturing Capacity

Wind turbine or component manufacturing facilities are spread across the United States (Figure E-1). At least 15 have closed or exited the wind industry since 2012. This includes at least three original equipment manufacturers (Clipper, Nordic, and Nordex), seven tower manufacturers in eight different locations (Aerisyn, Ameron, DMI, Katana, SIAG, Martifer, and Trinity) [1], and other suppliers of key components across the supply chain, such as bearings (Kaydon) and generators (Danotek). More domestic wind manufacturing facilities closed in 2013 than opened. Only one new manufacturing facility opened in 2013, compared to seven in 2012. Unlike previous years, in 2013, no major announcements were made about prospective wind turbine and component manufacturing and assembly facilities [2].



Sources: AWEA 2014 [4]

Figure E-1. Domestic wind energy supply chain facilities 2013

Some U.S. tower manufacturers have shifted capacity to other industries with more stable demand, such as tank car production and electrical tower manufacturing, or to other energy markets such as oil and gas [3]. International suppliers remaining in the industry have shifted focus back to their core markets, generally Europe. Despite the recent extension of the federal production tax credit and new turbine orders in 2013, the lag in demand means that many skilled workers have left the industry and much of the supply is likely to be imported from suppliers with a more global footprint, rather than from reopened domestic capacity. Two major exceptions are tower and blade suppliers, which tend to be more resilient due to the high cost of transporting those components from abroad [1, 4, 5, 6, 7] (Table E-1).

Table E-1. Domestic Manufacturing Capacity

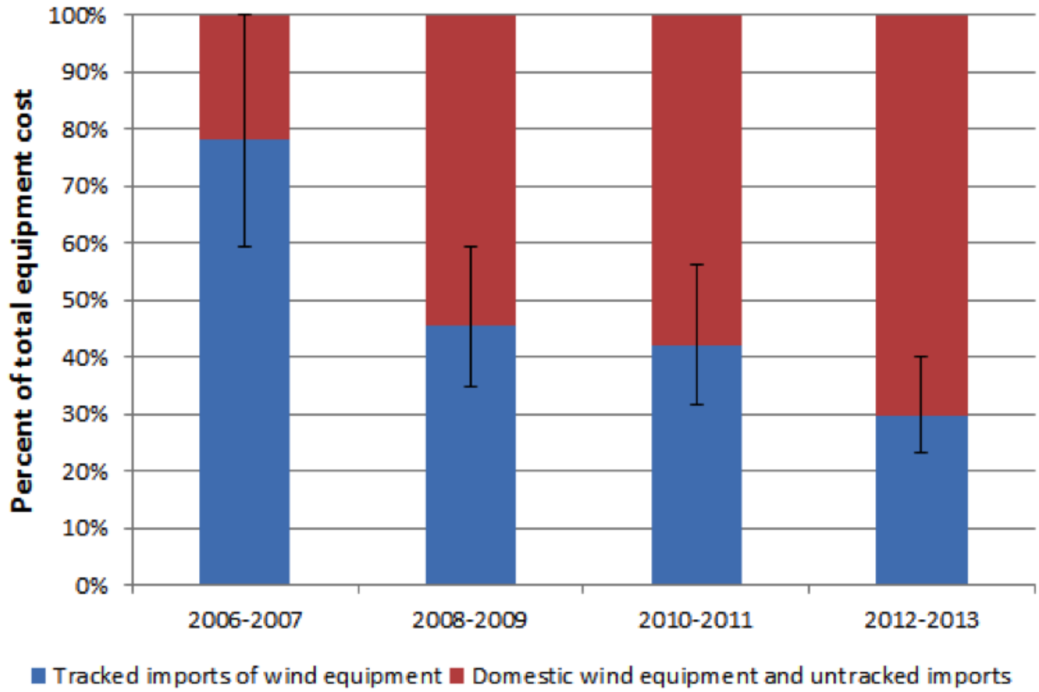
Manufacturing Capacity	2008	2012	2013
Tower facilities	11	12	14
Blade facilities	6	13	12
Nacelle assembly facilities	7	12	9
Nacelle assembly capacity (gigawatts)	6	13	12
Wind manufacturers total	240[a]	550	560
Manufacturing jobs	20,000	25,500	17,400

[a]2009 number

Sources: Wiser et al. 2013 [1]; AWEA 2014 [4]; AWEA 2013 [5]; AWEA 2009 [6]; AWEA, Blue Green Alliance, and United Steelworkers 2010 [7]

E.2 Domestic Content and International Trade

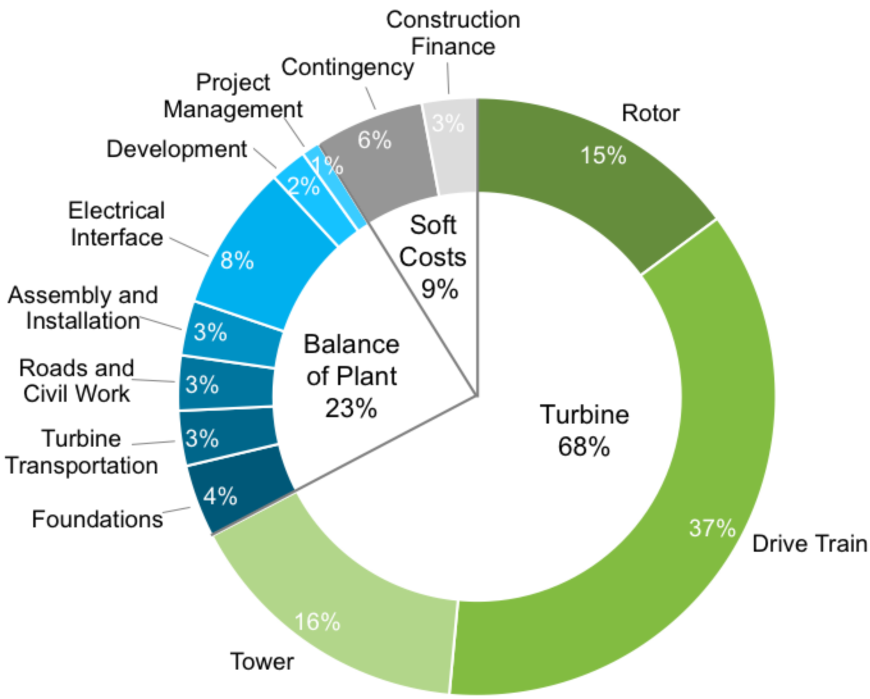
While many components are still being imported, the combined import share of selected wind equipment tracked by trade codes (i.e., blades, towers, generators, gearboxes and complete nacelles), when presented as a fraction of total equipment-related turbine costs, declined from roughly 75% in 2006–2007 to 30% in 2012–2013 (Figure E-2) [1]. Domestic content for some large key components, such as blades and towers, ranged between 50% and 80% from 2012–2013. Domestic content was considerably less than these levels for generators and much of the other equipment internal to the nacelle. However, much of this content is not tracked by trade codes. Exports of wind-powered generating sets from the United States have increased, rising from $16 million in 2007 to $422 million in 2013 [2].



Source: Wiser et al. 2013 [1]

Figure E-2. Estimated wind power equipment imports as a fraction of total turbine cost, focusing on select wind equipment tracked by trade codes

The installation of more than 13 gigawatts of wind capacity in 2012 represents an investment of more than $25 billion. In contrast, installation of 1.09 gigawatts in 2013 required $1.8 billion of investment [2]. Using the National Renewable Energy Laboratory's 1.5-megawatt (MW) land-based reference turbine, investment can be broken into the relative contributions of installed capital cost (Figure E-3) [8].



Source: Tegen et al. 2013 [8]

Figure E-3. Installed capital costs for the land-based wind reference project

Assuming that the majority of balance-of-system costs—such as transportation, foundations, and installation—are inherently for domestic activities, and that towers and rotors historically tend to have a high domestic content, much of the investment in wind energy between 2008 and 2013 has been spent domestically.

E.3 Raw Materials and Energy

Carbon Fiber

As new turbine designs have pushed average rotor diameters for new turbines up from 79 meters (m) in 2007 to 97 m in 2014 [2], more manufacturers are incorporating carbon fiber into blades to meet performance and cost needs. This has more than doubled global use of carbon fiber in wind turbine blades (Table E-2) [9, 10] and made the wind industry the top consumer of carbon fiber [10]. While there is no inherent shortage of carbon fiber precursors, and supply has largely met demand, future research and investments will be needed to produce sufficient cost-effective carbon fiber to replace the current glass fibers used for wind blade applications.Global Carbon Fiber Use in Wind Turbine Blades

Table E-2. Global Carbon Fiber Use in Wind Turbine Blades

Year	Metric Tonnes
2009	7,060
2012	15,000

Sources: Sloan 2011, 2013 [9, 10]

Rare Earth Materials

The vast majority of wind turbines currently deployed use a copper-wound electromagnetic architecture, such as a doubly-fed induction generator, to convert mechanical torque into electrical energy. However, original equipment manufacturers have developed alternate generator designs that replace some of the copper windings with permanent magnets. Permanent magnets can be manufactured from a variety of materials, but the most effective magnetic materials incorporate some rare earth elements, namely neodymium and dysprosium.

While there are sufficient rare earth minerals in the earth's crust, they can be difficult and costly to extract and process. China has dominated world production of rare earth metals, including 97% of the mining and nearly 100% of the refining [11]. This allowed China to impose tighter export quotas on rare earths, leading to dysprosium (metal) soaring from $100 per kilogram (kg) at the start of 2010 to $1,500/kg in 2011, while the price of neodymium (metal) increased from $90/kg to $300/kg over the same period [11].

While these increases have affected the cost of permanent magnet generators, the cost has since dropped significantly as new sources of rare earth materials are being developed. Also, much like carbon fiber versus glass fiber, rare earth metals are not required for a wind turbine generator and can be substituted by copper-wound generators like doubly-fed induction generators, a swap original equipment manufacturers like GE and Vestas have chosen to make for a variety of reasons [12, 13].

Commodity Price Impact on Wind Turbine Capital Costs

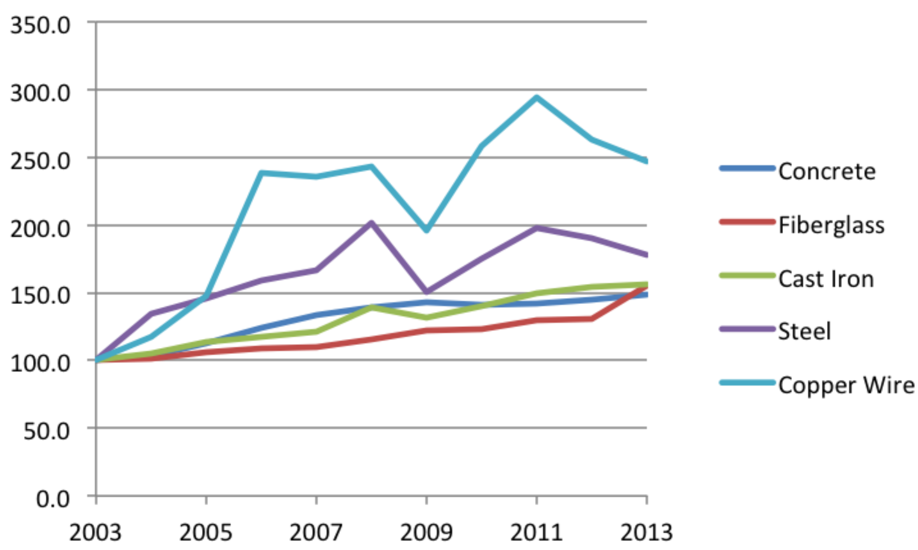
While there have not been any fundamental raw material supply concerns for wind turbines, trends in commodity material prices over the past decade have had an impact on wind turbine prices overall. Analysis performed by Lawrence Berkeley National Laboratory used a Vestas V82 1.65-MW turbine as a representative model to look at the impact of commodity materials on the overall turbine price. Using the information summarized in Table E-3 [14, 15], along with commodity price data, as shown in Figure E-4 [16], it was estimated that commodity price changes accounted for nearly 12% of the overall general turbine price increase that occurred in the industry between 2002 and 2008 and nearly 35% of the price decrease from 2008–2010 [14].

Table E–3. Condensed Bill of Materials for a Vestas V82 1.65-MW Turbine without Foundation

Material	Mass (kg/kW)	% of Total Mass	% of Total Material Cost (Estimated)[a]
Steel	96.3	70%	45%
Fiberglass	18.2	13%	40%
Cast iron	17.8	13%	5%
Copper	1.8	1%	8%
Aluminum	1.9	1%	2%
Total	**135.9**	**98%**	

[a]Cost estimates are based on 2011–2012 commodity prices.

Sources: Bolinger and Wiser 2011 [14], Vestas 2006 [15]



Source: U.S. Bureau of Labor Statistics 2013 [16]

Figure E–4. Producer price index for key wind turbine commodities

Energy Costs

While commodity price swings depend on activities across the global economy and are largely outside the control of the wind industry, there are some interesting trends in energy prices in the United States that could impact the relative competitiveness of domestic manufacturing. In the same Lawrence Berkeley National Laboratory report examining the turbine price trends, there is an analysis of energy costs that includes data on the embodied energy of the Vestas V82 wind turbine materials (Table E-4) [14, 15, 17].

Table E-4. Primary Energy Embodied in Materials Used to Build a Wind Turbine

Vestas V82 (1.65 MW)	Primary Energy Consumption[d]		
Material	**kg/kW**	**MJ/kg**	**GJ/kW**
Steel[a]	112.7	25.7[b]	2.890
Concrete	487.9	3.7	1.795
Fiberglass	18.2	45.7[c]	0.831
Cast iron	17.8	36.3	0.645
Copper	1.8	78.2	0.137
Aluminum	1.9	39.2[b]	0.074
Total	**640.1**		**6.372**

[a]Includes steel used in turbine foundation

[b]The primary energy content of steel and aluminum represent the average of the minimum and maximum. Values provided by Schleisner (2000) [17].

[c]Schleisner (2000) [17] does not include fiberglass, so the energy content provided for "Plastic (polyester and epoxy)" is used instead.

[d]MJ = megajoules, GJ = gigajoules, kW = kilowatt

Sources: Bolinger and Wiser 2011 [14], Vestas 2006 [15], Schleisner 2000 [17]

The majority of the embodied energy is in the concrete and steel. While concrete is primarily produced domestically, steel is produced throughout the world, and the cost is heavily affected by energy prices. Due to the affordable and reliable supply of natural gas from shale sources in the United States, domestic steel companies have begun investing in new facilities to produce iron and steel products. Due to the low cost of feedstocks (such as ethane) derived from natural gas, many large chemical companies have also expanded U.S. manufacturing capacity for a broad range of products, including plastics [18, 19].

E.4 Repair and Refurbishment Manufacturing

Over the lifetime of a wind turbine plant, various components wear out and require refurbishment or complete replacement. As the fleet of installed wind turbines ages, the demand for refurbishment and replacement parts increases. Failure rates of components vary. While some of these failures can be corrected quickly, such as electrical and control units, others (e.g., gearboxes and generators) often need refurbishment twice over the life of a wind plant and can be very costly [20].

Gearboxes

Gearboxes are a costly component, and the downtime caused by their replacement results in lost revenue that can become significant if there are delays. Gearbox manufacturers have taken a variety of approaches since 2008 to meet rising aftermarket demand. Gearbox manufacturers that are subsidiaries of original equipment manufacturers, independent suppliers to original equipment manufacturers, and pure aftermarket companies have expanded capacity to perform repairs and remanufacture components for both current models and legacy gearboxes [20]. The capability to provide quick service and parts to prevent extended downtime has become an increasing focus, and can generally only be accomplished using domestic facilities.

Blades

Blades have come to represent a significant opportunity for aftermarket repairs and replacement. While some original equipment manufacturers produce their own blades, the trend has been toward outsourcing blade production. Manufacturers and other blade service companies have expanded aftermarket products, ranging from annual inspections and repairs to extensive reconditioning and even production of spare blades that are no longer in production for older machines [20].

E.5 Transportation Constraints

Transportation Logistics

Over-the-road transportation has limitations because of the length, width, height, and weight of loads that vary across the United States (Table E-5). Most nacelles and large components are shipped on common 13-axle trailers, which have a load constraint of about 165,000 pounds. As weights move above that threshold, the number of available trailers drops dramatically and the use of dual-lane or line trailers is required. These trailers have diminishing returns in terms of cargo capacity because they are heavier. For example, the capacity of a 19-axle trailer (the largest conventional trailer) is approximately 225,000 pounds (102 tons), which is roughly equivalent to a 4-MW wind turbine nacelle with the drive train removed.

Wind turbine blades above 53 m in length also present a transportation obstacle due to the large turning radius, which hinders right-of-way or encroachment areas within corners or curves. Blade and tower transportation barriers are caused by the difficulty of trucking long blades with wide chords on U.S. roads (in the future, transportation of large diameter root sections will have similar concerns). This barrier limits the length of blade that can be transported over roadways to 53–62 m, depending on design characteristics of the blade, such as the amount of pre-curve and type of airfoils used in the region of the maximum chord dimension.

In addition to the physical limits, each state along a transportation route has different permit requirements. This problem is exacerbated by higher volumes of shipments to wider locations as wind turbine deployments have increased in number. States are also shifting the burden of proof for the safety of large high-volume shipments onto the wind industry. The increased complexity and resulting costs and delays associated with these challenges have led the American Wind Energy Association's Transportation & Logistics Working Group to coordinate with the American Association of State Highway and Transportation Officials in standardizing the permitting process across states.

Constraints on road transport have also led to an increased use of rail as an alternative for heavy wind components, such as the nacelle; high-volume components; and long-distance shipments. Rail is capable of shipping very heavy loads, greater than 163 metric tons, and does not generally require permits for each state. However, rail imposes its own length and width constraints and is not available in every location in which wind energy is being developed.

Table E–5. Summary of Key Minimum Logistics Constraints

Constraint	Road	Rail
Mass (metric tonnes)	75	>163
Length (m)	53	53
Width (m)	4.11	4.27
Height (m)	4.57	> 4.57

Trade-offs between rail and road transportation can also be constrained by cargo widths. Rail clearances are affected by overall shape of the cargo but begin to be restrictive on widths greater than 4.27 m (14 feet [ft]). Road transportation is subject to lane clearing constraints on loads exceeding 4.11 m (13 ft, 6 inches). A few select lanes can be cleared for widths up to 4.57 m (15 ft) for towers, but this is not a common occurrence. Road transport cost is affected by width but roads are generally capable of moving widths up to 4.87 m (16 ft). Widths in excess of 3.66 m (12 ft) require escorts. Widths in excess of 4.57 m (15 ft) may also include police escorts, which escalate cost and complexity.

Height can be a challenge in road transport, but rail is often capable of accommodating tall cargo without issue. Most wind turbines require a loaded height (cargo plus trailer deck height) of 4.72–4.77 m (15 ft, 6 inches–15 ft, 8 inches) in order to clear the tallest cargo (e.g., the nacelle or tower). This height is often at the upper limits of many areas of the country for road transport. Tower diameters that exceed 4.57 m (15 ft) often complicate the ability to find a clear route to site.

The numbers in this section are representative constraints; specific routes around the country may be more or less restricted. The key point is that transportation logistics issues are increasing, which can cause delays and added costs, as well as suboptimal component design (discussed in Chapter 2).

On-site Tower Construction

Rolled steel is the primary material used in wind turbine tower structures for a utility-scale wind projects. Steel is lightweight, malleable and strong, making it a suitable material to support heavy turbines. As hub heights increase, however, steel becomes more costly due to increased material and transportation costs. An alternative to conventional steel towers is precast concrete or a hybrid tower using both concrete and steel. Acciona Windpower recently constructed a demonstration project in Iowa consisting of two of its 3-MW turbines, one on a 100-m concrete tower and the other on a 92-m steel tower [21]. The concrete design could enable tower fabrication and construction on-site, thus avoiding costly and difficult transportation logistics. Innovative on-site construction of steel towers is being explored by Keystone Tower Systems, which is currently developing the concept through a federal Small Business Innovation Research grant. Finally, hybrid towers incorporating a concrete base transitioning to a steel tower have been demonstrated in Europe. Alstom is working with Max Bogl Wind AG of Germany to design and construct 139-m towers for its ECO 122 land-based turbine [22]. These and other approaches offer the potential to move beyond the height constraint imposed on current designs, enabling wind development in more areas of the United States.

E.6 Installation

Crane Availability

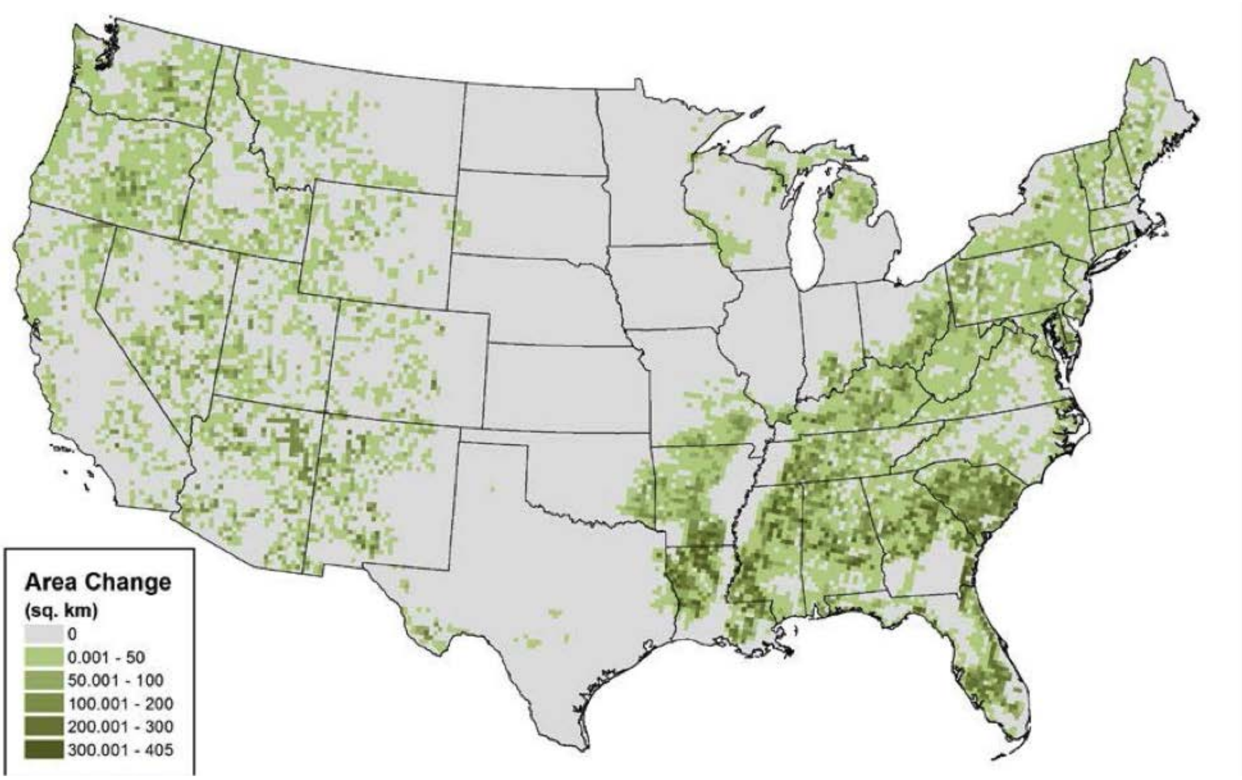
The availability of smaller (120–150 ton) “support” crawler cranes may also become more limited as the number of installed turbines increases. These small cranes are used to off-load turbine components, and to support the larger cranes required for the heaviest of nacelles or greater than 100-m hub-heights. These small crawlers are used in all forms of construction, especially infrastructure, and as infrastructure projects gain momentum, the supply of these cranes should increase.

With the decline in wind installations in 2013, crane manufacturers have realigned to supply ultra-large crawler cranes to the power generation and petro-chemical facilities. While development of machines to improve capacities at heights required by the wind industry continues, the pace of such investments has fallen considerably.

Height Restriction Impact on Resource

The National Renewable Energy Laboratory performed a preliminary analysis to estimate the possible effects of restricting turbine blade-tip heights to less than 152 m [23]. The analysis calculated the increase in U.S. land area that became more attractive for development by increasing the hub height of a GE 1.6-MW turbine with a 100-m diameter rotor from 96 m to 110 m (an increase in blade-tip height from approximately 146 m to 160 m). The gross capacity factor was computed for U.S. land area elements of 20 km2. Land area elements that showed increases of gross capacity factors to more than 30% were considered economically feasible for development, as 30% is generally considered the minimum gross capacity factor necessary in order for a wind plant to be economically viable. As wind technology advances and local power prices change, however, the potential use of other low-wind-speed areas may also increase.

Figure E-5 [23] illustrates in green the new land area that crosses this 30% threshold. The map displays only the change in land area—not the land areas which already meet or exceed the 30% threshold. The land that could be made viable for wind development by addressing the perceived regulatory height limit is approximately 320,000 km2. Much of this land is located in the east and southeast regions, which tend to have slower wind resources. This land area theoretically equates to nearly 1,000 gigawatts of new wind deployments if the assumption of 3 MW/km2 of potential wind turbine capacity is used.



Source: Cotrell et al. 2014 [23]

Figure E–5. New deployable land resulting from increasing hub height from 96 m to 110 m

References

[1] Wiser, R.; Bolinger, M.; et al. *2012 Wind Technologies Market Report.* NREL/TP-5000-58784; DOE/GO-102013-3948. Washington, DC: U.S. Department of Energy Energy Efficiency & Renewable Energy, August 2013; 92 pp. Accessed Dec. 26, 2014: *http://www.nrel.gov*.

[2] Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. *2013 Wind Technologies Market Report.* DOE/GO-102014-4459. Washington, DC: U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, August 2014. Accessed Jan. 7, 2015: *http://www.osti.gov/scitech/biblio/1155074*.

[3] "Trinity to Shift Resources Away from Tower Production." North American Windpower, July 26, 2012, press release. Accessed Jan. 17, 2015: *http://nawindpower.com/e107_plugins/content/content.php?content.10188*.

[4] *AWEA U.S. Wind Industry Annual Market Report.* American Wind Energy Association. Washington, DC: AWEA, 2014. Accessed Dec. 13, 2014: *http://www.awea.org/AMR2013*.

[5] "Small Wind Industry Standards." American Wind Energy Association, 2013c. Accessed Jan. 10, 2015: *http://www.awea.org/Issues/Content.aspx?ItemNumber=4651*.

[6] *American Wind Energy Association Annual Wind Industry Report, Year Ending 2008.* Washington, DC: American Wind Energy Association, 2009. Accessed Jan. 10, 2015: *http://www.awea.org*.

[7] *Winds of Change: A Manufacturing Blueprint for the Wind Industry.* American Wind Energy Association, BlueGreen Alliance, and United Steelworkers, June 28, 2010.

[8] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. *2011 Cost of Wind Energy Review.* NREL/TP-5000-56266. Golden, CO: National Renewable Energy Laboratory, March 2013; 50 pp. Accessed Dec. 26, 2014: *http://www.nrel.gov*.

[9] Sloan, J. "Carbon Fiber Market: Cautious Optimism." Composites World, March 1, 2011. Accessed Jan. 18, 2015: *http://www.compositesworld.com/articles/carbon-fiber-market-cautious-optimism*.

[10] Sloan, J. "Market Outlook: Surplus in Carbon Fiber's Future?" Composites World, March 1, 2013. Accessed Jan. 18, 2015: *http://www.compositesworld.com/articles/market-outlook-surplus-in-carbon-fibers-future*.

[11] Lehner, F.; Rastogi, A.; Sengupta, S.; Vuille, F.; Ziem, S. *Securing the Supply Chain for Wind and Solar Energy (RE-SUPPLY).* Prepared by E4tech and Avalon Consulting for IEA's Implementing Agreement on Renewable Energy Technology Deployment. Paris: International Energy Agency, November 2012. Accessed Jan. 15, 2015: *https://cleanenergysolutions.org/node/3340*.

[12] Quilter, J. "Close Up—Vestas Launches V110 2MW Turbine." *Windpower Monthly*, April 24, 2013. Accessed Jan. 18, 2015: *http://www.windpowermonthly.com/article/1179771/close---vestas-launches-v110-2mw-turbine*.

[13] "After 10 Years GE Goes Back to DFIGs." Windpower Monthly, Oct. 9, 2012. Accessed Jan. 19, 2015: *http://www.windpowermonthly.com/article/1153928/10-years-ge-goes-back-dfigs*.

[14] Bolinger, M.; Wiser, R. *Understanding Trends in Wind Turbine Prices Over the Past Decade*. LBNL-5119E. Berkeley, CA: Lawrence Berkeley National Laboratory, October 2011. Accessed Jan. 12, 2015: *https://escholarship.org/uc/item/4m60d8nt*.

[15] *Life Cycle Assessment of Electricity Produced from Onshore Sited Wind Power Plants Based on Vestas V82-1.65 MW Turbines.* Randers, Denmark: Vestas Wind Systems A/S, Dec. 29, 2006; 77 pp. Accessed Jan. 19, 2015: *http://www.scribd.com/doc/141673844/LCA-V82-1-65-MW-Onshore#scribd*.

[16] "Archived Producer Price Index Detailed Report Information: 2013." Washington, DC: U.S. Bureau of Labor Statistics, 2015. Accessed Jan. 19, 2015: *http://www.bls.gov/ppi/ppi_dr.htm#2013*.

[17] Schleisner, L. "Life Cycle Assessment of a Wind Farm and Related Externalities." *Renewable Energy* (20:3), 2000; pp. 279–288. Accessed Jan. 18, 2015: *http://www.researchgate.net/publication/222834610_Life_cycle_assessment_of_a_wind_farm_and_related_externalities*.

[18] "Shale Gas: A Renaissance in U.S. Manufacturing?" PricewaterhouseCoopers, 2011; 16 pp. Accessed Jan. 18, 2015: *http://www.pwc.com/us/en/industrial-products/publications/shale-gas.jhtml*.

[19] "Remaking the Global Steel Industry: Lower-Cost Natural Gas and Its Impacts." Deloitte, 2013. Accessed Jan. 13, 2015: *http://www2.deloitte.com/tw/en/pages/manufacturing/articles/steel-industry.html*.

[20] *Wind Operations & Maintenance Market, 2013 Update—Global Market Size, Share by Component, Competitive Landscape and Key Country Analysis to 2020*. Report GDAE1077MAR. London: GlobalData, August 2013; 188 pp. Accessed Jan. 14, 2015: *http://www.reportsnreports.com/reports/267610-wind-operations-maintenance-market-2013-update-global-market-size-share-by-component-competitive-landscape-and-key-country-analysis-to-2020.html*.

[21] Norfleet, G.R. "Acciona: Cuts Will Not Hurt Wind Farm." West Branch Times Online, March 29, 2013. Accessed Jan. 14, 2015: *http://www.westbranchtimes.com/article.php?id=9211*.

[22] "Alstom Signs MOU for Tall Hybrid Tower Design." North American Windpower, April 25, 2013, press release. Accessed Jan. 17, 2015: *http://www.nawindpower.com/e107_plugins/content/content.php?content.11415*.

[23] Cotrell, J.; Stehly, T.; Johnson, J.; Roberts, J.O.; Parker, Z.; Scott, G.; Heimiller, D. *Analysis of Transportation and Logistics Challenges Affecting the Deployment of Larger Wind Turbines*. NREL/TP-5000-61063. Golden, CO: National Renewable Energy Laboratory, 2014. Accessed Dec. 19, 2014: *http://www.nrel.gov*.

This page is intentionally left blank

Appendix F: Test Facilities

Test data are used to improve design models for components (e.g., blades, drive trains, controls, and towers); turbines assemblies (individual and grid-connected); and wind plant performance (complex flow). Understanding loads and failure modes informs improved design standards, codes, and certification criteria. In partnership with industry and academia, the federal government maintains and improves laboratory and field test facilities tailored to the needs of wind energy deployment (Table F-1). The broader community uses U.S. Department of Energy facilities to test to industry fatigue-life standards or to test the properties of new, innovative components that are still under development. Design verification through testing has been essential to gaining confidence from the financial community. Access to test facilities is an important catalyst in advancing wind energy technology development.

Component Testing

Advanced blade and drive train test facilities sized to accommodate development of larger land-based and offshore wind turbines have been constructed since 2011.

Blades

Failure testing and life testing of long wind turbine blades require large specialized facilities with deep foundations and powerful rigs for static and dynamic tests. The Wind Technology Testing Center, owned and operated by the Massachusetts Clean Energy Center (MassCEC) in Boston, Massachusetts, which gained certification in 2012 as a commercial large-blade testing facility, can test blades as long as 90 meters (m) (300 feet [ft.]). The center has enough space to conduct up to three simultaneous blade tests. With close proximity to offshore wind resources and a 360-m (1,200-ft.) dock for handling blades, the center will be able to test and certify blades for the emerging U.S. offshore wind industry. By the end of June 2014, MassCEC had completed testing on more than 12 multi-megawatt (MW) turbine blades. Another blade-testing option is the National Renewable Energy Laboratory's National Wind Technology Center (NWTC) near Boulder, Colorado, where three test stands can test 50-m blades and blade design and manufacturing innovations at scales up to 19 m.

Table F–1. Federal Government Supported U.S. Wind Energy Test Capabilities

Capability	Test Type or Facility Equipment	Location
Small and medium wind turbine drive train testing	**225-kW Dynamometer**	Boulder, Colorado (NWTC)
Medium-scale wind turbine drive testing; gearbox reliability collaborative research	**2.5-MW Dynamometer**	Boulder, Colorado (NWTC)
Utility-scale wind turbine drive train testing	**5.0-MW Dynamometer**	Boulder, Colorado (NWTC)
First-generation offshore wind turbine drive train testing	**7.5-MW Dynamometer**	Charleston, South Carolina (Clemson University)
Second-generation offshore wind turbine drive train testing	**15.0-MW Dynamometer**	Charleston, South Carolina (Clemson University)
Scale testing of wind turbine blade innovations; scaled evaluation of improved blade testing methods	**19-m Blade Test Stand**	Boulder, Colorado (NWTC)
Utility-scale wind turbine blade testing; full-scale evaluation of improved blade testing methods	**50-m Blade Test Stand**	Boulder, Colorado (NWTC)
Utility-scale blade testing; three test stands sized for the anticipated blade lengths of the offshore wind industry	**90-m Blade Test Facility**	Boston, Massachusetts (MassCEC)
Controls Advanced Research Turbines (CART-2/3): Two 600-kW turbines for advanced control algorithm R&D	**Controls Research Turbines**	Boulder, Colorado (NWTC)
General Electric 1.5-MW utility-scale wind turbine available to researchers for field testing innovative technology	**1.5-MW Research Turbine**	Boulder, Colorado (NWTC)
Simulation of electrical grid faults for testing wind turbine drive trains	**Controllable Grid Interface**	Boulder, Colorado (NWTC)
Research on turbine-to-turbine interactions in wind plants (2014)	**Grid Simulator**	Charleston, South Carolina (Clemson University)
Scaled Wind Farm Test Facility (SWiFT): Three 300-kW research turbines for turbine–turbine interaction R&D	**Wind Plant Test Facility**	Lubbock, Texas (Texas Tech University/ Sandia National Labs)

Drive Trains

Drive trains are tested using dynamometers—huge electric motors that simulate the action of the wind turbine rotor blades driving the gearbox and generator. As the rated capacity of wind turbines to be tested increases, dynamometers need to become more powerful. In 2008, the most powerful dynamometer for testing utility-scale wind drive trains was a 2.5-MW test stand at the NWTC. By 2013, two new drive train test facilities were available for much larger land-based and offshore applications. The range of dynamometers was chosen to represent current and future technology development in both land-based and offshore wind turbines.

- The Clemson University's drive train test facility, located on a former Navy base in Charleston, South Carolina, has two dynamometers (7.5-MW and 15-MW) capable of testing wind turbine drive trains with capacity ratings up to 15 MW. The test facility will conduct full-scale, highly accelerated testing of advanced drive train systems. It is equipped with a hardware-in-the-loop grid simulator that mimics real-world circumstances, such as wide-area power disruptions and frequency fluctuations, to determine the effects of wind turbines on utility grids and grids on wind turbines. The test facility allows wind turbine generator manufacturers to test both mechanical and electrical characteristics of their machines in a controlled and calibrated environment. The grid simulator moves many electrical testing scenarios that were previously only available via field demonstrations into a controlled environment, providing manufacturers an opportunity to test to stringent global electrical standards.
- The National Renewable Energy Laboratory's new dynamometer test facility at the NWTC can accommodate drive trains up to 5 MW and test electrical as well as mechanical performance of wind and solar generation. To provide engineers with a better understanding of how wind turbines react to grid disturbances, the test bed can be connected directly to the grid or to a controllable grid interface. The controllable grid interface can be connected either to the wind turbines or to electronic and mechanical storage devices undergoing a test. The system is designed to work with all types of generators and inverters used in wind turbines, solar photovoltaic systems, and energy storage systems.

Field Testing

Field testing turbines and measurements collected under atmospheric operating conditions are important for validating design codes. They are also useful for testing design modifications—for example, in control systems. Studying complex flows that affect wind plant performance can best be accomplished under field test conditions.

Full-Scale Turbine Testing

Beginning in 2009, the U.S. Department of Energy has been installing fully-instrumented, multi-MW turbines to collect data on aerodynamics, power characteristics, vibrations, system fatigue, acoustics, and other key measurements. By 2013, full-scale tests were continuing under cooperative research agreements with industry partners employing the four large wind turbines (1.5 MW, 2 MW, 2.3 MW, and 3 MW) at the NWTC. Additional test activities were taking place using the 2.5 MW turbine at the University of Minnesota and the 1.5 MW turbine at the Illinois Institute of Technology.

Array Testing

To study wake energy loss, wake-induced loads, advanced rotor development, turbine control in wind plants, and advanced sensing, the U.S. Department of Energy supported Texas Tech University and Sandia National Laboratories in developing the Scaled Wind Farm Technology, or SWiFT, facility that opened in Texas in 2013. The three modified, instrumented, 300-kilowatt (kW) wind turbines will produce data to support understanding of the complex wind flow and wakes within a wind plant. Anemometer towers around the array provide key data about the wind inflow. SWiFT's primary objective is to help address the underperformance of wind plants through better understanding of turbine-to-turbine wind interaction and complex flow issues. Research results gleaned from SWiFT will be used to direct technology investments and improve the validity of aerodynamic, aeroelastic, and aeroacoustic simulations. The test site can accommodate seven additional turbines for assessment of more complex interactions.

Scaled Turbine Testing

For accurate modeling of future offshore designs, the University of Maine and the National Renewable Energy Laboratory are analyzing results from scaled testing to validate the lab's coupled numerical tools. The offshore designs include the semisubmersible (1:8 scale) turbine the university deployed in 2013 at its deep water offshore wind test site near Monhegan Island, Maine.

Resource Measurements

To advance the science of forecasting, the Wind Forecast Improvement Project was designed to improve the ability of the National Oceanic and Atmospheric Administration's short-term weather forecast models to predict foundational weather parameters (e.g., wind speed, direction, and turbulence intensity) that impact wind energy generation. The U.S. Department of Energy and the National Oceanic and Atmospheric Administration research laboratories, the National Weather Service, and partners from the private sector collected and analyzed data to validate and improve the short-term forecast models.

Standards and Collaboration

Certification testing to international design standards is important in the wind turbine market because it offers a measure of confidence to investors. Although these standards may be developed by international organizations (e.g., the International Electrotechnical Commission, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, and the International Measuring Network of Wind Energy Institutes), U.S. experts work on committees that develop the standards and U.S. test facilities carry out the tests whenever possible.

International collaboration, through bilateral agreements and participation in international organizations, ensures the application of worldwide experiences with wind energy to U.S. certification efforts and vice versa. Research collaboration improves access by U.S. designers and test engineers to test data from other countries. Through International Energy Agency (IEA) Wind research projects, U.S. representatives from industry, universities, and national laboratories gain access to test data and experience from countries exploring the same technology and deployment issues. For example, IEA Wind Task 30, Offshore Code Comparison Collaboration Continuation, coordinates the work of modelers in 12 countries and 47 organizations to improve the design of offshore wind turbines using verified and improved codes. IEA Wind Task 31, Wakebench, manages the work of researchers in 14 countries to improve atmospheric boundary layer and wind turbine wake models by benchmarking wind and wake modeling techniques. The next phase of this project will use field test data to validate the wake models. In IEA Wind Task 32, LIDAR: Wind Lidar Systems for Wind Energy Deployment, U.S. experts coordinated development of the IEA Wind *Recommended Practice 15: Ground-Based, Vertically-Profiling Remote Sensing for Wind Resource Assessment,*[1] which outlines recommended data collection techniques for this relatively new technology.

1. *www.ieawind.org*

This page is intentionally left blank

Appendix G: Regional Energy Deployment System (ReEDS) Model—Additional Inputs and Assumptions

Chapter 3 provides a summary of the Regional Energy Deployment System (ReEDS) model and input assumptions. This appendix accompanies that chapter by providing more details about the model and the non-wind technology cost and performance assumptions. In particular, this appendix includes a description of the ReEDS model representation and data sources, and numerical values of key input assumptions used to develop the scenarios contained in the *Wind Vision* analysis.

The appendix is organized as follows:

- An overview of the ReEDS model and list of references to model documentation and other recent studies (Section G.1)
- The cost and performance assumptions of the non-wind generation technologies (Section G.2)
- Fuel price formulations and assumptions (Section G.3)
- Retirement assumptions (Section G.4)
- Financing parameters used in ReEDS investment and dispatch decisions (Section G.5)
- Electricity demand assumptions (Section G.6)
- Transmission cost and modeling assumptions (Section G.7).

Notably, the assumptions for wind technologies and resource are described in Appendix H.

G.1 ReEDS Model

The primary analytic tool used for this analysis is the ReEDS electric sector capacity expansion model [1]. ReEDS is a capacity expansion model that simulates the construction and operation of generation and transmission capacity to meet electricity demand. The model relies on system-wide, least-cost optimization to provide estimates of the type and location of fossil, nuclear, renewable, and storage resource development; the transmission infrastructure expansion requirements of those installations; and the generator dispatch and fuel needed to satisfy regional demand requirements and maintain grid system adequacy. The model also considers technology, resource, and policy constraints; including state renewable portfolio standards. ReEDS models scenarios of the continental U.S. electricity system in 2-year solve-periods out to 2050. In the *Wind Vision* analysis, ReEDS is used to analyze potential changes in the generation mix of the electricity sector under certain conditions and to generate a set of future scenarios for the U.S. electricity sector from which the impacts of a high penetration wind future are assessed. Although ReEDS scenarios are not forecasts or projections, they provide a common framework for understanding the incremental effects associated with specific power sector changes, such as those prescribed in the *Study Scenario*.

ReEDS is specifically designed to represent the unique characteristics of renewable generation, including wind—variability, uncertainty, geographic resource constraints, and transmission—and to assess its impacts on the broader electric system. Its high spatial resolution and statistical treatment of the impact of variable wind and solar resources enable representation of the relative value of geographically and temporally constrained renewable power resources. In ReEDS, the continental United States is divided into 356 wind/concentrating solar power (CSP) resource regions and 134 model balancing areas (BAs).[1] The resource regions are where wind (and CSP) resource availability and quality are evaluated and wind capacity expansion is modeled. The 134 BAs are where all other generation technologies are deployed in the model, and where electricity demand and reserves need to be met. Long-distance transmission is represented between adjacent BAs.

1 While the boundaries of real balancing authority areas helped to inform the design of the model BAs, the ReEDS BAs do not correspond perfectly with real balancing authority areas, where boundaries are dynamic and likely to change in the future.

ReEDS also uses a supply curve for resource capacity versus infrastructure investment costs to model the intra-BA, spur-line costs required to interconnect wind (and CSP) capacity from its region to the transmission grid. Capturing the resource cost and quality at such a high geographical granularity enables ReEDS to find the lowest-cost renewable resource expansions by interconnecting high-quality resources through appropriate long-distance inter-BA transmission and intra-BA spur-line expansions.

There are also larger sets of regions within ReEDS: 48 states, 18 curtailment regions designed loosely after existing regional transmission operator and other reliability regions [2], 13 North American Electric Reliability Corporation (NERC) regions [3], and the three major interconnections—Western, Eastern, and Electric Reliability Council of Texas. The NERC regions are used to model inputs, such as load growth and fuel prices from the EIA and the National Energy Modeling System.

ReEDS dispatches all generation using multiple time slices to capture seasonal and diurnal demand and renewable generation profiles. In particular, each of the "solve years" from 2010 to 2050 is divided into 17 time slices that represent four diurnal time slices (morning, afternoon, evening, night) for each of the four seasons (winter, spring, summer, fall), and a summer peaking time slice (representing the top 40 hours of summer load). While this model time resolution allows the model to capture seasonal and diurnal variations in demand and wind profiles, it is insufficient to capture some of the shorter timescale phenomena associated with high, variable generation penetration and address the related challenges. To bolster how renewable grid integration might affect investment and dispatch decisions, the ReEDS model includes statistical parameters to address the variability and uncertainty of wind and certain other renewable resources. These parameters include capacity value for planning reserves, forecast error reserves, and curtailment estimates [1].

In addition to modeling wind—land-based and offshore—technologies, ReEDS includes a full suite of major generation and storage technologies, including coal-fired, natural gas–fired, oil and gas steam, nuclear, biopower, geothermal, hydropower, utility-scale solar, pumped-hydropower storage, compressed-air energy storage, and batteries[2]. To determine competition between the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost minimization routine is performed for each of 21 two-year periods from 2010 to 2050.

The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel demand and prices, and direct-combustion carbon dioxide emissions. Through these output metrics, ReEDS is able to provide estimates of the nationwide impact of higher wind penetration on the system over the coming decades. Greater detail for these model technology categories is provided in the next section. ReEDS applies standardized financing assumptions for investments in all technologies represented in the model (see section G.6). Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization, as discussed in latter sections.

The ReEDS documentation [1] provides a more detailed description of the model structure and equations. Recent publications using ReEDS include the SunShot Vision Study [4], the Renewable Electricity Futures study [5], other lab reports [6,7,8,9], and journal articles [10,11,12,13].[3] The ReEDS model was also used to develop scenarios for the 20% *Wind Energy by 2030* report [14].[4] The model documentation and more recent publications, however, describe a large number of model developments subsequent to that study. This appendix focuses on the primary

2 Coal and natural gas with and without carbon capture and storage are included. ReEDS models natural gas combined cycle and combustion turbine technologies independently. Utility-scale solar includes photovoltaic and CSP with and without thermal energy storage; rooftop solar deployment is not modeled but applied as an exogenous input into the system. Section G.2 and Short et al. [1] describe the array of technologies modeled in ReEDS in greater detail.

3 See *www.nrel.gov/analysis/reeds* for a list of publications about and further description of ReEDS.

4 The version of the model used in the *20% Wind Energy by 2030* report [14] was referred to as the Wind Deployment System (WinDS) model; ReEDS reflects the current name of the model.

data assumptions and model representations that are used specifically for the *Wind Vision* analysis, which may differ from assumptions applied in prior studies using ReEDS.

While ReEDS represents many aspects of the U.S. electric system, it has certain key limitations. First, ReEDS is a system-wide optimization model and, therefore, does not consider revenue impacts for individual project developers, utilities, or other industry participants. Second, ReEDS does not explicitly model constraints associated with the manufacturing sector. All technologies are assumed to be available up to their technical resource potential. Third, technology cost reductions from manufacturing economies of scale and "learning by doing" are not endogenously modeled for this analysis; rather, current and future cost reduction trajectories are defined as inputs to the model (see also Appendix H). Fourth, with the exception of future fossil fuel prices, foresight is not explicitly considered in ReEDS (i.e., the model makes investment decisions based on current conditions, without consideration for how those conditions may evolve in the future). Furthermore, ReEDS is deterministic and has limited considerations for risk and uncertainty. Fifth, the optimization algorithm in ReEDS does not fully represent the prospecting, permitting, and siting hurdles that are faced by project developers for either electricity generation capacity or transmission infrastructure. Moreover, ReEDS does not include fuel infrastructure or land competition challenges associated with fossil fuel extraction and delivery. Finally, ReEDS models the power system of the continental United States and does not represent the broader United States or global energy economy. For example, competing uses of resources across sectors (e.g., natural gas) are not dynamically represented in ReEDS and end-use electricity demand is exogenously input to ReEDS for this study.

One consequence of these model limitations is that system expenditures estimated in ReEDS may be understated, as the practical realities associated with planning electric system investments and siting new generation and transmission facilities are not fully represented in the model. As wind technologies are expected to require new transmission infrastructure development and benefit from broad-based system coordination, this impact may be amplified when considering high wind penetration scenarios. At the same time, ReEDS' spatial resolution provides much more sophisticated evaluation of the relative economics among generation resources and significant incremental insight into key issues surrounding future wind deployment, including locations for future deployment, transmission expansion needs, impacts on planning and operating reserves, and wind curtailments.

With a system-wide optimization outlook, ReEDS is not designed to evaluate distributed generation scenarios. Accordingly, ReEDS analysis is supported by the Solar Deployment System (SolarDS) model [15]. SolarDS is used to generate a projection of rooftop solar photovoltaic (PV) deployment, which is then input into ReEDS. All ReEDS scenarios presented in this report rely on the same single rooftop PV capacity projection. The input parameters for SolarDS used in this analysis are similar to those used in the *SunShot Vision Study* [4] with some exceptions presented in section G.2. No other distributed generation technologies are modeled explicitly in the *Wind Vision*, although the unique impacts associated with distributed wind generation are discussed in Chapter 3.

G.2 Generator Assumptions—Technology Cost and Performance

ReEDS models a full suite of generation technologies, including renewable, non-renewable, and storage. The technologies modeled in ReEDS represent the existing capacity fleet as well as newer generation technologies that have not realized commercial deployment in the United States. With the exception of rooftop PV, the existing capacity in ReEDS only includes units that are primarily used to generate and transmit electricity to the grid and excludes facilities that generate electricity primarily for on-site consumption or combined heat and power facilities.[5] In addition, ReEDS does not allow capacity expansion for certain technology types due to the age of the technology or data limitations.

5 The treatment of rooftop PV is described in section G.2.2.

New capacity growth for the following technologies is allowed in ReEDS:

- Natural gas-fired combustion turbine (NGCT)
- Natural gas—combined cycle (NGCC)
- Natural gas with carbon capture and storage (NGCCS)[6]
- Coal-pulverized[7]
- Coal-integrated gasification combined cycle (Coal-IGCC)
- Coal with carbon capture and storage (Coal-CCS)[8]
- Nuclear
- Biopower
- Cofired coal and biomass[9]
- Utility-scale solar PV[10]
- Wind (land-based and offshore)
- CSP with and without thermal energy storage (TES)[11]
- Hydropower[12]
- Geothermal[13]

The following technologies are also modeled in ReEDS but new capacity additions are not allowed for:

- Old coal (with and without scrubbers)[14]
- Landfill gas and municipal solid waste[15]
- Oil and gas steam

In addition to the previously listed technologies, new rooftop PV capacity is exogenously included (see section G.2.2). ReEDS also models three separate energy storage technologies: pumped hydropower storage, batteries, and compressed air energy storage. The assumed resource, cost, and performance projections for these storage options are based on those modeled in the Renewable Electricity Futures study [16].

6 While CCS technologies are included in the ReEDS model and allowed to be built, none of the modeled scenarios in this report resulted in the deployment of CCS capacity

7 New coal plants are assumed to have scrubbers. Coal plants that existed before 2010 are included in ReEDS and separated into three categories: new coal, old coal without scrubbers, and old coal with scrubbers. Old coal with and without scrubbers comprise plants built pre-1995. For the reported coal capacity and generation in Chapter 3, all coal technologies are aggregated together (new and old coal, coal-IGCC, and coal-CCS).

8 Coal with CCS reflects IGCC coal technologies.

9 Cofired plants represent new plants that can accommodate coal and biomass fuels, and retrofits to existing coal plants. In ReEDS, no more than 15% of the capacity of a cofired coal plant can operate on biomass feedstocks at any time. In Chapter 3, cofired capacity is separated into coal and biomass categories in the reported capacity and generation values. More particularly, the reported cofired coal capacity is split between coal and biomass (85% of the capacity included with coal and 15% included with biomass). The generation from cofired plants is split by the generation from each fuel in the modeled plants with energy from biomass feedstocks included in the biomass category.

10 The cost and performance of utility-scale PV reflect 100-MW single-axis tracking systems.

11 CSP without TES is represented by trough systems with a solar multiple of 1.4. CSP with TES includes trough and tower systems with a solar multiple of at least two and at least six hours of storage. ReEDS endogenously optimizes the system configuration of CSP with TES plants within these limits.

12 Section G.2.3 discusses the hydropower resources modeled in ReEDS. No ocean or marine hydrokinetic technologies are included in ReEDS for the present analysis.

13 Section G.2.4 discusses the geothermal resource modeled in ReEDS for the present analysis.

14 Old coal represents facilities installed before 1995 and active as of the model start year (2010). A retrofit option is included in ReEDS to allow upgrades of coal capacity from the “without scrubber” category to the “with scrubber” category.

15 In Chapter 3, landfill gas and municipal solid waste generation and capacity are included in the biomass values.

G.2.1 General Technology Assumptions

Each modeled technology is characterized by its regional resource potential, capital cost, operations and maintenance (O&M) costs, and heat rates or capacity factors. Other technology characteristics such as lifetime, reserve capability, and tax credits are also modeled as described in Short et al. [1]. Regional variations and adjustments in some of the technology characteristics are also included and described in the following sections and other ReEDS publications listed in section G.2. This section presents the capital, fixed O&M, variable O&M, and heat rates for all technologies modeled.

Cost and performance assumptions for all new conventional technologies and certain renewable technologies (e.g., biopower and geothermal) are largely based on projections from the EIA's Annual Energy Outlook (AEO) 2014 Reference scenario [17]. The modeling tool in the AEO 2014 endogenously models technology learning, wherein technology cost and performance parameters are informed by the amount of capacity deployed in a given scenario. As a result, the technology cost assumptions reflect the learning estimated in the AEO 2014 Reference scenario and are directly applied in ReEDS. ReEDS does not include any explicit representation of technology learning in the *Wind Vision* analysis. In addition, technology projections beyond 2040 are assumed to remain flat from the 2040 levels, as the AEO 2014 only includes data through 2040. For some technologies (e.g., hydropower), only O&M costs from the AEO 2014 Reference scenario are used, while capital costs are based on other data sources (see sections G.2.3 and G.2.4). Solar technology assumptions also diverge from the AEO and are described in section G.2.2. Assumptions for wind technologies and resource are described in Appendix H. Overnight capital, fixed O&M, and variable O&M cost projections are shown in Tables G-1, G-2, and G-3, respectively. Heat rate assumptions for new capacity are shown in Table G-4. All costs presented in this appendix are in real 2013 dollars unless otherwise noted.

Table G–1. Overnight Capital Cost Projections (2013$/Kilowatt [kW])

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
Hydropower[a]	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve
NGCT	839	832	807	784	766	753	746	746	746
NGCC	988	1,010	954	931	912	899	889	889	889
NGCCS	NA	2134	1,967	1,883	1,806	1,746	1,695	1,695	1,695
Old coal with scrubbers	NA	NA	NA	NA	NA	NA	NA	NA	NA
Old coal without scrubbers	NA	NA	NA	NA	NA	NA	NA	NA	NA
New coal	2,988	3,389	3,284	3,218	3,157	3,105	3,060	3,060	3,060
Coal-IGCC	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853
Coal-CCS	NA	6,478	6,218	6,008	5,803	5,630	5,465	5,465	5,465
Oil/gas steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nuclear	4,871	4,871	4,708	4,594	4,476	4,325	4,186	4,186	4,186
Geothermal[b]	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve
Biopower[c]	4,188	4,188	3,651	3,587	3,520	3,451	3,363	3,363	3,363

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
Co-fire retrofit[d]	290	290	290	290	290	290	290	290	290
SO_2 scrubber retrofit[e]	536	536	536	536	536	536	536	536	536
Landfill gas	NA	NA	NA	NA	NA	NA	NA	NA	NA

[a] Hydropower capital costs are represented through regional supply curves. No capital cost reductions are assumed for these technologies. See section G.2.3.

[b] Geothermal capital costs are represented through regional supply curves. No capital cost reductions are assumed for these technologies. See section G.2.4.

[c] The costs under the "biopower" category represent costs for new dedicated biopower plants.

[d] The capital cost represents the cost to retrofit any existing coal facilities to be able to co-fire with biomass. Biomass co-firing is assumed to be limited to up to 15% of the total plant capacity. A plant that has been retrofitted to co-fire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant. ReEDS includes an option to deploy new facilities that can co-fire coal and biomass; however, none of the scenarios discussed in the *Wind Vision* analysis relied on this option.

[e] Sulfur dioxide (SO_2) scrubber retrofits upgrade capacity from the "Old Coal without Scrubbers" category to the "Old Coal with Scrubbers" category.

Table G–2. Fixed O&M Costs for New and Existing Generators (2013$/kW-year)

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
Hydropower	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05	15.05
NGCT	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
NGCC	14.48	14.48	14.48	14.48	14.48	14.48	14.48	14.48	14.48
NGCCS	NA	32.27	32.27	32.27	32.27	32.27	32.27	32.27	32.27
Old coal with scrubbers	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52
Old coal without scrubbers	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52
New coal	31.65	31.65	31.65	31.65	31.65	31.65	31.65	31.65	31.65
Coal-IGCC	52.16	52.16	52.16	52.16	52.16	52.16	52.16	52.16	52.16
Coal-CCS	NA	73.93	73.93	73.93	73.93	73.93	73.93	73.93	73.93
Oil/gas steam	27.44	27.44	27.44	27.44	27.44	27.44	27.44	27.44	27.44
Nuclear	94.68	94.68	94.68	94.68	94.68	94.68	94.68	94.68	94.68
Geothermal	114.61	114.61	114.61	114.61	114.61	114.61	114.61	114.61	114.61
Biopower	107.22	107.22	107.22	107.22	107.22	107.22	107.22	107.22	107.22
Co-fire retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill gas	398.70	398.70	398.70	398.70	398.70	398.70	398.70	398.70	398.70

[a] A plant that has been retrofitted to co-fire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

Table G–3. Variable O&M Costs for New and Existing Generators (2013$/Megawatt-hour [MWh])

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
Hydropower	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69
NGCT	13.10	13.10	13.10	13.10	13.10	13.10	13.10	13.10	13.10
NGCC	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
NGCCS	NA	6.88	6.88	6.88	6.88	6.88	6.88	6.88	6.88
Old with scrubbers	5.93	6.55	7.23	7.99	8.82	9.74	10.75	11.87	13.10
Old coal without scrubbers	5.93	6.55	7.23	7.99	8.82	9.74	10.75	11.87	13.10
New coal	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.54
Coal-IGCC	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33
Coal-CCS	NA	8.58	8.58	8.58	8.58	8.58	8.58	8.58	8.58
Oil/gas steam turbines	4.19	4.62	5.11	5.64	6.22	6.87	7.59	8.38	9.25
Nuclear	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biopower	5.34	5.34	5.34	5.34	5.34	5.34	5.34	5.34	5.34
Cofire retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill gas	8.88	8.88	8.88	8.88	8.88	8.88	8.88	8.88	8.88

[a] A plant that has been retrofitted to co-fire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

Table G–4. Heat Rates for New and Existing Generators (Million British Thermal Units [MMBtu]/MWh)

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
Hydropower	NA	NA	NA	NA	NA	NA	NA	NA	NA
NGCT	10.28	10.02	9.76	9.50	9.50	9.50	9.50	9.50	9.50
NGCC	6.74	6.68	6.62	6.57	6.57	6.57	6.57	6.57	6.57
NGCCS	NA	7.51	7.50	7.49	7.49	7.49	7.49	7.49	7.49
Old Coal with Scrubbers	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98
Old Coal without Scrubbers	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26
New Coal	8.80	8.78	8.76	8.74	8.74	8.74	8.74	8.74	8.74
Coal-IGCC	8.70	8.28	7.87	7.45	7.45	7.45	7.45	7.45	7.45
Coal-CCS	NA	9.90	9.10	8.31	8.31	8.31	8.31	8.31	8.31
Oil/gas Steam	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65
Nuclear	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46	10.46
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA
Biopower	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50
Co-fire Retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill Gas	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00

[a] A plant that has been retrofitted to co-fire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

G.2.2 Solar Technologies

The *Wind Vision* analysis includes three primary solar technologies: utility-scale PV, rooftop PV, and CSP. Solar power technology capital costs are benchmarked to cost data reported by Bolinger and Weaver [18] and GTM Research/Solar Energy Industries Association [19]. Capital cost projections from the base year to 2020 are aligned with the DOE 62.5% Reduction scenario (from 2010) documented in the *SunShot Vision Study* [4]. This cost trajectory was subsequently grounded against a sample of cost projections from the EIA [17], International Energy Agency [2,] Bloomberg New Energy Finance [20], Greenpeace/European Photovoltaic Industry Association [21], and GTM Research/Solar Energy Industries Association [19,22]. After 2020, costs decline linearly to reach the DOE 75% Reduction scenario [4] by 2040. Although literature estimates that emphasize this time period are fewer, this cost trajectory is also generally consistent with an average literature estimate [2,23,24]. Costs are assumed to be unchanged (in real terms) from 2040 to 2050.[16] Performance for all solar technologies varies regionally and is based on solar irradiance data from the National Solar Radiation Database.

Table G-5 presents the capital and O&M cost assumptions over the model horizon for utility-scale PV, which ReEDS models based on 100-megawatt (MW) single-axis tracking systems. Regional capacity factors are

16 Potential justifications for a flat cost over this time period include increasing uncertainty with time and diminishing returns from research and development investment.

developed from the System Advisor Model's PV module [25] and range from 0.17 to 0.28.[17] The performance characteristics for ReEDS were developed using hourly weather data from the National Solar Radiation Database for 939 sites from 1998 to 2005. The representative PV capacity factor for each model BA reflects the site within each BA with the highest annual average capacity factor. No changes or improvements in capacity factor are assumed for utility-scale PV.

Table G–5. Technology Cost Assumptions for Utility-Scale PV (2013$)

Cost Type	2010	2013	2015	2020	2025	2030	2035	2040	2045	2050
Capital cost ($/kW$_{DC}$)	4,346	2,674	2,368	1,604	1,470	1,337	1,203	1,069	1,069	1,069
Fixed O&M ($/kW$_{DC}$-year)	21.73	18.47	16.30	7.61	7.61	7.61	7.61	7.61	7.61	7.61
Variable O&M ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Rooftop PV includes commercial and residential systems. The SolarDS model [15], a diffusion model for the continental U.S. rooftop market, is used to develop a future scenario for rooftop PV capacity. A single Rooftop PV scenario is exogenously defined for ReEDS and used across all scenarios in the *Wind Vision* analysis.

Similar to utility-scale PV, the cost assumptions used in the SolarDS modeling are based on the *SunShot Vision Study's* 62.5% and 75% solar cost reduction scenarios [4]. More specifically, the 62.5% cost reduction is reached in 2020 and the 75% cost reduction is reached in 2040.[18] Consistent with assumptions for all other technologies and policies, the current solar investment tax credit (ITC) trajectory is included in the SolarDS analysis. Specifically, a 30% ITC through 2016 dropping to 10% ITC after 2016 is included for all commercial systems.[19] All other assumptions are the same as those used in the *SunShot Vision Study* [4]. Figure G-1 shows the resulting capacity and generation trajectory for rooftop PV based on these assumptions and the SolarDS modeling. The rooftop PV trajectory shown in Figure G-1 includes 84 gigawatts (GW) by 2030 and 245 GW by 2050. Degradation of the efficiency of solar PV capacity over time is also modeled at 0.5% per year. This degradation is modeled by reducing the capacity of PV that generates energy by 0.5% per year.

The cost impacts of the scenarios presented in Chapter 3 exclude any costs associated with rooftop PV. Since the rooftop PV capacity trajectory is identical across all scenarios, essentially no impact on reported *incremental* costs of achieving the *Study Scenario* penetration levels is impacted by excluding costs associated with distributed generation. The only differences across scenarios associated with rooftop PV relate to rooftop PV curtailment estimates within ReEDS, which have only minor impacts. In addition, rooftop PV capital and O&M costs are excluded from ReEDS system expenditure estimates.

17 Capacity factors for utility-scale PV are based on the system capacity in watts direct current (W_{DC}) and generation in watts alternating current (W_{AC}). The capacity factor includes the conversion from DC to AC power.

18 Similar to other solar technologies, rooftop PV capital costs are linearly interpolated between 2020 and 2040 and the capital costs are held constant at the 75% *SunShot Vision Study* cost reductions in all years after 2040.

19 This assumption differs from the *SunShot Vision Study*, where the ITC was assumed to be eliminated after 2016.

The cost impacts of the scenarios presented in Chapter 3 exclude any costs associated with rooftop PV. Since the rooftop PV capacity trajectory is identical across all scenarios, essentially no impact on reported incremental costs of achieving the Study Scenario penetration levels is impacted by excluding costs associated with distributed generation. The only differences across scenarios associated with rooftop PV relate to rooftop PV curtailment estimates within ReEDS, which have only minor impacts. In addition, rooftop PV capital and O&M costs are excluded from ReEDS system expenditure estimates.

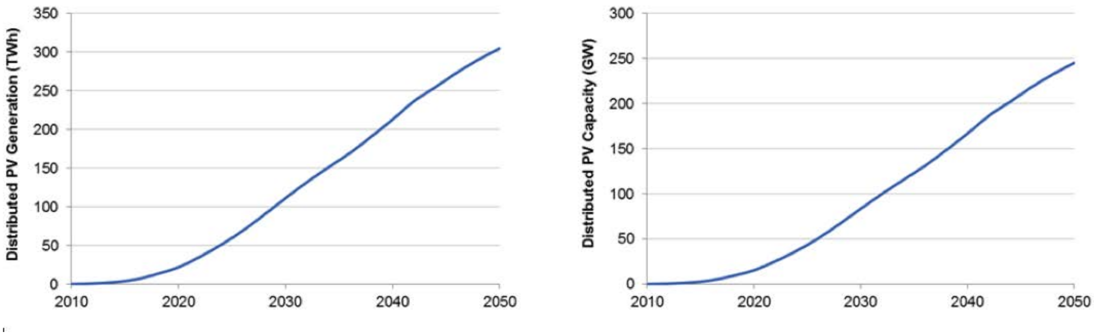


Figure G–1. Capacity GW and potential generation in terawatt-hours (TWh) of rooftop PV for all Study and Baseline Scenarios[20]

Consistent with assumptions around solar PV, assumptions for CSP with thermal energy storage (TES) costs are based on the 62.5% and 75% cost reduction scenarios from the SunShot Vision Study [4]. CSP capital costs are more complicated than other technologies because ReEDS optimizes the CSP system configuration through separate considerations for the turbine, solar field, and storage components of the system. Within its solutions, ReEDS can deploy CSP with TES plants with any configuration of solar multiples and storage capacity within certain limitations [4]. For example, the TES capacity must be between 6 and 12 hours of storage (rated at maximum power output), resulting in a capacity factor between 0.40 and 0.65. While future deployment of CSP systems will likely result in a range of technologies, the cost and performance assumptions in ReEDS assumes that trough systems are deployed prior to 2025 and power towers are deployed subsequently. Further details on CSP modeling in ReEDS can be found in the SunShot Vision Study [4].

Table G-6 shows the capital and O&M cost projections for CSP systems with six hours of TES and a solar multiple of two.[21]

Table G–6. Technology Cost Assumptions for CSP Systems with Six Hours of TES and a Solar Multiple of Two (2013$)

Cost Type	2010	2015	2020	2025	2030	2035	2040	2045	2050
Capital cost ($/kW)	6,780	6,780	4,072	3,824	3,576	3,328	3,080	3,080	3,080
Fixed O&M ($/kW-year)	84.98	67.98	50.99	50.99	50.99	50.99	50.99	50.99	50.99
Variable O&M ($/MWh)	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26	3.26

20 Potential generation does not remove curtailments, which are estimated internally by ReEDS. Curtailments for variable generation are removed in the generation reported in Chapter 3.

21 Solar multiple is defined as the ratio of the solar field capacity to the power block.

G.2.3 Hydropower

ReEDS includes approximately 76 GW of existing hydropower capacity for the model start year (2010). Existing hydropower energy potential is defined using region-specific, seasonal hydropower capacity factors averaged for 2001–2010, which are calculated from EIA historical generation and capacity data.

New hydropower resource potential is derived from national resource assessments performed by the Oak Ridge National Laboratory (ORNL). ORNL has assessed new hydropower stream-reach development potential using the U.S. Geological Survey National Hydrography Dataset and a hydropower development model. This model determines hydropower capacity and energy along all U.S. stream reaches while excluding sensitive regions such as national parks. It assumes new "low head" sites only with inundation bounded by the 100-year floodplain [26]. New hydropower resource also includes potential for adding power generating capacity to existing dams without generating capacity (non-powered dams). Non-powered dam potential has also been assessed by ORNL using the Army Corps of Engineers National Inventory of Dams [27]. These resource assessments include 37 GW of new site potential, capable of producing 213 TWh/year and 12 GW of non-powered dam potential, capable of producing 48 TWh/year.

O&M costs for all hydropower categories are based on the EIA AEO 2014 Reference scenario (Tables G-2 and G-3). Capital costs for new site development and non-powered dams are calculated using the Idaho National Laboratory hydropower cost model, which is a technology-agnostic model of cost as a function of design capacity [28]. This model was developed based on historical U.S. data on hydropower costs and can be applied to any hydropower category. Aggregating all hydropower resource and cost data for the contiguous United States forms a national hydropower supply curve (Figure G-2).

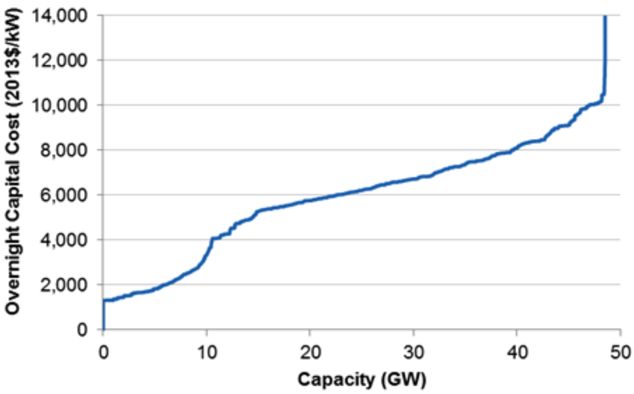


Figure G–2. National capital cost supply curve for new hydropower capacity

Hydropower operation is characterized by a seasonal energy budget and the ability to provide operating reserves and resource adequacy reserves. Existing sites, new sites, and non-powered dams are assumed to have sufficiently large water storage reservoirs to respond to diurnal variations in electricity demand, so all hydropower resources may distribute power output across ReEDS time slices in a season within the constraints of seasonal energy budgets. In addition, hydropower can offer up to 50% of total capacity (if not utilized for energy provision) for ReEDS operating reserves. All capacity contributes to resource adequacy reserves because the hydropower is assumed flexible enough to ramp quickly to full output if necessary. Reserve provision ability is a rough approximation based on limited information, as data are not readily available on historical reserve provision or capabilities for various regions. Further research is needed to identify the ability of hydropower to provide grid flexibility as well as the technological, financial, and environmental aspects of flexible hydropower operation.

G.2.4 Geothermal

Geothermal capital costs in ReEDS are based on regional supply curves developed from "Updated U.S. Geothermal Supply Curves" [29]. Augustine et al. [29] include capital costs and resource potential for identified and undiscovered hydrothermal, near-hydrothermal field-enhanced geothermal systems, and deep enhanced geothermal system wells, including discovered and potentially discovered resource. The geothermal supply curve in ReEDS for the *Wind Vision* analysis (Figure G-3) includes only the identified hydrothermal and near-hydrothermal field-enhanced geothermal. These two resource classes total about 15 GW of potential new capacity; however, only resources under $14,000/kW are shown in Figure G-3. The *Wind Vision* analysis excludes undiscovered hydrothermal, deep and greenfield-enhanced geothermal system, and other geothermal resources, which could expand the resource potential for geothermal. The set of geothermal resources assumed to be available is consistent with that used in the AEO 2014 Reference scenario [17]. A different set of resource and/or cost assumptions could yield different geothermal deployment levels in the scenarios.

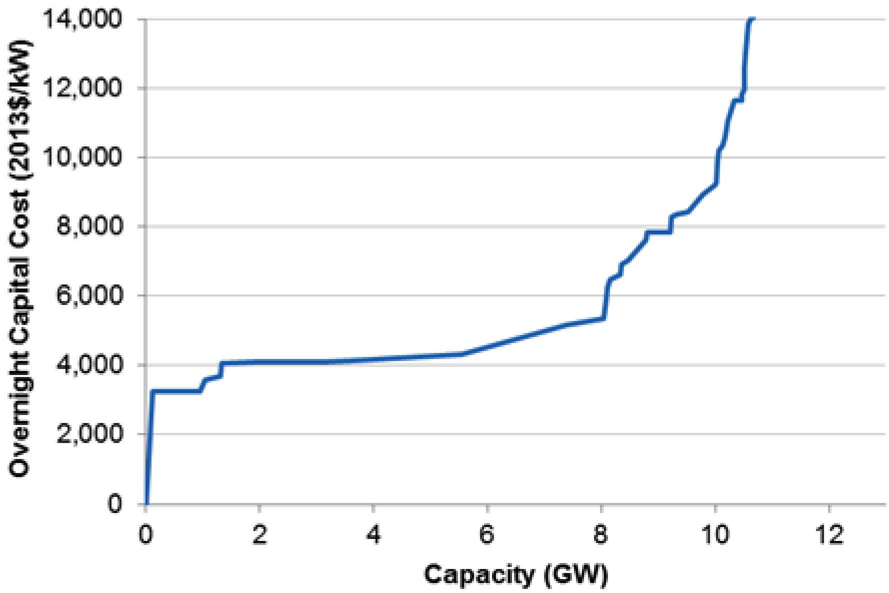
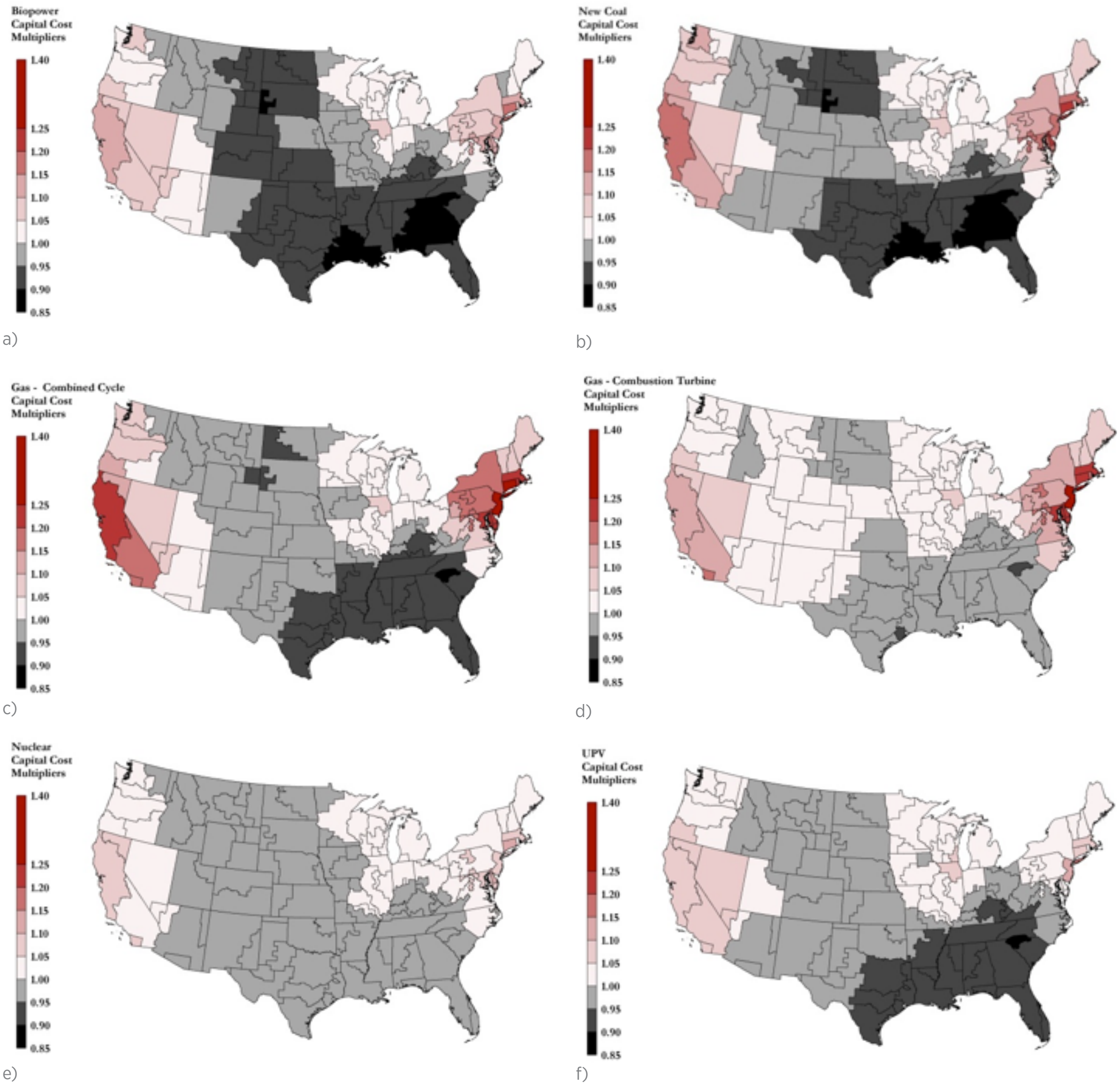


Figure G–3. Geothermal capacity supply curve for new, identified hydrothermal and near-hydrothermal enhanced geothermal system resources

G.2.5 Capital Cost Multipliers

For most generation technologies, regional cost multipliers are applied to reflect variations in installation costs across the United States. These regional multipliers are applied to the base overnight capital cost of the associated technology presented in earlier sections. The regional multipliers are technology-specific and are derived from Science Applications International Corporation's report for EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" [30]. While the regional costs presented in the Science Applications International Corporation report are based on particular cities, the regional multipliers for ReEDS are calculated by interpolating between these cities and using the average value over the ReEDS regions for each technology. The multipliers are applied to the base capital cost of each technology within ReEDS.[22] The resulting non-wind capital cost multipliers used in ReEDS are shown in Figure G-4.



Note: UPV = Utility-scale photovoltaics

Figure G–4. Maps of regional capital cost multipliers

22 Wind capital costs also have regional capital cost multipliers, which are described in detail in Appendix H.

G.3 Fuel Prices

The natural gas, coal, and uranium price assumptions used in the *Wind Vision* analysis are based on AEO 2014 scenarios [17]. Three natural gas scenarios are based on three AEO 2014 scenarios: Reference, Low Oil and Gas Resource, and High Oil and Gas Resource [17]. The analysis also relies on three coal price trajectories from AEO 2014: Reference, High Coal Price, and Low Coal Price. Since the AEO 2014 scenarios only extend to 2040, fuel prices are assumed to be constant between 2040 and 2050.[23] The application of these distinct fossil fuel cost projections to the modeled scenarios is described in Chapter 3. The *Central Study Scenario* and other scenarios that rely on Central Fuel Cost assumptions use the AEO 2014 Reference scenario prices for coal and natural gas; the High Fuel Cost sensitivity uses the AEO 2014 High Coal Cost and Low Oil and Gas Resource scenarios for coal and natural gas prices, respectively; and the Low Fuel Cost sensitivity uses the AEO 2014 Low Coal Cost and High Oil and Gas Resource scenarios. Figures G-5 and G-6 present the base natural gas and coal price trajectories, respectively, directly from the AEO scenarios.[24] All scenarios rely on the same uranium price trajectory based on the AEO 2014 Reference scenario (Figure G-7).

Natural gas prices in ReEDS are represented using a combination of a national and regional supply curves to take into account the price response to greater electric-sector natural gas consumption. In each year, each census region is characterized by a price-demand set point taken from the AEO Reference scenario, and two elasticity coefficients that model the rate of regional price change with respect to change in the regional gas demand from its set point and the overall change in the national gas demand from the national price-demand set point. These elasticity coefficients are developed through a regression analysis across an ensemble of AEO scenarios (as described in Logan et al. [11], though the numbers have since been updated using more recent AEO scenarios). The supply curves reflect natural gas resource, infrastructure, and non-electric sector demand assumptions embedded within the AEO modeling.

In addition to the natural gas supply curve representation in ReEDS, limited foresight is also included in the model for new natural gas capacity investments.[25] In particular, the effective investment cost for new NG-CC capacity includes an additional foresight term representing the present value of the difference between flat natural gas prices and expected future natural gas prices. This term is based on the trajectories in the associated AEO Natural Gas scenario.[26] This foresight does not affect the operation of an NG-CC plant in a given year, but it does affect the investment decision for new capacity.

23 Base natural gas prices are assumed constant during this time period, but the prices estimated in ReEDS vary by year.

24 Figure G-5 shows natural gas price trajectories directly from the AEO 2014 scenarios. While these trajectories are the basis of the prices observed in ReEDS, as described in this section, ReEDS endogenously conditions changes to natural gas prices based on its own estimates of natural gas consumption by the electricity sector.

25 Foresight terms are not included for other fuel-based technologies, as the slope of the fuel price trajectories for these other fuels is generally shallower than for natural gas.

26 For example, larger foresight terms are found for the Low Oil/Gas Resource scenario than for the Reference scenario because of the more rapid increase in estimated natural gas prices.

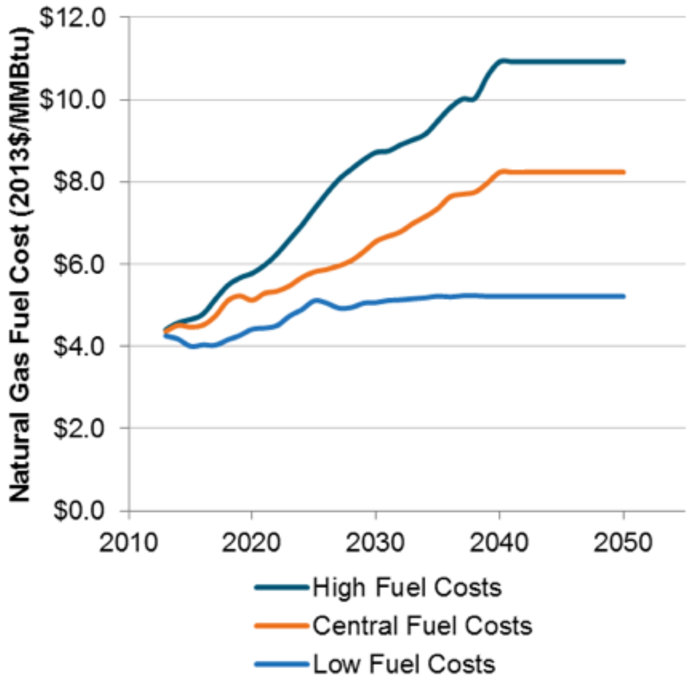


Figure G-5. Base natural gas price trajectories applied in the *Wind Vision* analysis (2013$/MMBtu)

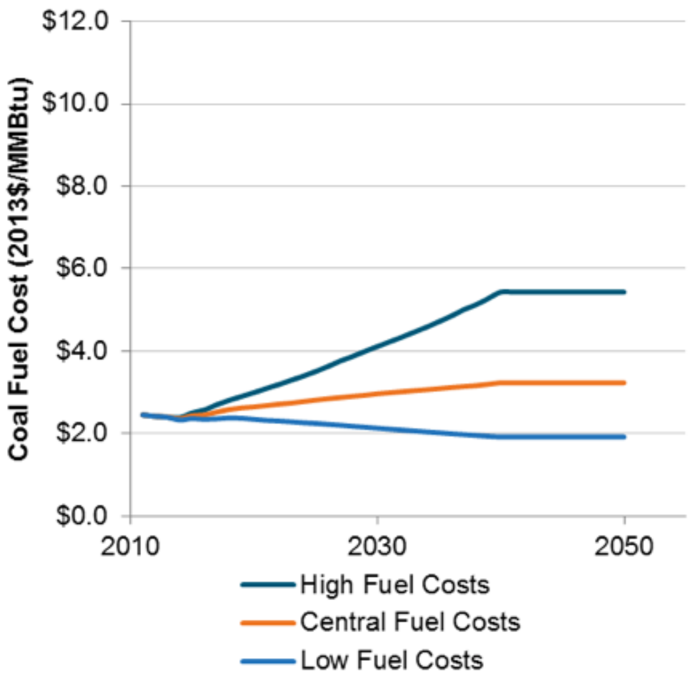


Figure G-6. Coal price trajectories applied in the *Wind Vision* analysis

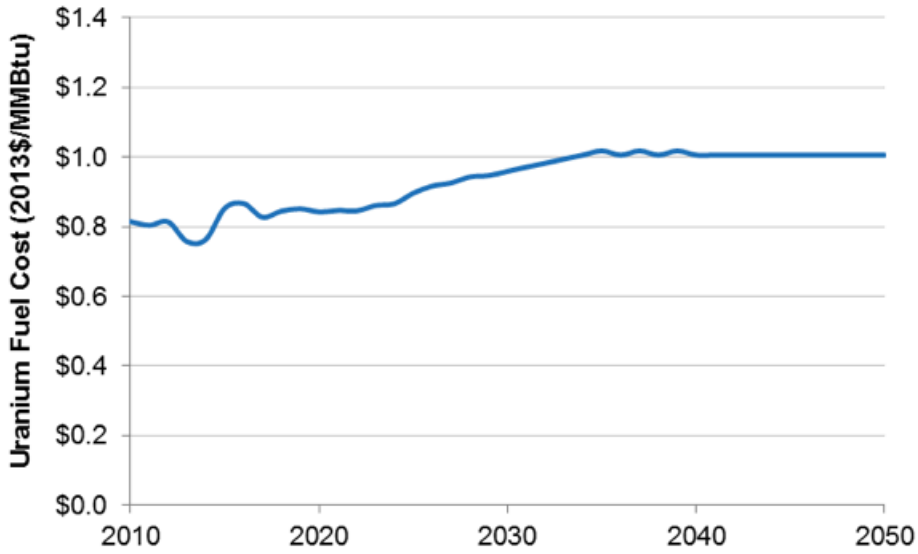


Figure G-7. Uranium Prices applied in the *Wind Vision* analysis

G.4 Retirements

Retirements in ReEDS are primarily a function of plant age and assumed lifetimes. Fossil fuel–fired plant ages are derived from data reported by Ventyx [31]. Coal plants less than 100 MW in capacity are retired after 65 years; coal plants greater than 100 MW in capacity are retired after 75 years. Natural gas and oil-fired capacity is assumed to have a 55-year lifetime. Nuclear plants are assumed to be approved for a single service life extension period, giving existing nuclear plants a 60-year life. No refurbishment costs or increased O&M costs are applied to extend the nuclear or fossil plant life. These age-based retirement assumptions result in nearly all of the existing (2012) oil and gas steam turbines and existing nuclear units being retired by 2050.[27] By 2050, about half of the existing coal capacity is also retired based solely on the age-based retirement assumptions. Age-based retirements have a lesser impact on natural gas capacity, with only about 35% of 2013 NGCT capacity and about 10% of 2013 NG-CC capacity retired by 2050.

In addition to age-based retirements, other near-term coal retirements are captured by incorporating announced retirements [32]; other long-term retirements are captured by considering plant utilization. Assumed age-based and announced coal retirements total 42 GW of coal capacity retirements from 2013 to 2020, 54 GW by 2030, and 166 GW by 2050. Modeled utilization-based coal retirements represent a proxy for economic-based considerations and accelerate coal retirements. This utilization-based retirement is implemented using an annual capacity factor threshold for each model BA. If the capacity factor is beneath the threshold in a given year, an amount of capacity is retired such that the capacity factor of the BA would be equal to that threshold. The utilization-based retirement is not active until 2020 and becomes increasingly stringent over time.[28] The oldest and least efficient extant coal units are retired preferentially in this scheme. In sum, the cumulative (starting in 2013) coal retirements in the Central Study Scenario total 43 GW by 2020, 67 GW by 2030, and 186 GW by 2050. While all generator types retire at the end of their defined equipment lifetimes, the site-specific technologies that have resource accessibility supply curves (wind, solar, geothermal) require some special consideration. When their capacity retires (e.g., wind capacity retires upon reaching its assumed 24-year life), the freed

27 The age-based retirements result in essentially no nuclear retirements by 2030. However, recent and announced nuclear retirements (e.g., the San Onofre Nuclear Generating Station retirement in 2013) are included in ReEDS.

28 The capacity factor threshold starts at 0.01% in 2020, increases linearly to 0.5% in 2040, and stays flat at that value until 2050.

resource potential in that site is available for new builds, but with a zero accessibility cost as the existing spur line and other site infrastructure for any new builds remain available from the prior facility.

As described previously in Section G.2.2, degradation of the efficiency of solar PV capacity over time is also modeled at 0.5% per year, which indicates that the capacity of PV that generates energy is reduced by 0.5% every year. For results detailed in this report, however, the total PV capacity does not reflect this degradation and remains at the initial nameplate capacity, while the generation reported from this capacity is reduced, reflecting the efficiency degradation of that capacity over time.

G.5 Financial Assumptions

ReEDS uses generalized financial assumptions that are standardized across technologies. While this may not accurately represent project financing today, the standardized method allows for a consistent comparison of technologies, without projecting uncertain technology-specific risk profiles into the future. The ReEDS financing assumptions allow for the comparison and competition of different projects and technologies with a long-term decadal perspective and with the spatial resolution of ReEDS.

Table G-7 lists the major financial parameters used in the ReEDS analysis. All costs, including new capital investments, O&M, fuel, and transmission investments, are considered on a 20-year, net-present-value basis. The discount rate used in the present value evaluation, which is the weighted average cost of capital based on the parameters shown by Table G-7, is 8.9% nominal (6.2% real).[29]

Table G–7. Major Financial Assumptions

Type of Assumption	Value Used
Evaluation period	20 years
Inflation rate	2.5%
Interest rate—nominal	8%
Rate of return on equity—nominal	13%
Debt fraction	50%
Combined state and federal tax	40%
Discount rate—nominal (real)	8.9% (6.2%)
Modified accelerated cost recovery system (MACRS) (non-hydropower renewables)	5 years
MACRS (nuclear, combustion turbines)	15 years
MACRS (other fossil, hydropower, storage)	20 years

In addition to the general financial assumptions, some technology-specific parameters are used in ReEDS. In particular, technology-specific construction periods yield different construction financing costs. Tax credits and accelerated tax depreciation rules also yield different financing effects across technologies. Finally, an additional risk adder is applied to new coal power plant capacity that does not include carbon capture and sequestration to reflect the long-term risk associated with potential new carbon or other environmental policies. This risk premium is represented by a three-percentage point increase on the interest rate and rate of return, which increases the 20-year net-present-value capital cost by approximately 11% [1]. This approach is consistent with assumptions made in the AEO [33].

29 ReEDS considers all costs in real dollar terms, but the parameters presented in Table G-7 are primarily nominal.

G.6 End-Use Electricity Demand

The primary constraint in ReEDS is to serve electricity load in each BA and time-slice. The end-use electricity demand projection used in ReEDS is exogenously defined. The scenarios presented in Chapter 3 all rely on the same end-use demand projection. The 2010 electricity demand in ReEDS is calibrated from Ventyx [31] (2013) and *EIA's Electric Power Annual 2012* [34]. In particular, Ventyx's hourly load data is temporally aggregated to determine the 17 time-slice load profiles for the model BAs. These 2010 profiles are scaled to match the state level annual load data from *EIA's Electric Power Annual 2012* [34]. The load growth factors for years after 2010 are calculated from the AEO 2014 Reference scenario's load projections by census regions [17].[30] For each solve year in ReEDS, the regional load profiles are increased by regional growth factors.[31]

Figure G-8 shows the end-use electricity demand projection for the continental United States as modeled in all scenarios presented in Chapter 3. While regional variations exist, the annual growth rate in this projection is about 0.8% per year from 2013 to 2050. In addition, ReEDS assumes 5.3% of the end-use demand as losses in the distribution system for all years and all regions.

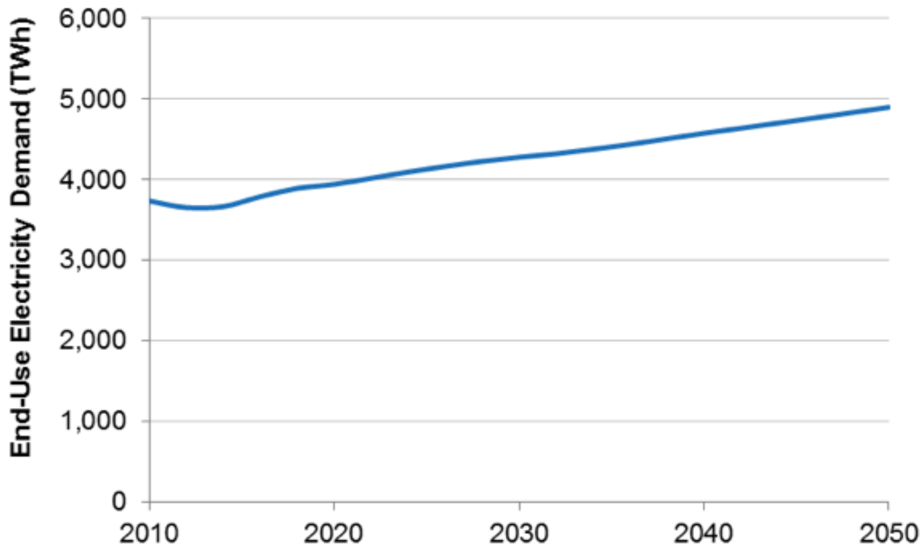


Figure G–8. Continental U.S. end-use electricity demand used in the *Wind Vision* analysis

The price-demand elasticity option in ReEDS is not used for the scenarios modeled for this report. Energy efficiency is only modeled indirectly through the embedded results of the AEO 2014 Reference scenario [17]. Similarly, demand response is only included to the extent that it was included in the AEO 2014 Reference scenario; the ReEDS scenarios did not explicitly include demand-side options to support wind integration or, more broadly, grid operations. Demand response is an option to increase grid flexibility through scheduled or fixed changes in electricity demand profiles and can be used to help support renewable grid integration. All things being equal, the absence of demand response likely overestimates the incremental cost of the Study Scenario, as a potentially important flexibility option is not made available in the model. Further work is needed to evaluate the costs and benefits of demand response within the scenarios explored in the *Wind Vision* analysis.

30 The demand growth factors from AEO's census regions are applied to the ReEDS NERC-level regions. Due to differences in AEO's census regions and the similarly sized NERC regions in ReEDS, the projected national load in ReEDS does not agree exactly with AEO's demand projections, but the differences are small, particularly on the national-level results.

31 For years after 2040, for which AEO does not have projections, the average growth rate projected between 2030 and 2040 is used.

G.7 Transmission Assumptions

For each scenario, ReEDS estimates the amount and location of transmission expansion, including long-distance inter-BA transmission, as well as intra-BA spur-line transmission needs for new wind capacity. Transmission dispatch is modeled for each of the ReEDS 17 time slices through a linearized direct current (DC) power flow algorithm between the 134 model BAs. This section provides further detail on the transmission assumptions used in modeled scenarios.

G.7.1 Long Distance Transmission

The existing (2010) long-distance transmission infrastructure is modeled in ReEDS with more than 300 aggregate long-distance transmission lines connecting 134 BAs, shown in Figure G-9. The initial transmission infrastructure is based on data for 2010.[32] The existing transmission network comprises primarily alternating current (AC) transmission lines. Expansion of the AC network between adjacent BAs is a model decision based on the overall system optimization of the model. Due to the long siting, permitting, and construction lead times needed for transmission projects, ReEDS restricts all pre-2020 transmission expansion to projects already underway (see Table G-8).

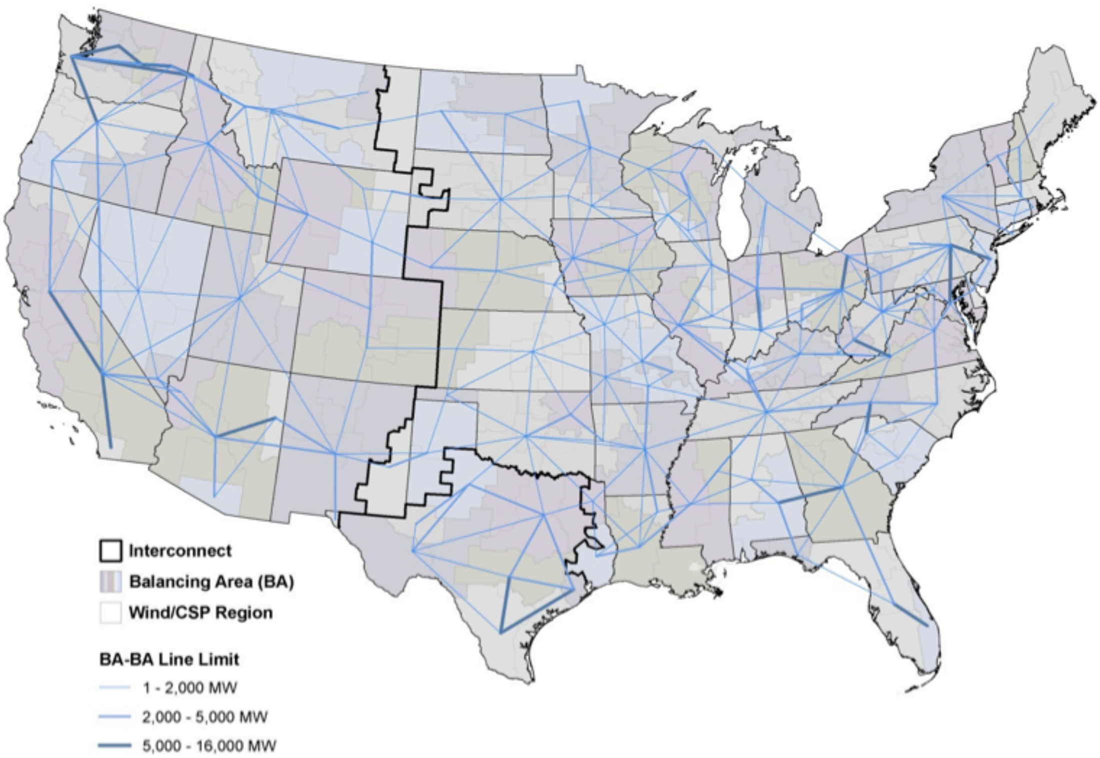


Figure G–9. Existing long-distance transmission infrastructure in ReEDS

ReEDS also considers DC transmission lines, including existing DC lines and any DC interties between the three major interconnections. Expansion of the DC network is limited to the planned DC projects under construction (Table G-9) and the expansion of the cross-interconnection AC-DC-AC interties. It is important to note that, while the system-wide optimization and linear program in ReEDS is intended to consider the transmission needs for

32 See Short et al. [1].

remote resources and to provide high-level estimates of transmission expansion and associated costs, it is not designed as a transmission planning tool. As such, the transmission results from and assumptions used in ReEDS are not intended to distinguish among different transmission technologies into the future, including important distinctions between AC and DC lines.

Table G–8. Allowed AC Transmission Builds Before 2020

Adair-Ottumwa
Adair-Palmyra Tap
Big Eddy-Knight
Big Hill-Kendall
Bluff Creek-Brown
Brookings-Hampton
Central Bluff-Bluff Creek
Clear Crossing-Willow Creek
Fargo-St. Cloud
Glenwillow-Bruce Mansfield
Gray-Tesla
Greater Springfield Reliability Project
Greenline
Hampton-La Crosse
High Plains Express
Hitchland-Woodward
I-5 Corridor Reinforcement
Interstate Reliability Project
KETA Project
Lakefield Junction-Webster
Las Vegas-Los Angeles
McNary-JohnDay
Midwest Transmission Project
Mountain States Transmission Intertie
N. LaCrosse-Cardinal
North Gila-Imperial Valley
Odessa-Bakersfield
One Nevada Transmission Line
Palmyra Tap-Pawnee
Pawnee-Pana
Pioneer Transmission
Pleasant Prairie Zion Energy Center
Reynolds Rockport
Riley-Bowman
Riley Krum West

Table G-8. *(cont.)* Allowed AC Transmission Builds Before 2020

RITELine
RS20-Silver King-Coronado
Seminole-Muskogee Project
Southwest Intertie
Sunzia Southwest
Susqeuenanna-Roseland
Tesla-West Shackelford
Tippet-North McCamey
Toronto-Harmon Star
Trans Allegheny Interstate Line
TUCO-Texas/Oklahoma Interconnect
Twin Buttes-Brown
Winco-Hazleton
Woodward-Hitchland

Table G–9. List of Allowed DC Transmission Builds.

Zephyr
Southern Cross
Plains and Eastern Clean Line
High Plains Express
Grainbelt Express Clean Line
Northeast Energy Link

G.7.2 Spur-line Transmission and Geospatial Supply Curves

Because the resources for wind and CSP are highly sensitive to location, they are assessed additional costs to represent the needed spur lines, based on an estimated distance to transmission infrastructure. These supply curves are developed based on geographic-information-system analysis, which estimates the resource accessibility costs in terms of supply curves based on the expected cost of linking renewable resource sites to the high-voltage, long-distance transmission network. The details on the assumptions and methods used to estimate the supply curves for these intra-regional spur lines are provided in Appendix H.

G.7.3 Transmission Costs

The long distance and spur-line transmission costs in ReEDS are based on ReEDS line voltage and regional multiplier assumptions. For long-distance interregional transmission lines, an assumed voltage (345 kilovolts [kV], 500 kV, or 765 kV) is applied for each region. This voltage assumption for each BA for long-distance transmission is taken from the highest voltage line currently operating in the BA from the Homeland Security Infrastructure Program [35]. For BAs where the highest voltage of currently operating transmission lines is less than 500 kV, the voltage in the future is assumed to be 765 kV; and the associated costs for 765 kV lines are used for all years. For BAs where the highest voltage of currently operating transmission lines is 500 kV, the costs for 500-kV lines are used. The only exceptions to these rules for voltages are in the Eastern Interconnection, for BAs in New England (Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine) and New York, which are assumed to use 345-kV transmission lines for all years. A base capital cost is associated with each voltage line from the Phase II Eastern Interconnection Planning Collaborative (EIPC) report [36]. The base transmission costs taken from the EIPC report used in ReEDS are $2,333/MW-mile, $1,347/MW-mile, and $1,400/MW-mile for 345-kV, 500-kV, and 765-kV transmission lines, respectively [36].[33]

All wind spur-line costs are based on 230-kV line costs, assumed to be $3,667/MW-mile [36].[34] Because the plant envelope used to determine technology capital cost assumptions includes the on-site switchyard, the short spur line, and the relevant upgrades at the substation [30]; technologies that are generally sited close to load incur no additional grid interconnection cost.

In addition to the base transmission costs for long-distance transmission lines, regional multipliers, largely based on assumptions from the EIPC report [36], are also applied. Regional transmission cost multipliers, which are the average of the EIPC report's high and low multipliers in each North American Electricity and Environmental Model region, are associated with the assumed voltage for the region. BAs in the Electric Reliability Council of Texas and the Western Interconnection (excluding Canada) are assumed to have a regional transmission multiplier of one. Long-distance transmission costs in BAs in the California Independent System Operator are 2.25 times the cost of the other baseline costs for the rest of the Western Interconnection. For long-distance transmission between BAs with different transmission costs, the average cost is used. The same process is applied for wind spur-line costs.

Figures G-10 and G-11, respectively, show the regional long-distance and spur-line transmission costs resulting from the previously described steps and assumptions.

33 The base transmission costs for ReEDS are converted into dollars/MW-mile according to new transmission line cost and capacity assumptions for single-circuit conductors for each voltage in the EIPC report [36]. The costs reported are in 2010 dollars as used by the EIPC.

34 The wind spur-line costs are applied within the development of the wind resource supply curve (see Appendix F).

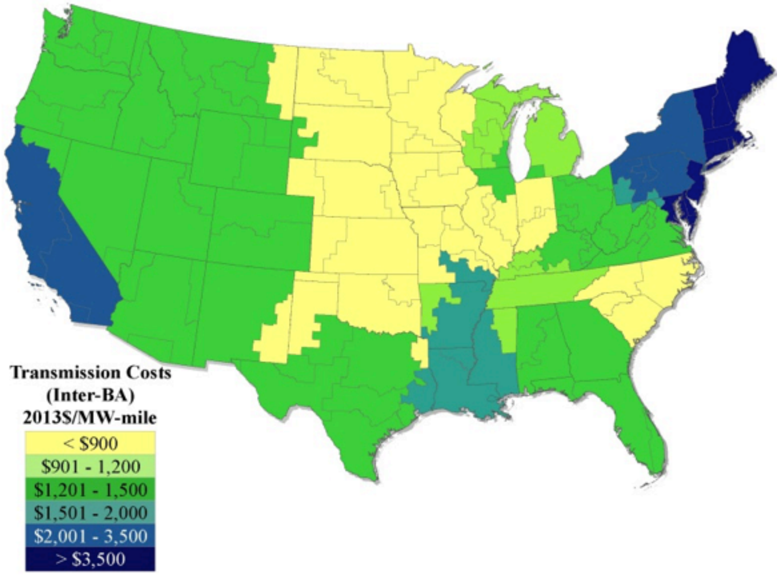


Figure G–10. Map of long-distance transmission costs

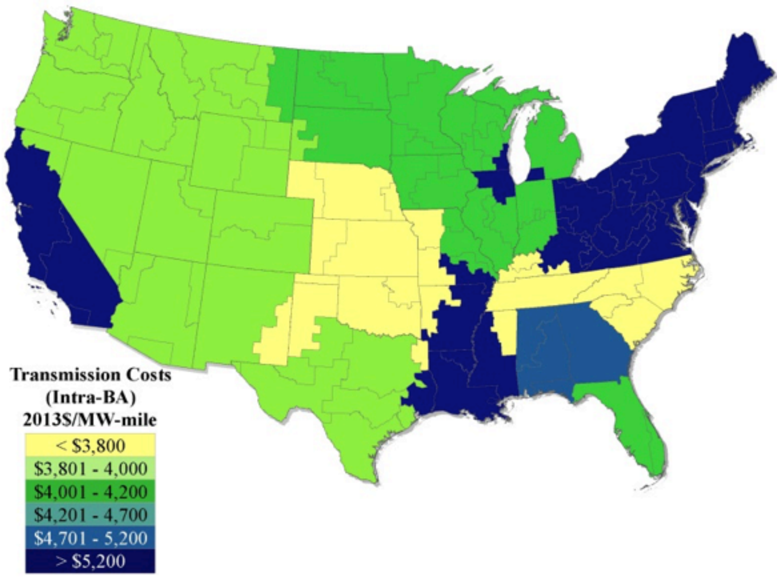


Figure G–11. Map of spur-line transmission costs

G.7.4 Transmission Dispatch

The long-distance transmission dispatch is modeled in ReEDS using a linearized DC power flow algorithm for the AC transmission network [10]. The algorithm approximates Kirchhoff's voltage law by determining the power flow in a network based on injections and withdrawals at each BA, and the line susceptances and carrying capacities. Full flow control is modeled for DC lines in ReEDS. The ReEDS model considers these transmission flow limits when dispatching energy generation in each of the 17 time slices and in contracting firm capacity for system adequacy needs. Adding capacity on a transmission corridor in a particular ReEDS solve year increases that line's susceptance in subsequent years, thus increasing the proportion of a power injection that takes that route. ReEDS does not address the AC-power-flow issues of voltage, frequency, or phase angle. Intra-BA transmission and distribution networks are similarly ignored. However, the transmission dispatch accounts for losses in the long-distance transmission, as well as the distribution networks. Long-distance transmission energy losses are assumed to be 1% per 100 miles. These losses are representative of the losses occurring over the high-voltage bulk transmission system. As mentioned earlier, for losses within a distribution network and between the distribution and transmission networks, a 5.3% loss is assumed for each model BA.

G.8 References

[1] Short, W.; Sullivan, P.; Mai, T.; Mowers, M.; Uriarte, C.; Blair, N.; Heimiller, D.; Martinez, A. *Regional Energy Deployment System* (ReEDS). NREL/TP-6A20-46534. Golden, CO: National Renewable Energy Laboratory, December 2011; 94 pp. Accessed Jan. 7, 2015: www.nrel.gov.

[2] "Form EIA-411 Data." U.S. Department of Energy Energy Information Administration, Jan. 28, 2013. Accessed Jan. 26, 2015: http://www.eia.gov/electricity/data/eia411/.

[3] *The National Energy Modeling System: An Overview 2009.* DOE/EIA-0581(2009). Washington, DC: U.S. Department of Energy Energy Information Administration, October 2009; 77 pp. Accessed Jan. 26, 2015: http://www.eia.gov/oiaf/aeo/overview/.

[4] *SunShot Vision Study.* DOE/GO-102012-3037. Washington, DC: U.S. Department of Energy Office of Energy Efficiency & Renewable Energy (February 2012); 320 pp. Accessed Jan. 26, 2015: http://data.globalchange.gov/report/doe-go-102012-3037.

[5] Mai, T.; Wiser, R.; Sandor. D.; Brinkman, G.; Heath, G.; Denholm, P.; Hostick, D.; Darghouth, N.; Schlosser, A.; Strzepek, K. *Exploration of High-Penetration Renewable Electricity Futures.* Vol. 1 of *Renewable Electricity Futures Study.* NREL/TP-6A20-52409-1. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Jan. 5, 2015: www.nrel.gov.

[6] Lantz, E.; Steinberg, D.; Mendelsohn, M.; Zinaman, O.; James, T.; Porro, G.; Hand, M.; Mai, T.; Logan, J.; Heeter, J.; Bird, L. *Implications of a PTC Extension on U.S. Wind Deployment.* NREL/TP-6A20-61663. Golden, CO: National Renewable Energy Laboratory, April 2014. Accessed Jan. 5, 2015: www.nrel.gov.

[7] Eurek, K.; Denholm, P.; Margolis, R.; Mowers, M. *Sensitivity of Utility-Scale Solar Deployment Projections in the SunShot Vision Study to Market and Performance Assumptions.* NREL/TP-6A20-55836. Golden, CO: National Renewable Energy Laboratory, 2013. Accessed Jan. 3, 2015: www.nrel.gov.

[8] Martinez, A.; Eurek, K.; Mai, T.; Perry, A. Integrated Canada-U.S. *Power Sector Modeling with the Regional Energy Deployment System (ReEDS).* NREL/TP-6A20-56724. Golden, CO: National Renewable Energy Laboratory, 2013. Accessed Jan. 6, 2015: www.nrel.gov.

[9] Logan, J.; Heath, G.; Macknick, J.; Paranhos, E.; Boyd, W.; Carlson, K. *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity.* NREL/TP-6A50-55538. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Jan. 5, 2015: www.nrel.gov.

[10] Mai, T.; Mulcahy, D.; Hand, M.; and Baldwin, S. 2014. "Envisioning a Renewable Electricity Future for the United States." Energy. Vol. 65 pp. 374-386. 1 February, 2014. http://dx.doi.org/10.1016/j.energy.2013.11.029

[11] Logan, J.; Lopez, A.; Mai, T.; Davidson, C.; Bazilian, M.; Arent, D. "Natural Gas Scenarios in the U.S. Power Sector." *Energy Economics* (40), November 2013; pp. 183–195. Accessed Jan. 5, 2015: http://www.sciencedirect.com/science/article/pii/S0140988313001217.

[12] Clemmer, S.; Rogers, J.; Sattler, S.; Macknick, J.; Mai, T. "Modeling Low-Carbon US Electricity Futures to Explore Impacts on National and Regional Water Use." *Environmental Research Letters* (8:1), January-March 2013; 11 pp. Accessed Dec. 29, 2014: http://dx.doi.org/10.1088/1748-9326/8/1/015004.

[13] Mignone, B.K.; Alfstad, T.; Bergman, A.; Dubin, K.; Duke, R.; Friley, P.; Martinez, A.; Mowers, M.; Palmer, K.; Paul, A.; Showalter, S.; Steinberg, S.; Woerman, M.; Wood, F. "Cost-Effectiveness and Economic Incidence of a Clean Energy Standard." *Economics of Energy & Environmental Policy* (1:3), 2012; pp. 59–86. Accessed Jan. 6, 2015: http://www.iaee.org/en/publications/eeeparticle.aspx?id=32.

[14] *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply.* DOE/GO-102008-2567. Washington, DC: U.S. Department of Energy, 2008. Accessed Dec. 13, 2014: http://www.20percentwind.org/.

[15] Denholm P.; Drury, E.; Margolis, R. The Solar Deployment System (SolarDS) *Model: Documentation and Sample Results.* NREL/TP-6A2-45832. Golden, CO: National Renewable Energy Laboratory, 2009. Accessed Dec. 30, 2014: www.nrel.gov.

[16] Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D.; eds. *Renewable Electricity Futures Study*. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory, 2012, 4 vols. Accessed Dec. 28, 2014: http://www.nrel.gov/.

[17] *Annual Energy Outlook 2014 with Projections to 2040.* DOE/EIA-0383(2014). Washington, DC: U.S. Department of Energy Energy Information Administration, April 2014a; 269 pp. Accessed Jan. 26, 2015: www.eia.gov/forecasts/aeo.

[18] Bolinger, M.; Weaver, S. *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* LBNL-6408E. Berkeley, CA: Lawrence Berkeley National Laboratory, 2013. Accessed Dec. 29, 2014: http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends.

[19] "Solar Market Insight 2013 Q3." GTM Research and Solar Energy Industries Association (SEIA). Washington, DC: SEIA, 2013. Accessed Jan. 3, 2015: http://www.seia.org/search/Q3%202013.

[20] "Q1 2013 North America Wind Market Outlook." New York: Bloomberg New Energy Finance, 2013.

[21] *Energy [R]evolution,* 4th ed. Prepared by Global Wind Energy Council, Greenpeace International, European Renewable Energy Council. Washington, DC: Greenpeace, July 2012; 340 pp. Accessed Jan. 3, 2015: http://www.greenpeace.org/international/en/campaigns/climate-change/energyrevolution/.

[22] "Solar Market Insight 2011 Q4." GTM Research and Solar Energy Industries Association (SEIA). Washington, DC: SEIA, 2011. Accessed Feb. 9, 2015: http://www.seia.org/research-resources/us-solar-market-insight-report-2011-year-review.

[23] *Technology Roadmap: 2013 Edition.* Paris: International Energy Agency, 2013; 63 pp.

[24] "Q4 2013 PV Market Outlook." New York: Bloomberg New Energy Finance, 2013b.

[25] "System Advisor Model (SAM)." Version 2010.4.12. Golden, CO: National Renewable Energy Laboratory, 2010. Accessed Jan. 27, 2015: https://www.nrel.gov/analysis/sam/.

[26] Hadjerioua, B.; Kao, S.-C.; McManamay, R.A.; Pasha, M.F.K.; Yeasmin, D.; Oubeidillah, A.A.; Samu, N.M.; Stewart, K.M.; Bevelhimer, M.S.; Hetrick, S.L.; Wei, Y.; Smith, B.T. *An Assessment of Energy Potential from New Stream-Reach Development in the United States: Initial Report on Methodology.* Technical Manual 2012/298. Oak Ridge, TN; Oak Ridge National Laboratory, 2013. Accessed Jan. 4, 2015: http://nhaap.ornl.gov/nsd.

[27] Hadjerioua, B.; Wei, Y.; Kao, S.-C. *An Assessment of Energy Potential at Non-Powered Dams in the United States.* GPO DOE/EE-0711. Prepared by Oak Ridge National Laboratory for the U.S. Department of Energy Wind and Water Power Program. Oak Ridge, TN: Oak Ridge National Laboratory, April 2012. Accessed Jan. 4, 2015: http://www.worldcat.org/title/assessment-of-energy-potential-at-non-powered-dams-in-the-united-states-report/oclc/842094581.

[28] Hall, D.G.; Hunt, R.T.; Reeves, K.S.; Carroll, G.R. *Estimation of Economic Parameters of U.S. Hydropower Resources.* INEEL/EXT-03-00662. Idaho Falls, ID: Idaho National Engineering and Environmental Laboratory, June 2003; 74 pp.

[29] Augustine, C.; Young, K.; Anderson, A. "Updated U.S. Geothermal Supply Curve." NREL/CP-6A2-47458. Presented at the 35th Stanford Geothermal Workshop, Stanford University, Feb. 1–-3, 2010. Golden, CO: National Renewable Energy Laboratory, 2010; 19 pp. Accessed Dec. 28, 2014: www.nrel.gov.

[30] Beamon, A.; Leff, M. *EOP III Task 1606, Subtask 3—Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report. Appendix B of Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Work performed by SAIC Energy, Environment & Infrastructure, McLean, VA. Washington, DC: U.S. Energy Information Administration, April 2013. Accessed Dec. 21, 2014: http://www.eia.gov/.

[31] "Energy Market Intelligence & Forecasting Solutions." Ventyx, 2013. Accessed Jan. 27, 2015: http://www.ventyx.com/velocity/energy-market-data.asp.

[32] Saha, A. "Review of Coal Retirements." Concord, MA: M.J. Bradley and Associates, April 12, 2013; 8 pp. Accessed Jan. 7, 2015: http://www.mjbradley.com/reports/coal-plant-retirement-review.

[33] *Assumptions to the Annual Energy Outlook 2014.* Washington, DC: U.S. Department of Energy Energy Information Administration Independent Statistics & Analysis, June 2014; 197 pp. Accessed Jan. 26, 2015: http://www.eia.gov/forecasts/aeo/assumptions/.

[34] *Electric Power Annual 2012.* Washington, DC: U.S. Department of Energy Energy Information Administration, December 2013; 235 pp. Accessed Jan. 26, 2015: http://www.eia.gov/electricity/annual/. Electric Power Annual 2012. Washington, DC: U.S. Department of Energy Energy Information Administration, December 2013; 235 pp. Accessed Jan. 26, 2015: http://www.eia.gov/electricity/annual/.

[35] "Homeland Security Infrastructure Program" (HSIP). HSIP, 2012. Accessed February 10, 2015: https://www.hifldwg.org/hsip-guest.

[36] *Phase 2 Report: DOE Draft Parts 2–7—Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Washington, DC: Eastern Interconnection Planning Collaborative, Dec. 22, 2012; 103 pp. Accessed Jan. 27, 2015: http://www.eipconline.com/Phase_II_Documents.html.

This page is intentionally left blank

Appendix H: *Wind Vision* Wind Power Technology Cost and Performance Assumptions

This appendix defines cost and performance assumptions for wind technology in the *Wind Vision* analysis. First, the landscape of current U.S. land-based and offshore wind (OSW) technology costs is described. Second, the conversion of market-reported numbers to terms appropriate for use in the Regional Energy Deployment System (ReEDS) model is traced. Finally, the future wind cost reduction trajectories applied in the *Wind Vision* analysis are outlined. The scope of this appendix is utility-scale wind technology installations[1] in the United States. Scenarios analyzing the impact of changes expected in wind technology over the coming decades are discussed in Chapter 3 of the *Wind Vision* report. Actions that could assist in bringing about the cost reductions and performance improvements in these scenarios are highlighted in Chapter 4. Modeling assumptions for current and future costs of other power generation, transmission, and storage technologies are found in Chapter 3 and Appendix G.

The primary elements of this appendix are:

- A description of base-year technology cost and performance parameters
- A description of the methodology used to convert market data into a format that can be used as input to the ReEDS model
- A description of project-level costs to connect to the transmission grid (not including long-haul transmission costs that are "built" by the ReEDS model based on how a study scenario is developed)
- A table of the cost and performance parameters chosen as inputs to represent techno-resource groups (TRGs) in the ReEDS model
- A graphical representation of the elements that produce the total project costs as "seen" by ReEDS for all potential project sites
- A description of future wind power cost and performance characteristics applied in the *Wind Vision* analysis.

H.1 Overview

The ReEDS model represents a range of electricity generation technologies, including land-based and offshore wind technologies. This appendix describes the methods used to develop ReEDS inputs for wind power technologies, based on market data, geographic cost and performance variation, distance to existing transmission infrastructure, and project financing. To the extent possible, ReEDS model assumptions reflect the best available published representation of land-based and offshore wind plant costs, performance, and geographic variation for the base year (2012). In addition, projections of future capital cost, operating cost, and energy production through 2050 are based on published literature and industry perspectives, with the latter obtained through interviews and additional literature.

H.1.1 Development of the Wind Energy Supply Curve

The Wind Energy Supply Curve is a representation of the cost of energy at all potential wind plant sites in contiguous states at a single point or snapshot in time. Figure H-1 demonstrates the elements needed to represent wind technology as a Wind Energy Supply Curve: project financing, grid connection costs, and wind plant techno-economic cost and performance in the base year and future years. The starting points for ReEDS deployment decisions are the cost and performance parameters that go into the supply curve calculations. ReEDS capacity expansion and dispatch decision-making considers the present value of investments associated with adding and operating new generation capacity (considering transmission and operational integration)

1 Land-based and offshore. Distributed wind is not modeled in the *Wind Vision.*

over an assumed financial lifetime.[2] The metric Levelized Cost of Electricity (LCOE) is used in this appendix to illustrate the relative cost of potential wind plant capacity additions, in a manner that is consistent with the ReEDS net present value estimates.

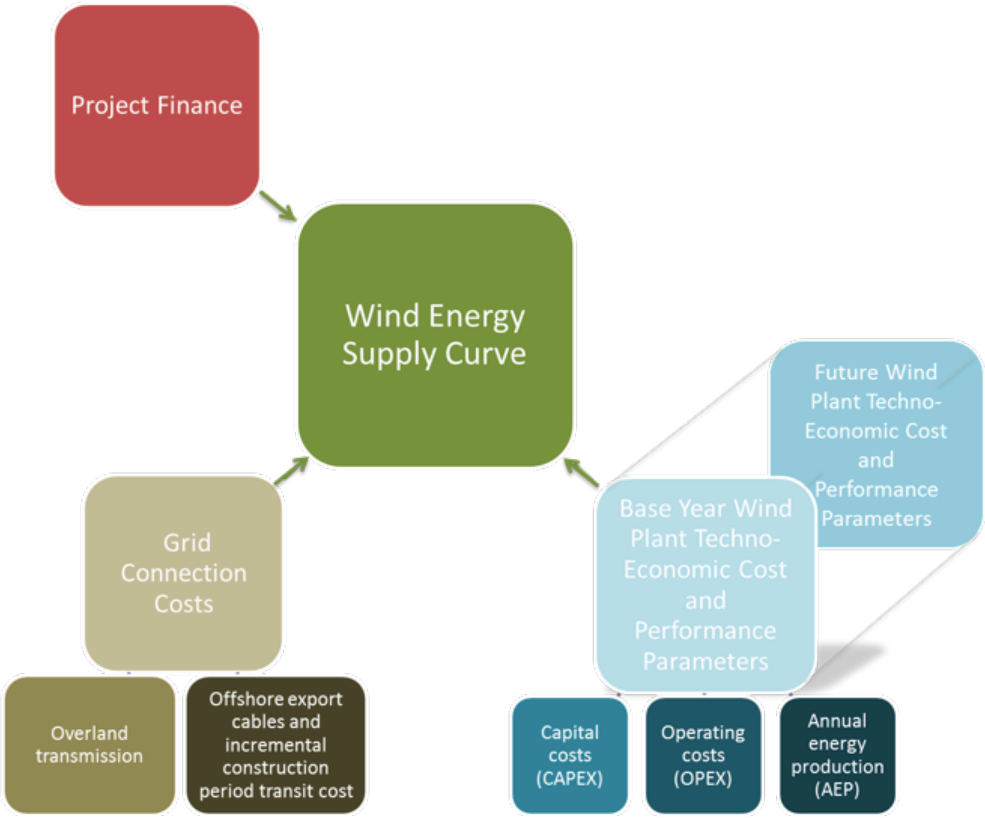


Figure H-1. Components of the wind energy supply curve

Wind plant techno-economic cost and performance parameters, considering geographic parameters, are presented for the base year as well as future years. For each potential wind plant location, energy production is estimated based on a wind turbine power curve and hourly wind profile. Capital costs and operating costs are developed reflecting market observations of recently installed wind plants. All potential wind plant locations are sorted into techno-resource groups (TRGs) for representation in the ReEDS model. There are five TRGs for land-based wind technology and 10 TRGs for offshore wind technology. Base-year wind plant assumptions are described in Section H.2. Base-year costs in this appendix are presented in 2013$. For land-based projects, the base year is assumed to be 2012, as costs are derived from projects installed in 2012. For offshore projects, the base year is assumed to represent financial close in 2012 and installation in 2014; no offshore plants have been built in the United States at the time of this report. LCOE estimates represent the cost of a wind plant and do not include potential revenue offsets such as the Production Tax Credit or Investment Tax Credit.

To simplify modeling, electric generation plant financing costs are assumed to be equivalent for nearly all technology options modeled in the *Wind Vision* analysis, implying a similar long-term perception of risk among

2 For more information about ReEDS, see Chapter 3 and Appendix G.

the finance community for all technologies.[3] While offshore wind financing is presumably at a premium today, this analysis assumes that this premium diminishes rapidly with demonstrated experience of the technology in the United States and further experience through deployment in Europe and Asia. Therefore, standard ReEDS financing assumptions were used throughout the study period.[4] LCOE calculations in this appendix use a Fixed Charge Rate (FCR) to approximate annualized charges associated with offshore wind project financing. For ReEDS financing, FCR = 10% reflecting a nominal weighted average cost of capital (WACC) of 8.9%. The FCR value is derived from the detailed ReEDS model assumptions on project financing costs summarized in Table H-1 and described in Section H.3.

Grid connection costs are the costs to connect to the transmission network, including costs to associate potential wind plants with a grid feature (e.g., existing substation or population center) and build a plant-level spur transmission line to access the grid feature. Offshore wind plants include an additional incremental distance-based cost associated with connecting the wind plant to shore and transit during construction. The methodology used to derive grid connection costs is described in Section H.4.

As shown in Figure H-2, the United States has nearly 8,000 gigawatts (GW) of available resource, after applying standard exclusions, which are represented in terms of the strength of the wind resource (e.g., expected energy output), project capital and operating costs, financing costs, and the cost of getting the electricity to the grid. Base-year costs for delivered electricity range from approximately $50/megawatt-hour (MWh) to less than $100/MWh for land-based wind, and from approximately $170/MWh to about $240/MWh for offshore wind. The LCOE equation used to represent the range of potential wind plant cost of energy is described below; subsequent sections of the appendix provide additional context for each of the variables in the equation. Wind energy supply curves representing base-year wind plant assumptions for each region of the United States are included in Section H.5.

3 New coal plant capacity without carbon capture and sequestration capabilities are an exception. These technologies are assessed with a three-percentage-point financing cost premium on both debt and equity due to the long-term carbon emissions risk associated with these facilities (see also Appendix G).

4 Offshore wind base-year LCOE calculations are also presented at a market finance rate for reference purposes in Table H-1.

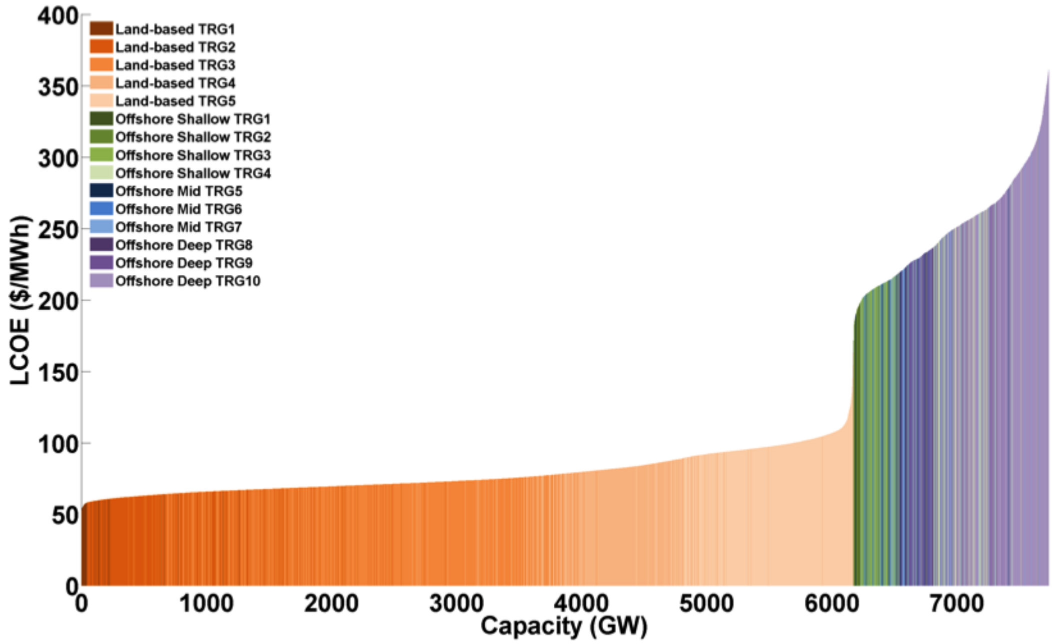


Figure H-2. Base-year wind plant LCOE for the contiguous United States

The following equations are used to calculate LCOE in the Wind Energy Supply Curve:

$$LCOE = \frac{FCR * CAPEX + OPEX}{CF * 8760}$$
$$FCR = CRF * ProFinFactor$$
$$CRF = \frac{WACC - 1}{1 - \left(\frac{1}{WACC}\right)^{t}}$$
$$WACC = \frac{(1 + [(1 - DF)(RROE * i - 1)] + [DF(IR * i - 1)(1 - TR)])}{i}$$
$$ProFinFactor = \left(\frac{1 - TR * PVD}{1 - TR}\right)$$
$$PVD = \sum_{y=1}^{M+1} FD_y f_y$$
$$f_y = \frac{1}{d^y}$$
$$d = WACC * i$$
$$CAPEX = ConFinFactor * (OCC * CapRegMult + GCC)$$
$$ConFinFactor = \sum_{y=0}^{C-1} AI_y\, FC_y$$
$$AI_y = 1 + (1 - TR) * (IDC^{y+0.5} - 1)$$
$$GCC = GF + OnSpurCost + OffSpurCost$$
$$OnSpurCost = OnDist \times OnTransCost \times OnRegTransMult$$
$$OffSpurCost = OffDist \times OffDistFactor$$

Table H-1. Parameters Required to Calculate LCOE

	Symbol	Name	Definition
Project Finance	*t*	Economic Lifetime (years)	Length of time for paying off assets. (20 years for all technologies)
	DF	Debt Fraction	Fraction of capital financed with debt. *1-DF* is assumed financed with equity. (50% for all technologies)
	RROE	Rate of Return on Equity (real)	Assumed rate of return on the share of assets financed with equity. (10% real/13% nominal for all technologies)
	IR	Interest Rate (real)	Assumed interest rate on debt. (5.4% real/8% nominal for all technologies)
	i	Inflation Rate	Assumed inflation rate based on historical data. (2.5%)
	TR	Tax Rate	Combined state and federal tax rate. (40%)
	M	Depreciation Period (years)	Number of years in in Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. (5 for wind plants)
	FD	Depreciation Fraction	Fraction of capital depreciated in each year, 1 to M. (20%, 32%, 19.2%, 11.5%, 11.5%, 5.76% for wind plants)
	CRF	*Capital Recovery Factor*	*The ratio of a constant annuity to the present value of receiving that annuity for a given length of time. (8.89% real/10.9% nominal); CRF is a function of WACC and t.*
	WACC	*Weighted Average Cost of Capital (real)*	*The average expected rate that is paid to finance assets. (6.2% real/8.9% nominal); WACC is a function of DF, RROE, IR, i, and TR.*
	ProFinFactor	*Project Finance Factor*	*Technology-specific financial multiplier to account for the taxes and depreciation. (1.137); ProFinFactor is a function of TR, WACC, i, M, and FD.*
Wind Plant Techno-Economic Cost & Performance Parameters	*OCC*	Overnight Capital Cost ($/MW)	Capital expenditures, excluding construction period financing. Includes on-site electrical equipment and grid connection costs but does not include additional transmission features to reach a high-voltage transmission system.
	CapRegMult	Capital Regional Multiplier	Capital cost multipliers to account for regional variations that affect plant costs; e.g., labor rates.
	C	Construction Duration	Number of years in the construction period. (3)
	FC	Capital Fraction	Fraction of capital spent in each year of construction. (80%, 10%, 10%)
	IDC	Interest During Construction	Interest rate for financing project during the construction period. (8%)
	OPEX	Operation and Maintenance Expenses ($/MW-year)	Annual expenditures to operate and maintain equipment that are incurred on a per-unit-capacity basis.

	Symbol	Name	Definition
Wind Plant Techno-Economic Cost & Performance Parameters	*CF*	Capacity Factor (%)	Generally defined as the ratio of actual annual output to output at rated capacity for an entire year. When multiplied by number of hours in a year (8760 hours), expected annual average energy production over the technical life of the wind plant is estimated.
	CAPEX	*Installed Capital Cost*	*Total capital expenditure to achieve commercial operation up to the plant gate.*
	ConFinFactor	*Construction Finance Factor*	*Portion of CAPEX associated with construction period financing (1.039); ConFinFactor is a function of C, FC, and IDC.*
Grid Connection Costs	*GF*	Grid Feature	Point of interconnection at the high-voltage transmission network, including substation, transmission lines, load center, or balancing area center. (Default in ReEDS is $0/kW for substation and load center and $14/kW for others)
	OnDist	Onshore Distance	Total onshore distance covered by the onshore transmission spur lines.
	OffDist	Offshore Distance	Total offshore distance covered by the offshore export cables.
	OnTransCost	Onshore Transmission Costs (for spur line)	Base onshore transmission line costs. ($3922/MW-mile)
	OffDistFactor	Offshore Distance Factor	Incremental capital expenditure for offshore wind plant export cable length between landfall and offshore wind plant site and construction-period transit costs between port and offshore wind plant site. Assumed HVAC for cables that are less than 70 km and HVDC otherwise. ($8.10/kW-km for AC cables and $13.49/kW-km for DC cables)
	OnRegTransMult	Onshore Regional Transmission Multiplier	Transmission cost multipliers to account for regional variations that affect onshore transmission line costs; e.g., labor rates, terrain, and siting.
	GCC	*Grid Connection Costs*	*All costs from the plant gate to the high-voltage transmission network.*
	OnSpurCost	*Onshore Spur Line Costs*	*Cost for onshore transmission lines from the plant gate to the grid feature; OnSpurCost is a function of OnDist, OnTransCost, and OnRegTransMult.*
	OffSpurCost	*Offshore (underwater) Spur Line Costs*	*Cost for offshore (underwater) export cables from the offshore turbines to land, including incremental construction-period transit cost; OffSpurCost is a function of OffDist and OffDistFactor.*

Note: *Italics entries* are intermediate calculations required to compute LCOE; non-italics are input assumptions. Input assumptions not defined in the table are described in subsequent sections of this appendix.

The future wind plant techno-economic cost and performance inputs reflect three different future LCOE reduction scenarios. Figures H-3 and H-4 illustrate the mid-cost technology advancement scenarios for land-based and offshore wind, respectively; additional scenarios can be found in Section H.6. In these mid-cost technology advancement scenarios, the cost of land-based wind energy drops by 22% by 2050; the cost of offshore wind drops by 37% over the same time period. For comparison, the High Cost case represents no future cost reduction or performance improvement through 2050 for land-based wind, and the Low Cost case represents a land-based wind LCOE reduction of 37% by 2050. The High Cost case represents an LCOE reduction of 18% by 2050 for offshore wind, and the Low Cost case represents an offshore wind LCOE reduction of 51% by 2050, as shown in Table H-2. Section H.6 describes the methodology used to develop three sets of cost and performance projections for land-based and offshore wind technologies.

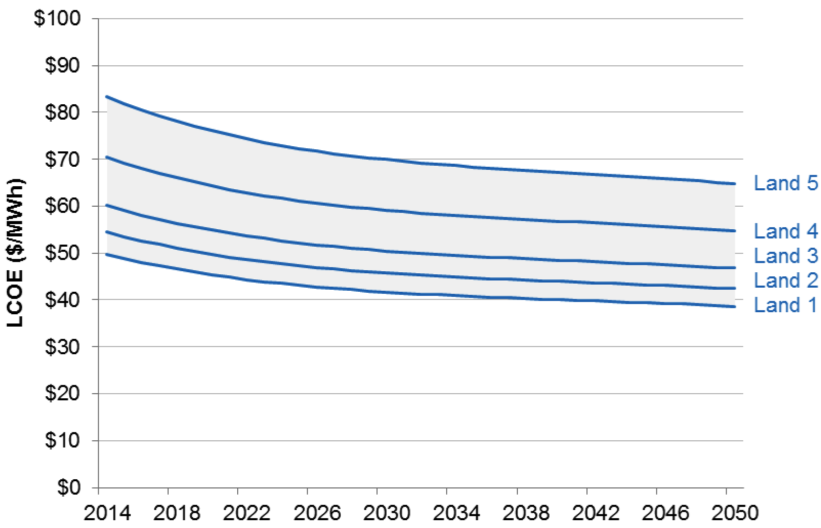


Figure H-3. Future land-based wind plant mid-cost technology advancement projection

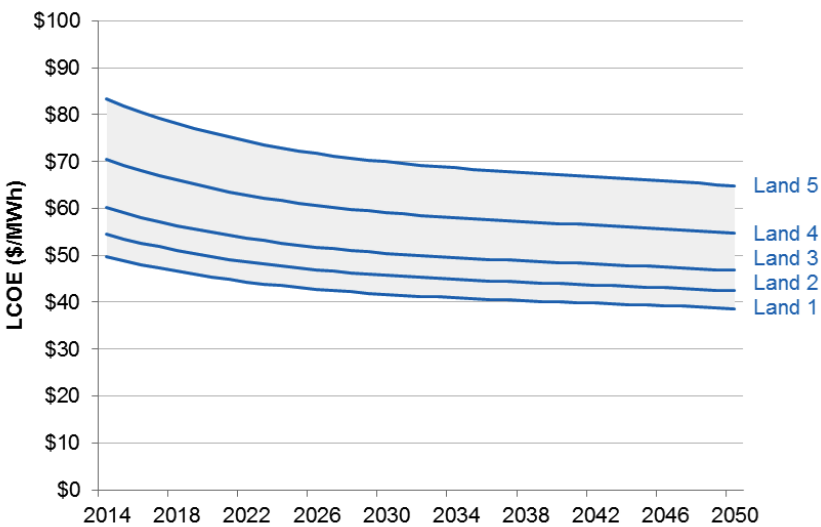


Figure H-4. Future offshore wind plant mid-cost technology advancement projection, including the grid connection cost at 30 km from shore

Table H-2. Future Cost Reduction Scenarios

Cost Reduction Scenario	30-km Offshore Grid Connection Cost		Weighted Average Grid Connection Cost		Percentage Reduction
	Base-year cost $/MWh	2050 cost $/MWh	Base-year cost $/MWh	2050 cost $/MWh	
Land Low Cost	51–86	31–53			37%
Land Mid Cost	51–86	39–65			22%
Land High Cost	51–86	51–86			0%
Offshore Low Cost	172–242	84–118	170–269	83–131	51%
Offshore Mid Cost	172–242	109–153	170–269	107–170	37%
Offshore High Cost	172–242	142–199	170–269	140–221	18%

Table H-2 presents two ranges of LCOE for offshore wind technology that differ in the methodology used to represent grid connection costs based on the distance from shore. One set of Base Year and 2050 costs is shown assuming a 30-km distance from shore, representative of the current offshore wind plant installations in Europe. The other set of Base Year and 2050 costs represents weighted averages, including unique grid connection costs based on the distance from shore for all potential offshore wind plant locations, within a given resource bin, in the study. The representative LCOE estimates are shown and discussed in the rest of the appendix to illustrate the methodology used to derive all of the separate input parameters required to model the offshore wind cost of energy in the *Wind Vision* analysis. The weighted average LCOE values are more representative of the combination of these various input parameters in the ReEDS model, where site-specific grid connection costs are used.

H.1.2 Primary Elements of the Wind Energy Supply Curve

A number of simplifying assumptions are necessary to represent wind technology in ReEDS. Most reports or publications on wind plant capital cost reference CAPEX, also called the Installed Capital Cost, which is the total up-front investment needed to bring a new wind plant to commercial operation. The ReEDS model requires an overnight capital cost to which construction financing is added. Table H-3 illustrates the base-year ReEDS inputs for land-based and offshore wind plants in each TRG. The cost elements that relate all-in capital cost to overnight capital cost are included for reference. The table also shows characteristics of the TRGs, such as capacity-weighted average annual wind speed and available capacity.

An LCOE using the equation in Section H.1.1 and the ReEDS model financing rates is presented in Table H-3. Because offshore wind plants installed in the near term (through 2020–2025) are likely to be financed at higher rates than those anticipated when market maturity is achieved in the long-term, a second LCOE estimate using market-based finance assumptions for offshore (FCR = 12% reflecting a WACC of 10.5%) is included for reference.

The base-year land-based wind plant represents a plant installed in the least expensive region of the country, the Interior, such that no additional regional cost impacts are present (Regional Capital Cost Multiplier = 1). This plant is assumed to easily access the grid (GCC = 0). The base-year offshore wind plant also has no incremental cost associated with regional capital-cost influences or access to the grid. However, it does assume a distance of 30 km from shore (OffSpurCost = $243/kilowatt [kW]). The CAPEX values shown in Table H-3 reflect market data observations of similar land-based and offshore wind plants as described in Section H.2.3 and H.2.4. In the ReEDS model, regional capital cost multipliers, onshore spur line costs, and offshore distance-related costs are added to the base-year wind plant cost using the geographic characteristics of each potential wind plant site.

Table H-3. Elements of the Wind Energy Supply Curve

	Included for Reference					Estimated Geographic Costs Set in ReEDS			ReEDS Inputs for the Base Year		
TRG	Wind Speed[a] (m/s)	Available Capacity[b] (GW)	CAPEX[c] ($/kW)	LCOE ($/MWh)[d] Reeds finance assumptions	LCOE ($/MWh)[e] Market finance assumptions	Construction Financing[f] ($/kW)	Regional Capital Cost Mutliplier[g]	Offshore Spur Cost[h] ($/kW)	Overnight Capital Cost[i] ($/kW)	OPEX[j] ($/kW/ year)	Capacity Factor (Net)[a] (%)
Land1	8.9	70	1,597	51		60	1	0	1,537	51	47%
Land2	8.1	1,171	1,730	56		65	1	0	1,665	51	46%
Land3	7.4	2,429	1,854	62		70	1	0	1,784	51	44%
Land4	6.7	1,175	1,877	73		70	1	0	1,807	51	38%
Land5	6.1	1,323	1,877	86		70	1	0	1,807	51	32%
OSW1	9.1	11	5,766	172	198	216	1	243	5,307	132	47%
OSW2	8.5	61	5,766	188	216	216	1	243	5,307	132	43%
OSW3	8.0	191	5,766	205	237	216	1	243	5,307	132	40%
OSW4	7.3	165	5,766	242	279	216	1	243	5,307	132	34%
OSW5	9.1	48	6,340	188	217	238	1	243	5,859	132	47%
OSW6	8.6	87	6,340	200	231	238	1	243	5,859	132	44%
OSW7	8.4	181	6,340	210	242	238	1	243	5,859	132	42%
OSW8	9.5	82	7,379	210	242	277	1	243	6,859	162	49%
OSW9	9.0	184	7,379	221	255	277	1	243	6,859	162	47%
OSW10	8.6	549	7,379	238	274	277	1	243	6,859	162	44%

a Capacity-weighted average for all potential wind plant sites in the TRG. This is the nominal wind speed. The capacity factor is calculated using elevation-corrected air density. The nominal wind speed would be reduced by 2%–4% to correspond to a sea-level wind speed.

b Information on excluded land area and maps of capacity location by TRG are included in subsequent sections.

c Capacity-weighted average for potential land-based wind plant sites in the TRG; spur cost based on standard distance for potential offshore wind plant sites in the TRG

d Estimated cost of energy for land-based and offshore wind plant sites based on the ReEDS financing assumptions defined in Table H-1

e Estimated cost of energy for offshore wind plant sites based on financing expectations for initial U.S. projects (FCR = 12%, reflecting a nominal WACC = 10.5% and inflation rate of 2.5%)

f Roughly 3.7% of CAPEX based on construction duration and the interest rate during construction; calculated internally in ReEDS

g Multiplier to account for regional differences in construction costs, land value, labor wages, etc. In this table, the regional cost is assumed to be 1.

h Offshore Spur Cost is unique to each potential wind plant site based on the distance to shore; assuming 30-km distance for reference in this table.

i Calculated as CAPEX minus construction financing and offshore spur cost

j Standard estimate by technology type

H.1.3 Future Wind Plant Cost and Performance Assumptions

The projections of future wind plant cost and performance represent three levels of wind technology advancement through 2050. Grid connection costs and financing costs are assumed to remain unchanged during the scenario; only the wind plant capital cost, operating costs, and capacity factor are changed. Tables H-4 and H5 contains the ReEDS model input assumptions that represent the three technology advancement perspectives. As noted above, the ReEDS model requires overnight capital cost (OCC), excluding construction-period finance costs.

Table H–4. Land-Based Future Wind Plant Cost and Performance Assumptions

Land-Based Cost Component	TRG	2012	2014	2020	2030	2050
Overnight capital cost (2013$/kW)	1 Low Cost	1,537	1,641	1,388	1,281	1,268
	1 Mid Cost	1,537	1,641	1,571	1,518	1,512
	1 High Cost	1,537	1,641	1,641	1,641	1,641
	2 Low Cost	1,665	1,641	1,388	1,281	1,268
	2 Mid Cost	1,665	1,641	1,571	1,518	1,512
	2 High Cost	1,665	1,641	1,641	1,641	1,641
	3 Low Cost	1,784	1,729	1,487	1,399	1,389
	3 Mid Cost	1,784	1,729	1,674	1,630	1,625
	3 High Cost	1,784	1,729	1,729	1,729	1,729
	4 Low Cost	1,807	1,758	1,570	1,540	1,536
	4 Mid Cost	1,807	1,758	1,738	1,724	1,722
	4 High Cost	1,807	1,758	1,758	1,758	1,758
	5 Low Cost	1,807	1,758	1,570	1,540	1,536
	5 Mid Cost	1,807	1,758	1,738	1,724	1,722
	5 High Cost	1,807	1,758	1,758	1,758	1,758
Net capacity factor (%)	1 Low Cost	47%	51%	58%	61%	62%
	1 Mid Cost	47%	51%	54%	57%	60%
	1 High Cost	47%	51%	51%	51%	51%
	2 Low Cost	46%	47%	53%	56%	57%
	2 Mid Cost	46%	47%	49%	52%	55%
	2 High Cost	46%	47%	47%	47%	47%
	3 Low Cost	44%	44%	51%	54%	56%
	3 Mid Cost	44%	44%	47%	50%	53%
	3 High Cost	44%	44%	44%	44%	44%
	4 Low Cost	38%	38%	45%	50%	51%
	4 Mid Cost	38%	38%	41%	44%	47%
	4 High Cost	38%	38%	38%	38%	38%
	5 Low Cost	32%	32%	38%	42%	43%
	5 Mid Cost	32%	32%	35%	37%	40%
	5 High Cost	32%	32%	32%	32%	32%

Land-Based Cost Component	TRG	2012	2014	2020	2030	2050
OPEX (2013$/kW/year)	Low Cost	51	51	47	43	39
	Mid Cost	51	51	49	47	46
	High Cost	51	51	51	51	51

Table H-5. Offshore Future Wind Plant Cost and Performance Assumptions

Offshore Cost Component	TRG	2014	2016	2020	2023[a]	2030	2050
Overnight capital cost (2013$/kW)[b]	1 Low Cost	5,307	4,683	4,111	3,591	3,227	2,733
	1 Mid Cost	5,307	5,080	4,527	4,007	3,851	3,629
	1 High Cost	5,307	5,522	5,099	4,735	4,735	4,735
	2 Low Cost	5,307	4,683	4,111	3,591	3,227	2,733
	2 Mid Cost	5,307	5,080	4,527	4,007	3,851	3,629
	2 High Cost	5,307	5,522	5,099	4,735	4,735	4,735
	3 Low Cost	5,307	4,683	4,111	3,591	3,227	2,733
	3 Mid Cost	5,307	5,080	4,527	4,007	3,851	3,629
	3 High Cost	5,307	5,522	5,099	4,735	4,735	4,735
	4 Low Cost	5,307	4,683	4,111	3,591	3,227	2,733
	4 Mid Cost	5,307	5,080	4,527	4,007	3,851	3,629
	4 High Cost	5,307	5,522	5,099	4,735	4,735	4,735
	5 Low Cost	5,860	5,170	4,537	3,961	3,559	3,012
	5 Mid Cost	5,860	5,613	4,997	4,422	4,249	4,003
	5 High Cost	5,860	6,092	5,630	5,227	5,227	5,227
	6 Low Cost	5,860	5,170	4,537	3,961	3,559	3,012
	6 Mid Cost	5,860	5,613	4,997	4,422	4,249	4,003
	6 High Cost	5,860	6,092	5,630	5,227	5,227	5,227
	7 Low Cost	5,860	5,170	4,537	3,961	3,559	3,012
	7 Mid Cost	5,860	5,613	4,997	4,422	4,249	4,003
	7 High Cost	5,860	6,092	5,630	5,227	5,227	5,227
	8 Low Cost	6,859	6,049	5,306	4,631	4,158	3,517
	8 Mid Cost	6,859	6,571	5,846	5,171	4,969	4,680

Offshore Cost Component	TRG	2014	2016	2020	2023[a]	2030	2050
Overnight capital cost (2013$/kW)[b]	8 High Cost	6,859	7,132	6,589	6,117	6,117	6,117
	9 Low Cost	6,859	6,049	5,306	4,631	4,158	3,517
	9 Mid Cost	6,859	6,571	5,846	5,171	4,969	4,680
	9 High Cost	6,859	7,132	6,589	6,117	6,117	6,117
	10 Low Cost	6,859	6,049	5,306	4,631	4,158	3,517
	10 Mid Cost	6,859	6,571	5,846	5,171	4,969	4,680
	10 High Cost	6,859	7,132	6,589	6,117	6,117	6,117
Net Capacity Factor	1 Low Cost	47%	48%	49%	53%	54%	55%
	1 Mid Cost	47%	47%	49%	52%	52%	53%
	1 High Cost	47%	47%	48%	52%	52%	52%
	2 Low Cost	44%	44%	45%	49%	49%	50%
	2 Mid Cost	43%	43%	44%	47%	48%	49%
	2 High Cost	44%	43%	44%	47%	47%	47%
	3 Low Cost	40%	40%	41%	45%	45%	46%
	3 Mid Cost	40%	40%	41%	43%	44%	45%
	3 High Cost	40%	40%	40%	43%	43%	43%
	4 Low Cost	34%	34%	35%	38%	38%	39%
	4 Mid Cost	34%	34%	35%	37%	37%	38%
	4 High Cost	34%	34%	34%	37%	37%	37%
	5 Low Cost	47%	47%	48%	53%	53%	54%
	5 Mid Cost	47%	47%	48%	51%	51%	53%
	5 High Cost	47%	47%	47%	51%	51%	51%
	6 Low Cost	44%	44%	45%	49%	50%	51%
	6 Mid Cost	44%	44%	45%	48%	48%	49%
	6 High Cost	44%	44%	44%	48%	48%	48%
	7 Low Cost	42%	42%	43%	47%	47%	48%
	7 Mid Cost	42%	42%	43%	46%	46%	47%
	7 High Cost	42%	42%	42%	46%	46%	46%

Offshore Cost Component	TRG	2014	2016	2020	2023[a]	2030	2050
Net Capacity Factor	8 Low Cost	49%	49%	51%	55%	56%	57%
	8 Mid Cost	49%	49%	51%	54%	54%	55%
	8 High Cost	49%	49%	50%	54%	54%	54%
	9 Low Cost	47%	47%	48%	53%	53%	54%
	9 Mid Cost	47%	47%	48%	51%	51%	53%
	9 High Cost	47%	47%	47%	51%	51%	51%
	10 Low Cost	44%	44%	45%	49%	49%	50%
	10 Mid Cost	44%	44%	45%	47%	48%	49%
	10 High Cost	44%	44%	44%	47%	48%	48%
OPEX (2013$/kW/year)	Shallow and Mid Low Cost	132	121	111	106	99	92
	Shallow And Mid Mid Cost	132	129	115	107	102	99
	Shallow and Mid High Cost	132	132	121	119	119	119
	Deep Low Cost	162	149	136	130	122	114
	Deep Mid Cost	162	159	141	131	125	122
	Deep High Cost	162	162	149	146	146	146

[a] This year is included because several of the cost reduction trajectories in the literature describe cost reductions for offshore wind through 2023.

[b] Grid connection cost is not included in this table. To duplicate LCOE values in Table H-1 and Figure H-4, an additional $243/kW representing 30 km distance from shore must be added to the overnight capital cost.

H.2 Base-Year Wind Plant Techno-Economic Cost and Performance Parameters

H.2.1 Introduction

In order to provide the most representative cost and performance inputs for ReEDS base year modeling, the analysis estimated cost and performance parameters for current technology, and matched technology with resource (for land-based wind plants) or resource and water depth (for offshore wind plants). An LCOE was calculated for each potential wind plant site, including operations and financing cost; sites were grouped by cost; and the capacity-weighted average for each group was calculated. Adjustments were then made to make the numbers compatible with the ReEDS model format.

H.2.2 AWS Truepower Wind Resource Data

Figure H-5 illustrates the process by which the analysis made the wind resource data usable in the model. The wind resource data used for this study were developed for the National Renewable Energy Laboratory (NREL) by AWS Truepower (AWST). These specific site data include a typical meteorological year of simulated hourly wind resource data, along with certain variability statistics, for defined areas of the contiguous United States, including offshore regions. The site data were provided for each 20x20-kilometer (km) grid cell of the United States, except for areas excluded because of environmental and land-use restrictions, based on exclusion layer databases developed by NREL and AWST [1]. Each 20x20-km grid cell can contain multiple prospective project sites. Each site has a specified amount of area and a different level of wind resource as determined by its estimated gross capacity factor (GCF) at 80-meter (m) height, grouped into GCF bins ("sites") of 3% increments.[5] The GCF was estimated by AWST using a generic power curve for a wind turbine classified as Class II under International Electrotechnical Commission (IEC) ratings.[6] In reality, GCF estimates for a detailed site assessment study could differ significantly, because different power curves and different classes of wind turbines may be used in the detailed assessments.

Figure H–5. Potential wind plant site identification process

The offshore wind resource modeled by AWST was restricted to 50 nautical miles from shore; for the *Wind Vision*, wind resource was extrapolated beyond 50 nautical miles to reach a 700-m depth contour. Because the 50 nautical miles cut-off is not related to offshore wind project feasibility, a new methodology for bounding the wind resource was adopted for the *Wind Vision* based on Dhanju et al. (2007) [3]. Using this method, resource boundaries are defined based on depth contours, which can be segmented based on technological feasibility. The shallow water gradient is defined from 0–30 m to reflect the current range for monopile technology. The mid-depth water gradient is defined from 30–60 m to reflect the expected design space for jacket technology. The deep water gradient is defined from 60–700 m[7] to reflect the anticipated range for floating technology. Exclusive economic zone boundaries are restricted to the United States only (i.e., excluding Canada and the Caribbean).

Wind resource data are filtered to exclude a standard set of areas considered unlikely to be developed for environmental or technical reasons. Most land and water areas are associated with a number of competing interests that may or may not result in wind plant sites at some point in the future. For modeling purposes, it is important to identify areas where future wind plant sites are unlikely due to current uses and define them as standard exclusions. In reality, a number of additional considerations beyond those reflected in the standard exclusions must be taken into account to site wind plants on land or water.

Places on land that are completely excluded from future wind plant development are federal and state protected areas (e.g., parks, wilderness areas, wildlife sanctuaries), water, urban areas, wetlands, and airports. Recognizing some incremental challenges to development but not complete exclusions, some areas are defined as 50% excluded. Areas that are 50% excluded are non-ridgecrest forest, non-ridgecrest U.S. Forest Service and Department of Defense lands, and state forests (where available in a geographic information system). Water areas that are completely excluded are national marine sanctuaries, marine protected areas, wildlife refuges,

5 GCF represents theoretical energy capture from an individual turbine at a given location. An assumption of 15% losses is applied to estimate the net capacity factor, which represents annual energy capture for a wind plant of multiple turbines. This wind plant representation is used subsequently in reference to capacity factor.

6 Full methodology can be found in the AWST paper: *New U.S. Wind Energy Potential Estimates, Background and Explanation of Changes from Prior Estimates,* available at *http://www.awstruepower.com/assets/ [2]*.

7 Oil and gas industry experience suggests that it could be technically feasible to deploy floating substructures in very deep waters. Since the cut-off for economic feasibility has not been established, a cut-off of 700 m was selected through discussions with floating technology developers.

shipping and towing lanes, offshore platforms, and ocean pipelines.[8]

For the land-based data set, 2.4 million km² (approximately 31% of the continental United States) are excluded. For the offshore data set, 403,600 km² (approximately 36% of the water area) are excluded. Figures H-6 and H-7 show maps of areas excluded from the modeling exercise for land-based wind and offshore wind, respectively.

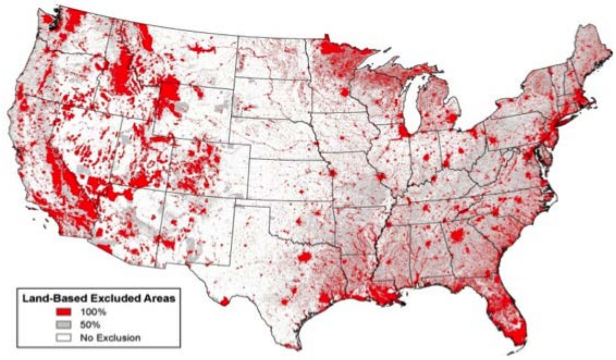


Figure H–6. Map of excluded area in the land-based wind resource data set

Figure H–7. Map of excluded area in the offshore wind resource data set

Figure H-8 lists five sample 20x20-km grid cells in various locations across the country with the area of land in each GCF bin to provide a snapshot of how the data are presented.[9] Areas excluded from the study based on the criteria defined above are also shown. The land area within a given 20x20-km grid cell associated with a GCF bin is considered a potential wind plant site. In total, the land-based data set has more than 61,400 potential project sites, while the offshore data set has more than 30,900.[10] Assuming a wind plant density of 3 megawatts (MW)/km² [4], there are more than 6,000 GW of potential land-based wind plant sites and more than 1,500 GW of potential offshore wind plant sites.[11] Even with the standard exclusions applied, future wind plant potential capacity exceeds current U.S. electric-sector installed capacity by six times for land-based wind plants and 1.5 times for offshore wind plants.

8 In addition to these land/water use exclusions, some resource areas fall outside of economic filters and are therefore not included in the resource capacity estimates summarized in this section. Economic filters are described in subsequent sections.

9 Because of the extrapolation beyond 50 nm, some offshore grid cells contain more than 400 km².

10 18,059 shallow water sites; 6,695 mid-depth sites; and 6,208 deep water sites

11 For reference, the total installed electric generating capacity in the continental U.S. in 2013 was 1,065 GW (EIA's Electric Power Monthly Report (February 2014 Issue) *http://www.eia.gov/electricity/monthly/* [5].

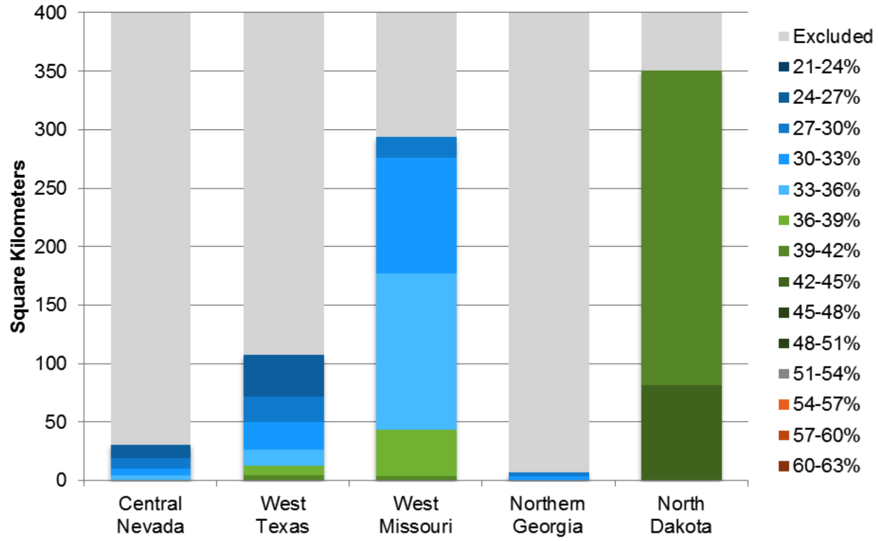


Figure H-8. Area of potential wind plant sites in five sample 20x20-km grid cells

H.2.3 Land-Based Techno-Economic Data

Base-year cost and performance assumptions for land-based wind plants were developed according to the steps outlined in Figure H-9. Three representative wind plant types were defined, including capital cost and operating cost, across a range of annual average wind speeds based on market observations for U.S. wind plants installed in 2012. CAPEX values were interpolated between the three representative wind plant estimates based on annual average wind speed at the potential wind plant site. Energy capture at each potential wind plant site was estimated using the hourly wind profile at the site and a power curve, also interpolated between the three representative wind turbines as a function of annual average wind speed. An LCOE value was estimated for each potential wind plant site. The potential wind plant sites were ranked by LCOE and divided into five TRGs for representation in ReEDS. Each of the TRGs is represented in ReEDS by the capacity-weighted average CAPEX, net capacity factor, operating costs, and financing costs. CAPEX estimates were adjusted to overnight capital costs for input into the ReEDS model format.

Figure H-9. Land-based wind plant cost and performance techno-economic parameter calculation process

H.2.3.1 Three Representative Turbines

There are a number of different turbine types deployed in the United States. These turbines are defined generally by machine rating, rotor diameter, and hub height. The IEC turbine ratings are classified I–III for a range of annual average wind speeds.[12] Turbines used in the highest wind speed sites are the Class I turbines. These turbines have smaller rotors relative to the size of the generator, or a higher specific power (watts per meter squared, or W/m^2), and are therefore rated to withstand higher winds. In medium wind regimes, the IEC Class II turbine is used.

12 IEC Class I—annual average wind speeds of 10m/s and higher; IEC Class III—annual average wind speed of 7.5 m/s and lower; blend of Class II and Class III turbines at annual average wind speeds of 7.5–8.5 m/s; blend of Class II and Class I turbines at annual average wind speeds of 8.5–10 m/s

Its larger rotor allows it to have a higher capacity factor (all else equal), and it does not need to withstand the higher winds. In the lowest wind resources, Class III turbines are primarily used to gain the highest capacity factor possible in lower wind speeds.

The *Wind Vision* analysis estimates the cost of three generic turbines, appropriate for different wind conditions.[13] This estimate uses reported data, interviews with industry experts, and previous research about the wind energy market in the latest year for which data was published prior to this report (2012). Table H-6 summarizes the three turbine types.

Table H–6. Land-Based Wind Plant Specifications

Technology Characteristics	IEC Class I Turbine	IEC Class II Turbine	IEC Class III Turbine
Specific power (W/m^2)	320	300	205
Hub height (m)	80	80	80
CAPEX ($/kW)	$1,523	$1,624	$1,878
Overnight capital cost ($/kW)	$1,466	$1,563	$1,808
Construction finance ($/kW)[a]	$57	$61	$70
Operating costs ($/kW/year)	$51	$51	$51
Annual average wind speed (m/s)	10	8.5	7.5

a Construction finance equates to about 3.7% of total installed capital cost.

Figure H-10 shows the regional boundaries used for data collection and reporting in the *Wind Technologies Market Report* [6]. These boundaries also influence cost assumption decisions in this appendix by affecting the costs selected to represent base-year, land-based project costs. In general, the lowest cost wind plants are installed in the Interior region of the country. It is assumed that wind plants installed in the Interior region represent the base cost, and that higher costs in other regions result primarily from geographic differences in labor wages, permitting or siting complications, logistics requirements, or other unique characteristics that may extend beyond the wind plant technology. The base cost of wind plant technology is shown in Table H-3; regional influences are incorporated as a multiplier to the base wind plant technology cost.

Figure H–10. Regional boundaries for data collection and reporting

13 Data sources include *2012 Wind Technologies Market Report [6], Bloomberg New Energy Finance Wind Turbine Price Index*, Prior NREL research [7, 8, 9], and industry queries and interviews.

The *Wind Vision* analysis assumes that IEC Class I turbines are installed at all sites with annual average wind speeds of 10 meters/second (m/s) and higher; and IEC Class III turbines are used at all sites with an annual average wind speed of 7.5 m/s and lower. For sites with a wind speed between 7.5 m/s and 8.5 m/s, it is assumed that a smoothly transitioning blend of Class III and Class II turbines are used. Similarly, for wind speeds between 8.5 m/s and 10 m/s, a blend of Class II and Class I turbines are assumed to be installed. Figure H-11 illustrates the proportion of turbine types for each wind speed.

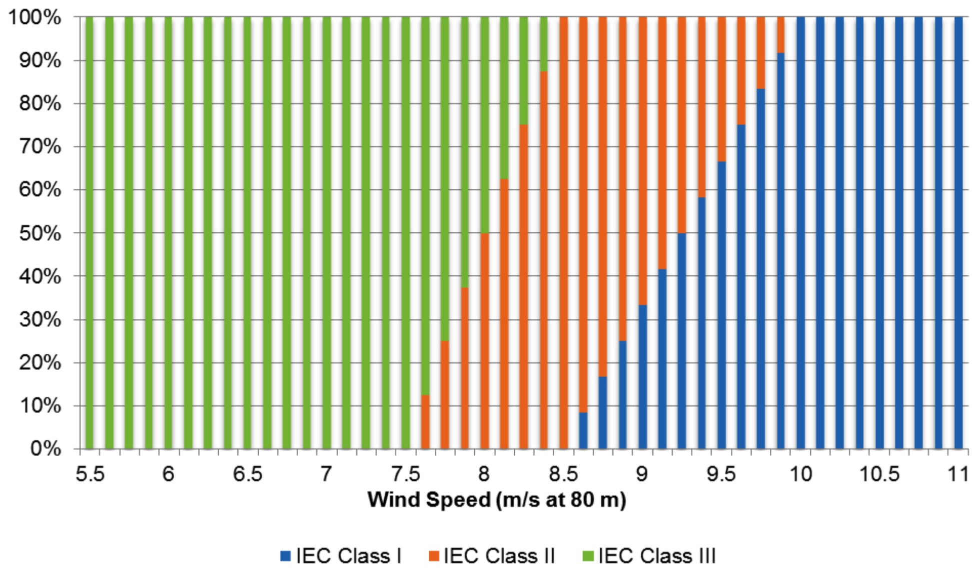


Figure H-11. Wind turbine composition by wind speed

Figure H-12 illustrates normalized power curves representing each of the three turbine types.

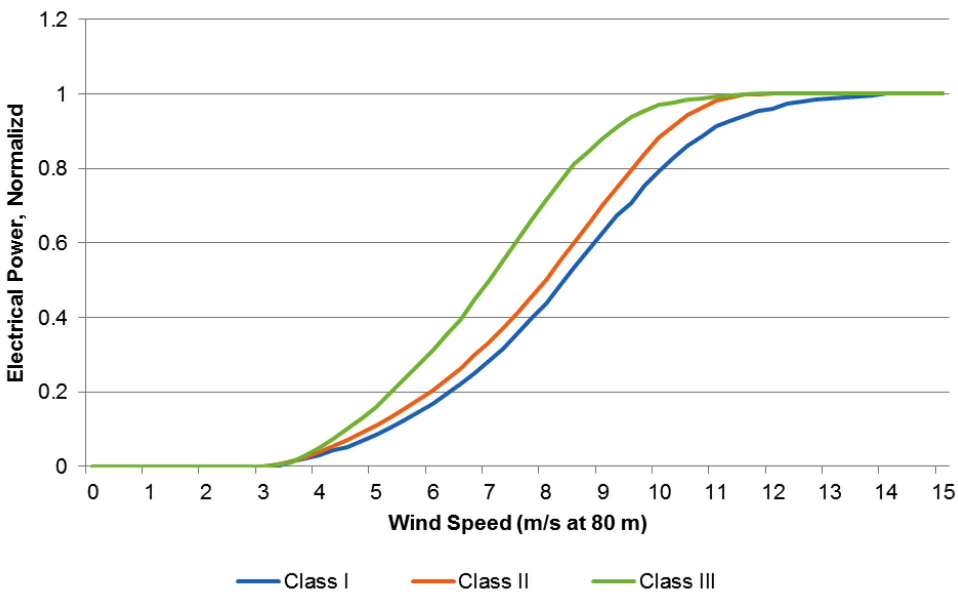


Figure H-12. Power curves for representative land-based wind turbines

Capital Cost

The *Wind Vision* analysis assumes wind plant capital costs based on wind turbines appropriate for different wind conditions to develop the wind energy supply curve. According to the *Wind Technologies Market Report* [6], the specific power for projects installed in the Interior region of the country in 2012 is 282 watts/m^2. The reported hub height in this region is 81.9 m and the reported CAPEX is $1,760/kW. As shown in Table H-6, in order to reflect observed market conditions in 2012, the analysis estimated that the CAPEX of the turbines (in 2012$) would range from $1,500/kW–$1,850/kW ($1,523–$1,878/kW in 2013$) and specific power ratings would range from 320–205 watts/m^2. For each of the 61,406 potential wind plant sites, wind plant capital cost was calculated based on the annual average wind speed and interpolation between the three representative wind plant CAPEX values, as shown in Figure H-13.

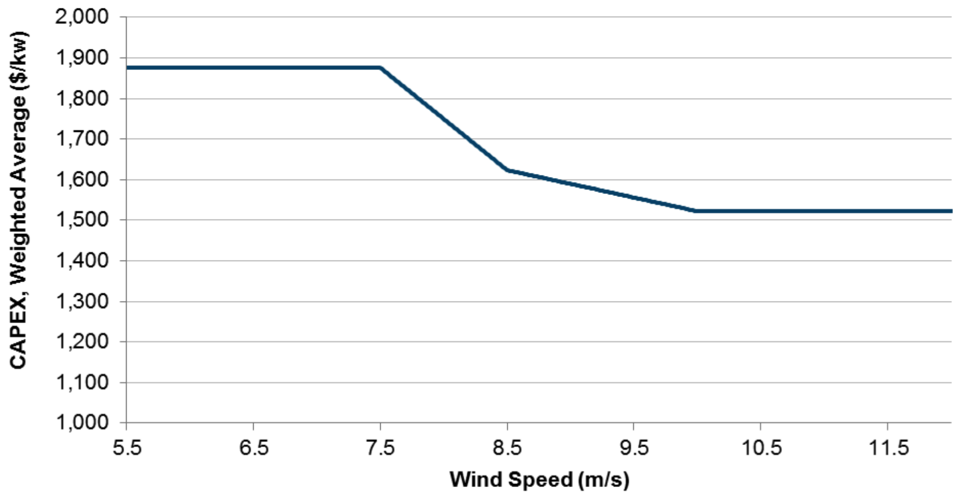


Figure H–13. Land-based wind plant CAPEX over a range of wind speeds

In addition to the base capital cost for each representative wind plant, ReEDS imposes regional cost multipliers that are intended to "reflect the impact of remote location costs, costs associated with seismic design that might vary with region, and labor wage and productivity differences by region." Figure H-14 shows regional capital cost multipliers by ReEDS region based on cost multipliers developed by Science Applications International Corporation (SAIC) for use in electric sector capacity expansion modeling [10]. For the *Wind Vision*, a 20% increment was added to the SAIC data in the Northeast to reflect the empirical 2012 Northeast market data [6].

SAIC accounts for the following in its wind plant multipliers:

- Seismic design differences (step increases in costs for seismic Zones 1–4)
- Remote locations (freight costs and projects requiring construction camps or higher per diem)
- Labor wage and productivity differences
- Location adjustments (cost of living and population density)
- Owner cost adjustments (for utility upgrades or where new facility transmission lines to tie to existing substations are required)
- Increase in overhead associated with these adjustments.

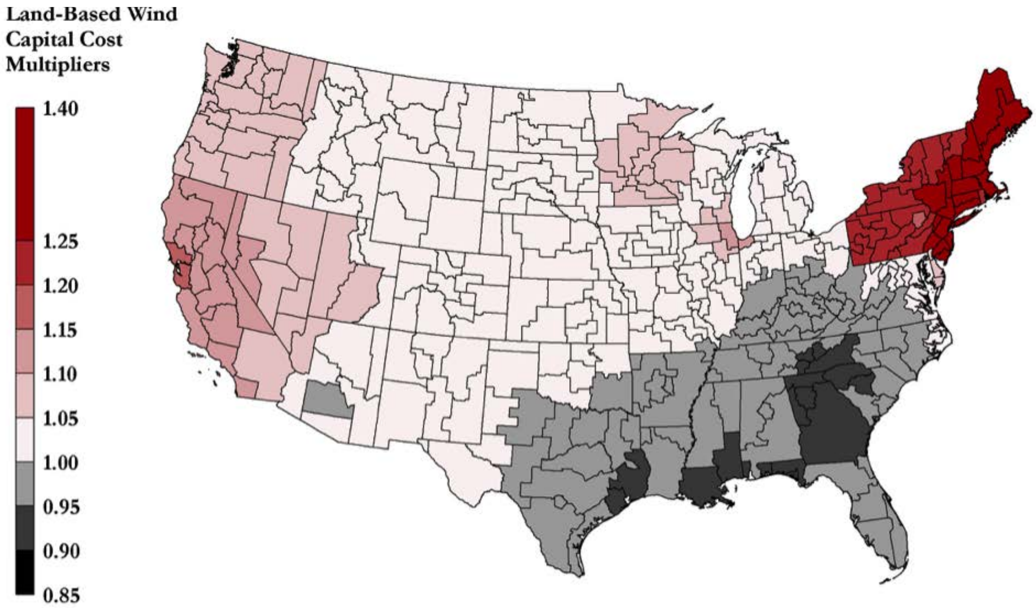


Figure H–14. Land-based wind plant capital cost regional multipliers by ReEDS region based on cost multipliers developed by SAIC

Operating Cost

Land-based wind plant operating costs are assumed to be $51/kW/year (pre-tax) for all projects; this value reflects both fixed and variable operating costs. Annual operating expenses typically include land-lease costs, operation and maintenance (O&M) wages and materials, and levelized replacement costs. According to the *Wind Technologies Market Report* [6], capacity-weighted average annual operating costs for 2000–2012 were $66/kW/year for projects in the sample constructed in the 1980s, $55/kW/year for projects constructed in the 1990s, $28/kW/year for projects constructed in the 2000s, and $25/kW/year for projects constructed since 2010. It is unclear to what extent the data reported by Wiser and Bolinger include all expected annual operating costs; it is likely that only direct turbine maintenance costs are reported. The degree of uncertainty around actual annualized operating costs leads to the above estimate used for modeling purposes.

Capacity Factor

Annual energy production is represented by capacity factors in ReEDS modeling. The GCF is calculated as the annual energy generated divided by the rated power of the wind turbine operating every hour of the year. For each of the 61,406 potential wind plant sites, annual energy production was calculated using the hourly wind profile and a wind turbine power curve appropriate for the wind speed. For sites in the blended zones, the annual energy production was calculated with both turbines, and the output was weighted as appropriate for the blend.

For instance, at 8.0 m/s, output was calculated with a Class III turbine power curve and a Class II turbine power curve. The output was then weighted 50/50 to represent the assumed 50/50 split of the two turbine types. The hourly wind profiles were adjusted to account for the lower air density at higher elevation sites based on the respective 20x20-km grid cell. The average elevation of the larger 20x20-km grid cell was assumed for all potential wind sites within the grid cell. GCF was calculated with the estimated output from the appropriate turbine or the weighted average blend. To represent wind plant performance, wind turbine GCF was converted to wind plant net capacity factor (CF) with an assumption of 15% losses, representing electrical and wake effect losses within the wind plant.

Figure H-15 shows the net CF for each potential wind site. Actual wind plants installed in the United States, operating in 2013 had net CFs ranging from less than 20% to over 50%, with a generation-weighted capacity average for new plants installed in 2012 of about 34%. This compares favorably with the range of potential wind plant CFs shown in Figure H.15. These potential net CFs represent the best available wind technology in 2013, which should tend toward the high end of observed CFs for installed plants due to recent advances in wind technology options. The lower bound of 28% results from applying an economic filter such that LCOE <= $97/MWh, which excludes many very low wind speed areas.

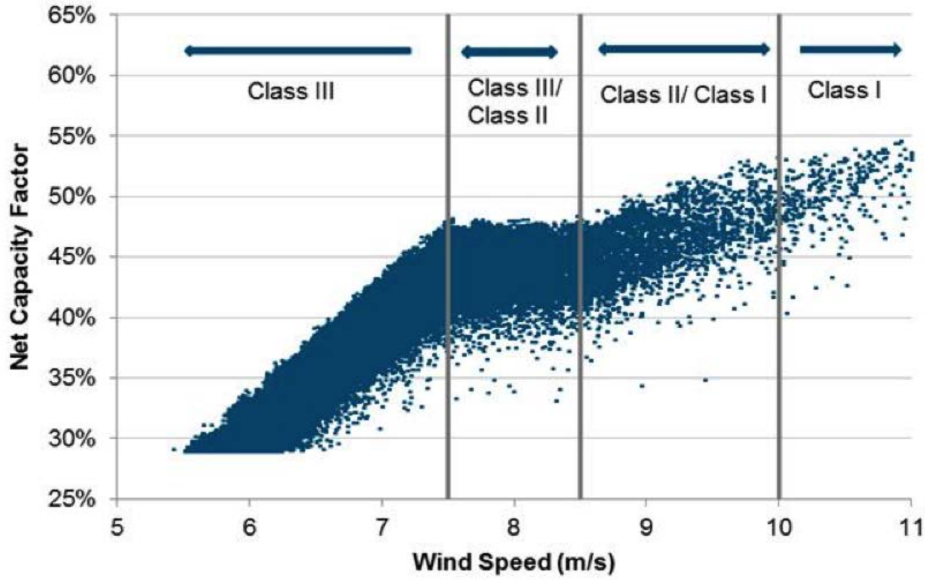


Figure H–15. Land-based wind plant CF over a range of wind speeds

H.2.3.2 Calculation of LCOE for each Potential Wind Plant Site

Using the site-specific capital cost and CF, annual operating costs, and financial assumptions; an LCOE was calculated for each potential wind plant site using the following equation.

$$LCOE = \frac{FCR * CAPEX + OPEX}{CF * 8760}$$

Figure H-16 represents the range of LCOE values for each potential wind plant site. Five TRGs were defined to group projects with similar costs, into one representative category for the set of projects. A maximum LCOE of $97/MWh was applied to reduce data volume and restrict potential sites to the most economically viable. Table H-7 summarizes the characteristics of each of the five land-based wind plant TRGs.

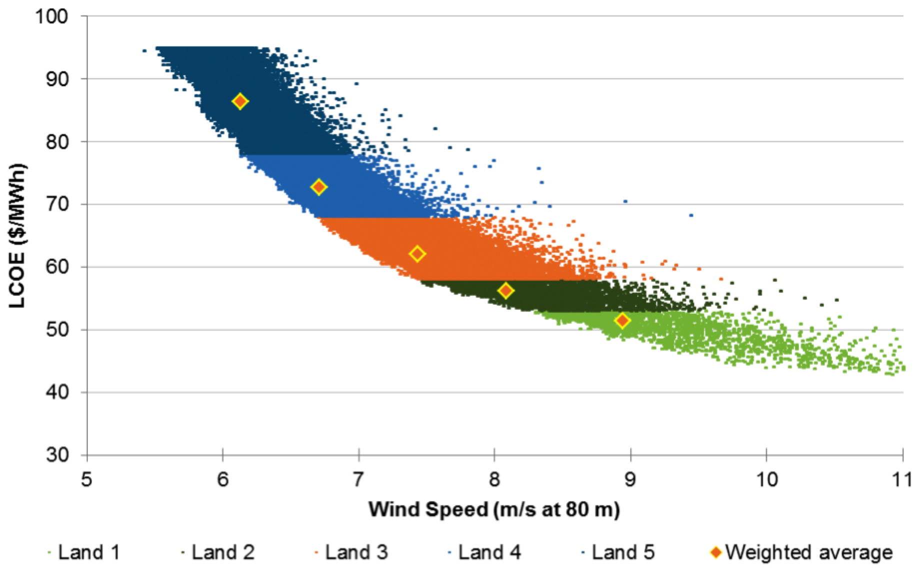


Figure H–16. LCOE for all potential land-based wind plant sites, by TRG

Table H–7. Definition of Land-Based TRGs

TRG	LCOE Range ($/MWh)	Weighted Average Wind Speed (m/s)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
Land 1	<=53	8.9	70	289
Land 2	53< LCOE <=58	8.1	1,171	4,705
Land 3	58<LCOE<=68	7.4	2,429	9,281
Land 4	68<LCOE<=78	6.7	1,175	3,842
Land 5	78<LCOE<=97	6.1	1,323	3,674
Total			6,168	21,792

H.2.3.3 Calculation of Capacity Weighted Averages

For modeling purposes, five representative wind plants reflect land-based wind technology. Capacity-weighted averages for capital costs and net CFs were calculated using the TRG definitions above. The capacity-weighted average net CF and the adjusted capacity-weighted average CAPEX become the land-based wind plant cost and performance parameters used in ReEDS. Figures H-17 and H-18 illustrate CAPEX and net CF for all potential wind sites grouped by TRG. The capacity-weighted averages are shown as yellow diamonds.

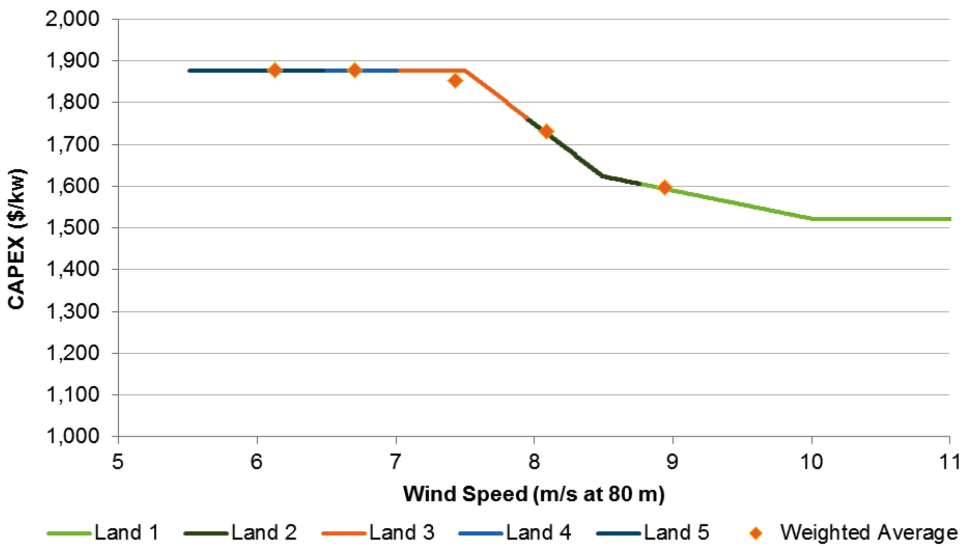


Figure H‑17. CAPEX for all potential land-based wind plant sites, by TRG

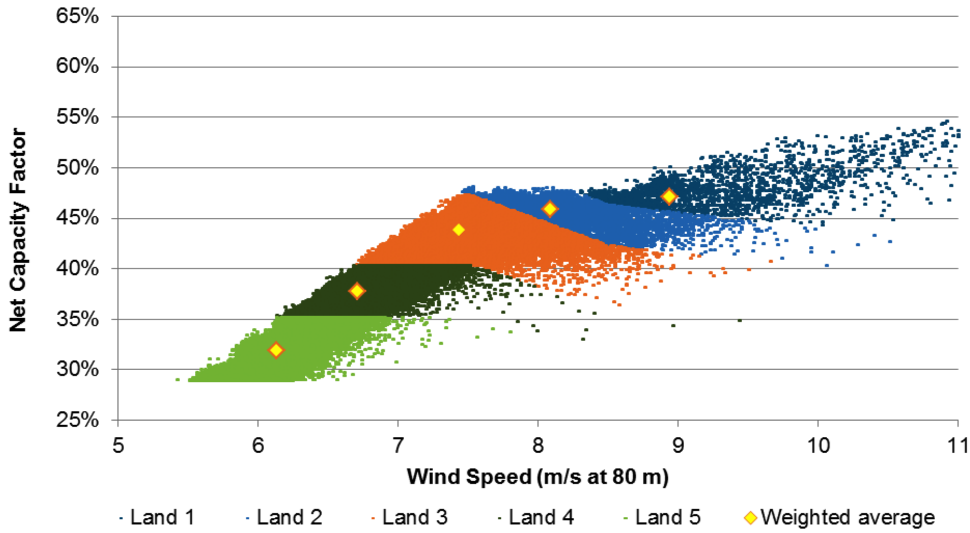


Figure H‑18. CF for all potential land-based wind plant sites, by TRG

H.2.3.4 Market-Based Estimate Adjustment for ReEDS Model Inputs

The ReEDS model requires overnight capital cost as an input because it calculates construction-period financing internally based on the input parameters described in Table H-1. Construction finance represents about 3.7% of total installed CAPEX. This amount is subtracted from the capacity-weighted average CAPEX for each TRG to arrive at the overnight capital cost value. Table H-8 contains the ReEDS inputs after adjustments; an example translation between CAPEX and the overnight capital cost is shown in Tables H-3 and H-6.

Table H–8. Land-based Wind Plant Inputs to ReEDS Model

	Inputs to ReEDS Model for the Base Year Name Definition		
TRG	Overnight Capital Cost (2013$/kW)	OPEX ($/kW/ year)	Net CF (%)
Land 1	1,537	51	47%
Land 2	1,665	51	46%
Land 3	1,784	51	44%
Land 4	1,807	51	38%
Land 5	1,807	51	32%

H.2.3.5 Mapped TRGs

Figures H-19 to H-24 show the location of the U.S. land-based wind resource, as defined by the TRGs. Figure H-19 is a visual representation of the potential capacity available to ReEDS when it needs to "build" new capacity. Existing wind facilities, by location and size of capacity, are superimposed for reference.

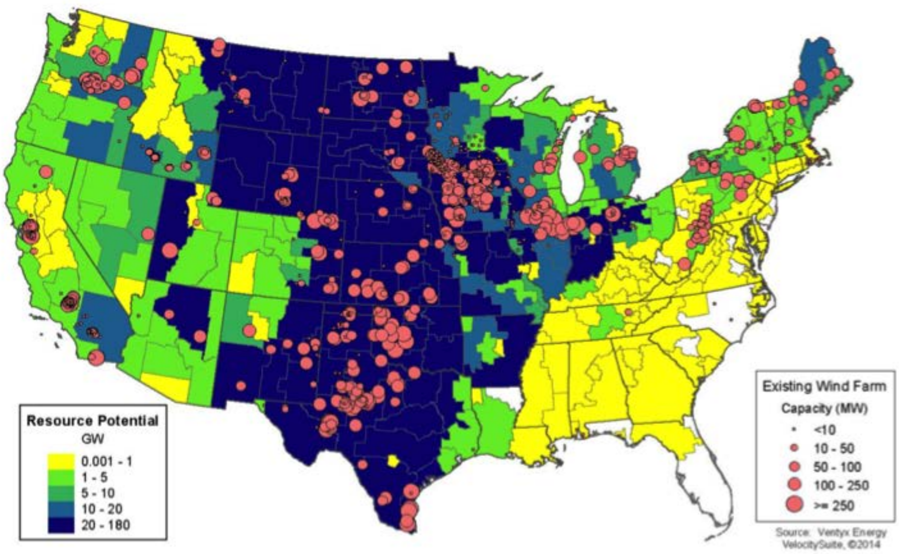


Figure H–19. Map of U.S. land-based wind resource potential by ReEDS region, with existing wind plant capacity and location [11]

Figures H-20 to H-24 show the location and potential capacity of land-based TRG1–5, with existing wind plants superimposed to show which locations are in each cost and performance group. The units are 20x20-km (or 400-km²) grid cells, colored for the potential wind plant capacity associated with each TRG in the cell. The potential capacity is based on the land area within a given TRG and an assumption of 3 MW/km².

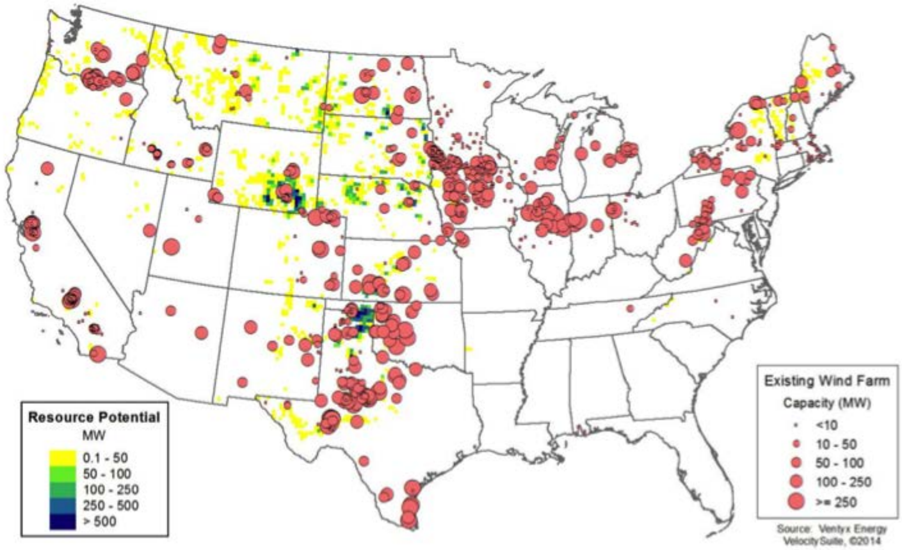


Figure H–20. Map of TRG1 resource potential [11]

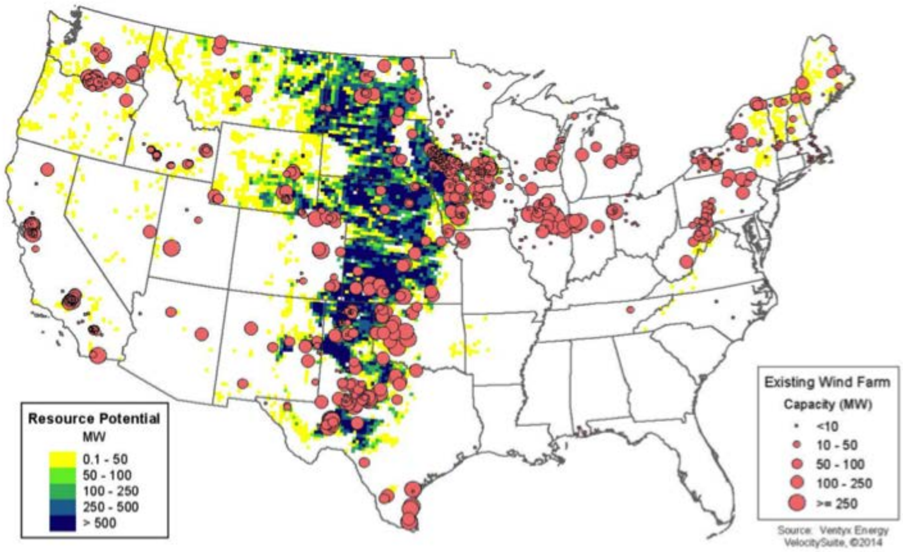


Figure H–21. Map of TRG2 resource potential [11]

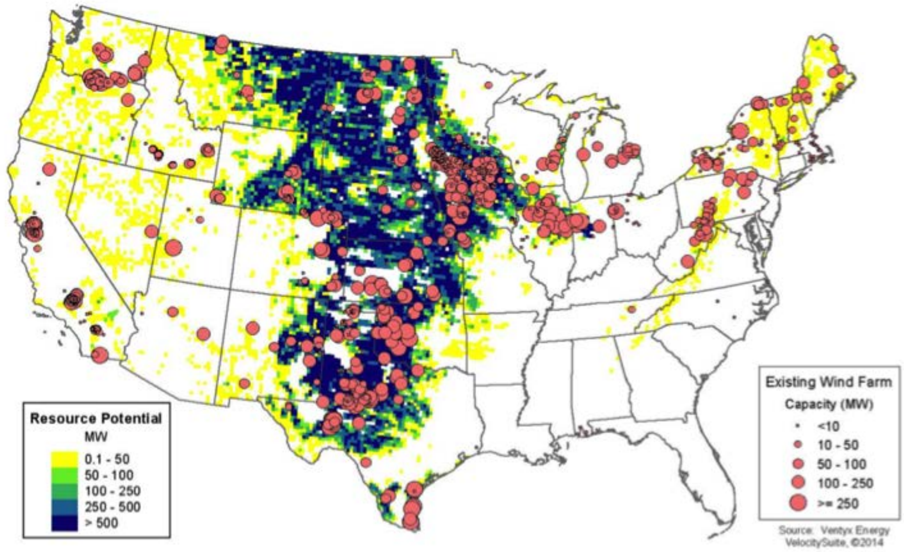


Figure H–22. Map of TRG3 resource potential [11]

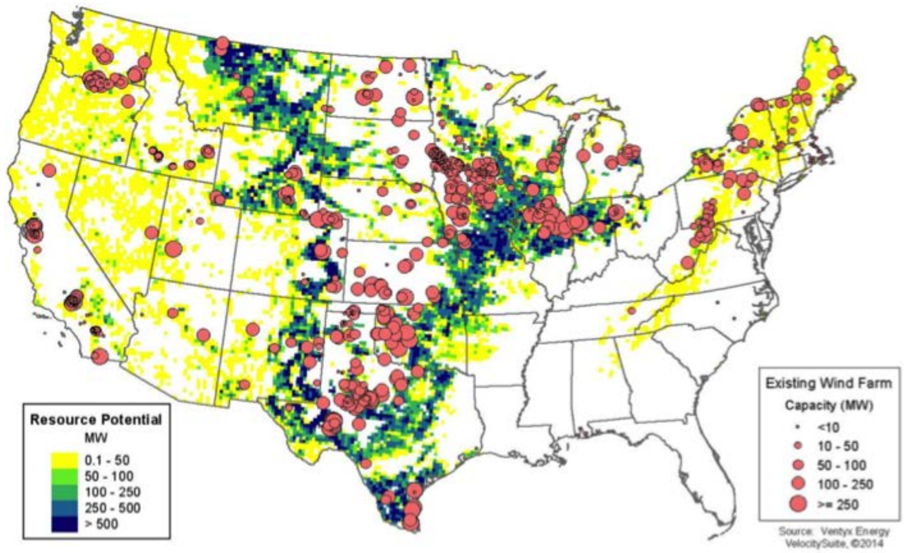


Figure H–23. Map of TRG4 resource potential [11]

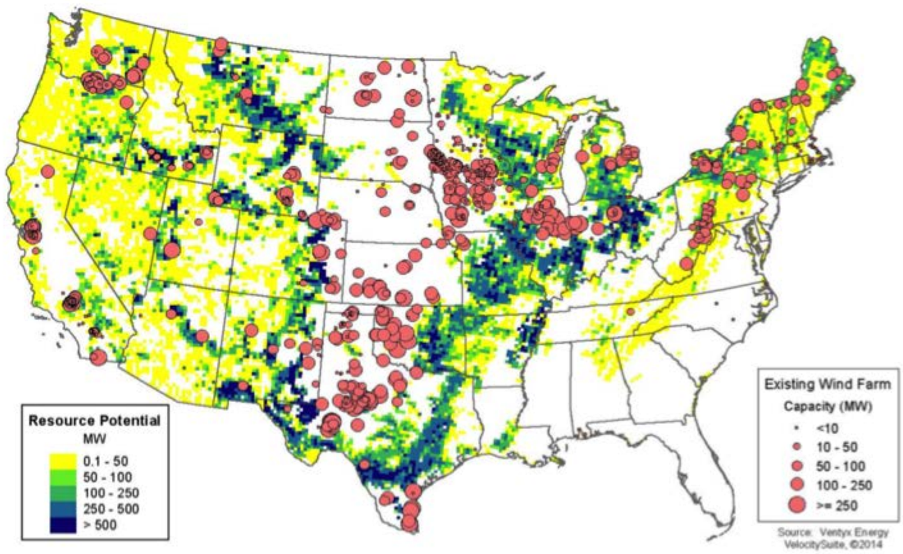


Figure H–24. Map of TRG5 resource potential [11]

H.2.4 Offshore Technology Costs

As shown in Figure H-25, the steps for defining the base-year offshore wind plant, techno-economic cost and performance parameters are similar to that for land-based wind. However, for offshore wind, only one turbine power curve was used. In addition, differentiation at prospective project sites results from the type of support structure associated with changes in water depths. Capital costs were also added to the projects, based on the distance from shore, to represent incremental costs associated with export cable length and construction-period installation transit costs.

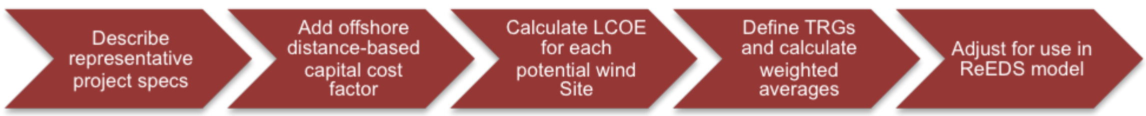


Figure H–25. Offshore wind plant cost and performance techno-economic parameter calculation process

H.2.4.1 One Standard Power Curve, Three Representative Structures

Using information about the global offshore wind energy market, including information from later-stage projects proposed in the United States, parameters for three types of offshore projects were defined. Each type of offshore wind project applied the same turbine but different support structures, depending on the water depth.[14] Projects in shallow water (0 to 30 m) are assumed to use monopile structures; projects in medium water depths (30 to 60 m) are assumed to use four-leg jacket structures; and projects in deep water are assumed to use floating structures. Table H-9 summarizes the offshore wind plant parameters.

14 Data sources include NREL Offshore Wind Projects Database, literature review (e.g., BVG Associates [12], Prognos AG. [13], Navigant [14], and Tegen, S. et al. [9]); industry queries and interviews (Offshore Wind Task Force); and NREL Balance of System Model and Preliminary Floating Offshore Cost Analysis Estimates.

Table H–9. Offshore Wind Plant Specifications

Technology Characteristics	Shallow	Mid-Depth	Deep
Water depth (m)	0 to 30	31 to 60	61 to 700
Turbine IEC class	1S	1S	1S
Specific power (W/m²)	318	318	318
Hub height (m)	90	90	90
CAPEX ($/kW)	5,766	6,340	7,379
Overnight capital cost ($/kW)	5,307	5,859	6,859
Construction financing ($/kW)	216	238	277
Offshore spur cost @ 30 km ($/kW)[a]	243	243	243
Operating costs ($/kW/year)	132	132	162

a Based on analysis of the NREL Offshore Wind Database, a representative distance of 30 km is assumed for this study.

All offshore wind plants are assumed to use an IEC Class 1S turbine with a specific power of 318 watts/m² and a hub height of 90 m. The representative wind plant capacity is 500 MW. Figure H-26 shows the normalized power curve for the representative offshore wind turbine.

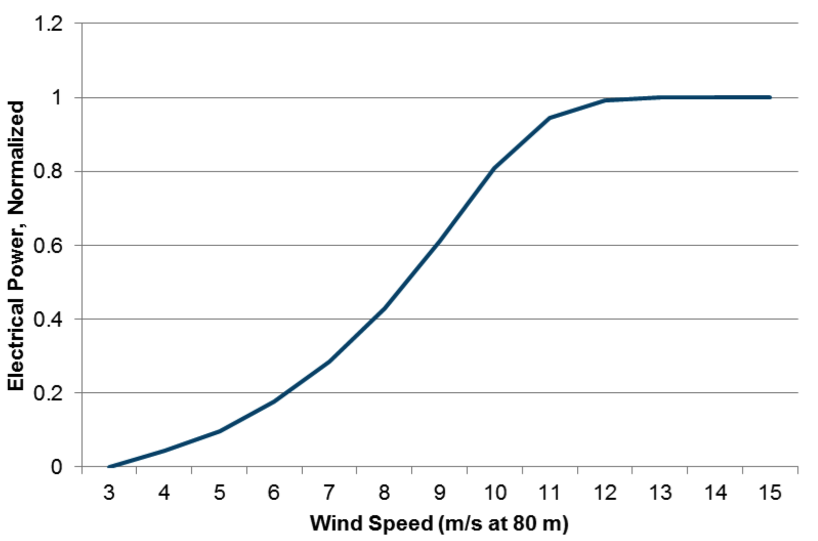
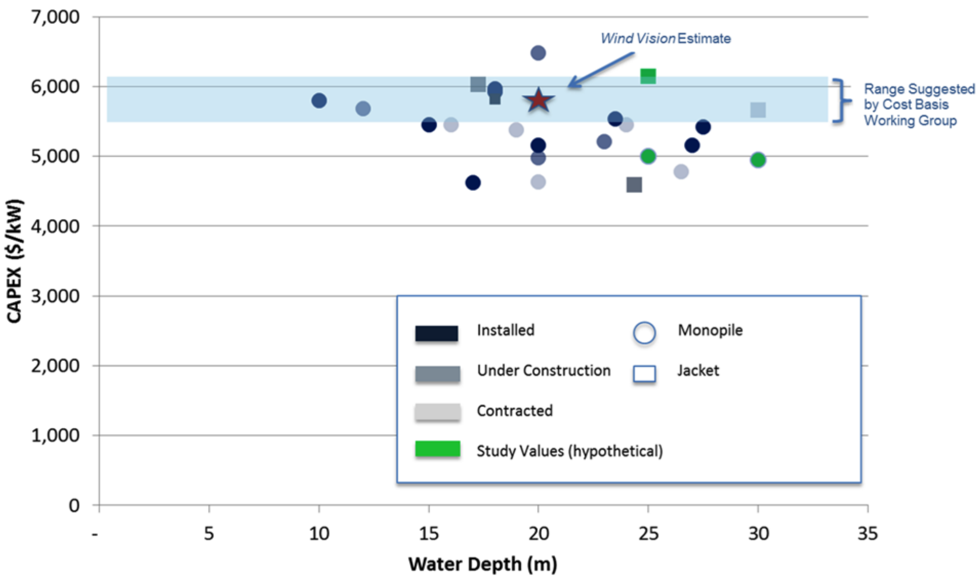


Figure H–26. Power curve for representative offshore wind turbine

Capital Costs

As shown in Figures H-27 and H-28, data from the NREL Offshore Wind Database[15] indicates a range of CAPEX from approximately $4,500–$6,500/kW for projects in shallow water, and approximately $5,000–$6,500/kW for mid-depth projects.[16] This data represents projects commissioned since 2011 and those with expected commissioning dates through 2015. European and U.S. projects greater than 100 MW in size are included. The dataset represents 3.6 GW of installed capacity, 3.7 GW under construction, and 2.1 GW under contract with major suppliers. Insufficient data exist to develop a similar comparison for deep water offshore wind technologies, as no commercial projects are in advanced stages of development. Based on the limited available data, along with expert input from the *Wind Vision* Offshore Wind Task Force, a floating offshore CAPEX assumption of $7,300/kW was developed. Similar to land-based wind plant market data, these CAPEX estimates include construction financing, but the offshore CAPEX also includes an estimated cost associated with distance from shore.

To fully represent the capital investment cost of offshore wind plants, the incremental costs associated with the length of export cable and construction-period transit, as a function of the distance from plant to shore must be considered. An incremental capital cost factor represents these costs, as described in Section H.3.2. An assumed distance of 30 km from shore was used to estimate the portion of the CAPEX observed in market data associated with the export cable and construction-period transit costs for this analysis. As noted in Table H-9, the assumptions used in modeling are slightly different than the high-level, market data-based capital cost estimates identified with input from the Offshore Wind Task Force due to the iterative nature of developing methods and assumptions to allocate CAPEX across elements that are used in ReEDS. However, the assumptions fall within the range of CAPEX identified for offshore wind plants within the analysis.

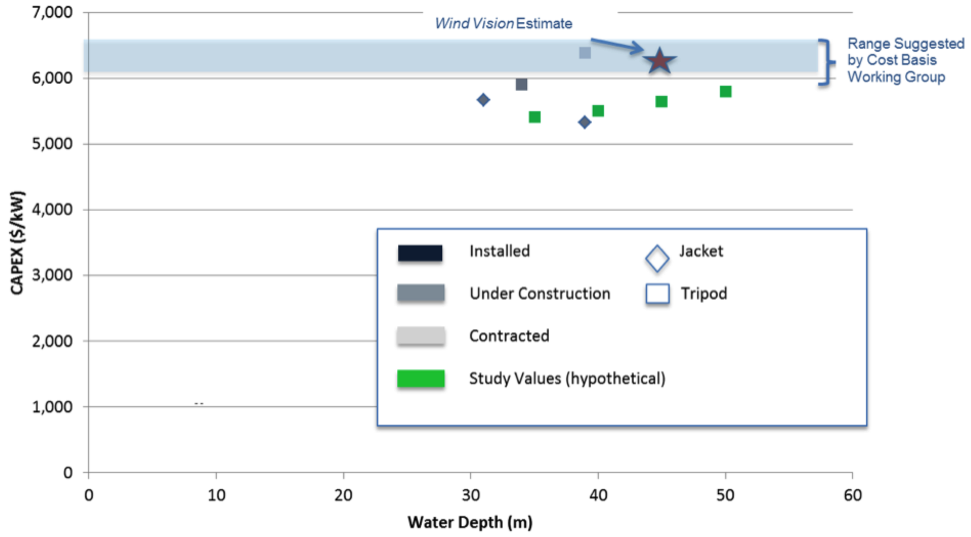


Source: NREL Offshore Wind Database

Figure H-27. CAPEX of shallow offshore projects with reference to market data

15 This is an informal collection of Excel files kept by NREL researchers that may evolve into a structured database for internal purposes. Current, official information can be found at *http://www.nrel.gov/wind/offshore_wind.html*

16 HVDC export system costs for German projects are excluded from the all-in capital cost presented; the BARD Offshore I (tri-pile foundation) wind plant is not included because of cost overruns resulting in project costs of about 1 billion euros ($1.36 billion, based on June 2014 conversion).



Source: NREL Offshore Wind Database

Figure H–28. CAPEX of mid-depth offshore projects with reference to market data

As it does for land-based wind plants, ReEDS imposes regional cost multipliers for offshore wind plants to reflect regional market influences such as labor wage and productivity differences. Figure H-29 identifies the regional multipliers developed by SAIC for offshore wind plants [10]. There is insufficient market data for U.S. offshore wind plants to compare with the expected regional variation determined by SAIC; however, the general trends appear consistent with expectations (e.g., Gulf region costs are likely to be lower than Northeast region costs, in part, because of the existing oil and gas infrastructure as well as lower wage rates generally).

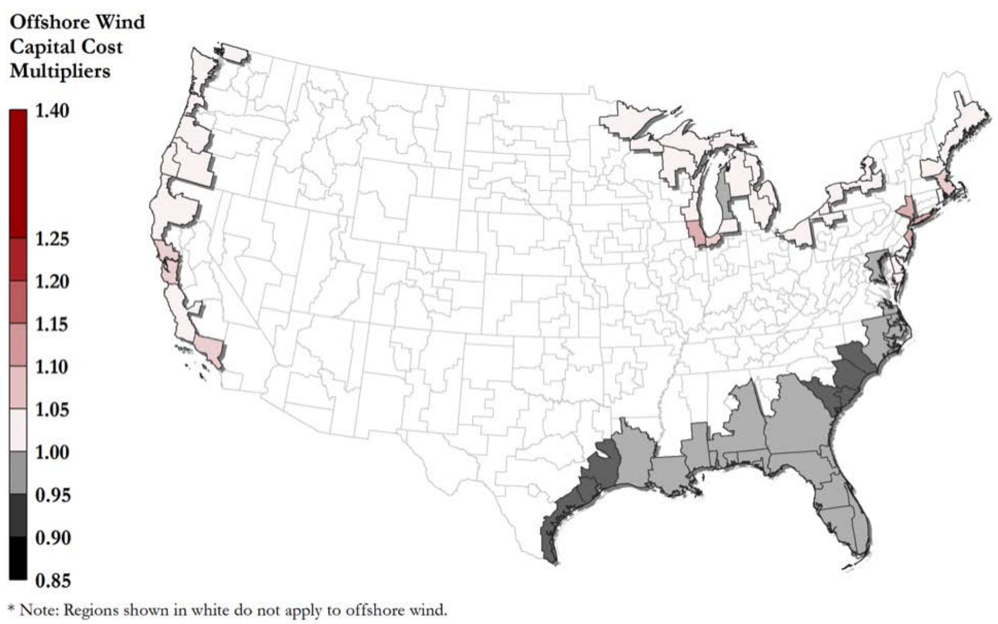


Figure H–29. Offshore wind plant capital cost regional multipliers

Operating Costs

Offshore wind plant operating costs are assumed in this report to be $132/kW/year for all shallow water and mid-depth projects, and $162/kW/year for all deep water projects. Annual operating expenditures for offshore wind projects are subject to greater uncertainty than capital costs because no projects have been installed in the United States, and European project owners in Europe do not generally report these costs. As explained in the NREL *Cost of Wind Energy Review* [15], NREL's "best guess" estimate is $40/MWh, or approximately $130/kW/year. These data represent plants that are in water depths up to about 60 m; an increment of $30/kW/year was imposed for deeper water projects because of greater uncertainty and lack of existing data related to floating projects. The degree of uncertainty around actual annualized operating costs makes the above estimates reasonable assumptions for modeling purposes.

Capacity Factor

As with land-based wind plants, annual energy capture for offshore wind plants is represented by net CF in ReEDS. For each of the more than 30,000 potential offshore wind plant sites, annual energy production was calculated using the hourly wind profile and wind turbine power curve. The gross wind turbine CF was converted to net wind plant CF with an assumption of 15% losses, including electrical, transmission, and wake-effect losses. No U.S. offshore wind plant production data exists, so the loss assumption is the same as for land-based wind. An economic filter of CF >= 30% was applied to exclude the lowest performing potential wind plant areas.

H.2.4.2 LCOE Calculation for Each Potential Wind Plant Site

As for land-based wind, an LCOE was calculated with the site-specific capital cost, net CF, operating cost, and project finance cost for each of the three water depth definitions. An incremental capital cost (OffSpurCost) was developed for each potential wind plant site based on geographic distance to land, as described in Section H.3.2. In order to define TRGs for offshore wind plants based on groups of similar cost, the distance-based capital cost factor was included in the plant LCOE estimates.

LCOE was calculated with the following equation:

$$LCOE = \frac{FCR * CAPEX + OPEX}{CF * 8760}$$

The range of LCOEs for each potential wind plant site is shown in Figures H-30 to H-32 for shallow, mid-depth and deep water sites. For shallow water, four TRGs were defined. For mid-depth and deep water, three TRGs each were defined.

The higher cost band is associated with sites that exceed 70 km from shore and use a high-voltage, direct current (HVDC) electrical export cable. The vertical spikes are associated with wind plant sites at a given wind speed that are farther from shore and are thus more heavily affected by the impact of the distance-based capital cost factor. The capacity-weighted average LCOE value for each TRG is shown along with the representative LCOE value assuming a CAPEX based on a 30-km distance from shore, as represented in Table H-3 and H-9. LCOE values are not ReEDS inputs but are shown here for reference.[17]

17 The weighted-average LCOE is based on the site-specific grid connection costs. The ReEDS input assumptions for CAPEX require a base plant cost so that a unique grid connection cost can be applied to each potential wind plant location. To calculate the weighted-average LCOE values, the weighted-average grid connection cost for each TRG must be added to the overnight capital cost to equal the CAPEX. The weighted-average grid connection costs are: TRG1 = $156/kW; TRG2 = $101/kW; TRG3 = $194/kW; TRG4 = $224/kW; TRG5 = $278/kW; TRG6 = $381/kW; TRG7 = $1068/kW; TRG8 = $324/kW; TRG9 = $573/kW; and TRG10 = $1327/kW.

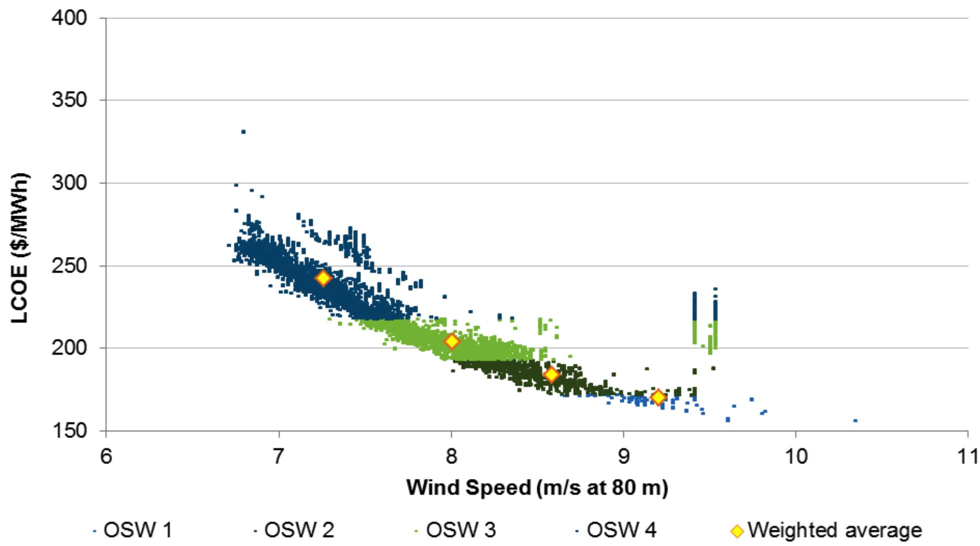


Figure H-30. LCOE for all potential shallow water offshore wind plants, by TRG

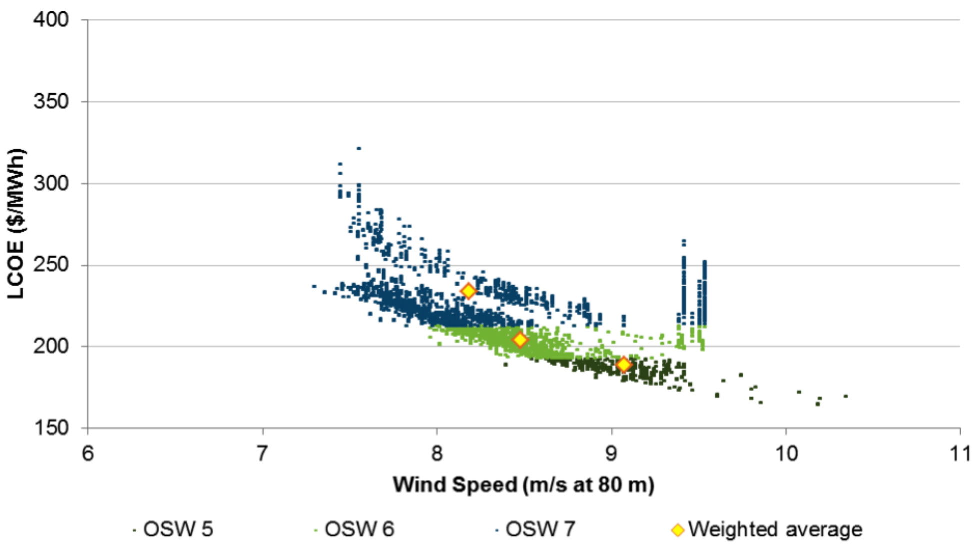


Figure H-31. LCOE for all potential mid-depth offshore wind plants, by TRG

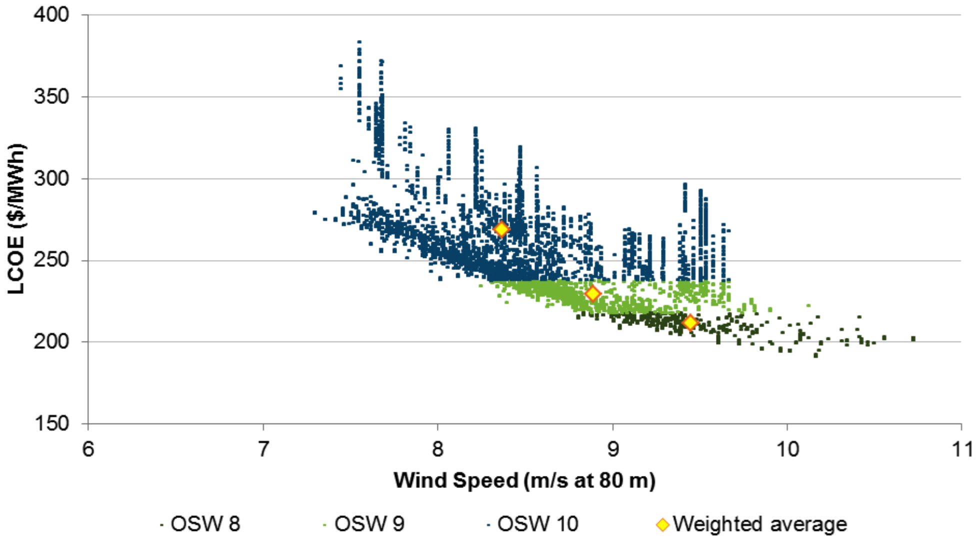


Figure H-32. LCOE for all potential deep water offshore wind plants, by TRG

Table H-10 summarizes the characteristics of each of the ten offshore wind plant TRGs.

Table H-10. Definition of Offshore TRGs

TRG		LCOE Range ($/MWh)	Weighted Average Wind Speed (m/s)	Potential Wind Plant Capacity (GW)	Potential Wind Plant Energy (TWh)
Shallow	OSW 1	LCOE <= 172	9.1	11	46
	OSW 2	172< LCOE <= 193	8.5	61	231
	OSW 3	193< LCOE <= 218	8.0	191	674
	OSW 4	218< LCOE	7.3	165	500
Mid-depth	OSW 5	LCOE <= 193	9.1	48	197
	OSW 6	193< LCOE <= 213	8.6	87	338
	OSW 7	213< LCOE	8.4	181	661
	OSW 8	LCOE <= 218	9.5	82	355
Deep	OSW 9	218< LCOE <= 238	9.0	184	756
	OSW 10	238< LCOE	8.6	549	2,078
Total				1,559	5,835

H.2.4.3 Calculation of Capacity-Weighted Averages

Ten representative wind plants are used for modeling purposes to reflect offshore wind technology. Using the TRG definitions above, capacity-weighted averages for net CF were calculated. These capacity-weighted average values become the offshore wind plant performance parameters used in ReEDS modeling. Figures H-33 to H-35 illustrate CAPEX with a distance-based capital cost factor for all potential wind plant sites, grouped by TRG. The vertical spikes of high capital costs associated with high wind speeds are most likely an artifact of the decision to extrapolate offshore areas to a particular depth contour.

In these large grid cells (see maps below), some locations with high wind speed are very far from shore, so the offshore distance factor becomes large. The upper band of CAPEX is associated with an assumption of direct current (DC) cables for sites exceeding 70 km from shore, while the lower band represents costs associated with alternating current (AC) cables for locations up to 70 km from shore (see below for an explanation of cost assumptions). Instead of the weighted average, a representative site at 30 km is highlighted here because this distance represents sites most likely to be developed first. The ReEDS inputs do not include the distance-based capital cost factor because it is added later in the ReEDS modeling process.

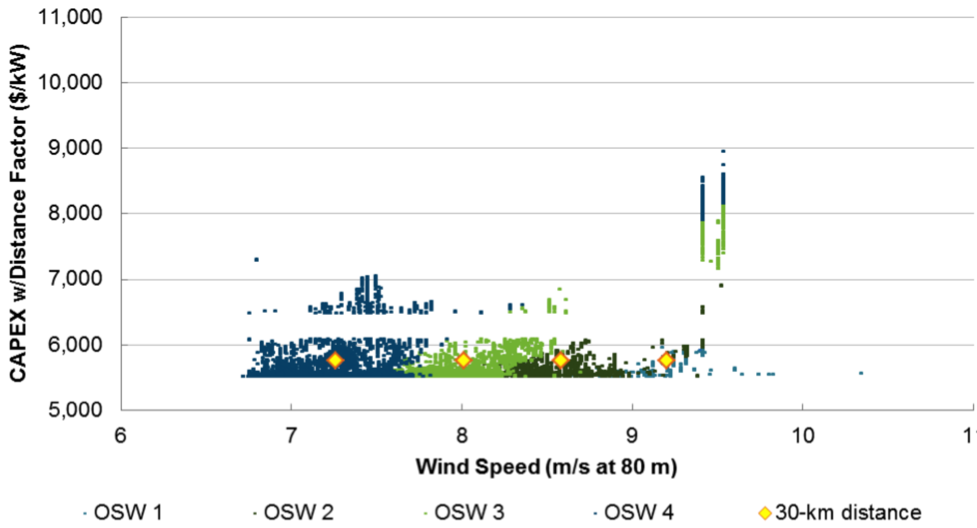


Figure H-33. CAPEX, including distance factor, for all potential shallow water offshore wind plant sites, by TRG

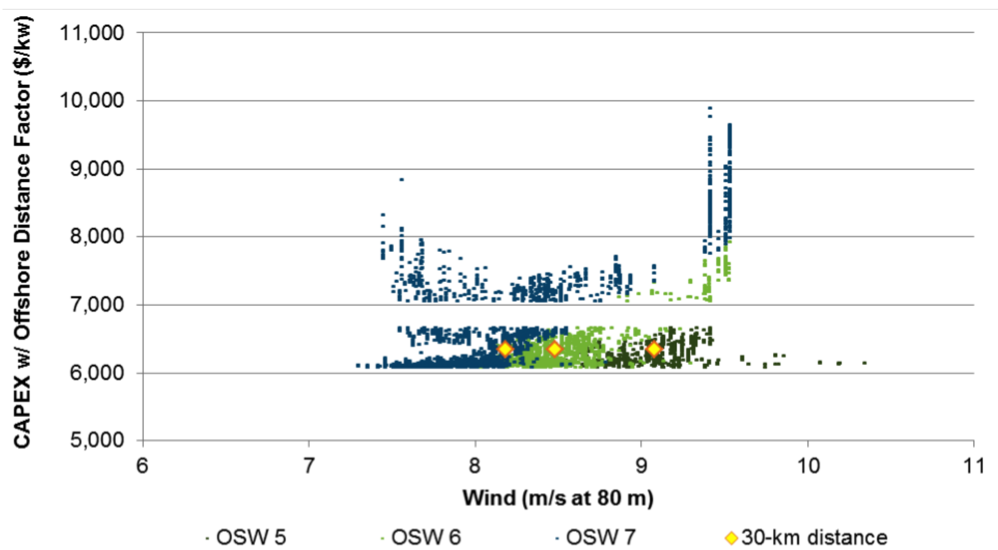


Figure H-34. CAPEX, including distance factor, for all potential mid-depth offshore wind plant sites, by TRG

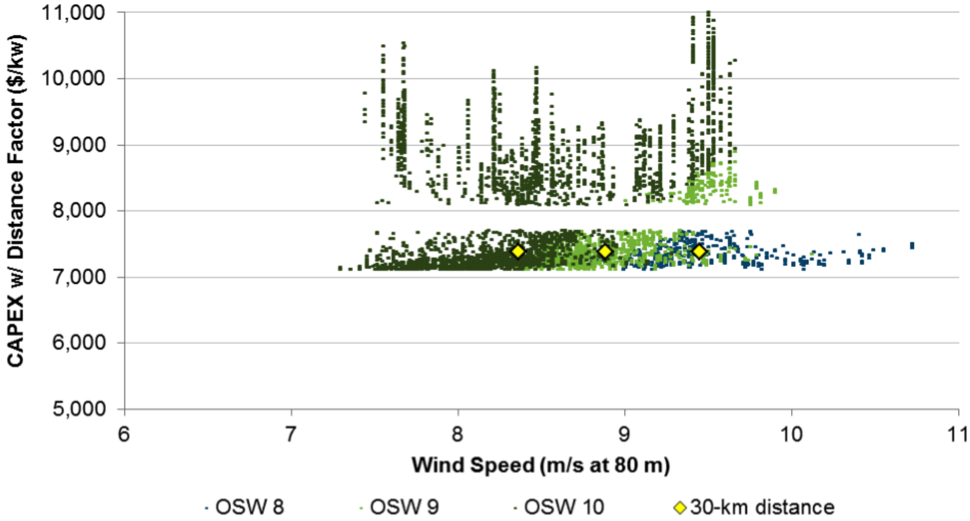


Figure H‑35. CAPEX, including distance factor, for all potential deep water offshore wind plant sites, by TRG

Figures H-36 to H-38 show the net CF for each potential wind site by TRG. The capacity-weighted average net CF is plotted in yellow. These factors become the ReEDS inputs.

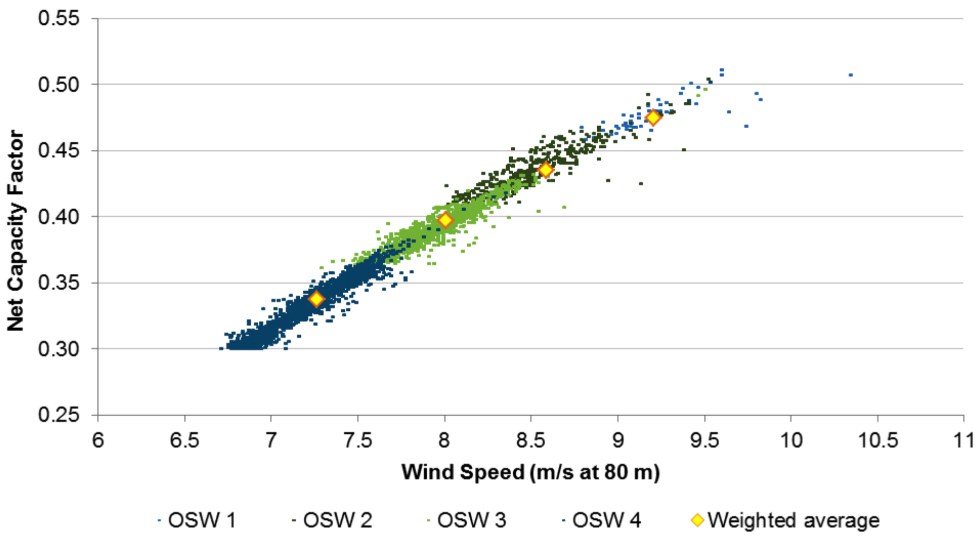


Figure H‑36. CF for all potential shallow water offshore wind plant sites, by TRG

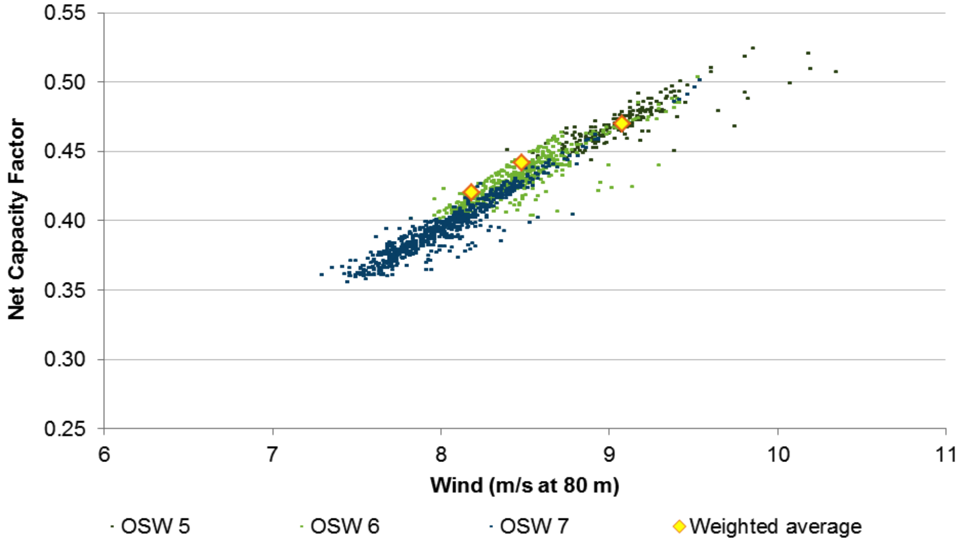


Figure H-37. CF for all potential mid-depth offshore wind plant sites, by TRG

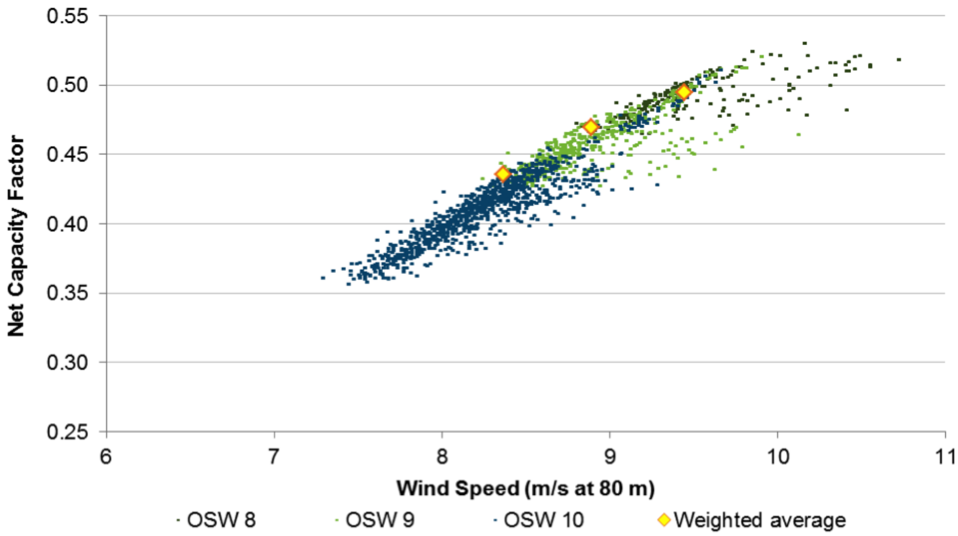


Figure H-38. CF for all potential deep water offshore wind plant sites, by TRG

The wind plant cost parameters are based on the base wind plant capital investment alone; the offshore distance factor, unique to each site, is added separately. The wind plant cost parameters for ReEDS are based on the representative cost of each of the three technologies shown in Table H-11, as there is no assumed cost variability for a given water depth category. The corresponding CAPEX, including each site's distance-based capital cost factor, are shown for illustration.

H.2.4.4 Market-Based Estimate Adjustment for ReEDS Inputs

The ReEDS model requires overnight capital cost as an input because it calculates construction-period financing internally, based on the input parameters described in Table H-1. Construction finance represents about 3.7% of total installed CAPEX. This amount is subtracted from the capacity-weighted average CAPEX for each TRG to arrive at the overnight capital cost value.

The distance-based capital cost factor is not maintained as part of the representative wind plant. It was included in the definition of offshore wind plant TRGs in order to group projects of similar cost, accounting for the distance from shore. The distance-based capital cost factor is reflected as a grid connection cost (OffSpurCost) in the ReEDS model and is not included in the overnight capital cost. Table H-11 contains the ReEDS offshore wind plant inputs after adjustments. Tables H-1 and H-9 illustrate the translation between CAPEX and overnight capital cost.

Table H–11. Offshore Wind Plant Inputs to the ReEDS Model

TRG	Inputs to ReEDS Model for the Base Year		
	Overnight Capital Cost (2013$/kW)	OPEX ($/kW/ year)	Net CF (%)
OSW1	5,307	132	47%
OSW2	5,307	132	43%
OSW3	5,307	132	40%
OSW4	5,307	132	35%
OSW5	5,859	132	47%
OSW6	5,859	132	44%
OSW7	5,859	132	42%
OSW8	6,859	162	49%
OSW9	6,859	162	47%
OSW10	6,859	162	43%

H.2.4.5 Mapped TRGs

Figures H-39 to H-49 show the location of the U.S. offshore wind resource, as defined by TRGs. Figure H-39 shows ReEDS regions colored according to TRG. It is a visual representation of the potential capacity available to ReEDS when it needs to “build” new capacity.

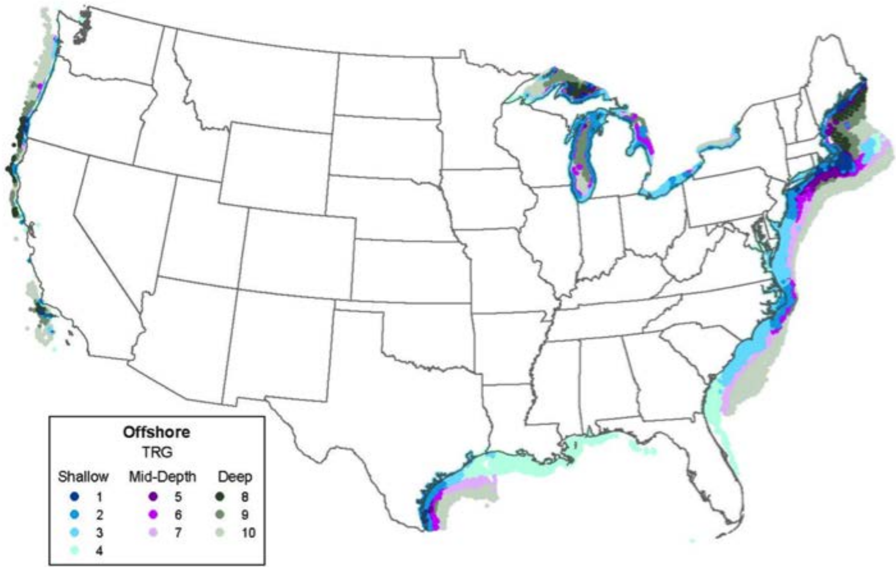


Figure H–39. U.S. Map of offshore wind resource

Figures H-40 to H-49 show the location and potential capacity of offshore TRG1-10. The units are 20x20-km (20-km^2) grid cells, colored according to potential wind plant capacity associated with each TRG within the cell. The potential capacity is based on the land area within a given TRG and an assumption of 3 MW/km^2. Grid cells beyond 50 nautical miles were extrapolated to incorporate everything within a 700-m depth contour within the U.S. exclusive economic zone.

Figure H–40. Map of TRG1 (shallow) resource potential

Figure H–41. Map of TRG 2 (Shallow) Resource Potential

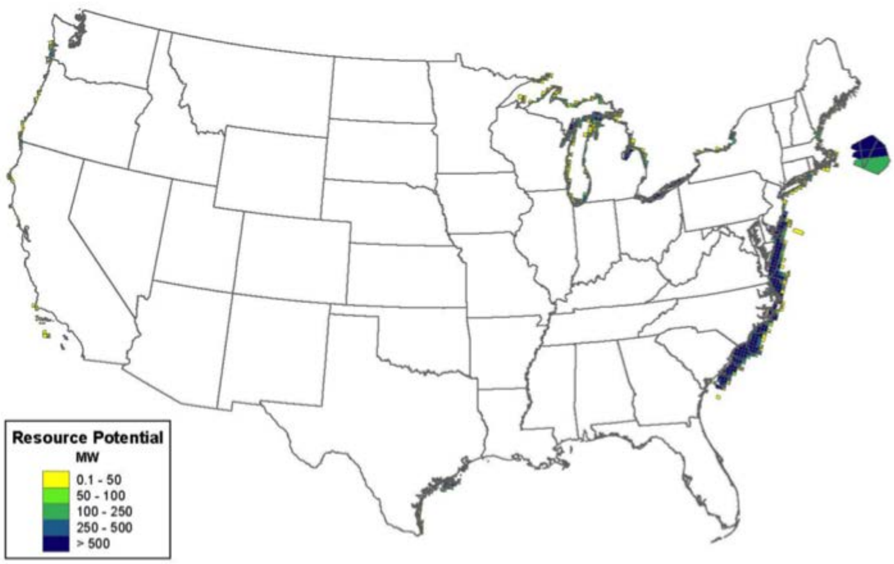


Figure H–42. Map of TRG 3 (shallow) resource potential

Figure H–43. Map of TRG4 (shallow) resource potential

Figure H–44. Map of TRG5 (mid-depth) resource potential

Figure H–45. Map of TRG6 (mid-depth) resource potential

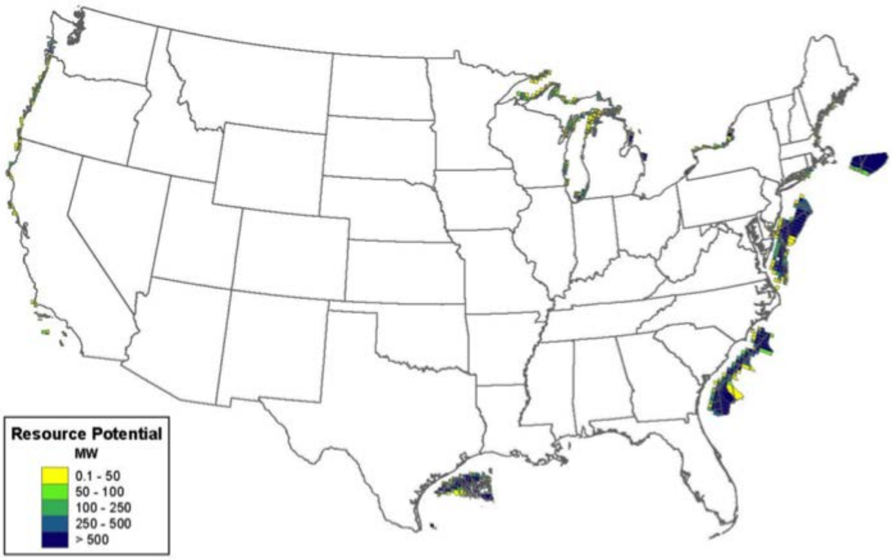


Figure H–46. Map of TRG7 (mid-depth) resource potential

Figure H–47. Map of TRG8 (deep) resource potential

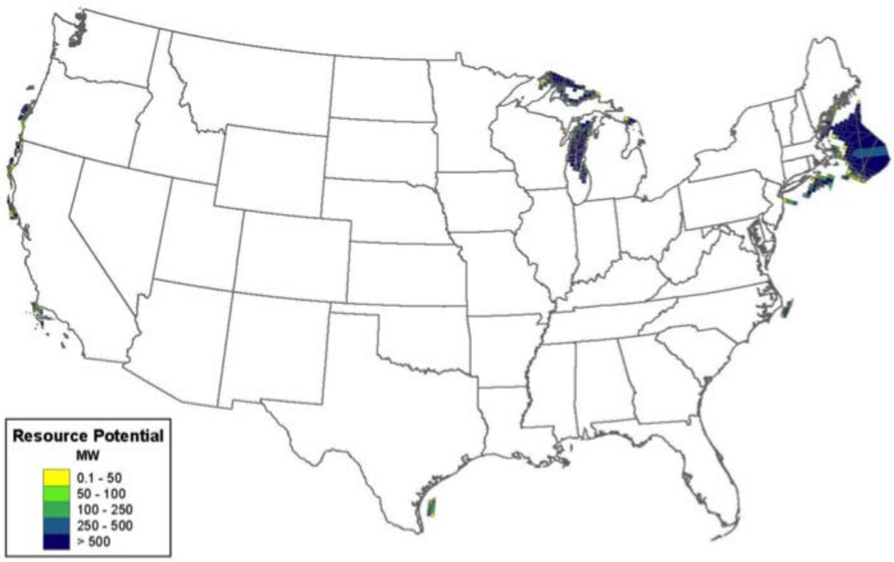


Figure H–48. Map of TRG9 (deep) resource potential

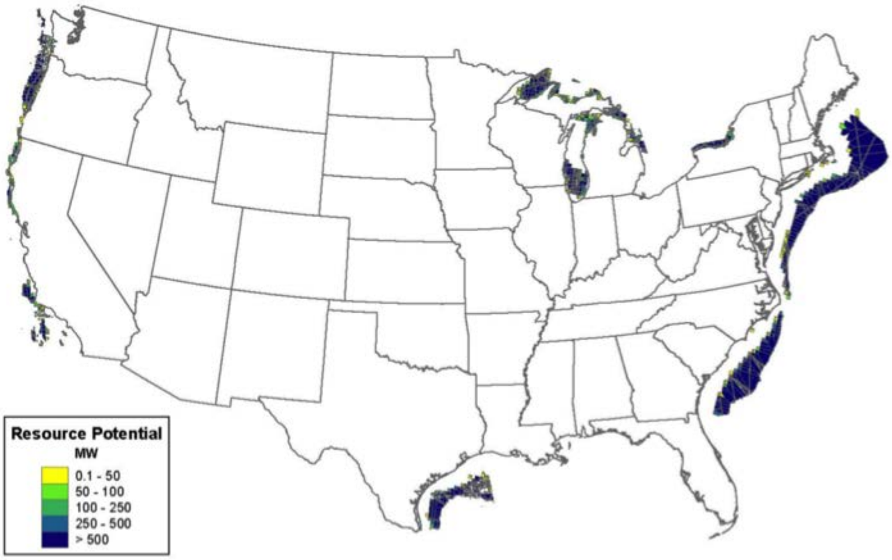


Figure H-49. Map of TRG10 (deep) resource potential

H.3 Grid Connection Costs

The cost to connect each potential wind plant site to the grid is estimated based on the geographic distance from the site to a grid feature. Overland grid connection costs are applied to all potential wind plant sites. An additional distance factor to represent offshore wind plant export cable length and construction-period transit costs is included for potential offshore wind plant sites.

H.3.1 Overland Grid Connection Costs

The ReEDS model assigns each potential wind-plant site costs associated with a "grid feature" that has available capacity to connect new wind plants, and project-specific costs for connecting the plant to the grid feature on a 230-kilovolt spur line. Grid features can be an existing substation, an existing transmission line, a load center (with greater than 10,000 people), or a potential central export point. An algorithm sorts each wind-plant site by cost and ranks potential wind-plant sites, as discussed in the following section. For more information on the modeling algorithm, refer to the ReEDS documentation.

$$GCC = GF + OnSpurCost + OffSpurCost$$

$$OnSpurCost = OnDist \times OnTransCost \times OnRegTransMult$$

$$OffSpurCost = OffDist \times OffDistFactor$$

Overland grid connection costs include:

- Grid feature cost, based on the type of infrastructure available for that feature:
  - $28/kW—substations and load centers, where direct tie-in to an existing substation is available
  - $43/kW—transmission lines and central export locations, where a new substation would need to be built.
- Regional spur line costs, applied using a base cost of $3,667/MW-mile to build a 230-kilovolt line connecting the wind plant to the grid feature [16]. The spur line cost is also subject to regional transmission cost multipliers (Figure H-50 and Appendix G) mapped to ReEDS zones.

Figure H-50 shows the costs of building spur lines by ReEDS zone, after the application of the regional cost multipliers.

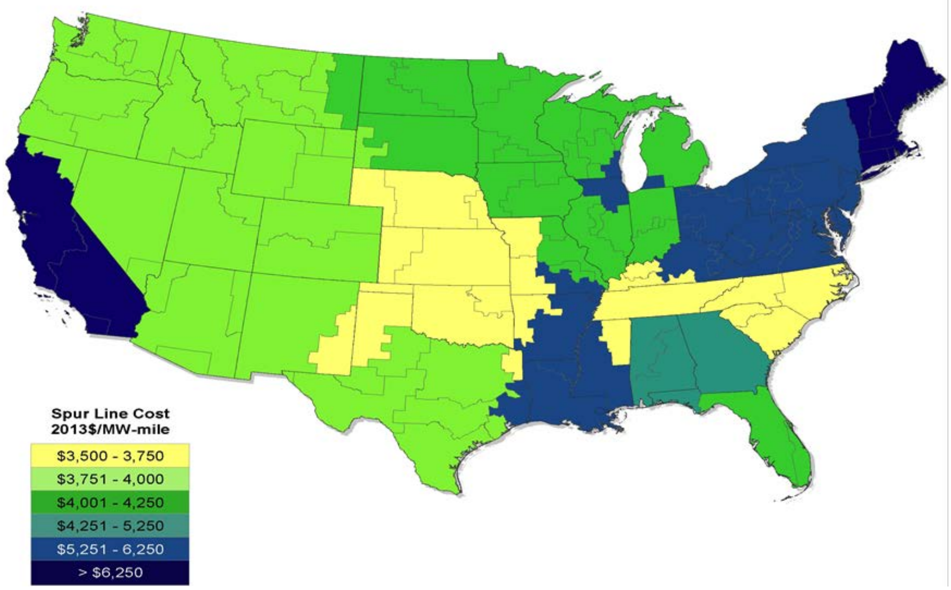


Figure H–50. Spur-line regional transmission costs including regional multipliers

H.3.2 Offshore Cable and Construction Distance-Based Capital Cost Factor

Offshore wind plant costs vary significantly with distance due to cable length and construction-period transit costs. To account for this variability, an offshore distance factor was developed using the NREL Offshore Balance of System model [17] (NREL offshore database) and analysis of German offshore wind projects utilizing HVDC technologies. The offshore distance factor accounts for longer export cables, increased construction-period transportation costs, and other costs that increase as projects are located farther from shore. Export cable costs are based on the general assumption that plants more than 70 km from shore would utilize HVDC technologies. Industry analysts believe that the higher cost of HVDC could be more than offset by a minimization of losses, but this analysis did not take into account the variability of electricity losses with the distance from shore. While the costs associated with distance and the breakpoint between HVDC or HVAC technology is uncertain, this relationship provides a method for ranking potential wind plant site costs that includes the critical element of distance.

Figure H-51 shows the offshore distance factor for HVDC and HVAC export cable systems. Because of limited HVDC system cost data, the economic breakpoint between HVAC and HVDC cable costs are widely debated and may shift as more offshore wind plants are installed.

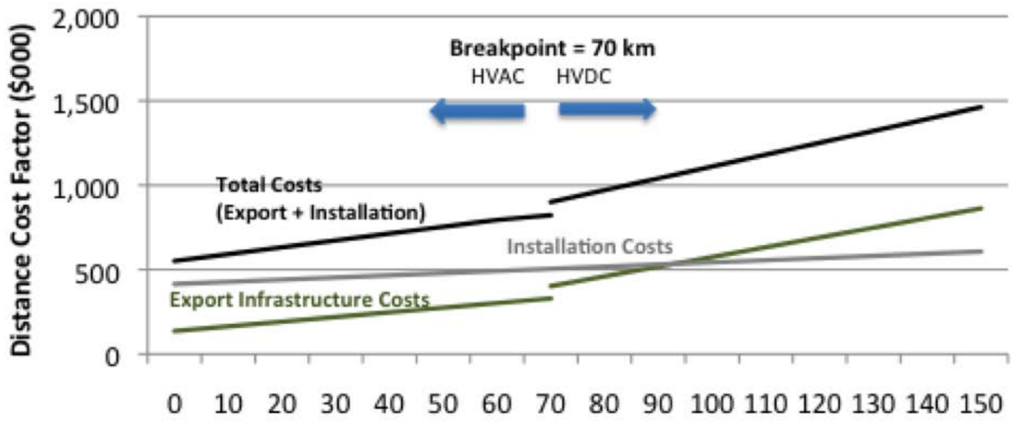


Figure H-51. Offshore Distance Factor

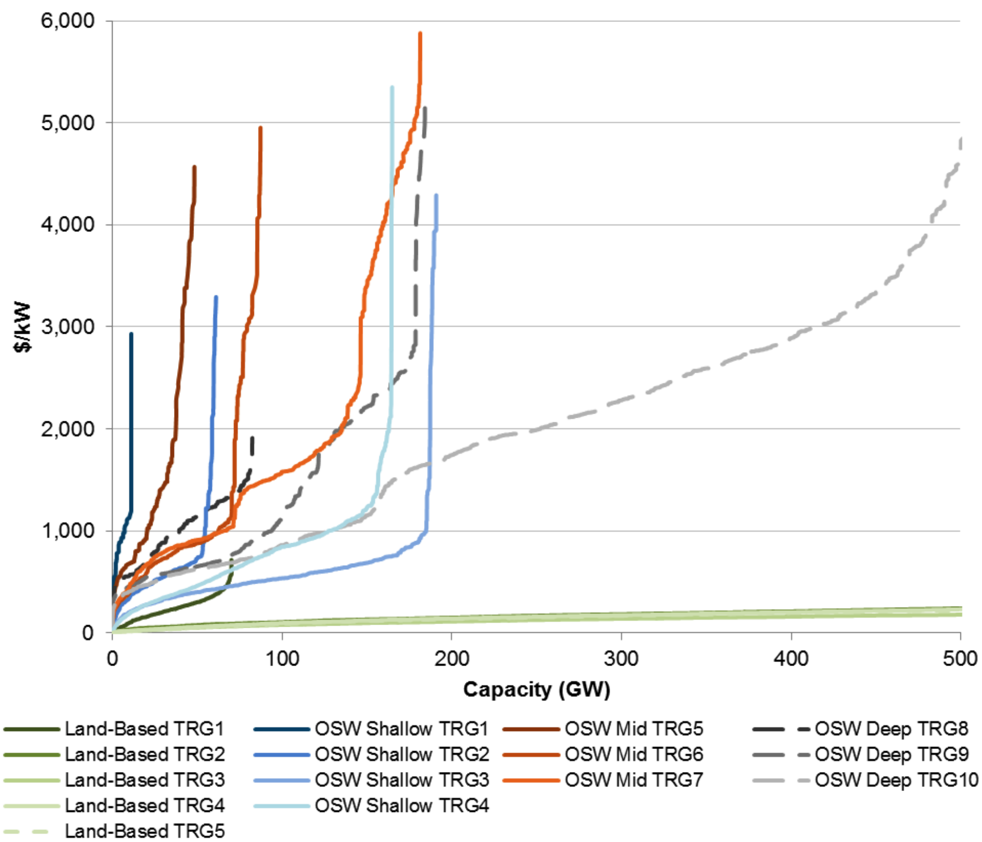


Figure H-52. Grid connection cost by TRG, restricted to 500 GW

The offshore distance factor is represented as the slope of the total cost line in the figure above for distances less than or greater than 70 km.

It is calculated as follows:

If OffDist<= 70 km, assume HVAC system; OffDistFactor = $8.10/kW/km

If OffDist > 70 km, assume HVDC system; OffDistFactor = $13.49/kW/km

The grid connection cost increment associated with offshore wind plants is then:

OffSpurCost = OffDist x OffDistFactor

H.3.3 Grid Connection Cost Curves

An algorithm that ranks each potential wind plant site by cost, including grid connection costs, has been applied similarly to previously conducted studies [18]. Each potential wind plant site is associated with all grid feature options within a ReEDS region and sorted by cost. The algorithm systematically associates the lowest-cost potential wind plant site with a grid feature by assessing the available capacity at the grid feature. Available capacity is assumed to be 10%. The algorithm associates potential wind plants with grid features until the available capacity is filled; the next lowest-cost wind plant site is then associated with a different grid feature. This is repeated for all potential wind plant sites. The assumption is that once existing grid features are filled to capacity, all additional potential wind plant energy could be transported to other regions via long-distance transmission lines, represented as a central export location within each region.

The following are graphic representations of only the grid connection costs associated with each potential wind site. Figure H-52 shows the data by TRG. The grid connection cost for each potential wind plant site is represented in the ReEDS model and is assumed to remain constant throughout the scenario period. That is, the ranking of potential wind plants sites within each of the ReEDS region is fixed based on this assessment of current technology cost, performance, and grid connection cost. Assumptions about future wind plant cost and performance change the absolute value of the potential wind plant site based on the solution year in the scenario, but the relative order of the sites is unchanged.

In Figure H-52, we see that the distance-based offshore capital cost factor results quickly in additional costs as projects get farther from shore. For most of the land-based resource groups, grid connection costs are minimal. Costs for the highest wind areas (TRG1) rise quickly, however, reflecting that the windiest regions of the country are typically in remote locations.

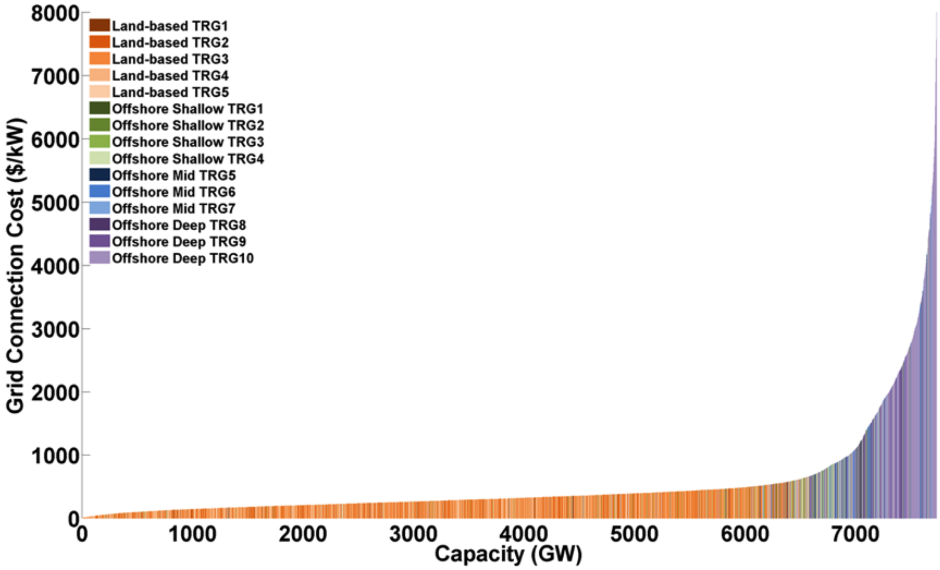


Figure H–53. Base-year grid connection cost for contiguous United States

Figures H-53 to H-58 summarize the data by geographic region. The lowest costs to connect are in the Interior region. The highest costs are in the Northeast, reflective of the fact that much of the resource in the Northeast is offshore.

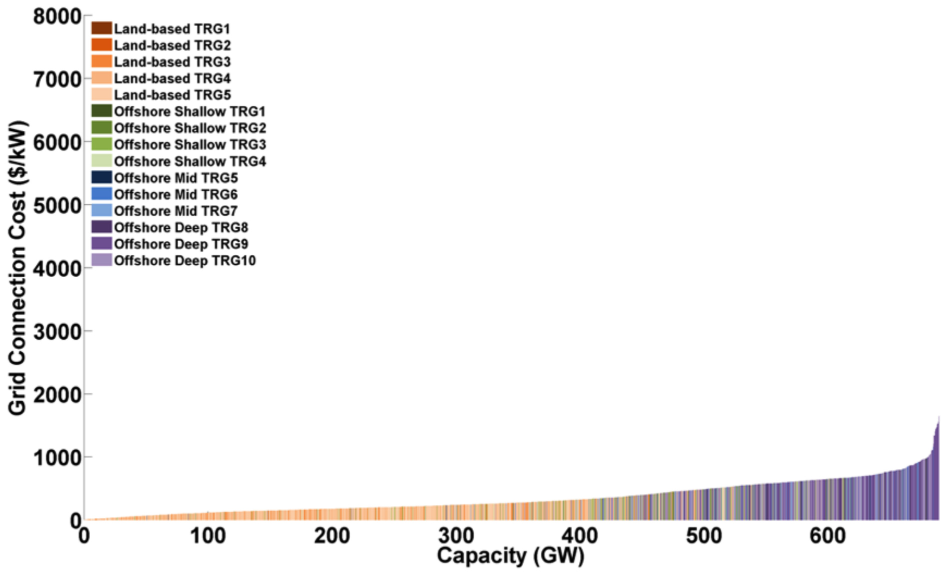


Figure H-54. Grid connection costs—Great Lakes region

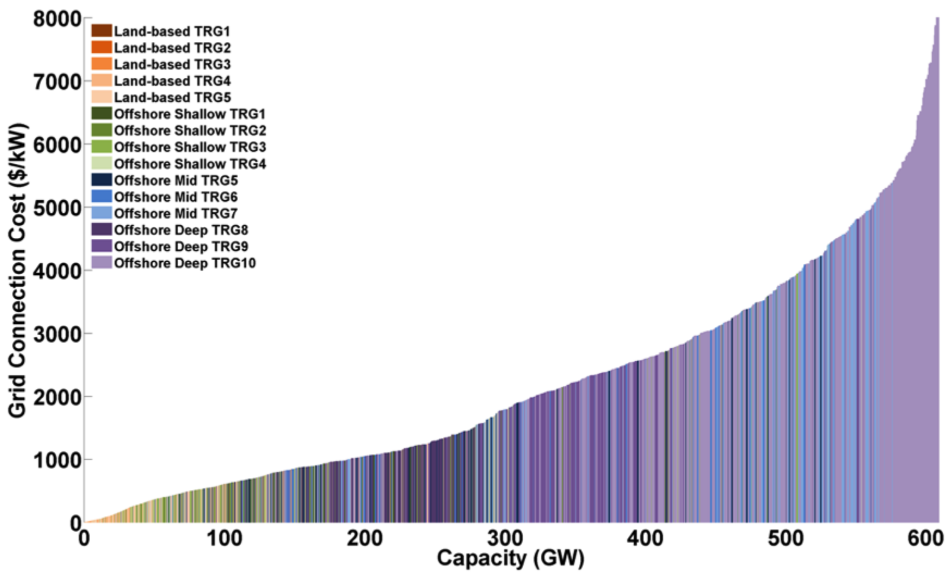


Figure H-55. Grid connection costs—Northeast region

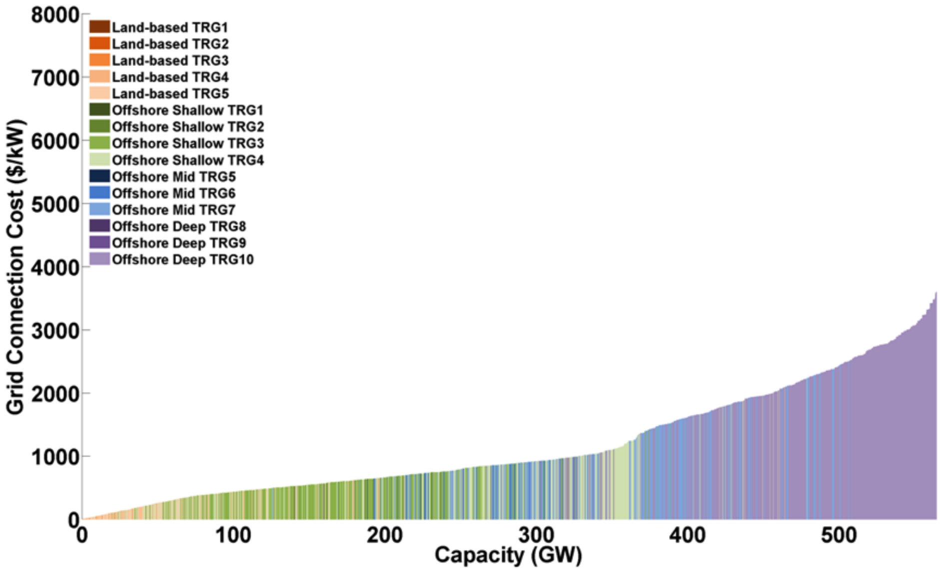


Figure H-56. Grid connection costs—Southeast region

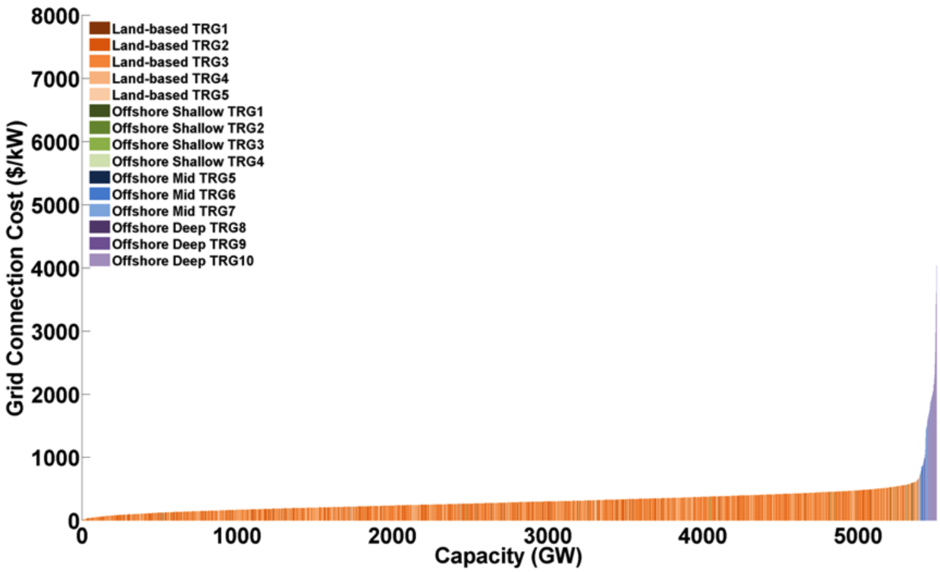


Figure H-57. Grid connection costs—Interior region

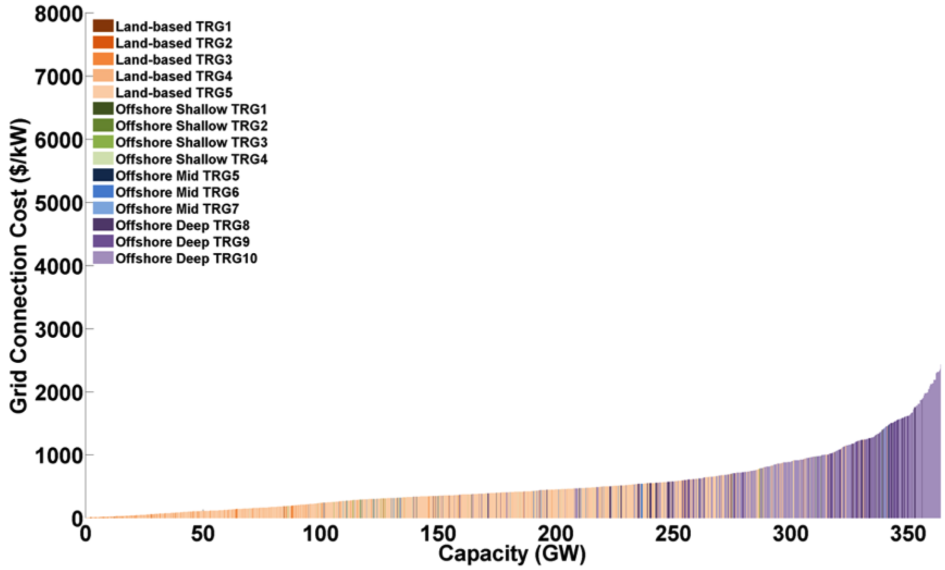


Figure H-58. Grid connection costs—West region

H.4 Financing Assumptions

This section describes project financing assumptions and construction costs in ReEDS.

H.4.1 Project Financing Assumptions

The *Wind Vision* analysis applied similar financing assumptions to all generating technology options in ReEDS. This reflects the assumption that, over the long-term through 2050, all electricity generation technology options have similar levels of maturity and risk perception. While this is likely not the case for offshore wind plants at the time of the *Wind Vision* publication, it is assumed this level of maturity will be achieved rapidly with demonstrated experience of the technology and U.S. deployment. Project finance assumptions are constant throughout the scenario period, 2010–2050. Detailed financing assumptions are shown in Table H-12. The ReEDS model assumes a 24-year useful life, but makes new generation evaluation decision based on costs over an evaluation period of 20 years.

Table H-12. Electric Generation Plant Financing Assumptions

Type of Assumption	Quantity
Evaluation period	20 years
Inflation rate	2.50%
Interest rate—nominal	8%
Rate of return on equity—nominal	13%
Debt fraction	50%
Combined state and federal tax	40%
Discount rate—nominal (real)	8.9% (6.2%)
MACRS (non-hydropower renewables)	5 years

Type of Assumption	Quantity
MACRS (nuclear, combustion turbines)	15 years
MACRS (other fossil, hydropower, storage)	20 years

The FCR value used in this appendix to illustrate relative LCOE estimates was derived from the project finance assumptions shown above. Market data suggests that offshore wind plant financing may be better represented by a WACC of 10.5% for the first projects in the United States [15]. An LCOE estimate using an FCR reflecting this market-referenced WACC is shown in Table H-3 for reference.

H.4.2 Construction Finance Costs

Construction finance costs are added in ReEDS to the overnight capital cost, based on parameters specific to each generation technology. Wind plant construction finance is split 10%, 10%, 80% over a two-year period (10% is accrued in year -2, 10% accrued in year -1 and 80% accrued in the year of commercial operation). Construction periods vary for other technologies, ranging from 0–6 years.

H.5 LCOE Supply Curves

Inside the ReEDS model, all components of cost—wind plant techno-economic cost and performance, project financing, and grid connection costs—come together. In each solution period, ReEDS compares the net present value of a number of potential generation technologies to meet electricity demand by region, while maintaining appropriate levels of planning and operating reserves.

Supply curves representing all potential wind plant sites ranked by LCOE are shown here for illustration. These supply curves represent the base-year cost of energy of more than 61,000 potential land-based sites and more than 43,000 potential offshore wind plant sites. The supply curves include the TRG-based wind plant cost and performance estimates, the site-specific grid connection costs, and the commonly applied project finance costs for the base year, 2012. Figure H-59 shows the data by TRG through 500 GW of installed capacity. Land-based wind costs range from just over $50/MWh to about $75/MWh and do not change significantly for installed capacity greater than 500 GW. The exception is costs for land-based TRG1, which increases quickly at about 75 GW of installed capacity because of grid connection costs. Offshore wind costs range from just over $150/MWh to about $220/MWh, but rise quickly as distance from shore increases.

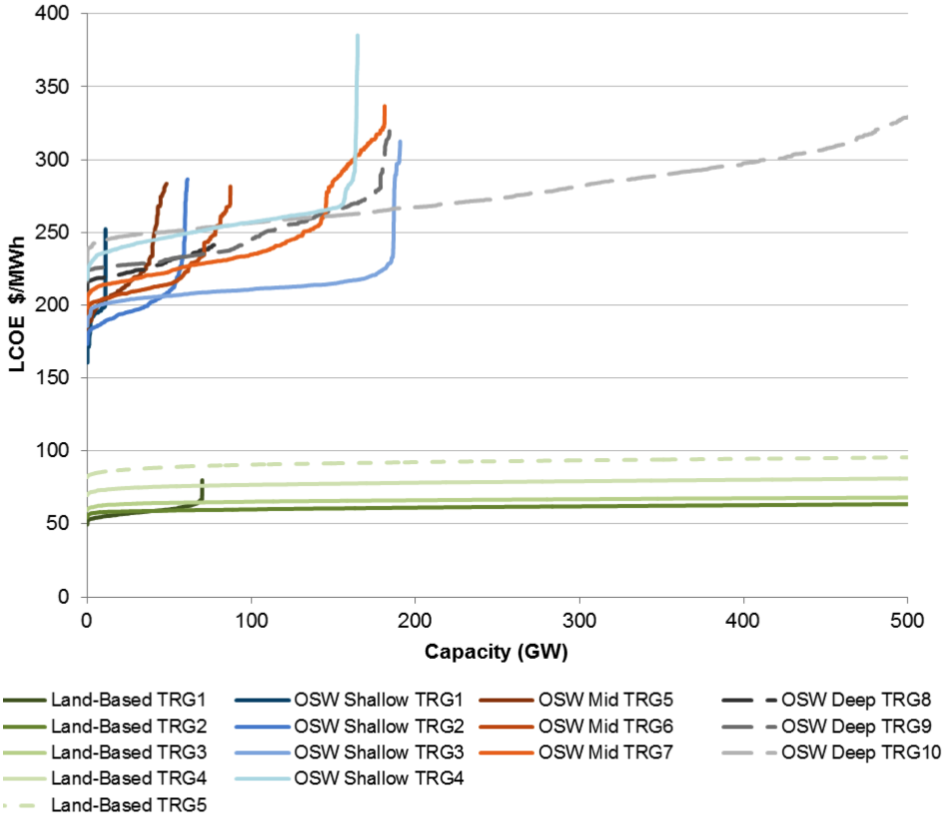


Figure H-59. Wind plant base-year cost of energy by TRG, restricted to 500 GW

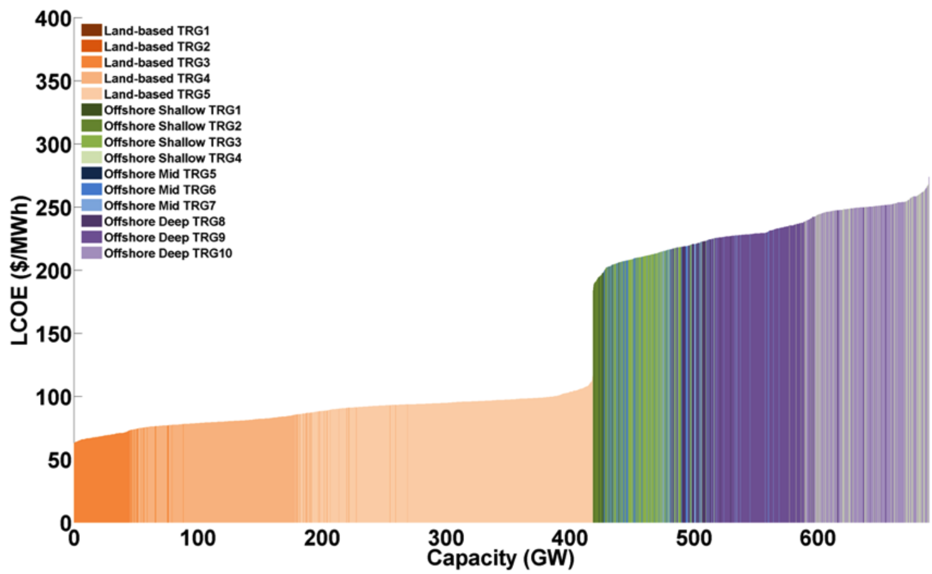


Figure H-60. Wind plant base-year cost of energy—Great Lakes region

Figures H-60 to H-64 show the data by geographic region (the graph for the full LCOE supply curve for the United States is found in Figure H-2).

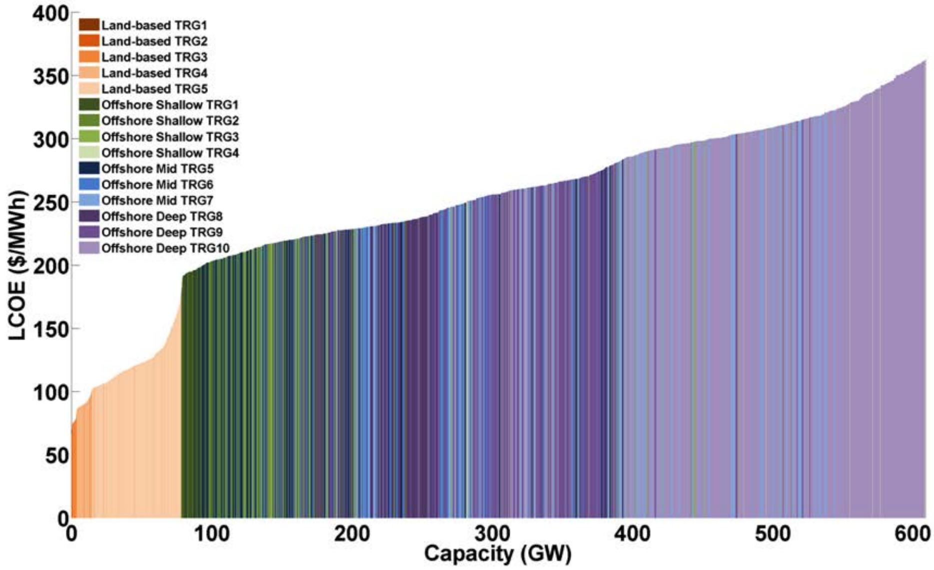


Figure H–61. Wind plant base-year cost of energy—Northeast region

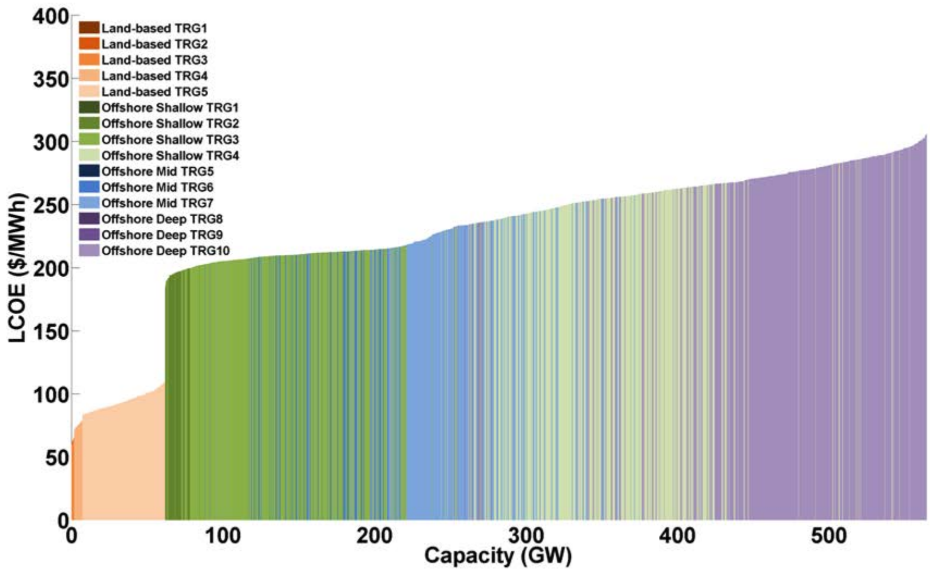


Figure H–62. Wind plant base-year cost of energy—Southeast region

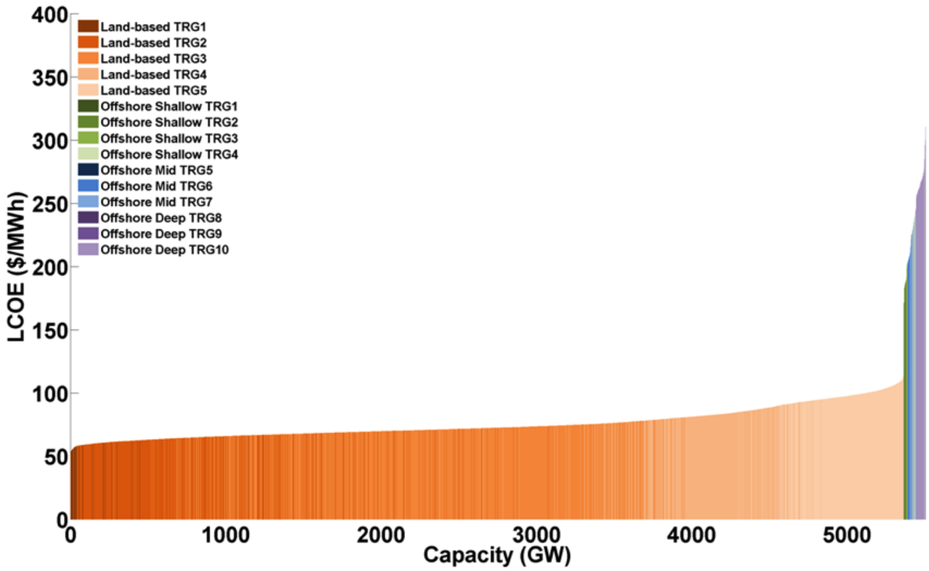


Figure H-63. Wind plant base-year cost of energy—Interior region

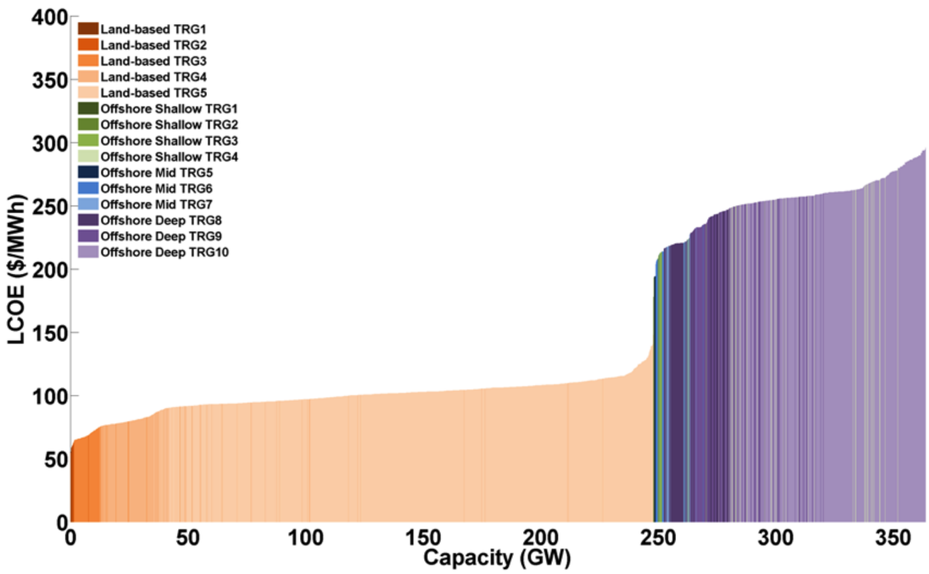


Figure H-64. Wind plant base-year cost of energy—West region

H.6 Future Cost Trajectories

To determine a range of assumptions for future wind technology costs, NREL conducted a literature review of cost reduction potential to identify the median, as well as the upper and lower, bounds of future LCOE reduction percentages. LCOE reduction values were selected to align with these values; and a set of capital cost, net capacity factors, and operations expenditure scenarios were developed to meet the LCOE targets.

These scenarios are based on a presumption that advancements are made in the wind turbine and balance-of-system technologies; plant design and control; logistics and operational strategies; industrialization of the supply chain; and the market, although the scenarios were not developed to represent any particular set of changes. The Low Cost case presumes that the pace of improvement is broader and faster than in the Mid- and High Cost cases. For land-based wind, the High Cost case projects no improvement in the technology or the market from current levels. The types of changes that could bring costs down and performance up for land-based and offshore wind plants are explored in Chapter 4 of the *Wind Vision* report.

Values for each specific variable were determined based on the required change in LCOE and qualitative assessment of the opportunities for cost reduction/performance improvement across these three core variables. For land-based technologies, a maximum net CF of just over 60% was assumed; for offshore technologies, the maximum net CF was assumed to be slightly lower at 56% (approximately 10%, or 5–6 percentage points, lower) as a result of the expectation of more extreme meteorological events in the marine environment. For land-based technology, approximately three primary technology/turbine types were considered. This allowed for a proportionally greater share of future cost reduction in lower-quality resource regimes to be derived from continued CF improvement (e.g., through taller towers and larger rotors, as well as plant optimization), while simultaneously allowing for higher quality sites to obtain a larger share of their cost reduction from capital cost reductions (achieved through optimization of technology and lower material use). In the offshore regime support structure, technology diversification was assumed across shallow, mid-depth, and deep water sites, but within a specific technology type (e.g., shallow water). No differences in capital costs (with the exception of the grid interconnection costs and distance-based export cable and installation cost multiplier) across TRGs were assumed for offshore. Assessment results are in Tables H-4 and H-5.

H.6.1 Land-Based Future Cost Reduction Scenarios

Land-based LCOE projections through 2050 were developed from review and analysis of independent literature-based projections of wind technology LCOEs. More than 20 different projection scenarios from more than 15 independent studies were considered. Individual LCOE projections were extracted and normalized to a common starting point similar to the method used by Lantz et al. 2012 [7]. Given an overall range of projected LCOEs of approximately 0%–40% cost reduction through 2050, the *Wind Vision* identifies three explicit wind cost projections to be modeled:

- Low Cost: Maximum annual cost reduction identified in the literature
- Mid Cost: Median annual cost reduction identified in the literature
- High Cost: Constant wind LCOEs from 2014–2050.

To adjust LCOEs from the base year in 2012 to present day 2014, LCOEs were assumed to progress along the median literature curve trajectory before subsequently flattening as in the High Cost case, or returning to the maximum annual cost reduction trajectory as in the Low Cost case. The number of capital cost values is decreased from five points in 2012 to three in 2014, reflecting the expected long-term diversity of the industry. This includes increased costs and energy production for TRG1, consistent with a shift for TRG1 from Class I machines to a mix of IEC Class II and III machines. Figure H-65 illustrates the range of land-based literature cost projections from 2014 to 2050, as well as the High Cost, Mid Cost, and Low Cost projections noted above. Figures H-66 to H-68 show changes postulated from 2014 LCOEs: 0% by 2050 in the High Cost case; 22% by 2050 in the Mid Cost case; and 37% by 2050 in the Low Cost case, as shown in Table H-2.

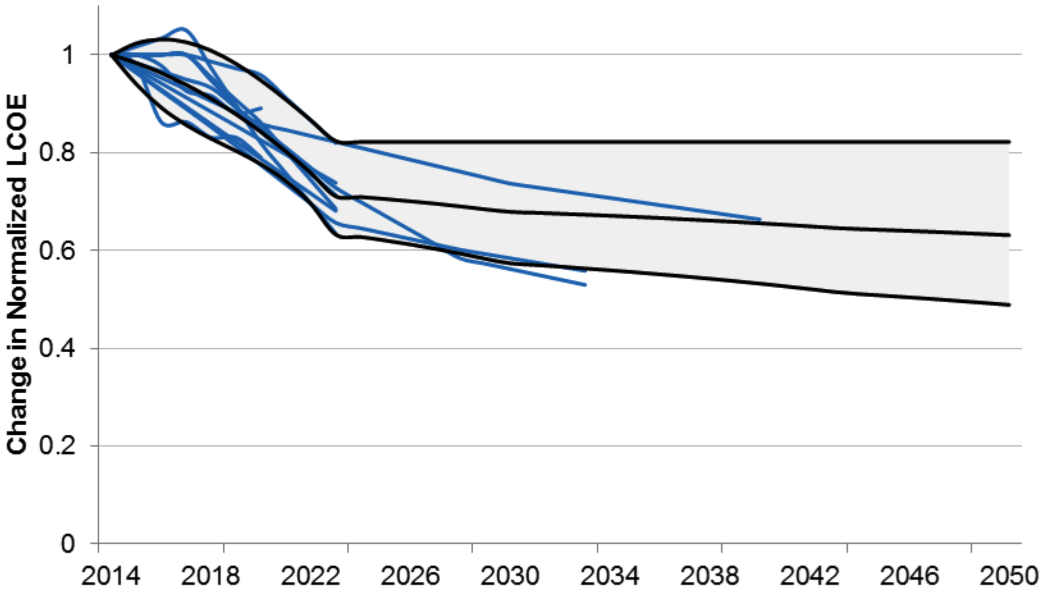


Figure H-65. Land-based wind cost reduction literature review

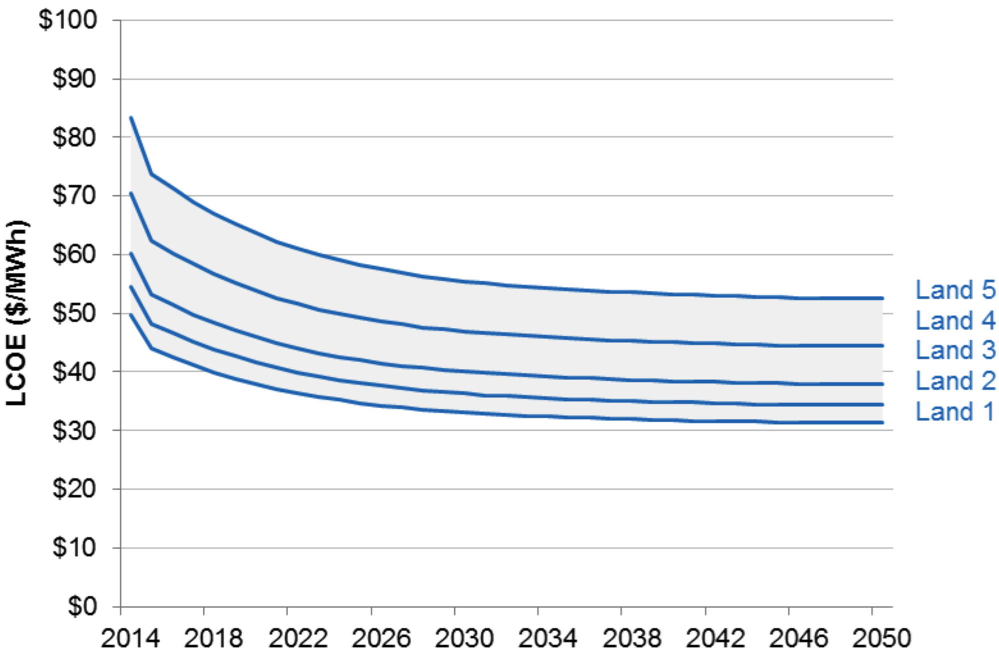


Figure H-66. Future land-based wind plant cost projection—low cost

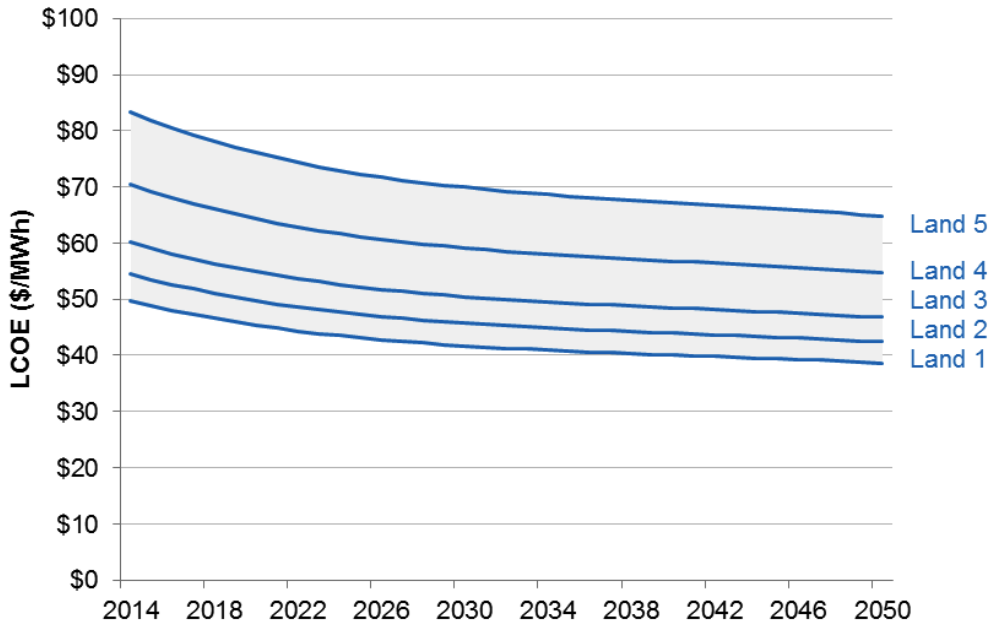


Figure H-67. Future land-based wind plant cost projection—mid cost

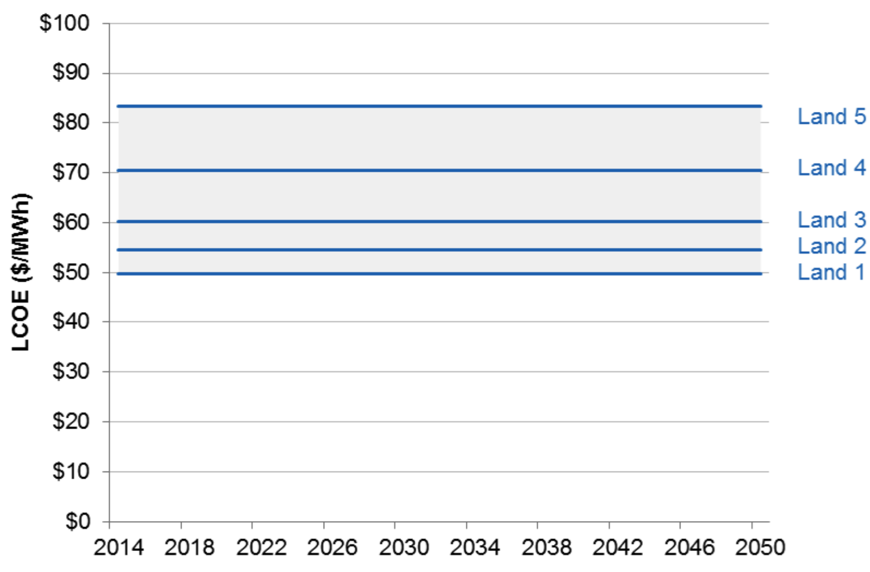


Figure H-68. Future land-based wind plant cost projection—high cost

H.6.2 Offshore Future Cost Reduction Scenarios

Most studies projecting offshore wind cost of energy are dated and do not extend through the *Wind Vision* time period (2050). There is growing recognition within the industry that achieving substantial cost reductions is necessary for offshore wind to compete with other sources of generation. Recent analysis conducted by BVG Associates for the United Kingdom Crown Estate outlines several pathways for cost reduction tied to specific technical advancements [12]. For the *Wind Vision*, the relative cost of mid-depth water plants and deep water, or floating, offshore wind plants is maintained throughout the scenario period for simplicity. It is hypothesized that the unique aspects of floating technologies, such as the ability to assemble and commission turbines at the port, could reduce costs beyond the levels considered here.

Offshore wind LCOE projections through 2050 were developed from a combination of methods (see also Chapter 3). Review and analysis of independent literature-based projections were used to inform estimates of cost reduction through the mid-2020s.[18] Beyond the mid-2020s, offshore wind projections rely on three independent learning rate estimates to project costs from the mid-2020s to 2050.[19] Common learning rates were applied independent of site-specific impacts on technology (e.g., water depth, geotechnical considerations, and distance from staging area). For the High Wind Cost inputs, a 0% learning rate is assumed; in effect, no further improvements are considered.[20] For the Central Wind Cost inputs, a 5% learning rate is assumed. For the Low Wind Cost inputs, a 10% learning rate is assumed.

Figure H-69 illustrates the range of offshore literature cost projections from 2014–2050, as well as the High Cost, Mid Cost, and Low Cost projections noted above. Figures H-70 to H-72 illustrate changes postulated from 2014 LCOEs: 18% by 2050 in the High Cost case; 37% by 2050 in the Mid Cost case; and 51% by 2050 in the Low Cost case, as shown in Table H-2. Although it is unlikely that each of the specific offshore plant types will progress in cost reduction at the same rate, as the modeling assumptions suggest, the *Wind Vision* analysis has applied this approach, in the absence of better information.

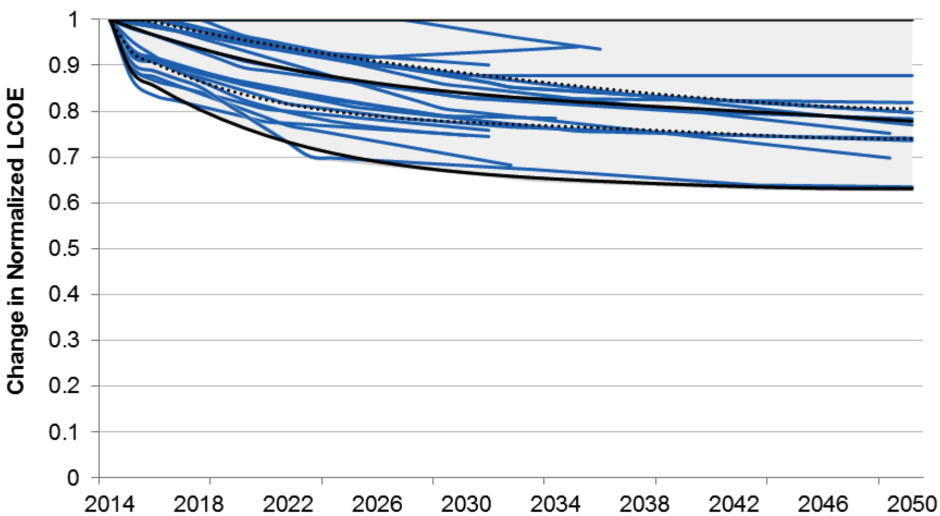


Figure H–69. Offshore wind cost reduction (from the literature review)

18 Literature projections were not applied to the long term because only a small sample of projections extend beyond the mid-2020s and representation of recent industry trends in those studies is poor.

19 Learning rates rely on historical trends to project future technological improvement. The learning rate is defined as the percent change in cost for every doubling in cumulative production or units installed.

20 Given the current maturity of offshore wind technology, this learning rate assumes very limited or no industry growth outside of the United States and, in many respects, an inability for the industry to achieve adequate scale and volume required to reduce costs.

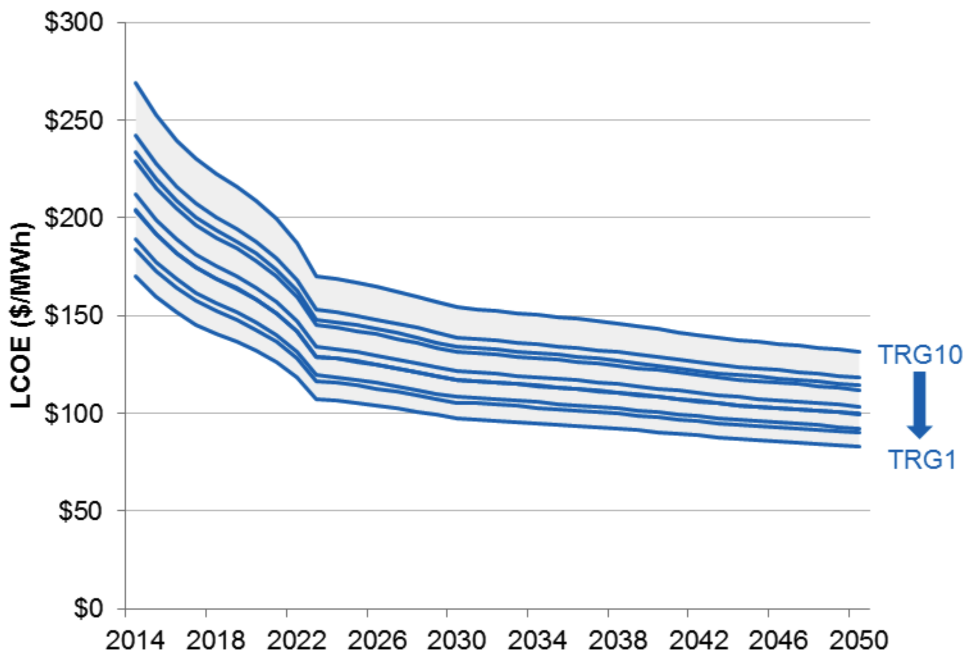


Figure H-70. Future offshore wind plant cost projection—low cost

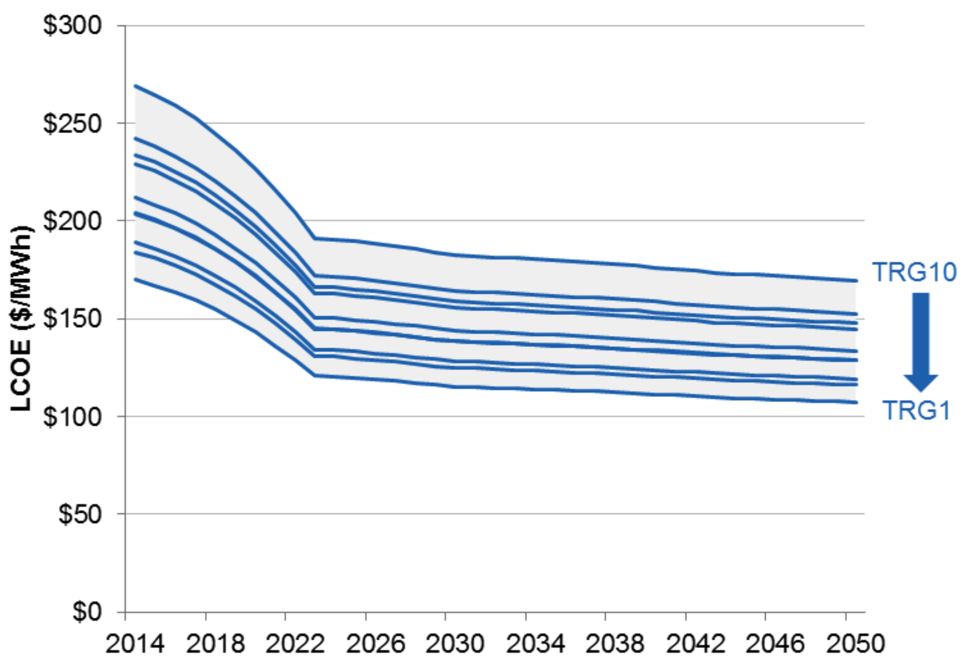


Figure H-71. Future offshore wind plant cost projection—mid cost

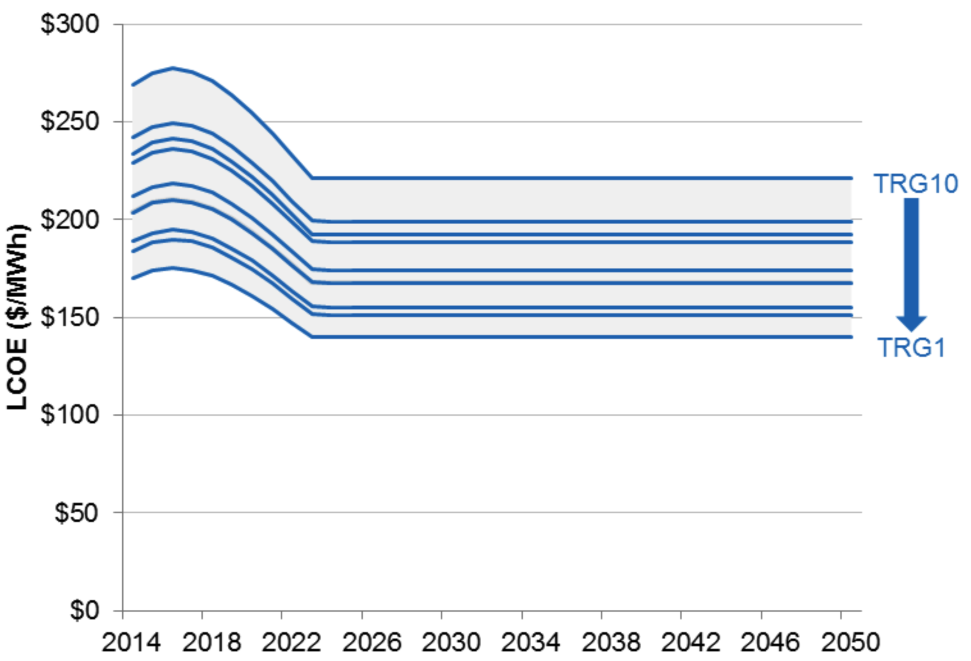


Figure H-72. Future offshore wind plant cost projection—high cost

H.7 References

[1] Lopez, A.; Roberts, B.; Heimiller, D.; Blair, N.; Porro, G. *U.S. Renewable Energy Technical Potentials*: *A GIS-Based Analysis.* NREL/TP-6A20-51946. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Dec. 26, 2014: http://www.nrel.gov.

[2] "New U.S. Wind Energy Potential Estimates: Background and Explanation of Changes from Prior Estimates." Albany, NY: AWS TruePower, 2010. Accessed Dec. 21, 2014: https://www.awstruepower.com/knowledge-center/item/new-u-s-wind-energy-potential-estimates-background-and-explanation-of-changes-from-prior-estimates/.

[3] Dhanju, A.; Whitaker, P.; Kempton, W. "Assessing Offshore Wind Resources: An Accessible Methodology." Renewable Energy (33:1), January 2008; pp. 55–64. Accessed Feb. 17, 2015: http://www.sciencedirect.com/science/article/pii/S096014810700078X.

[4] Denholm, P.; Hand, M.; Jackson, M.; Ong, S. *Land Use Requirements of Modern Wind Power Plants in the United States.* NREL/TP-6A2-45834. Golden, CO: National Renewable Energy Laboratory, 2009.

[5] *Electric Power Monthly with Data for December 2013.* Total Electric Power Industry Summary Statistics, Year-to-Date 2013 and 2012. Net Generation and Consumption of Fuels for January through December. Washington, DC: U.S. Energy Information Administration, 2014. Accessed Feb. 13, 2015: http://www.eia.gov/electricity/monthly/index.cfm.

[6] Wiser, R.; Bolinger, M.; et al. *2012 Wind Technologies Market Report.* NREL/TP-5000-58784; DOE/GO-102013-3948. Washington, DC: U.S. Department of Energy, Energy Efficiency & Renewable Energy, August 2013; 92 pp. Accessed Dec. 26, 2014: http://www.nrel.gov.

[7] Lantz, E.; Wiser, R.; Hand, M. IEA Wind Task 26: *The Past and Future Cost of Wind Energy, Work Package 2.* NREL/TP 6A20-53510. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Dec. 26, 2014: http://www.nrel.gov.

[8] Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects." WINDExchange presentation, Feb. 1, 2012. Washington, DC: U.S. Department of Energy Wind Program, Office of Energy Efficiency & Renewable Energy; 42 pp. Accessed Dec. 26, 2014: http://emp.lbl.gov/publications/recent-developments-levelized-cost-energy-us-wind-power-projects.

[9] Tegen, S.; Lantz, E.; Hand, M.; Maples, B.; Smith, A.; Schwabe, P. 2011 *Cost of Wind Energy Review.* NREL/TP-5000-56266. Golden, CO: National Renewable Energy Laboratory, March 2013; 50 pp. Accessed Dec. 26, 2014: http://www.nrel.gov.

[10] Beamon, A.; Leff, M. *EOP III Task 1606, Subtask 3—Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report. Appendix B of Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Work performed by SAIC Energy, Environment & Infrastructure, McLean, VA. Washington, DC: U.S. Energy Information Administration, April 2013. Accessed Dec. 26, 2014: http://www.eia.gov/.

[11] *Ventyx Velocity Suite. 2013*. Accessed Jan. 7, 2015: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite.

[12] *Offshore Wind Cost Reduction Pathways Study.* London: The Crown Estate, May 2012. Accessed Dec. 19, 2014: http://www.thecrownestate.co.uk/energy-and-infrastructure/offshore-wind-energy/working-with-us/strategic-workstreams/cost-reduction-study/.

[13] *Kostensenkungspotenziale der Offshore-Windenergie in Deutschland.* Offshore Wind Foundation. Berlin: Prognos AG and Hamburg: Fichtner Group, 2013. Accessed Dec. 26, 2014: http://www.prognos.com/publikationen/publikationen-suche/338/show/fc3cf511f301128c92ad2988517d79bc/.

[14] *Offshore Wind Market and Economic Analysis: Annual Market Assessment*. DE-EE0005360. Prepared for U.S. Department of Energy. Burlington, MA: Navigant Consulting, Feb. 22, 2013. Accessed Dec. 28, 2014: http://www.navigant.com.

[15] Tegen, S.; Hand, M.; Maples, B.; Lantz, E.; Schwabe, P.; Smith, A. *2010 Cost of Wind Energy Review.* NREL/TP-5000-52920. Golden, CO: National Renewable Energy Laboratory, April 2012; 111 pp. Accessed Dec. 26, 2014: http://www.nrel.gov.

[16] *Phase 2 Report: DOE Draft Parts 2–7—Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Washington, DC: Eastern Interconnection Planning Collaborative, Dec. 22, 2012; 103 pp. Accessed Jan. 27, 2015: http://www.eipconline.com/Phase_II_Documents.html.

[17] Saur, G.; Maples, B.; Meadows, B.; Hand, M.; Musial, W.; Elkinton, C.; Clayton, J. "Offshore Wind Plant Balance-of-Station Cost Drivers and Sensitivities." Poster session presented at *Offshore WINDPOWER* October 9–11, 2012, Virginia Beach, Virginia. NREL/PO-5000-56132. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Dec. 26, 2014: http://www.nrel.gov.

[18] Previsic, M.; Epler, J.; Hand, M.; Heimiller, D.; Short, W.; Eurek, K. *The Future Potential of Wave Power in the United States.* Sacramento, CA: RE-Vision, 2012.

This page is intentionally left blank

Appendix I: JEDI Model Documentation

The *Wind Vision* uses the Land-Based Wind and Offshore Wind versions of the Jobs and Economic Development Impact (JEDI) model. The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) has created a suite of JEDI input-output (I-O) models that estimate economic impacts supported by investment in different energy technologies. NREL and MRG & Associates developed the Land-Based and Offshore Wind JEDI models to incorporate the unique aspects of wind development in an economic impact tool that can be accessed and used by the public.[1]

I-O models are used to estimate economic impacts associated with investments or expenditures. These models map how sectors in an economy—such as businesses, households, workers, capital, and governments—interact with one another via purchases and sales at a single point in time. Because sectors are related, an increase in demand from one sector can lead to an increase in demand from other sectors. An increase in demand for steel towers, for example, results in increased demand for iron ore. JEDI estimates the changes in demand for these goods and services with data input by the user, also known as the "project scenario."

The JEDI project scenario is a set of data that describes a project. Each project scenario contains two sets of line-item expense categories; one set covers the construction of the project, while the other covers operation and maintenance. Expenses in these categories include items such as equipment (e.g., blades and towers), materials and services, and labor. JEDI models contain default project scenario and cost data that are based on actual projects, interviews with industry experts, and engineering models.

The JEDI models also allow a user to specify what portions of expenditures are made within the region of analysis. For example, users can specify whether wind turbine blades are manufactured in the state in which the project is being built or outside the state (assuming the state is the region of analysis). JEDI uses expenditures made within the region of analysis, or local expenditures, to estimate local economic impacts. JEDI does not estimate economic impacts outside the particular, defined region of analysis.

I.1 JEDI Parameterization: Local Content, Expenditures, and Capacity

Section 3.11 contains broad assumptions for local (in this scenario, local is domestic) content of wind installations and a discussion of the factors that could push domestic wind expenditures up or down. Specifically, section 3.11 lists "lower" and "higher" local content percentage assumptions for broad expenditure categories. Table I-1 shows how these percentages were applied to more-specific expenditure items in the JEDI model.

1 All publicly available JEDI models can be downloaded from *http://www.nrel.gov/analysis/jedi.*

Table I–1. Domestic Content by JEDI Expenditure Category

JEDI Expenditure Category	Domestic Content Lower Scenario	Domestic Content Higher Scenario
Towers	60%	90%
Blades	60%	90%
Nacelles	20%	50%
Balance of system—materials, grid interconnection	80%	95%
On-site labor (construction and operations and maintenance)	100%	100%
Engineering	80%	95%
Professional services (legal and public relations)	100%	100%
Site certificate, permitting, other government payments	100%	100%
Payments to landowners	100%	100%
Air, marine transportation, and transportation equipment services (offshore)	60%	90%
Ground transportation	90%	90%
Replacement parts	30%	60%
Site maintenance machinery, equipment, tools, and supplies	80%	95%

The Offshore Wind JEDI model contains several additional construction-phase financial expenditure categories. Financial expenditures are also included in the Land-Based JEDI model, but are embedded in the cost for all other construction expenditures. In order to treat these expenditures consistently in the Land-Based and Offshore JEDI models, the Offshore Wind JEDI model uses average local content of all nonfinancial expenditures as the assumed local content for its financial expenditure categories.

JEDI wind cost and capacity expansion data come from NREL's Regional Energy Deployment System (ReEDS) model.[2] ReEDS produces expansion and cost estimates separated into technical resource groups, for 356 wind resource regions in the United States. ReEDS costs are reported as totals, not in the line-item expenditures used by JEDI. ReEDS-reported totals are allocated to individual expenditure items based on default JEDI assumptions.

I.2 JEDI Results

JEDI reports economic impact estimates for two phases, construction and operation and maintenance. Construction-phase results are one-time totals that span the equivalent of one year[3]. Operation and maintenance results are annual and ongoing for the assumed 24-year life of the wind facility. All results are based on expenditures and local content data contained within the project scenario.

2 For more information about ReEDS, see Appendix G and Appendix H.

3 If, for example, JEDI reports a construction phase impact of 50 workers to build a project that takes two years to complete, this is the equivalent of an average of 25 workers per year. If the same project took three years, the average would be 17 (rounded) workers per year.

JEDI organizes the estimated impacts into three categories:

- **Project development and on-site labor impacts** represent economic activity that is either directly associated with a project's development and implementation or that occur on-site. These impacts typically occur in the construction, maintenance, engineering and professional services, and port-staging sectors.
- T**urbine and supply chain impacts** represent economic activity that is supported by inputs purchased for a project or business-to-business services. These include domestically manufactured inputs, such as blades, and domestically procured inputs used to manufacture those blades, such as resin and fiberglass.
- **Induced impacts** accrue as money circulates in an economy. Households spend earnings from project development and on-site labor, as well as from the turbine manufacture and supply chain. The portion of these earnings spent within the region of analysis supports induced impacts. These impacts commonly occur in the retail sales, child care, leisure and hospitality, and real estate sectors.

As an example of the three categories, workers who install a wind turbine are on-site; workers who help manufacture a turbine are part of the supply chain; and installers and manufacturers who earn wages and spend money within the region of analysis support further induced economic activity (see Figure I-1). [4]

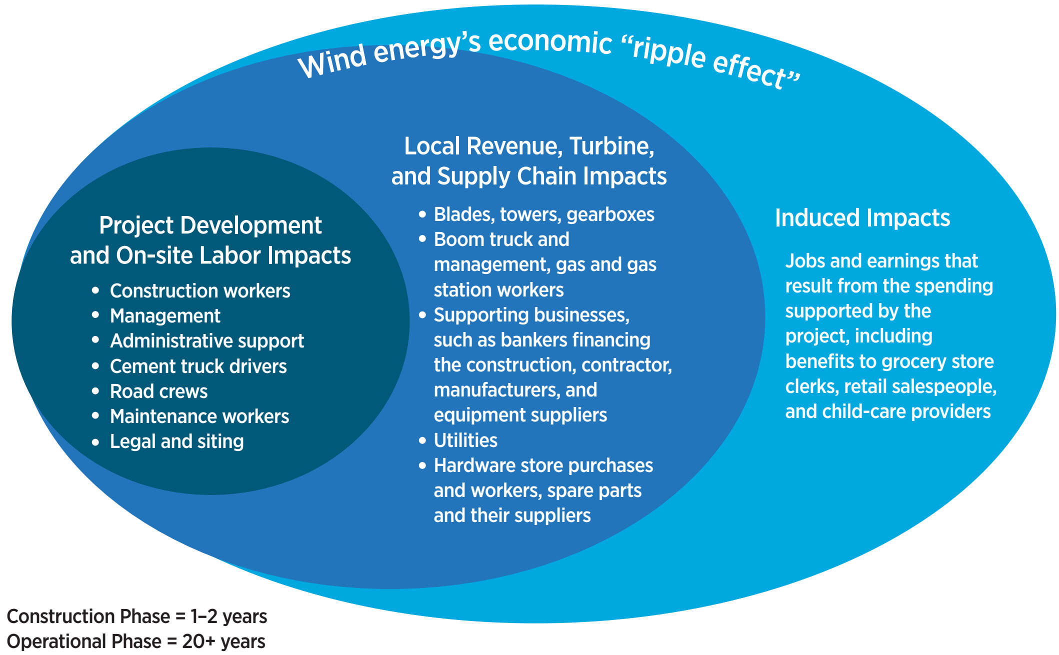


Figure I–1. Representation of different types of JEDI impacts

4 Typically, I-O models organize impacts into direct, indirect, and induced effects. JEDI categories differ from these. The JEDI "project development and on-site labor" category is narrower than "direct" impacts from project expenditures, and the JEDI "turbine and supply chain impacts" are broader than the "indirect" impacts from project expenditures. The Offshore Wind JEDI User Reference Guide *(http://www.nrel.gov/analysis/jedi)* contains more information about these differences.

JEDI reports three different metrics for each category of impact: jobs, earnings, and gross output.

Each metric has a specific definition that informs how it should be interpreted.

- **Jobs** are expressed as full-time equivalents. One job is the equivalent of one person working 40 hours per week, year-round. Two people working full-time for six months is one full-time equivalent. Two people each working 20 hours per week for 12 months also equal one full-time equivalent. A full-time equivalent can be referred to alternately as a person-year or job-year.
- **Earnings** include any type of income from work, generally an employee's wage or salary, plus supplemental costs paid by employers, such as health insurance and retirement.
- **Gross output** is the total amount of economic activity that occurs within an economy (i.e., within the region of analysis). It is the sum of all expenditures that occur because of the given scenario. For example, a scenario in which a developer purchases a locally manufactured $500,000 blade that used $100,000 of locally procured fiberglass represents $600,000 in gross output.

I.3 Aggregation and Geography

The analysis in Section 3.11 contains nationwide aggregate job estimates, yet JEDI is inherently oriented toward individual projects. The distribution of expenditures within default project data reflects actual and potential wind plants, not collections of plants within a state or region.

For this reason, economic impact estimates were created for every ReEDS wind resource region and reporting period, then aggregated to generate nationwide estimates. These final estimates, therefore, use the United States as the region of analysis—local content estimates reflect materials sourced nationwide. Similarly, data used to calculate supply chain and induced impacts reflect U.S.-sourced labor and materials used by businesses, governments, and households. Though only national estimates are presented in section 3.11, the economic development impacts associated with on-site labor (construction and operation and maintenance) can also be readily estimated at the state level. These state-level results are presented in section 3.12.1.

I.4 Explanation of JEDI Limitations and Caveats

Regarding the use of JEDI, there are caveats and limitations as with all economic models. I-O models in general use fixed, proportional relationships between sectors in an economy. This means that factors that could change these relationships, such as price changes that lead households to change consumption patterns, are not considered.

JEDI provides estimates of economic impacts based on user-specified expenditure assumptions and the economic conditions when the I-O data were compiled. Impacts that extend into the future, such as operation and maintenance impacts, are assumed to do so. There may, however, be any number of changes in a dynamic economy that JEDI is not capable of considering. As such, JEDI results should not be considered a perfect forecast. Instead, JEDI results reflect the possible impacts of a project were it completed in the current economy, under the user-specified cost and local content assumptions.

JEDI results are based on user-provided project inputs, and these inputs can change from project to project. This is especially true of nascent technologies or technologies that have not yet been widely deployed in the United States. If the objective is to estimate impacts from a specific project, tailoring the inputs to that specific project should produce more accurate results. JEDI does not evaluate whether inputs are reasonable, nor does it determine whether a project is feasible or profitable.

Results from JEDI models are gross—not net—economic development impacts. JEDI only estimates the economic activity that would be supported by demand created by project expenditures. Other changes in the economy, including any displacement and macroeconomic effects, are not considered. These include supply-side impacts, such as price changes, changes in taxes or subsidies, utility rate changes, and jobs lost or gained in other industries. JEDI also does not incorporate far-reaching effects, such as greenhouse gas emissions, displaced investment, and the potential side effects of a project (e.g., changes in fishing, recreation, and tourism).

I.5 Offshore Wind Lease Calculations

Offshore lease calculations are based on operating fees established in Bureau of Ocean Energy Management outer continental shelf (OCS) commercial leases OCS-A 0483, OCS-A 0486, and OCS-A 0487 off the coasts of Rhode Island, Massachusetts, and Virginia [1, 2, 3]. These contracts establish fee payments according to the following equation:

Annual Fee = (Nameplate Capacity) × (Hours per Year) × (Capacity Factor) × (Power Price) × (Fee Rate)

The only variables in this equation that are constant are the fee rate and the number of hours per year. The fee rate is set at 2% in all contracts, as is 8,760 hours per operating year. Nameplate capacity and capacity factor estimates come from ReEDS. The only exception to this is the capacity factor during a plant's first year of operation, which the Bureau of Ocean Energy Management sets at 40% while empirical data from the plant's operation is being collected.

The power price is defined in this analysis as the 2013 average on-peak wholesale electricity price per megawatt-hour, as provided by the Energy Information Administration [4]. Rather than speculate about future prices and how they might change with deployment scenarios, this analysis sets nominal wholesale prices as changing with overall inflation, leaving real prices constant in 2013$. This reflects uncertainty about long-term electricity price forecasts that extend to 2050.

Electricity price data vary across the United States. This analysis selects price data from major electricity hubs, based on how close those hubs are to the planned offshore wind installations. Hubs and corresponding states with planned capacity additions are listed below:

Massachusetts Hub

- Massachusetts
- Rhode Island
- Maine
- Connecticut

New York independent service operator

- New York
- New Jersey
- Delaware
- Maryland

Southern

- North Carolina
- South Carolina
- Georgia
- Alabama

Electric Reliability Council of Texas Houston

- Texas
- Louisiana

Pennsylvania-New Jersey-Maryland interconnection West

- Pennsylvania
- Ohio

Midcontinent Independent System Operator Illinois

- Michigan
- Wisconsin

California independent service operator Zone NP-15

- California

I.6 References

[1] "Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf." OCS-A 0483. U.S. Department of the Interior Bureau of Ocean Energy Management, 2013a. Accessed Feb. 2, 2015: *http://www.boem.gov/VA-Lease-OCS-A/.*

[2] "Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf." OCS-A 0486. U.S. Department of the Interior Bureau of Ocean Energy Management, 2013b. Accessed Feb. 2, 2015: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/RI/Executed-Lease-OCS-A-0486.aspx.*

[3] "Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf." OCS-A 0487. U.S. Department of the Interior Bureau of Ocean Energy Management, 2013c. Accessed Feb. 2, 2015: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/RI/Executed-Lease-OCS-A-0487.aspx.*

[4] "New England and Pacific Northwest Had Largest Power Price Increases in 2013." U.S. Energy Information Administration, Jan. 8, 2014. Accessed Feb. 2, 2015: *http://www.eia.gov/todayinenergy/detail.cfm?id=14511.*

This page is intentionally left blank

This page is intentionally left blank

Appendix J: Life-Cycle GHG Emissions and Net Energy Metrics

J.1 Life-Cycle GHG Emissions

Aggregate greenhouse gas (GHG) emissions for the *Wind Vision Study Scenario* and *Baseline Scenario* leverage both output from the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) model and literature estimates of life-cycle GHG emissions. The life-cycle assessment (LCA) literature typically reports GHG emissions normalized per kilowatt-hour (kWh) of electricity generation (for emissions related to plant operations, or "ongoing") or per kilowatt (kW) of installed capacity (for emissions related to plant construction, or "upstream," and decommissioning, or "downstream"). Both normalization metrics, applied to different life-cycle phases, were used to estimate the contribution of each energy source to total life-cycle GHG emissions for the *Wind Vision Study* and *Baseline* scenarios.

NREL's LCA Harmonization project conducted an exhaustive literature search, extracting normalized life-cycle GHG emission estimates from published LCA literature. All collected literature was first categorized by content (recording key information from every collected reference) and added to a bibliographic database. Then, screens were applied to select only those references that met stringent quality and relevance criteria. This procedure has been described by Heath and Mann 2012 [1] and, for wind technologies, by Dolan and Heath 2012 [2].

The estimates of life-cycle GHG emissions by energy source used in the *Wind Vision* are the same as those reported by Mai et al. 2012 [3] in Appendix C of Volume 1 of the Renewable Electricity Futures study, except that the latest literature for wind technologies was reviewed and used as an update, following the same procedures as in Dolan and Heath 2012 [2]. The estimates used for land-based and offshore wind in this analysis (i.e., the combined results of studies included in Dolan and Heath 2012 [2], plus updates made herein) are reported in Table J-1. It should be noted that there are many fewer estimates for offshore wind (18) than land-based wind (62). Offshore wind is still an emerging area of study in life-cycle assessment. As more studies are conducted, the estimates of life-cycle GHG emissions may change from the current median estimates reported here, based on the currently available literature. Yet, it is also important to remember that wind, both land-based and offshore, exhibits life-cycle GHG emissions on par with other renewable technologies and nuclear energy, but substantially lower than those found for fossil-based systems.

Table J-2 describes characteristics of the studies included as updates to those reported by Dolan and Heath 2012 [2] (see Dolan and Heath 2012 [2] for earlier studies). Again, for all other energy sources, see the documentation in Mai et al. 2012 [3].

Table J–1. Median Estimates of GHG Emissions by Life-Cycle Stage [2] and Updates

Wind Technology	Upstream Emissions (kg CO_2e/MW)	Ongoing Emissions (g CO_2e/kWh)	Downstream Emissions (kg CO_2e/MW)
Land-based	610	0.74	14
Offshore	1,240	4.40	30

Note: kg = kilogram; g = grams; MW = megawatt; CO_2e = carbon dioxide equivalent

To estimate total GHG emissions for the *Wind Vision Study* and *Baseline* scenarios, GHG emissions estimates were assembled into four general life-cycle stages that correspond to ReEDS output, as follows:

- One-time upstream emissions, which include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction. Emissions for this life-cycle stage used in the analysis were median estimates taken from the LCA literature.

- Ongoing non-combustion emissions during the operating phase, which include fuel-cycle emissions (i.e., emissions associated with extraction, processing, and transportation of fuels, where applicable) and emissions resulting from non-combustion-related operation and maintenance activities. Emissions for this life-cycle stage used in the analysis were median estimates taken from the LCA literature.
- Ongoing combustion emissions resulting from combustion at the power plant (where applicable) for the purpose of electricity generation. Emissions for this life-cycle stage used in the analysis are outputs of ReEDS, based on generation technology, electricity generation, heat rate assumptions, and the carbon content of the fuel.
- One-time downstream emissions, which include emissions resulting from project decommissioning, disassembly, transportation to a waste site, and ultimate disposal and/or recycling of the equipment and other site materials. Emissions for this life-cycle stage used in the analysis were median estimates taken from the LCA literature.

One-time emissions (upstream and downstream) are related to the embodied emissions of the facility, which are largely determined by the capacity of the technology deployed. ReEDS reports capacity by technology installed or decommissioned in a given year. The analysis further assumes that ReEDS-estimated rebuilds (i.e., repowering) are approximately equivalent to new construction for the purposes of GHG emission accounting, and so sums these two ReEDS outputs (new build and repowering) into one “installed” category. Multiplying literature-estimated, one-time upstream GHG emissions normalized per kW of installed capacity by ReEDS-estimated installed capacity yields an estimate of GHG emissions associated with the addition of that technology’s capacity in that year. An analogous method was used to estimate GHG emissions associated with facility decommissioning in a given year.

Ongoing emissions are mainly related to the production of electricity. ReEDS explicitly reports c*ombustion-related* carbon dioxide (CO_2) emissions by technology each year. In the case of biomass, combustion produces GHG emissions. However, because the carbon emitted during combustion was absorbed during photosynthesis in biomass feedstock production, these emissions were assumed to cancel when summed over the life cycle.

ReEDS also reports electricity generation by each technology in a given year. Estimates of GHG emissions associated with the fuel cycle and other non-combustion-related ongoing activities were derived by multiplying literature-estimated, ongoing non-combustion-related GHG emissions normalized per kWh by ReEDS-estimated generation.

Summing year- and technology-specific GHG emissions associated with the four life-cycle phases over all years of the period studied in the *Wind Vision* (2013–2050) and all technologies yielded estimates of cumulative life-cycle GHG emissions for each scenario.

The cost impacts of the scenarios presented in Chapter 3 exclude any costs associated with rooftop PV. Since the rooftop PV capacity trajectory is identical across all scenarios, essentially no impact on reported incremental costs of achieving the Study Scenario penetration levels is impacted by excluding costs associated with distributed generation. The only differences across scenarios associated with rooftop PV relate to rooftop PV curtailment estimates within ReEDS, which have only minor impacts. In addition, rooftop PV capital and O&M costs are excluded from ReEDS system expenditure estimates.

Table J–2. Characteristics of Studies Included in This Update to Dolan and Heath 2012 [2]

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Chermak 2009 [4]	Land-based	1.5	40	35%	West Texas	Theoretical	GE
Chermak 2009 [4]	Land-based	2.3	40	35%	West Texas	Theoretical	Siemens
Chermak 2009 [4]	Land-based	1.78	40	35%	West Texas	Theoretical	GE and Siemens mix; Without substation
Chermak 2009 [4]	Land-based	1.78	40	35%	West Texas	Theoretical	GE and Siemens mix; With substation
Varun and Bhat 2010 [5]	Land-based	1.5	20	35%	India	Theoretical	Unspecified manufacturer
D'Souza et al. 2011 [6]	Land-based	3	24	43%		Empirical	Vestas V112; IEC II conditions
Garrett and Rønde 2011 [7]	Land-based	2	20	47%		Empirical	Vestas V80; IEC I, 80-m hub height, SF6, 85% recyclability
Garrett and Rønde 2011 [8]	Land-based	2	20	36%		Empirical	Vestas V90; IEC III, 80-m hub height
Santoyo-Castelazo et al. 2011 [9]	Land-based			23%	Mexico	Theoretical	GEMIS model; unspecified manufacturer
Wagner et al. 2011 [10]	Offshore	5	40	22%	Germany	Theoretical	RePower and Areva Multibrid; with foundation and subcable
Wagner et al. 2011 [10]	Offshore	5	20	45%	Germany	Theoretical	RePower and Areva Multibrid; Beta Ventus
Wagner et al. 2011 [10]	Offshore	5	20	45%	Germany	Theoretical	RePower and Areva Multibrid
Wagner et al. 2011 [10]	Offshore	5	20	45%	Germany	Theoretical	RePower and Areva Multibrid; 1/2 maintenance

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Wiedmann et al. 2011 [11]	Offshore	2	20	30%	United Kingdom	Theoretical	Process based; unspecified manufacturer
Wiedmann et al. 2011 [11]	Offshore	2	20	30%	United Kingdom	Theoretical	Integrated hybrid; unspecified manufacturer
Wiedmann et al. 2011 [11]	Offshore	2	20	30%	United Kingdom	Theoretical	I-O hybrid; unspecified manufacturer
Zimmerman 2013 [12]	Land-based	2.3	20	25%		Theoretical	Enercon
Arvesen and Hertwich 2012 [13]	Land-based	2.5	20	24%		Theoretical	Hybrid. Assumes 2.5-MW turbine based on 2- and 3-MW turbines. Deployed through 2050
Arvesen and Hertwich 2012 [13]	Offshore	2.5	25	38%		Theoretical	Hybrid. Assumes 2.5-MW turbine based on 2- and 3-MW turbines. Deployed through 2050
Garrett and Rønde 2013 [14]	Land-based	2.6	20	38%	Europe	Empirical	Vestas V100; IEC II, SF6
Garrett and Rønde 2012 [15]	Land-based	3	20	41%	Europe	Empirical	Vestas V90; IEC 1
Ghenai 2012 [16]	Land-based	2	25	40%		Theoretical	With recycling; Vestas
Ghenai 2012 [16]	Land-based	2	25	40%		Theoretical	Without recycling; Vestas

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Guezuraga et al. 2012 [17]	Land-based	1.8	20	21%		Theoretical	GEMIS modeled; unspecified manufacturer
Guezuraga et al. 2012 [17]	Land-based	2	20	34%		Theoretical	IECIIA, GEMIS modeled; unspecified manufacturer
Guezuraga et al. 2012 [17]	Land-based	2	20	20%		Theoretical	30% grid curtailment and 2% degraded performance; unspecified manufacturer
Guezuraga et al. 2012 [17]	Land-based	2	20	24%		Theoretical	30% grid curtailment; unspecified manufacturer
Guezuraga et al. 2012 [17]	Land-based	2	20	28%		Theoretical	2% degraded performance; unspecified manufacturer
Skone et al. 2012 [18]	Land-based	1.5	20	30%	U.S.	Theoretical	Conventional; GE technology
Skone et al. 2012 [18]	Offshore	1.5	20	0.39	U.S.	Theoretical	GE
Skone et al. 2012 [18]	Land-based	6	20	30%	U.S.	Theoretical	Advanced technology
Wang and Sun 2012 [19]	Land-based	1.65	20	41%	China	Theoretical	Vestas V82; CO_2 only
Wang and Sun 2012 [19]	Land-based	3	20	30%	China	Theoretical	Vestas V90; CO_2 only

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Wang and Sun 2012 [19]	Offshore	3	20	54%	China	Theoretical	Vestas V90; CO_2 only
Li et al. 2012 [20]	Land-based	0.8	Not given	26%	China	Theoretical	Total for China, I-O-hybrid
Arvesen et al. 2013 [21]	Offshore	5	25	32%	Norway	Theoretical	Low OWT scenario, hybrid; Havsul I wind farm
Arvesen et al. 2013 [21]	Offshore	5	20	32%	Norway	Theoretical	Lifetime 20, hybrid; Havsul I wind farm
Arvesen et al. 2013 [21]	Offshore	5	30	32%	Norway	Theoretical	Optimistic scenario, hybrid; Havsul I wind farm
Arvesen et al. 2013 [21]	Offshore	5	20	32%	Norway	Theoretical	Pessimistic scenario, hybrid; Havsul I wind farm
Arvesen et al. 2013 [21]	Offshore	5	25	32%	Norway	Theoretical	Reference, hybrid; Havsul I wind farm
Arvesen et al. 2013 [21]	Offshore	5	25	32%	Norway	Theoretical	Max replacement scenario, hybrid; Havsul I wind farm
Demir and Taskin 2013 [22]	Land-based	0.33	20	14%		Theoretical	50 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.33	20	21%	Pinarbasi-Kayseri, Turkey	Theoretical	80 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.33	20	26%	Pinarbasi-Kayseri, Turkey	Theoretical	100 m; unspecified manufacturer

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Demir and Taskin 2013 [22]	Land-based	0.5	20	16%	Pinarbasi-Kayseri, Turkey	Theoretical	50 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.5	20	21%	Pinarbasi-Kayseri, Turkey	Theoretical	80 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.5	20	23%	Pinarbasi-Kayseri, Turkey	Theoretical	100 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.81	20	17%	Pinarbasi-Kayseri, Turkey	Theoretical	50 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.81	20	21%	Pinarbasi-Kayseri, Turkey	Theoretical	80 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	0.81	20	24%	Pinarbasi-Kayseri, Turkey	Theoretical	100 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	2.05	20	15%	Pinarbasi-Kayseri, Turkey	Theoretical	50 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	2.05	20	22%	Pinarbasi-Kayseri, Turkey	Theoretical	100 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	3.02	20	10%	Pinarbasi-Kayseri, Turkey	Theoretical	50 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	3.02	20	13%	Pinarbasi-Kayseri, Turkey	Theoretical	80 m; unspecified manufacturer
Demir and Taskin 2013 [22]	Land-based	3.02	20	15%	Pinarbasi-Kayseri, Turkey	Theoretical	100 m; unspecified manufacturer

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (year)	Capacity Factor	Location	Study Type	Comments
Mallia and Lewis 2013 [23]	Land-based	2	20	33%	Canada	Theoretical	Enercon; Ripley South
Mallia and Lewis 2013 [23]	Land-based	1.5	20	27%	Canada	Theoretical	GE; Princefarm
Mallia and Lewis 2013 [23]	Land-based	1.5	20	29%	Canada	Theoretical	GE; Port Burwell
Mallia and Lewis 2013 [23]	Land-based	1.5	20	20%	Canada	Theoretical	GE; Amaranth
Mallia and Lewis 2013 [23]	Land-based	2.3	20	13%	Canada	Theoretical	Siemens; Port Alma
Mallia and Lewis 2013 [23]	Land-based	1.65	20	21%	Canada	Theoretical	Vestas; Underwood
Mallia and Lewis 2013 [23]	Land-based	2	20	31%	Canada	Theoretical	Vestas; Kingsbridge
Marimuthu and Kirubakaran 2013 [24]	Land-based	1.65	20	21%	India	Theoretical	I-O hybrid; unspecified manufacturer

Notes: (1) The comments in the table provide details that are not covered in the other columns and/or information to distinguish different scenarios from the same author. Blank cells in the table indicate that there is no amplifying information or that it is the base case for the author. Empirical studies are those based on recorded performance data, while theoretical studies are based on detailed analyses of projected performance.

(2) m = meter; IEC = International Electrotechnical Commission; I-O = Input-Output; MW = megawatt; OWT = offshore wind turbine; IECIIA = IEC class IIA; GEMIS = Global Emissions Model for integrated Systems.

J.2 Net Energy Metrics

Using the same screening criteria as for the GHG evaluation, the review of net energy metrics for wind technologies started by extracting estimates of net energy ratio and energy payback time from the LCA literature that was collected in Dolan and Heath 2012 [2]. That literature was then updated, in a similar fashion as the GHG review. Some additional recent studies that were not LCAs, but reported one or more net energy metrics were identified. Ultimately, 55 references with more than 130 estimates passed the *Wind Vision* review screens and provided either net energy ratio or energy payback time estimates or both. Figures J-1 and J-2 display the results of the collected estimates for land-based and offshore, wind as well as the two combined. (The combined category also includes estimates where the categorization between land-based and offshore is not clear.) Table J-3 lists the individual studies and their results. The results reflect the conditions analyzed in each study, which sometimes exercised results across a wide range of conditions, producing widely varying results. For instance, results for Demir and Taskin 2013 [22] reflect a range of turbines assessed for a Pinarbasi-Kayseri location. The high end represents a 330-kW turbine at a 50-meter (m) hub height. The low end represents a 2.05-MW turbine at a 100-m hub height.

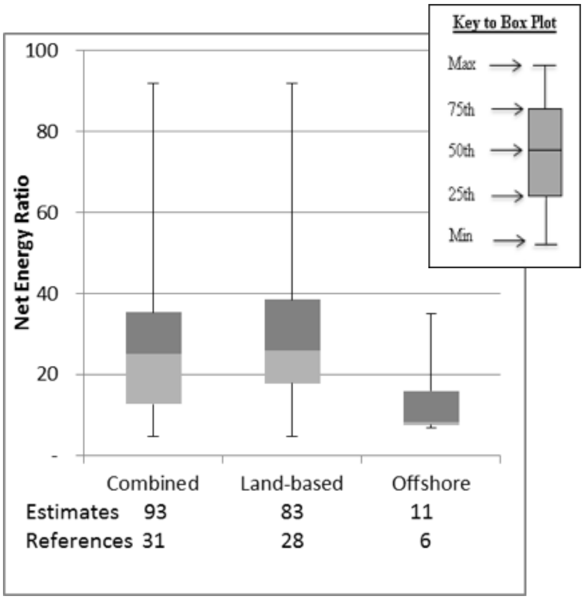


Figure J–1. Distribution of estimates of reported net energy ratios for land-based, offshore, and combined results

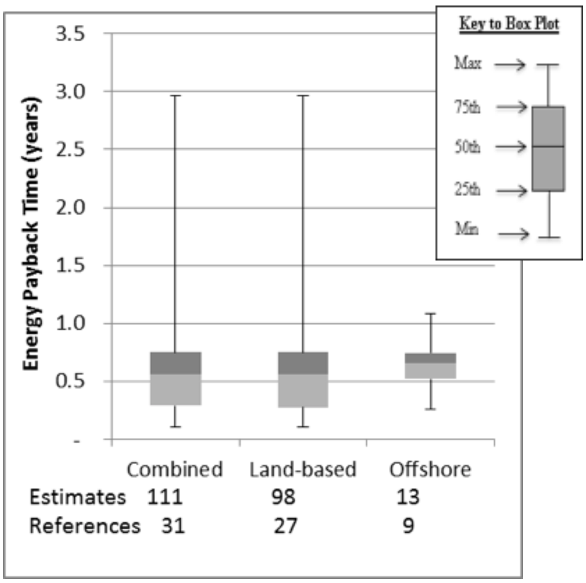


Figure J–2. Distribution of estimates of reported energy payback time (years) for land-based, offshore, and combined results

Table J-3. Estimates of Net Energy Metrics for Literature Considered in This Study

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Cavallaro and Salomone 2003 [25]	Offshore	20	0.78	
Crawford 2009 [26]	Land-based	20		21
Crawford 2009 [26]	Land-based	20		23
Demir and Taskin 2013 [22]	Land-based	20	1.22	
Demir and Taskin 2013 [22]	Land-based	20	2.97	
D'Souza et al. 2011 [6]	Land-based		0.18	
D'Souza et al. 2011 [6]	Land-based	20	0.20	
D'Souza et al. 2011 [6]	Land-based	24	0.20	
D'Souza et al. 2011 [6]	Land-based	16	0.20	
D'Souza et al. 2011 [6]	Land-based		0.20	
D'Souza et al. 2011 [6]	Land-based		0.20	
D'Souza et al. 2011 [6]	Land-based		0.23	
D'Souza et al. 2011 [6]	Land-based		0.23	
D'Souza et al. 2011 [6]	Land-based	20	0.24	
D'Souza et al. 2011 [6]	Land-based		0.24	

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
D'Souza et al. 2011 [6]	Land-based		0.24	
D'Souza et al. 2011 [6]	Land-based		0.25	
D'Souza et al. 2011 [6]	Land-based		0.25	
D'Souza et al. 2011 [6]	Land-based		0.28	
D'Souza et al. 2011 [6]	Land-based		0.29	
D'Souza et al. 2011 [6]	Land-based		0.29	
Elsam Engineering A/S 2004 [27]	Land-based	20	0.65	
Elsam Engineering A/S 2004 [27]	Offshore	20	0.75	
Garrett and Rønde 2011 [7]	Land-based	20	0.71	28
Garrett and Rønde 2011 [7]	Land-based		0.25	
Garrett and Rønde 2011 [7]	Land-based	20	0.92	21
Garrett and Rønde 2011 [7]	Land-based	20	0.75	26
Garrett and Rønde 2011 [7]	Land-based	20	0.58	31
Garrett and Rønde 2011 [7]	Land-based		0.25	
Garrett and Rønde 2011 [7]	Land-based		0.25	
Garrett and Rønde 2011 [7]	Land-based		0.33	

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Garrett and Rønde 2011 [7]	Land-based	24	0.61	
Garrett and Rønde 2013 [14]	Land-based	20	0.87	23
Garrett and Rønde 2013 [14]	Land-based	16	0.70	29
Garrett and Rønde 2013 [14]	Land-based		0.25	
Garrett and Rønde 2013 [14]	Land-based		0.33	
Garrett and Rønde 2013 [14]	Land-based	20	0.70	
Garrett and Rønde 2013	Land-based	24	0.70	
Garrett and Rønde 2013 [14]	Land-based	20	0.56	
Garrett and Rønde 2013 [14]	Land-based	16	0.56	
Garrett and Rønde 2013 [14]	Land-based	24	0.56	
Garrett and Rønde 2013 [14]	Land-based	20	0.69	
Garrett and Rønde 2013 [14]	Land-based		0.87	
Ghenai 2012 [16]	Land-based	25	0.77	32
Ghenai 2012 [16]	Land-based	25	0.50	50
Guezuraga et al. 2012 [17]	Land-based	20	0.64	
Guezuraga et al. 2012 [17]	Land-based	20	0.65	

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Guezuraga et al. 2012 [17]	Land-based	20	0.79	
Guezuraga et al. 2012 [17]	Land-based	20	0.94	
Guezuraga et al. 2012 [17]	Land-based	20	1.13	
Guezuraga et al. 2012 [17]	Land-based	20	1.15	
Guezuraga et al. 2012 [17]	Land-based	20	1.99	
Guezuraga et al. 2012 [17]	Land-based		0.65	
Guezuraga et al. 2012 [17]	Land-based	20	2.36	
Guezuraga et al. 2012 [17]	Land-based	20	1.35	
Guezuraga et al. 2012 [17]	Land-based	20	1.15	
Gürzenich et al. 1999 [28]	Land-based			10
Gürzenich et al. 1999 [28]	Land-based			11
Gürzenich et al. 1999 [28]	Land-based	20		31
Jacobson 2009 [29]	Land-based	30	0.13	
Jacobson 2009 [29]	Land-based	30	0.36	
Khan et al. 2005 [30]	Land-based	20	0.16	
Koroneos and Koroneos 2007 [31]	Land-based	Not given		39

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Krohn 1997 [32]	Land-based	20	0.34	6
Krohn 1997 [32]	Land-based	20	0.32	7
Krohn 1997 [32]	Land-based	20	0.28	7
Krohn 1997 [32]	Land-based	20	0.26	7
Krohn 1997 [32]	Offshore	20	0.26	7
Kubiszewski et al. 2010 [33]	Land-based/ Offshore	Various		25
Kuemmel et al. 1997 [34]	Land-based/ Offshore	25	0.64	
Kuemmel et al. 1997 [34]	Land-based	20	0.83	
Lee and Tzeng 2008 [35]	Land-based	20	0.11	70
Lenzen and Wachsmann 2004 [36]	Land-based	20		5
Lenzen and Wachsmann 2004 [36]	Land-based	20		5
Lenzen and Wachsmann 2004 [36]	Land-based	20		6
Lenzen and Wachsmann 2004 [36]	Land-based	20		8
Lenzen and Wachsmann 2004 [36]	Land-based	20		8
Lenzen & Wachsmann 2004 [36]	Land-based	20		12

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Lenzen and Wachsmann 2004 [36]	Land-based	20		13
Lenzen and Wachsmann 2004 [36]	Land-based	20		16
Lenzen and Wachsmann 2004 [36]	Land-based	20		16
Lenzen and Wachsmann 2004 [36]	Land-based	20		16
Lenzen and Wachsmann 2004 [36]	Land-based	20		19
Lenzen and Wachsmann 2004 [36]	Land-based	20		19
Lenzen and Wachsmann 2004 [36]	Land-based	20		20
Lenzen and Wachsmann 2004 [36]	Land-based	20		21
Lenzen and Wachsmann 2004 [36]	Land-based	20		22
Lenzen and Wachsmann 2004 [36]	Land-based	20		25
Lenzen and Wachsmann 2004 [36]	Land-based	20		25
Lenzen and Wachsmann 2004 [36]	Land-based	20		25
Lenzen and Wachsmann 2004 [36]	Land-based	20		25
Lenzen and Wachsmann 2004 [36]	Land-based	20		27
Lenzen and Wachsmann 2004 [36]	Land-based	20		31

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Lenzen and Wachsmann 2004 [36]	Land-based	20		32
Lenzen and Wachsmann 2004 [36]	Land-based	20		33
Lenzen and Wachsmann 2004 [36]	Land-based	20		40
Lenzen and Wachsmann 2004 [36]	Land-based	20		41
Marimuthu and Kirubakaran 2013 [24]	Land-based	20	1.12	33
Martínez et al. 2009 [37]	Land-based	20	0.40	
Martínez et al. 2009 [38]	Land-based	20	0.58	34
Mathur and Bansal 2001 [39]	Land-based		0.85	23
Mathur and Bansal 2001 [39]	Land-based		0.74	27
Mathur and Bansal 2001 [39]	Land-based	20	0.26	76
Nalukowe et al. 2006 [40]	Land-based	20		20
Rule et al. 2009 [41]	Land-based	100		51
Rydh et al. 2004 [42]	Land-based	20	0.32	62
Rydh et al. 2004 [42]	Land-based	20	0.32	62
Rydh et al. 2004 [42]	Land-based	20	0.22	90

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Rydh et al. 2004 [42]	Land-based	30	0.33	92
Schleisner 2000 [43]	Land-based	20	0.26	30
Schleisner 2000 [43]	Offshore	20	0.39	21
Skone et al. 2012 [18]	Offshore	20		11
Spitzley and Keoleian 2004 [44]	Land-based	30		47
Spitzley and Keoleian 2004 [44]	Land-based	30		65
Tremeac and Meunier 2009 [45]	Land-based	20	0.51	
Tremeac and Meunier 2009 [45]	Land-based	20	0.58	
Tremeac & Meunier 2009 [45]	Land-based	20	0.72	
Tremeac and Meunier 2009 [45]	Land-based		2.03	
Tremeac and Meunier 2009 [45]	Land-based		2.29	
Tremeac and Meunier 2009 [45]	Land-based		2.61	
Tryfonidou and Wagner 2004 [46]	Offshore	20 for turbines; 40 for foundations	0.33	
Uchiyama 1996 [47]	Land-based		1.37	15
Uchiyama 1996 [47]	Land-based	20	0.98	22

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Uchiyama 1996 [47]	Land-based	20	0.69	30
Varun and Bhat 2010 [5]	Land-based	20	2.07	10
Varun and Bhat 2010 [5]	Land-based	20	1.79	11
Varun and Bhat 2010 [5]	Land-based	20	0.64	31
Varun and Bhat 2010 [5]	Land-based	20	0.39	
Vestas Wind Systems A/S 2006 [48]	Land-based	20		35
Vestas Wind Systems A/S 2006 [48]	Land-based	20	0.57	37
Vestas Wind Systems A/S 2006 [49]	Offshore	20	0.55	35
Voss 2001 [50]	Land-based	20	0.53	
Wagner and Pick 2004 [51]	Land-based		0.53	38
Wagner and Pick 2004 [51]	Land-based		0.39	39
Wagner and Pick 2004 [51]	Land-based		0.50	50
Wagner and Pick 2004 [51]	Land-based		0.38	53
Wagner and Pick 2004 [51]	Land-based	20	0.64	64
Wagner and Pick 2004 [51]	Land-based		0.29	70

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Wagner et al. 2011 [10]	Offshore	20	0.79	7
Wagner et al. 2011 [10]	Offshore	20	0.73	7
Wagner et al. 2011 [10]	Offshore	20	0.68	8
Wagner et al. 2011 [10]	Offshore	20	0.73	8
Wagner et al. 2011 [10]	Offshore	20	0.62	8
Wagner et al. 2011 [10]	Offshore	40	0.51	10
Weinzettel et al. 2009 [52]	Offshore	20	1.08	
White 2006 [53]	Land-based	20		11
White 2006 [53]	Land-based	25		24
White 2006 [53]	Land-based	30		28
White & Kulcinski 1998 [54]	Land-based	20		17
White and Kulcinski 1998 [54]	Land-based	25		23
White and Kulcinski 1998 [54]	Land-based	30		
White and Kulcinski 2000 [55]	Land-based	25		23
Zimmermann 2013 [12]	Land-based	20	0.57	35

Source Study	Technology Type	Lifetime (year)	Energy Payback Time (year)	Net Energy Ratio
Zimmermann 2013 [12]	Land-based	20	0.49	41
Zimmermann 2013 [12]	Land-based	20	0.39	51

Note: The comments in the table provide details that are not covered in the other columns and/or information to distinguish different scenarios from the same author. Blank cells in the table indicate that there is no amplifying information or that it is the base case for the author. Results are reported directly from literature and not harmonized.

J.3 References

[1 Heath, G.A.; Mann, M.K. "Background and Reflections on the Life Cycle Assessment Harmonization Project." *Journal of Industrial Ecology* (16:s1), April 2012; pp. S8–S11. Accessed Jan. 27, 2015: http://onlinelibrary.wiley.com/doi/10.1111/j.1530-9290.2012.00478.x/abstract.

[2] Dolan, S.L.; Heath, G.A. "Life Cycle Greenhouse Gas Emissions of Utility-Scale Wind Power." *Journal of Industrial Ecology* (16:s1), April 2012; pp. S136–S154. Accessed Jan. 27, 2015: http://onlinelibrary.wiley.com/doi/10.1111/j.1530-9290.2012.00464.x/abstract.

[3] Mai, T.; Wiser, R.; Sandor. D.; Brinkman, G.; Heath, G.; Denholm, P.; Hostick, D.; Darghouth, N.; Schlosser, A.; Strzepek, K. *Exploration of High-Penetration Renewable Electricity Futures. Vol. 1 of Renewable Electricity Futures Study.* NREL/TP-6A20-52409-1. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Jan. 5, 2015: http://www.nrel.gov/.

[4] Chermak, C. *The Environmental Impacts of Wind Integration and Comparison to Conventional Energy Sources: Life Cycle Analysis of Wind Generation and Transmission in Texas.* M.S. Thesis. Dallas, TX: Southern Methodist University, 2009; 250 pp. Accessed Jan. 27, 2015: http://gradworks.umi.com/14/67/1467133.html.

[5] Varun, R.P.; Bhat, I.K. "A Figure of Merit for Evaluating Sustainability of Renewable Energy Systems." *Renewable and Sustainable Energy Reviews* (14:6), August 2010; pp. 1640–1643. Accessed Jan. 27, 2015: http://www.sciencedirect.com/science/article/pii/S1364032110000353.

[6] D'Souza, N.; Gbegbaje-Das, E.; Shonfield, P. *Life Cycle Assessment of Electricity Production from a V112 Turbine Wind Plant.* Prepared by PE North West Europe (NWE) ApS for Vestas Wind Systems A/S. Copenhagen: PE NWE, February 2011; 87 pp.

[7] Garrett, P.; Rønde, K. *Life Cycle Assessment of Electricity Production from a V80-2.0 MW Gridstreamer Wind Plant.* Aarhus, Denmark: Vestas Wind Systems A/S, December 2011a; 104 pp.

[8] Garrett, P.; Rønde, K. *Life Cycle Assessment of Electricity Production from a V90-2.0 MW Gridstreamer Wind Plant.* Aarhus, Denmark: Vestas Wind Systems A/S, December 2011b; 105 pp.

[9] Santoyo-Castelazo, E.; Gujba, H.; Azapagic, A. "Life Cycle Assessment of Electricity Generation in Mexico." Energy (36:3), March 2011; pp. 1488–1499. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0360544211000193.

[10] Wagner, H.-J.; Baack, C.; Eickelkamp, T.; Epe, A.; Lohmann, J.; Troy, S. "Life Cycle Assessment of the Offshore Wind Farm Alpha Ventus." *Energy* (36:5), May 2011; pp. 2459–2464. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0360544211000594.

[11] Wiedmann, T.O.; Suh, S.; Feng, K.; Lenzen, M.; Acquaye, A.; Scott, K.; Barrett, J.R. "Application of Hybrid Life Cycle Approaches to Emerging Energy Technologies—The Case of Wind Power in the UK." *Environmental Science & Technology* (45:13), July 1, 2011; pp. 5900–5907. Accessed Jan. 28, 2015: http://www.censa.org.uk/papers.html.

[12] Zimmermann, T. "Parameterized Tool for Site Specific LCAs of Wind Energy Converters." *International Journal of Life Cycle Assessment* (18:1), 2013; pp. 49–60. Accessed Jan. 28, 2015: http://link.springer.com/article/10.1007%2Fs11367-012-0467-y#page-1.

[13] Arvesen, A.; Hertwich, E.G. "Corrigendum: Environmental Implications of Large-Scale Adoption of Wind Power: A Scenario-Based Life Cycle Assessment." *Environmental Research Letters* (7:3), 2012; 3 pp. Accessed Jan. 28, 2015: http://iopscience.iop.org/1748-9326/7/3/039501.

[14] Garrett, P.; Rønde, K. *Life Cycle Assessment of Electricity Production from an Onshore V100-2.6 MW Wind Plant.* Aarhus, Denmark: Vestas Wind Systems A/S, October 2013; 107 pp.

[15] Garrett, P.; Rønde, K. *Life Cycle Assessment of Electricity Production from an Onshore V90-3.0 MW Wind Plant.* Aarhus, Denmark: Vestas Wind Systems A/S, October 2013; 106 pp.

[16] Ghenai, C. "Life Cycle Analysis of Wind Turbine." Chapter 2. Ghenai, C., ed. *Sustainable Development: Energy, Engineering and Technologies—Manufacturing and Environment.* InTech, 2012; 276 pp. Accessed Jan. 28, 2015: http://www.intechopen.com/books/howtoreference/sustainable-development-energy-engineering-and-technologies-manufacturing-and-environment/life-cycle-analysis-of-wind-turbine.

[17] Guezuraga, B.; Zauner, R.; Pölz, W. "Life Cycle Assessment of Two Different 2 MW Class Wind Turbines." *Renewable Energy* (37:1), January 2012; pp. 37–44. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0960148111002254.

[18] Skone, T.J.; Littlefield, J.; Eckard, R.; Cooney, G.; Prica, M.; Marriott, J. *Role of Alternative Energy Sources: Wind Technology Assessment.* DOE/NETL-2012/1536. Washington, DC: U.S. Department of Energy National Energy Technology Laboratory, Aug. 30, 2012; 115 pp. Accessed Jan. 28, 2015: http://www.netl.doe.gov/.

[19] Wang, Y.; Sun, T. "Life Cycle Assessment of CO_2 Emissions from Wind Power Plants: Methodology and Case Studies." *Renewable Energy* (43), July 2012; pp. 30–36. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0960148112000043.

[20] Li, X.; Feng, K.; Siu, Y.L.; Hubacek, K. "Energy-Water Nexus of Wind Power in China: The Balancing Act Between CO2 Emissions and Water Consumption." *Energy Policy* (45), June 2012; pp. 440–448. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0301421512001711.

[21] Arvesen, A., Birkeland, C.; Hertwich, E.G. "The Importance of Ships and Spare Parts in LCAs of Offshore Wind Power." *Environmental Science & Technology* (47:6), March 2013; pp. 2948–2956. Accessed Jan. 28, 2015: http://pubs.acs.org/doi/abs/10.1021/es304509r.

[22] Demir, N.; Taskin, A. "Life Cycle Assessment of Wind Turbines in Pınarbaşı-Kayseri." *Journal of Cleaner Production* (54), Sept. 1, 2013; pp. 253–263. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S095965261300231X.

[23] Mallia, E.; Lewis, G. "Life Cycle Greenhouse Gas Emissions of Electricity Generation in the Province of Ontario, Canada." *International Journal of Life Cycle Assessment* (18:2), February 2013; pp. 377–391. Accessed Jan. 28, 2015: http://link.springer.com/article/10.1007%2Fs11367-012-0501-0.

[24] Marimuthu, C.; Kirubakaran, V. "Carbon Pay Back Period for Solar and Wind Energy Project Installed in India: A Critical Review." *Renewable and Sustainable Energy Reviews* (23), July 2013; pp. 80–90. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S1364032113001470.

[25] Cavallaro, F.; Salomone, R. "Life Cycle Assessment of an Offshore Wind Farm: Preliminary Results." Prepared for 2nd European Seminar, Offshore Wind and Other Marine Renewable Energies in Mediterranean and European Seas (OWEMES). April 10–12, 2003.

[26] Crawford, R.H. "Life Cycle Energy and Greenhouse Emissions Analysis of Wind Turbines and the Effect of Size on Energy Yield." *Renewable and Sustainable Energy Reviews* (13:9), December 2009; pp. 2653–2660. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S1364032109001403.

[27] *Life Cycle Assessment of Offshore and Onshore Sited Wind Farms.* Document 200128. Frederica, Denmark: Elsam Engineering A/S, 2004; 54 pp.

[28] Gürzenich, D.; Mathur, J.; Bansal, N.K.; Wagner, H.-J. "Cumulative Energy Demand for Selected Renewable Energy Technologies." *International Journal of Life Cycle Assessment* (4:3), May 1999; pp. 143–149. Accessed Jan. 28, 2015: http://link.springer.com/article/10.1007%2FBF02979448.

[29] Jacobson, M.Z. "Review of Solutions to Global Warming, Air Pollution, and Energy Security." *Energy & Environmental Science* (2), 2009; pp. 148–173. Accessed Jan. 28, 2015: http://pubs.rsc.org/en/Content/ArticleLanding/2009/EE/b809990c#!divAbstract.

[30] Khan, F.I.; Hawboldt, K.; Iqbal, M.T. "Life Cycle Analysis of Wind–Fuel Cell Integrated System." *Renewable Energy* (30:2), February 2005; pp. 157–177. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0960148104001843.

[31] Koroneos, C.J.; Koroneos, Y. "Renewable Energy Systems: The Environmental Impact Approach." *International Journal of Global Energy Issues* (27:4), 2007; pp. 425–441. Accessed Jan. 28, 2015: http://www.researchgate.net/publication/5172070_Renewable_energy_systems_the_environmental_impact_approach.

[32] "The Energy Balance of Modern Wind Turbines." Krohn, S., ed. WindPower Note (16), December 1997; 16 pp.

[33] Kubiszewski, I.; Cleveland, C.J.; Endres, P.K. "Meta-Analysis of Net Energy Return for Wind Power Systems." *Renewable Energy* (35:1), 2010; pp. 218–225. doi:10.1016/j.renene.2009.01.012. Accessed Jan. 5, 2015: http://www.researchgate.net/publication/222703134_Meta-analysis_of_net_energy_return_for_wind_power_systems.

[34] Kuemmel, B.; Sørensen, B.; Nielsen, S.K. Life-Cycle *Analysis of the Total Danish Energy System.* Research Group IMFUFA. Roskilde, Denmark: Roskilde University, 1997; 219 pp. http://www.worldcat.org/title/life-cycle-analysis-of-the-total-danish-energy-system-an-assessment-of-the-present-danish-energy-system-and-selected-future-scenarios-final-report-for-a-project-in-the-danish-energy-research-programme-efp-94/oclc/312763527/editions?referer=di&editionsView=true.

[35] Lee, Y.-M.; Tzeng, Y.-E. "Development and Life-Cycle Inventory Analysis of Wind Energy in Taiwan." *Journal of Energy Engineering* (134:2), June 2008; pp. 53–57. Accessed Jan. 28, 2015: http://cedb.asce.org/cgi/WWWdisplay.cgi?164554.

[36] Lenzen, M.; Wachsmann, U. "Wind Turbines in Brazil and Germany: An Example of Geographical Variability in Life-Cycle Assessment." *Applied Energy* (77:2), February 2004; pp. 119–130. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S0306261903001053.

[37] Martínez, E.; Sanz, F.; Pellegrini, S.; Jiménez, E.; Blanco, J. "Life Cycle Assessment of a Multi-Megawatt Wind Turbine." *Renewable Energy* (34:3), March 2009; pp. 667–673. Accessed Jan. 29, 2015: http://www.sciencedirect.com/science/article/pii/S0960148108002218.

[38] Martínez, E.; Sanz, F.; Pellegrini, S.; Jiménez, E.; Blanco, J. "Life-Cycle Assessment of a 2-MW Rated Power Wind Turbine: CML Method." *International Journal of Life Cycle Assessment* (14:1), January 2009; pp. 52–63. Accessed Jan. 29, 2015: http://link.springer.com/article/10.1007/s11367-008-0033-9.

[39] Mathur, J.; Bansal, N.K. "Analysis of Selected Renewable Energy Options for India." *Energy Sources* (23:10), 2001; pp. 877–888. Accessed Jan. 29, 2015: http://www.tandfonline.com/doi/abs/10.1080/009083101317071324?journalCode=ueso19#.VMptJGjF_os.

[40] Nalukowe, B.B.; Liu, J.; Damien, W.; Lukawski, T. "Life Cycle Assessment of a Wind Turbine." Stockholm: KTH (Royal Institute of Technology), 2006; 26 pp. [41] Rule, B.M.; Worth, Z.J.; Boyle, C.A. "Comparison of Life Cycle Carbon Dioxide Emissions and Embodied Energy in Four Renewable Electricity Generation Technologies in New Zealand." *Environmental Science & Technology* (43:16), 2009; pp. 6406–6413. Accessed Jan. 29, 2015: http://pubs.acs.org/doi/abs/10.1021/es900125e.

[42] Rydh, J.; Jonsson, M.; Lindahl, P. *Replacement of Old Wind Turbines Assessed from Energy, Environmental and Economic Perspectives.* Kalmar, Sweden: University of Kalmar Department of Technology, 2004; 33 pp. Accessed Jan. 29, 2015: http://www.researchgate.net/publication/237541649_Replacement_of_Old_Wind_Turbines_Assessed_from_Energy_Environmental_and_Economic_Perspectives.

[43] Schleisner, L. "Life Cycle Assessment of a Wind Farm and Related Externalities." *Renewable Energy* (20:3), 2000; pp. 279–288. Accessed Jan. 18, 2015: http://www.researchgate.net/publication/222834610_Life_cycle_assessment_of_a_wind_farm_and_related_externalities.

[44] Spitzley, D.V.; Keoleian, G.A. *Life Cycle Environmental and Economic Assessment of Willow Biomass Electricity: A Comparison with Other Renewable and Non-Renewable Sources.* CSS04-05R. Ann Arbor: University of Michigan Center for Sustainable Systems, 2004; 69 pp.

[45] Tremeac, B.; Meunier, F. "Life Cycle Analysis of 4.5 MW and 250 W Wind Turbines." *Renewable and Sustainable Energy Reviews* (13:8), October 2009; pp. 2104–2110. Accessed Jan. 29, 2015: http://www.sciencedirect.com/science/article/pii/S1364032109000045.

[46] Tryfonidou, R.; Wagner, H.-J. "Multi-Megawatt Wind Turbines for Offshore Use: Aspects of Life Cycle Assessment." *International Journal of Global Energy Issues* (21:3), 2004; pp. 255–262. Accessed Jan. 29, 2015: http://inderscience.metapress.com/content/x5et22qvaq8t1jtf/.

[47] Uchiyama, Y. "Life Cycle Analysis of Photovoltaic Cell and Wind Power Plants." Prepared for International Atomic Energy Agency (IAEA) Advisory Group Meeting on the Assessment of Greenhouse Gas Emissions from the Full Energy Chain of Solar and Wind Power, Oct. 21–24, 1996. Vienna: IAEA, 1996.

[48] *Life Cycle Assessment of Electricity Produced from Onshore Sited Wind Power Plants Based on Vestas V82-1.65 MW Turbines.* Randers, Denmark: Vestas Wind Systems A/S, Dec. 29, 2006; 77 pp. Accessed Jan. 19, 2015: http://www.scribd.com/doc/141673844/LCA-V82-1-65-MW-Onshore#scribd.

[49] *Life Cycle Assessment of Offshore and Onshore Sited Wind Power Plants Based on Vestas V90-3.0 MW Turbines.* Randers, Denmark: Vestas Wind Systems A/S, 2006; 60 pp.

[50] Voss, A. "LCA and External Costs in Comparative Assessment of Electricity Chains. Decision Support for Sustainable Electricity Provision?" *Externalities and Energy Policy: The Life Cycle Analysis Approach Workshop Proceedings,* November 15–16, 2001, Paris; pp. 163–181.

[51] Wagner, H.-J.; Pick, E. "Energy Yield Ratio and Cumulative Energy Demand for Wind Energy Converters." *Energy* (29:12–15), October-December 2004; pp. 2289-2295. Accessed Jan. 28, 2015: http://www.sciencedirect.com/science/article/pii/S036054420400115X.

[52] Weinzettel, J.; Reenaas, M.; Solli, C.; Hertwich, E.G. "Life Cycle Assessment of a Floating Offshore Wind Turbine." *Renewable Energy* (34:3), March 2009; pp. 742–747. Accessed Jan. 29, 2015: http://www.sciencedirect.com/science/article/pii/S0960148108001754.

[53] White, S.W. "Net Energy Payback and CO_2 Emissions from Three Midwestern Wind Farms: An Update." Natural Resources Research (15:4), December 2006; pp. 271–281. Accessed Jan. 29, 2015: http://link.springer.com/article/10.1007%2Fs11053-007-9024-y.

[54] White, S.W.; Kulcinski, G.L. *Net Energy Payback and CO_2 Emissions from Wind-Generated Electricity in the Midwest.* UWFDM-1092. Madison: University of Wisconsin, December 1998; 72 pp. Accessed Jan. 29, 2015: http://fti.neep.wisc.edu/research/env?page=1&order=bynum.

[55] White, S.W.; Kulcinski, G.L. "Birth to Death Analysis of the Energy Payback Ratio and CO_2 Gas Emission Rates from Coal, Fission, Wind, and DT-Fusion Electrical Power Plants." *Fusion Engineering and Design* (48:3–4), 2000; pp. 473–481. Accessed Jan. 29, 2015: http://www.sciencedirect.com/science/journal/09203796/48/3-4.

This page is intentionally left blank

Appendix K: Water Usage Reduction, Supplemental Results

Table K-1 lists total modeled water withdrawal and consumption in the contiguous United States for the *Study Scenario* and *Baseline Scenario* in 2012, 2030, and 2050. These data contribute to Figure 3-37 and Figure 3-38 in the Water Usage Reduction section of Chapter 3.

Table K–1. Water Withdrawal and Consumption in Study Years

2012		2030		2050	
Water Use	Actual	*Study Scenario*	*Baseline Scenario*	*Study Scenario*	*Baseline Scenario*
Withdrawal (trillion gallons/year)	37.1	35.3	36.6	7.1	8.5
Consumption (billion gallons/year)	1,350.0	1,370.0	1,540.0	880.0	1,150.0

Tables K-2 and K-3 include the water withdrawal and water consumption quantities for 2012, 2030 and 2050, supporting Figure 3-37 and Figure 3-38, respectively, in the Water Usage Reduction section of Chapter 3.

Table K–2. Water Withdrawals in Trillion Gallons/Year by Power-Cooling Technology Combination

2012		2030		2050	
Power-Cooling Technology	Actual	*Study Scenario*	*Baseline Scenario*	*Study Scenario*	*Baseline Scenario*
Nuclear O/P	15.3	13.9	13.9	0.1	0.1
Nuclear R	0.4	0.4	0.4	0.0	0.0
Coal O/P	18.7	18.7	19.5	4.8	5.6
Coal R	0.7	0.8	0.9	0.6	0.7
GasCC O/P	1.6	1.2	1.5	1.1	1.3
GasCC R	0.2	0.2	0.2	0.4	0.6
Bio/CSP	0.1	0.2	0.2	0.2	0.2
Other	0.2	0.0	0.0	0.0	0.0

Notes: Bio = biopower; CSP = concentrating solar power; GasCC = natural gas combined cycle; R = recirculating cooling system; O/P = once-through or pond cooling system.

Table K-3. Water Consumption in Billion Gallons/Year by Power-Cooling Technology Combination

2012		2030		2050	
Power-Cooling Technology	Actual	*Study Scenario*	*Baseline Scenario*	*Study Scenario*	*Baseline Scenario*
Nuclear O/P	168	155	155	6	6
Nuclear R	220	239	239	25	25
Coal O/P	220	230	251	98	113
Coal R	521	568	635	402	465
GasCC O/P	25	20	24	15	17
GasCC R	175	121	199	306	458
Bio/CSP	14	19	19	17	43
Other	9	12	15	15	17

Notes: Bio = biopower; CSP = concentrating solar power; GasCC = natural gas combined cycle; R = recirculating cooling system; O/P = once-through or pond cooling system.

Tables K-4 and K-5 provide water withdrawal and consumption data, respectively, by U.S. Geological Survey Hydrologic Unit Code (HUC)-2 watershed region for 2012, 2030 and 2050, along with the percentage of change from 2012 data. These tables highlight the underlying data for Figures 3-39 and 3-40 in the Water Usage Reduction section of Chapter 3, as well as Figures K-1 and K-2 in this appendix.

Table K-4. Water Withdrawals in Billion Gallons/Year and Percent Changes from 2012, by HUC-2 Region

2012		2030				2050			
HUC-2 Region	Actual	*Study Scenario*	Change from 2012 (%)	*Baseline Scenario*	Change from 2012 (%)	*Study Scenario*	Change from 2012 (%)	*Baseline Scenario*	Change from 2012 (%)
1	1,610	1,860	15.3%	1,920	18.8%	40	-97.5%	50	-97.0%
2	5,090	4,120	-19.1%	4,300	-15.6%	200	-96.1%	220	-95.6%
3	7,540	8,600	14.1%	8,790	16.6%	1,410	-81.3%	1,380	-81.7%
4	5,280	4,080	-22.6%	4,210	-20.2%	890	-83.2%	920	-82.5%
5	4,770	3,890	-18.4%	4,120	-13.7%	750	-84.2%	790	-83.5%
6	1,160	1,750	51.1%	1,780	53.8%	110	-90.6%	110	-90.5%
7	4,290	3,800	-11.5%	3,880	-9.6%	850	-80.1%	1,000	-76.8%
8	660	980	48.9%	830	25.6%	390	-41.3%	270	-58.2%
9	180	140	-18.8%	160	-7.6%	20	-89.8%	30	-80.2%

Table K-4. *(cont.)* Water Withdrawals in Billion Gallons/Year and Percent Changes from 2012, by HUC-2 Region

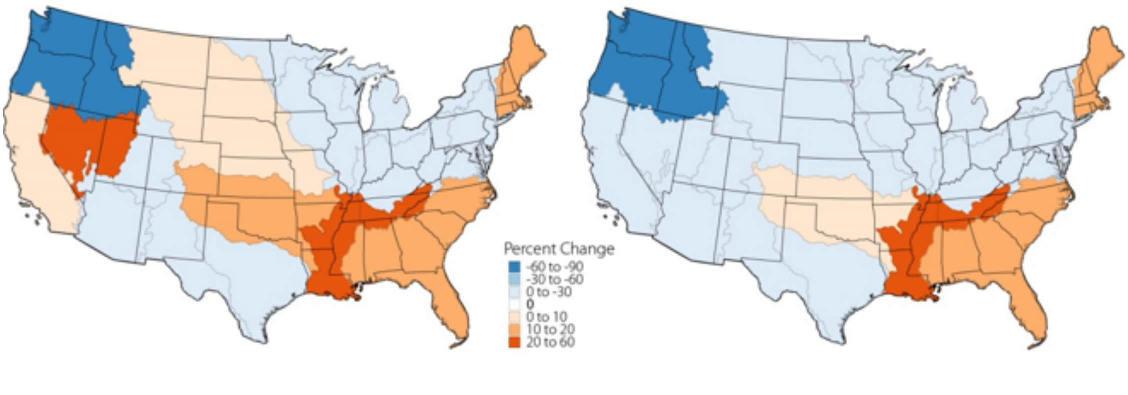
2012		2030				2050			
10	2,890	2,690	-7.0%	3,070	6.3%	850	-70.4%	1,610	-44.1%
11	630	640	1.8%	700	11.6%	330	-47.9%	590	-5.9%
12	1,490	1,300	-13.0%	1,360	-8.6%	920	-38.0%	1,030	-31.0%
13	200	150	-22.3%	160	-18.5%	40	-78.7%	50	-73.4%
14	80	70	-15.4%	70	-17.9%	40	-49.6%	50	-38.3%
15	140	140	-5.6%	140	-1.8%	70	-52.8%	80	-41.3%
16	50	50	-1.3%	60	24.8%	30	-37.3%	50	1.9%
17	80	20	-80.2%	20	-69.8%	0	-95.3%	20	-76.4%
18	1,010	1,010	-0.2%	1,010	0.0%	200	-80.0%	190	-81.3%

Table K-5. Water Consumption in Billion Gallons/Year and Percent Changes from 2012, by HUC-2 Region

2012		2030				2050			
HUC-2 Region	Actual	*Study Scenario*	Change from 2012 (%)	*Baseline Scenario*	Change from 2012 (%)	*Study Scenario*	Change from 2012 (%)	*Baseline Scenario*	Change from 2012 (%)
1	20	20	-8.6%	20	15.9%	10	-45.1%	20	-17.6%
2	130	120	-7.8%	130	-2.5%	60	-56.3%	80	-41.1%
3	210	270	30.6%	290	40.5%	200	-4.6%	210	-1.5%
4	80	80	-7.2%	90	3.2%	50	-35.9%	60	-24.2%
5	260	280	5.3%	290	10.9%	160	-38.2%	190	-29.3%
6	20	30	33.5%	30	45.9%	30	14.6%	30	19.5%
7	120	120	-6.5%	130	6.6%	50	-62.6%	80	-39.1%
8	40	50	14.6%	50	23.3%	40	-7.3%	40	1.6%
9	10	10	-14.4%	10	-1.7%	10	-47.1%	10	-14.0%
10	80	60	-24.1%	90	15.2%	40	-53.4%	80	-4.5%
11	70	60	-11.2%	80	20.8%	30	-49.5%	80	17.1%
12	120	110	-13.6%	130	3.6%	90	-27.6%	120	-5.8%
13	20	10	-5.4%	20	2.2%	10	-46.2%	10	-15.1%
14	30	30	-1.0%	30	-5.1%	20	-26.8%	30	-10.5%

2012		2030				2050			
15	60	60	-1.1%	60	5.1%	30	-43.2%	50	-14.8%
16	20	20	-1.3%	20	1.8%	20	-9.0%	20	6.0%
17	20	10	-48.1%	20	-14.2%	0	-86.0%	10	-24.0%
18	30	40	13.4%	40	39.6%	40	21.6%	50	44.3%

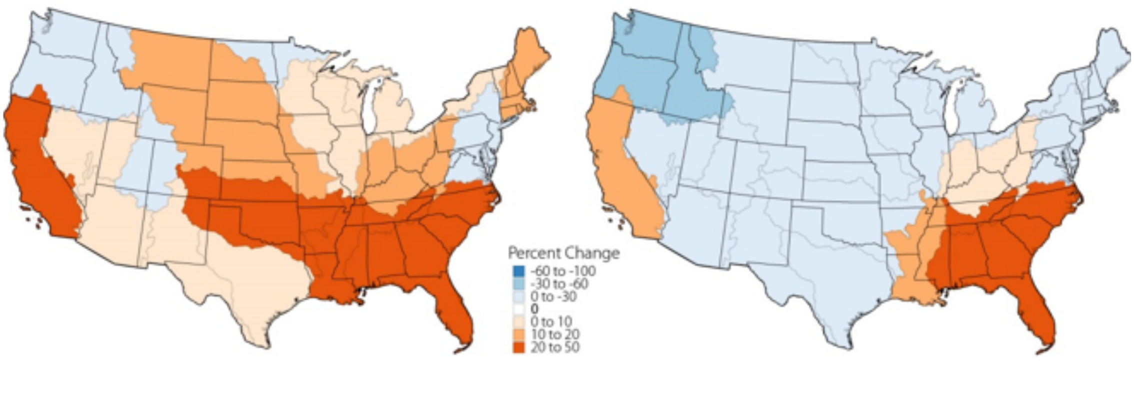
Figure K-1 highlights regional percentage changes in water withdrawals in 2030 compared to 2012 for the *Baseline Scenario* (left) and the *Study Scenario* (right). Figure K-2 highlights regional percentage changes in water consumption from 2012 to 2030 for the *Baseline Scenario* (left) and the *Study Scenario* (right).



Baseline Scenario (2012–2030)

Study Scenario (2012–2030)

Figure K–1. Percent change in water withdrawals from 2012 to 2030 for the *Baseline* and the *Study scenario*s



Baseline Scenario (2012–2030)

Study Scenario (2012–2030)

Figure K–2. Percent change in water consumption from 2012 to 2030 for the *Baseline* and *Study scenario*s

This page is intentionally left blank

This page is intentionally left blank

Appendix L: Health and Environmental Impact Methods

This appendix describes emission rates from energy generation and the potential health and environmental benefits of reducing emissions. The two methods used in the *Wind Vision Study* to estimate the potential health benefits of reducing emissions, the U.S. Environmental Protection Agency (EPA) and Air Pollution Emission Experiments and Policy (AP2, formerly APEEP) methods, are compared in section L.3. Section L.4 presents some of the uncertainties in the *Wind Vision* analysis caused by changing environmental regulations.

L.1 Emission Rates

The first step in emission rate analysis is to estimate the potential reduction in the sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and particulate matter ($PM_{2.5}$) emissions associated with the *Study Scenario*, relative to the *Baseline*. Emission reductions through 2050 are estimated using, in part, ReEDS electricity generation output for 134 distinct geographic regions from 2013 to 2050, by plant type. Initial year-one emission factors (in grams per megawatt-hour) for each of these regions and plant types are estimated from a bottom-up analysis of historical annual emissions and electricity generation for all power plants operating within each region. Future emission factors are then adjusted to account for announced and modeled power plant retirements; emission factors for future years are generated by removing retired plants and recalculating the average emission factors. Additionally, emission factors are adjusted to comply with the scheduled SO_2 and $PM_{2.5}$ limits described in EPA's Mercury and Air Toxics Standards (MATS) [1], and SO_2 and NO_x are capped regionally to comply with the implementation of EPA's Cross State Air Pollution Rule (CSAPR) [2].

Historical power plant-specific emissions of SO_2 and NO_x and electricity generation information are obtained from Ventyx [3] for the year 2010. For each region, emission factors for seven power plant categories are developed: three types of coal-fired power plants as defined by ReEDS (new, old with controls, old without controls), two types of natural gas power plants (combined cycle and combustion turbine), oil-fired generation, and co-fired biomass facilities. Specifically, for each plant type and region, total emissions from all applicable power plants are divided by the total electricity generation from those same power plants to determine an average emission factor by plant type and region. Emissions from dedicated biomass facilities are not included in this analysis. ReEDS predicts relatively small differences between dedicated biomass power generation under the *Study* and *Baseline* scenarios over the 2013–2050 period, so this omission has little impact.

Because Ventyx does not report emissions of $PM_{2.5}$, emission factors developed by Argonne National Laboratory [4,5] were used to describe $PM_{2.5}$ emissions for each U.S. state and by power plant type. Lacking plant-specific factors, the impact of specific announced retirements on $PM_{2.5}$ is approximated; the plants that retire are assumed to have the same emission rate as the average for the region and plant type. Because direct $PM_{2.5}$ emissions make a relatively small contribution to total health damages, this imperfect approximation is sufficient for the purposes of the *Study*.

Emissions of criteria air pollutants from power plants are regulated by the EPA. In 2015–2016 EPA projects, large (~38%) reductions in total SO_2 emissions from power plants resulted from the implementation of MATS [1]. MATS sets specific emission rate limits, based on the principal of maximum achievable control technology, for acid gases (e.g., hydrogen chloride [HCl] and SO_2), $PM_{2.5}$, and toxic metals from each power plant. To account for MATS, emission rates from coal and oil-fueled power plants above the MATS limits for SO_2 and $PM_{2.5}$ were lowered to the MATS limit starting in compliance year 2016. These MATS limits were implemented at the geographic level of the ReEDS analysis (134 regions), as opposed to the individual plant level. MATS sets $PM_{2.5}$ emission rate limits to 0.03 pounds per million British thermal units (lb/MMbtu) and "alternate" SO_2 limits at 0.2 lb/MMbtu.

MATS allows power plants to choose compliance with SO_2 limits or other HCl limits. The choice to control either HCL or SO_2 could potentially affect total SO_2 reductions; however, control of HCL often leads to control of SO_2 as well. The EPA estimates SO_2 reductions from MATS under the assumption that only the HCl limits are followed, finding the above mentioned 38% reduction to SO_2. This analysis, on the other hand, applies the alternate SO_2 limits. When MATS are applied to the *Baseline Scenario* ReEDS results under the assumption that only SO_2 "alternate" limits are followed, a 46% reduction to SO_2 was found, 21% larger but similar in general magnitude to the EPA estimated reductions.

Plant retirements in ReEDS are controlled in two ways: (1) ReEDS includes endogenous retirements based on plant age and utilization, and (2) ReEDS includes exogenous plant retirements based on announcements (see Section 3.4). Coal retirements, from 2010 to 2020, including age-based, announced, and a small number of utilization-based endogenous retirements, total 57 gigawatts (GW) (43 GW from 2013 to 2020) in ReEDS, reasonably consistent with the amount of retirements projected by U.S. Department of Energy, Energy Information Administration (EIA) [6] over this period under MATS and other prevailing conditions.

In addition to MATS, emission limits were set based on CSAPR. Unlike MATS, which limits emissions at the power plant level, CSAPR sets regional SO_2 and NO_x caps and allows emission trading within regions, as long as total regional emissions are below the cap. Once MATS was implemented, total regional emissions were below the caps set under CSAPR in almost all years and locations.

CSAPR was implemented in the analysis as a series of limits set separately for SO_2 and NO_x emissions. First, CSAPR sets an "assurance" limit for each state. An assurance limit defines the total annual emissions of a pollutant (SO_2 or NO_x) allowed for a state per year. As a group, all the power plants in a particular state are not allowed to hold more allowances (and therefore emit more) than the assurance limit. If the emissions from a state were estimated to be above the assurance limit, based on ReEDS-estimated generation and the emission rates calculated above, then all power-plant emissions in that state were scaled down evenly until the state's total matched the assurance limit.

A second limit is based on the regional cap. To account for this, if estimated emissions in a region exceed the cap, all power-plant emissions in the region are scaled evenly so that the total matches the regional cap. To be clear, this process does not directly model any changes to generation dispatch due to CSAPR (or MATS) because it simply limits emissions after ReEDS has been run. However, because the regional and state assurance caps were not strongly binding (specifically, implementation of CSAPR reduced total NO_x emissions by 0–2%, depending on the year, and did not affect SO_2 emissions after MATS was implemented), this omission is unlikely to be significant as it relates to CSAPR. Details regarding regional and state SO_2 and NO_x limits under CSAPR can be found in the EPA's Regulatory Impact Analysis (RIA) [2] and supplemental documentation posted by the EPA *(http://www.epa.gov/airtransport/CSAPR)* under "Resources for Implementation."

L.2 Potential Health Benefits from Emission Reductions

Two methods are used to estimate the potential health benefits that would occur with emission reductions: EPA's estimates of the benefit per ton (BPT) of power plant pollutant emission reductions presented in EPA's Clean Power Plan [7], and AP2 model analysis.

EPA: For the Clean Power Plan [7], EPA estimated the average BPT of reducing emissions from power plants. EPA estimated separate benefits by pollutant (SO_2, NO_x, and $PM_{2.5}$) for three large regions covering California, the states west of the Rockies, and the states east of the Rockies over time. Benefits account for reduced mortality and morbidity through many (but not all) health pathways, and do not consider other environmental concerns (e.g., visibility, materials damages, and crop effects). EPA methods are based on the methodology presented previously in Fann et al. [8,9]. EPA specifically presents two sets of BPT values based on the same air quality modeling (same changes to exposure) but two different epidemiological research lines [10,11,12, 13]. Results based on both sets of BPT values are included because both values are considered equally likely by EPA. EPA-estimated health data were used, incidence per ton (mortality and morbidity outcomes), to present not only monetary benefits, but also physical health benefits.

The EPA BPT values represent the average, as opposed to marginal, cost per ton of emissions from power plants. EPA calculates this cost in four steps:

(1) EPA uses a state-of-the-art meteorology and air quality model to track emissions from power plants as they are transformed through chemical reaction and transported through the atmosphere over the course of a year.

(2) EPA calculates the increased population exposure to $PM_{2.5}$ and ozone that can be tracked back to emissions of a particular pollutant from power plants.

(3) EPA applies two different sets of epidemiological exposure–response relationships to develop estimates of increased mortality from exposure to particulate matter and ozone, and one set of exposure–response relationships for increased morbidity.

(4) EPA applies estimates of the monetary cost of health impacts to calculate total monetary consequences.

For health effects that occur in years after the emissions, EPA makes assumptions for the temporal allocation of these impacts, and discounts them to the year of pollutant emission. The BPT values are then simply calculated as the ratio of the (discounted) cost of the health effects to the total emissions from power plants in any region. This process is repeated for each pollutant, for each region.

The meteorology modeling performed by EPA is based on the year 2005. Air quality is modeled based on historical emissions from 2005 and projected emissions in 2016, but with the same meteorology from 2005. EPA developed BPT estimates for the years 2020, 2025, and 2030 based on 2016 air quality modeling but with the damage factors scaled based on population and income projections. The constant emission assumption (post-2016) increases the uncertainty in the BPT estimates. However, most of the health damages are found to be from secondary sulfate $PM_{2.5}$ as opposed to ozone, and ozone is more sensitive to prior emissions than secondary sulfate $PM_{2.5}$, somewhat ameliorating the impact of this simplification.

To cover the full analysis period for the *Wind Vision* (2013–2050), BPT values are developed for each year within each of the three regions by linearly extrapolating the EPA's BPT values. In this manner, there is implicit representation of the population and income growth assumptions incorporated in the EPA's analysis. The 2013–2025 BPT values are based on the linear trend established by EPA's 2020 and 2025 BPT values. The 2026–2050 BPT values are based on the linear trend established by EPA's 2025 and 2030 BPT values. The same process is used for EPA's health incidence-per-ton (mortality and morbidity outcomes) estimates. Ultimately, the resulting BPT and incidence per ton values are multiplied by estimated emission reduction in the *Study Scenario* (relative to the *Baseline Scenario*) to estimate yearly benefits.

EPA's approach is followed in adapting BPT and incidence-per-ton values for primary $PM_{2.5}$ emissions. EPA specifically found lower damages for primary $PM_{2.5}$ emissions of "crustal material" than for "soot and organic carbon." However, the *Wind Vision* power plant emission rate estimates are for total primary $PM_{2.5}$ and do not differentiate among particle types. Consequently, when applying the EPA-based BPT and incidence-per-ton values, primary $PM_{2.5}$ emissions were weighted following EPA's assumption that 10% of primary $PM_{2.5}$ is soot or organic carbon, 78% is crustal material, and the remainder is primary sulfate or nitrate. Note that EPA benefits and, therefore, the EPA-based benefit estimates, do not account for primary sulfate and nitrate particle emissions. This treatment of primary $PM_{2.5}$ emissions adds some uncertainty, although, as detailed in the main text, the contribution of primary $PM_{2.5}$ to total benefits was <10%.

A final detail regarding the treatment of benefits from ozone exposure reduction is that the EPA benefits, and the *Wind Vision* representation of EPA benefits, account for ozone exposure only during the ozone season. However, ReEDS estimates of annual generation are used. To calculate ozone effects, annual NO_x emissions were multiplied by 5/12 to estimate emissions during the five months of the ozone season (May–September).

Further details about the EPA methodology, the specific health consequences included and excluded from that methodology, and the large remaining uncertainties concerning the health consequences of air pollution emissions can be found in EPA [7].

AP2: The Air Pollution Emission Experiments and Policy Analysis (APEEP, now AP2) model is also used to translate the emission reductions from the *Study Scenario* (relative to the *Baseline Scenario*) into estimated health and environmental damage reductions. The APEEP model (Version 1) was used similarly by Siler-Evans et al. [14], and prior to that by the National Research Council (NRC) [15]. AP2, a revised and updated version of APEEP, is a reduced-form, integrated-assessment economic model of air pollution for the United States that connects location-specific emissions of criteria pollutants to the physical and economic consequences of those emissions, considering both primary and secondary pollutants, as well as pollution transport [16,17]. AP2 estimates marginal benefits (the benefit of reducing a single ton of emissions) as opposed to calculating the average cost of total emissions from power plants (as under the EPA approach). The monetized adverse effects from pollutant emissions are primarily due to human health (principally premature mortality and, to a lesser extent, morbidity), but AP2 damage factors also include consequences from decreased timber and agriculture yields, reduced visibility, accelerated degradation of materials, and reductions in recreation services [18].

AP2 (and APEEP) models physical pollution transport based on climatological average meteorology and chemical transformation to secondary pollutants (fine particulates, and ozone) in order to connect final exposure to initial pollutant emissions. More information can be found in Muller and Mendelsohn [16,17,18]. The damage factors from AP2 depend on how emissions interact with pollutants already present in the atmosphere. For this analysis, non-electric sector emissions are assumed to stay constant at 2005 levels and damage factors are not adjusted over time, except for national population and income growth. As with the EPA estimates, the constant non-power sector emission assumption increases the uncertainty in the damage factor estimates but the uncertainty is somewhat ameliorated because of the heavy dependence on sulfate impacts as opposed to ozone.

In addition to SO_2, NO_x, and $PM_{2.5}$, NRC [15] also considered PM_{10}, whereas Siler-Evans et al. [14] did not, arguing that the health effects of PM_{10} are very small relative to SO_2, NO_x, and $PM_{2.5}$. The present analysis takes the approach of Siler-Evans et al. [14]. AP2 and the *Wind Vision* analysis do not include damages from toxic metals such as mercury, and also exclude many other impact pathways.

AP2 damage factors are specific to each U.S. County but are aggregated to the larger ReEDS regions so that they can be multiplied by emission estimates and summed to equal total benefits. Specifically, damage factors for the 134 ReEDS regions are estimated as averages of the county-level damage factors in AP2, weighted by actual power plant locations and generation within the ReEDS regions, as determined from Ventyx [3] data (year 2010). The county-level weightings do not change over time. AP2 damage factors for each county vary by emission height. In the case of power plants, following the methodology of Siler-Evans et al. [14], an effective stack height of 250–500 meters (including the physical stack height and subsequent plume rise) is used.

Ultimately, emission estimates for each of the 134 ReEDS regions for both the *Study* and *Baseline* scenarios were multiplied by AP2-averaged regional damage factors to estimate benefits. However, AP2 values were scaled over time, based on projected growth in population and income. National population growth estimates to 2050 come from Projections of the Population and Components of Change for the United States: 2015 to 2060 [19]. National per capita income growth estimates to 2040 come from EIA [20] and are extrapolated to 2050. Following NRC [15], the *Wind Vision* analysis presumes an elasticity of damages to per capita income growth of 0.5%. NRC [15] only scales the health-related damages with income growth, whereas the *Wind Vision* analysis scales all air quality-related damages accounted for by APEEP.

L.3 Comparison of EPA to AP2 Methods

Although there has not been a formal published comparison of EPA BPT to AP2 BPT, some of the main methodological differences are listed and discussed briefly below. Not discussed below, but covered above and in Chapter 3, is that EPA and AP2 cover somewhat different sets of health and environmental consequences.

Table K-1. Comparison of EPA to AP2 Methodology

Input	EPA	AP2
Meteorology	Based on year 2005	Based on climatological average
Air quality model complexity	Full air quality model underlying estimates	Reduced form air quality model
Regional specificity	Three large regions	Separate analysis for each county
Type of benefit	Average benefit per ton from reducing all power plant emissions	Marginal benefit of one-ton emission reduction
Epidemiology (mortality)	Range based on (1) American Cancer Society and (2) Harvard Six Cities Study	American Cancer Society

Two important potential advantages of the EPA methodology are: (1) a more complex representation of atmospheric chemistry and atmospheric dispersion of pollutants and (2) exposure–response relationships based on two different epidemiological research lines. Two important potential advantages of AP2 are: (1) climatological-averaged dispersion of pollutants, potentially eliminating any idiosyncratic weather patterns that occurred in 2005 and (2) locally explicit and marginal benefit estimates at the county level. Without a formal side-by-side comparison and evaluation, it is not possible to specifically identify the sources of the disagreement between EPA and AP2. However, the AP2 and EPA-Low estimates share similar epidemiology; as such, the large difference between AP2 and EPA-Low is most likely due to differences in air quality and meteorological modeling, indicating that uncertainty in air quality and meteorological modeling is of similar magnitude to uncertainty in epidemiology.

L.4 Uncertainties Due To Regulatory Representation

One important driver for the resulting health benefits of wind energy is related to the type of generation that wind energy offsets. Wind energy air pollution benefits are derived almost exclusively from reductions in coal (and oil) electricity generation. For example, in the region around the Ohio River Valley, a typical coal plant emits 21 times the amount of NO_x and 1810 times the amount of SO_2 as a typical gas plant per kilowatt-hour generated (based on Table 14 in Cai et al. [4]). Those same coal plants emit only 2 times the amount of carbon as the gas plants per kilowatt-hour generated, so criteria air pollution benefits are uniquely sensitive to the type of generation that is offset.

Recent changes to air pollution regulations and proposed carbon regulations are not fully incorporated into the present analysis. In particular, ReEDS generation and investment decisions include a representation of a nationwide SO_2 cap motivated by CSAPR and the Clean Air Interstate Rule, a precursor to CSPAR, but do not include MATS or a detailed treatment of CSAPR. This is because the ReEDS scenario design occurred during a period in which both MATS and CSAPR were being challenged in the courts so ReEDS was run under the then-current policy environment, which did not include either MATS or CSAPR. Because MATS and CSAPR have since been upheld, the approach described earlier is used to estimate emission reductions based on MATS and CSAPR, but only as a post-processing step applied to the ReEDS results.

Preliminary analysis suggests that this post-processing approach to MATS and CSAPR representation is not ideal in fully implementing MATS and CSAPR in ReEDS because the current ReEDS results are affected by an SO_2 cap and associated emissions factors that are not aligned with the expected outcomes of current regulations. In particular, as discussed further below, with MATS, the Clean Air Interstate Rule and CSAPR's SO_2 caps become non-binding, therefore increasing the amount of coal expected to be displaced by wind energy and increasing health benefits.

To account for these complexities, the treatment of air regulations in ReEDS was modified to account for MATS and CSAPR, generated alternate *Baseline* and *Study scenario*s (using otherwise identical central assumptions), and estimated the monetized health and environmental benefits of wind (using the steps presented previously in this appendix). Simplified assumptions were needed to represent MATS and CSAPR in ReEDS. To represent CSAPR, SO_2 and NO_x caps are included for two regions comprised of groups of states in the Eastern United States [2][1], as directed in the RIA [2]. Individual state assurances are not directly modeled nor is credit trading within each group. To represent MATS, nearly all coal plants are forced to retrofit with emissions controls in 2016.[2] For coal units without an SO_2 scrubber, a flue-gas desulfurization retrofit is required with costs consistent with assumptions from EIA [6]. On top of this, an additional retrofit cost is incurred for all existing coal plants. Because retrofit decisions for individual plants are not evaluated, a generic retrofit cost is used based on the capacity-weighted average of estimated control technology adoption [1][3] and costs from EIA [6].[4] Updated emission factors accompany these retrofits—post-MATS SO_2 emission factors are largely based on estimates from the MATS RIA [1], whereas NO_x emission factors are based on the internal analysis described previously in this appendix.[5]

Results from this preliminary analysis indicate that when MATS and CSAPR are directly modeled within the *Wind Vision* context, *Study Scenario* benefits associated with avoided SO_2, NO_x, and $PM_{2.5}$ emissions (relative to the *Baseline Scenario*) are estimated to be $68 billion, $129 billion, and $320 billion using the methods of AP2, EPA-Low, and EPA-High, respectively. These benefits are on a present value (2013-2050, 3% discount rate) basis and are higher than those for scenarios where MATS and CSAPR were considered as a post-processing step (see Section 3.10).

The reason for increased benefits is that wind energy is found to displace a greater amount of coal in the scenarios with updated air regulations modeled in ReEDS. In particular, MATS is estimated to reduce the SO_2 emission rates such that the cap from CSAPR is not binding in most years for both the *Baseline* and *Study* scenarios. Without a binding cap to neutralize differences between the *Baseline* and *Study* scenarios, differences are more pronounced, leading to greater air pollution-related benefits.

Additional uncertainties related to CSAPR could further increase the potential benefits of the *Study Scenario* beyond those estimated above. For example, in the new Baseline Scenario with MATS, the CSAPR SO_2 cap is not reached but the CSAPR NO_x cap is reached from 2018 to 2040. ReEDS, however, only represents national average emission factors by generator type, whereas actual NO_x emission rates are ~20% lower in the CSAPR NO_x region compared to the national average factor used in ReEDS (based on analysis of power plant emission factors in the Ventyx [3] database). As a result, the effect of the CSAPR cap may be overstated in this ReEDS scenario, and *Study Scenario* benefits could potentially increase further if localized emission factors were incorporated into ReEDS.

---

1 The annual SO_2 and NO_x allowance budgets are applied at the group level. The group budgets are found in EPA [2]. An annual estimate of NO_x allowance budgets is used for the states for which NO_x is controlled only during the ozone season (May–September).

2 Plants that are expected to retire by 2020 based on the ReEDS announced and lifetime retirement assumptions are exempted from any retrofit requirements driven by MATS.

3 EPA estimates about 17 electricity generating units retrofitting new scrubbers, 99 EGUs with activated carbon injection, 44 EGUs with dry sorbent injection, 102 EGUs with fabric filter and some EGUs undergoing scrubber change (Table 6-3 in EPA RIA [2]), resulting in a MATS compliance cost of about $9.6 Billion (2007 dollars) (Table ES-1 in EPA RIA [2]).

4 The estimated average cost of non-flue-gas-desulfurization retrofits is $83/kW while a scrubber retrofit is estimated to cost $536/kW (all in 2013 dollars). This preliminary analysis is only used to provide another data point on air pollution-related potential benefits of the *Study Scenario*. How MATS and CSAPR compliance affects the incremental electricity system or consumer costs (or other impacts) has not been estimated in the *Wind Vision*.

5 Post-MATS SO_2 factors for coal-old scrubbed and cofire-old is 0.2 lb/MMbtu and for coal-new and cofire new is 0.09 lb/MMbtu. Post-MATS NO_x emission factors for coal-old scrubbed and cofire-old is 0.19 lb/MMbtu and for coal-new and cofire new is 0.08 lb/MMbtu.

On the other hand, these revisions would not cover all uncertainties, and other types of regulatory or market changes could push the estimated benefits down. For example, the implementation of the Clean Power Plan or other types of carbon regulation would be expected to reduce the health and environmental benefits derived from the *Study Scenario*. In particular, were the Clean Power Plan implemented in ReEDS, one would expect greater natural-gas generation along with greater renewable and efficiency deployment and less coal-fired generation. Though it is uncertain how this would affect displacement as a result of wind, one would expect such a scenario to increase the amount of wind-related natural gas displacement and reduce the wind-related coal displacement. The resulting change in dispatch would, therefore, be anticipated to reduce *Study Scenario* health benefits.

L.5 References

[1] *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards*. EPA-452/R-11-011. Research Triangle Park, NC: U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, December 2011; 510 pp. Accessed Feb. 2, 2015: http://www.epa.gov/mats/actions.html.

[2] *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States.* Docket ID EPA-HQ-OAR-2009-0491. Washington, DC: U.S. Environmental Protection Agency, 2011a. Accessed Jan. 2, 2015: http://www.epa.gov/air/docket/comment.html.

[3] *Ventyx Velocity Suite.* 2013. Accessed Jan. 7, 2015: http://www.ventyx.com/en/solutions/business-operations/business-products/velocity-suite.

[4] Cai, H.; Wang, M.; Elgowainy, A.; Han, J. *Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units.* ANL/ESD/12-2. Lemont, IL: Argonne National Laboratory, 2012. Accessed Dec. 29, 2014: http://www.osti.gov/scitech/biblio/1045758.

[5] Cai, H.; Wang, M.; Elgowainy, A.; Han, J. *Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010.* Lemont, IL: Argonne National Laboratory, 2013. Accessed Dec. 29, 2014: www.osti.gov.

[6] "AEO2014 Projects More Coal-Fired Power Plant Retirements by 2016 Than Have Been Scheduled." U.S. Department of Energy, Energy Information Administration, Feb. 14, 2014, republished Mar. 10, 2014. Accessed Feb. 2, 2015: http://www.eia.gov/todayinenergy/detail.cfm?id=15031#.

[7] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants.* EPA-542/R-14-002. Research Triangle Park, NC: U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, June 2014.

[8] Fann, N.; Fulcher, C.M.; Hubbell, B.J. "The Influence of Location, Source, and Emission Type in Estimates of the Human Health Benefits of Reducing a Ton of Air Pollution." *Air Quality Atmospheric Health* (2:3), 2009; pp.169–176. Accessed Jan. 8, 2015: http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/.

[9] Fann, N.; Baker, K.R.; Fulcher, C.M. "Characterizing the $PM_{2.5}$-Related Health Benefits of Emission Reductions for 17 Industrial, Area and Mobile Emission Sectors Across the U.S." *Environment International* (49), Nov. 15, 2012; pp. 141–151. Accessed Jan. 8, 2015: http://www.sciencedirect.com/science/article/pii/S0160412012001985.

[10] Krewski, D.; Jerrett, M.; Burnett, R.T.; Ma, R.; Hughes, E.; Shi, Y.; Turner, M.C.; Pope, C.A. III; Thurston, G.; Calle, E.E.; Thun, M.J., et al. "Extended Follow- Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." Health Effects Institute (HEI) Research Report 140. Boston: HEI, 2009. Accessed Jan. 8, 2015: http://pubs.healtheffects.org/view.php?id=315.

[11] Bell, M.L.; McDermott A.; Zeger, S.L.; Samet, J.M.; Dominici, F. "Ozone and Short-Term Mortality in 95 US Urban Communities, 1987–2000." *Journal of the American Medical Association* (292:19), 2004; pp. 2372–2378. Accessed Jan. 8, 2015: http://www.ncbi.nlm.nih.gov/pubmed/15547165.

[12] Lepeule, J.; Laden, F.; Dockery, D.; Schwartz, J. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." *Environmental Health Perspectives* (120:7), 2012; pp. 965–970. Accessed Jan. 8, 2015: http://www.ncbi.nlm.nih.gov/pubmed/22456598.

[13 Levy, J.I.; Chemerynski, S.M.; Sarnat, J.A. "Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis." *Epidemiology* (16:4), July 2005; pp. 458–468. Accessed Jan. 8, 2015: http://www.ncbi.nlm.nih.gov/pubmed/15951663.

[14] Siler-Evans, K.; Azevedo, I.L.; Morgan, M.G.; Apt, J. "Regional Variations in the Health, Environmental, and Climate Benefits of Wind and Solar Generation." *Proceedings of the National Academy of Sciences* (110:29), July 2013; pp. 11768–11773. Accessed Jan. 7, 2015: http://www.pnas.org/content/110/29/11768.short.

[15] *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* National Research Council of the National Academies. Washington, DC: National Academies Press, 2010. Accessed Jan. 6, 2015: http://www.nap.edu/catalog/12794/hidden-costs-of-energy-unpriced-consequences-of-energy-production-and.

[16] Muller, N.Z.; Mendelsohn, R. "Measuring the Damages of Air Pollution in the United States." *Journal of Environmental Economics and Management* (54:1), 2007; pp. 1–14. Accessed Jan. 6, 2015: https://www.zotero.org/groups/energy_efficiency_gap/items/itemKey/SEX2IEKG.

[17] Muller, N.Z.; Mendelsohn, R. "Efficient Pollution Regulation: Getting the Prices Right." *American Economic Review* (99:5), 2009; pp. 1714–1739. Accessed Jan. 6, 2015: https://www.aeaweb.org/articles.php?doi=10.1257/aer.99.5.1714.

[18] Muller, N.Z.; Mendelsohn, R.; Nordhaus, W. "Environmental Accounting for Pollution in the United States Economy." *American Economic Review* (101:5), 2011; pp. 1649–1675. Accessed Jan. 6, 2015: https://www.aeaweb.org/articles.php?doi=10.1257/aer.101.5.1649.

[19] "Table 1. Projections of the Population and Components of Change for the United States: 2015 to 2060." 2012 National Population Projections Summary Tables. Washington, DC: U.S. Census Bureau Population Division, 2012. Accessed Feb. 2, 2015: https://www.census.gov/population/projections/data/national/2012/summarytables.html.

[20] *Annual Energy Outlook 2014 with Projections to 2040.* DOE/EIA-0383(2014). Washington, DC: U.S. Department of Energy, Energy Information Administration, April 2014a; 269 pp. Accessed Jan. 26, 2015: www.eia.gov/forecasts/aeo.

This page is intentionally left blank

Appendix M: Detailed Roadmap Actions

This Appendix expands on the top-tier actions outlined in the *Wind Vision* roadmap in Chapter 4. The roadmap describes the actions needed to achieve and reduce the cost of the *Wind Vision*. Most of the top-tier roadmap actions include additional, detailed sub-actions.[1] The relevant top-tier actions are listed here (without the text from Chapter 4), followed by the related detailed actions.

M.1 Wind Power Resources and Site Characterization

ACTION 1.1: Improve Wind Resource Characterization. *Collect data and develop models to improve wind forecasting at multiple temporal scales (e.g., minutes, hours, days, months, and years).*

DELIVERABLE: Data, validated models, and measurement techniques that improve ability to predict wind plant power output over several spatial and temporal scales.

IMPACT: Increased wind plant performance resulting in increased revenue, improved reliability, and decreased operating costs.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 1.1.1: Improve wind characteristics forecasting. Develop, validate, and apply models and measurement techniques that accurately characterize and forecast the wind in various time frames (e.g., hours, days, months, years).	Estimates of regional wind energy content and timing over generating-unit commitment and dispatch time intervals.	Accurate predictions of wind plant performance to reduce project financing costs, reduce power system operating costs, improve project siting, and provide a sound basis for advanced turbine and wind plant design.	2014	2020
ACTION 1.1.2: Develop models that predict the effect of climate change on wind resources. Develop credible forecasts of the impact of the changing climate and the inter-annual variability of weather patterns on regional wind resources.	Estimates of regional wind energy content versus time and location over periods of several decades.	Better informed decisions on investments in wind plant and transmission equipment.	2014	2030

ACTION 1.1.1: Improve wind characteristics forecasting.

Reducing the error and uncertainty of wind resource forecasts and wind power generation facilitates the integration of wind into the electric grid. Stakeholder action is needed to develop, validate, and apply models and measurement techniques that accurately characterize and forecast the wind in various time frames (e.g., minutes, hours, days, months, and years). Forecasts on the hourly scale support dispatch decisions; multi-hour forecasts warn of ramp events (rapid changes in power output); and day-ahead forecasts inform unit-commitment decisions.

1 There are no detailed sub-actions for roadmap Action 5.5: Develop Optimized Offshore Wind Grid Architecture and Integration Strategies, Action 9.1: Refine and Apply Energy Technology Cost and Benefit Evaluation Methods, Action 9.2: Refine and Apply Policy Analysis Methods, and Action 9.3: Maintain the Roadmap as a Vibrant, Active Process for Achieving the *Wind Vision Study Scenario.*

It is important that these forecasts address major wind characteristics beyond just wind speed, such as turbulence and stability. Two main aspects of numerical weather prediction models are the data assimilation scheme and the model physics, both of which can be improved through stakeholder action to support wind integration.

ACTION 1.1.2: Develop models that predict the effect of climate change on wind resources.

Wind power plants have economic lifetimes that can range from 20 to 30 years. Over this period, changes in the climate can affect the wind resource characteristics at a wind plant, with consequent changes in the plant's power production. It is important but challenging to reliably quantify these effects. A long-term measurement campaign is needed to develop and validate results of models that can align changes in global-scale atmospheric forcing to the detailed flow through a wind plant.

ACTION 1.2: Understand Intra-Plant Flows. *Collect data and improve models to understand intra-plant flow, including turbine-to-turbine interactions, micro-siting, and array effects.*

DELIVERABLE: Data, validated models, and measurement techniques to minimize turbulence induced by adjacent turbines through optimized siting.

IMPACT: Increased wind plant energy production and reduced turbine maintenance requirements.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 1.2.1: Improve remote sensing techniques. Develop high spatial resolution sensing technology and techniques for use in high-fidelity experiments and siting wind power plants.	"Bankable" remote sensing technologies for wind plant siting and scientific research.	Improved efficiency and performance of wind power systems.	2014	2020
ACTION 1.2.2: Optimize the siting of turbines in a wind power plant. Develop tools based on state-of-the-art models and standardized micro-siting methods; refine and set standards for modeling techniques for wind resource and micro-siting.	Computational tools with the capability to efficiently optimize turbine siting within a wind plant.	Increased energy capture and reduced fatigue loads.	2014	2030
ACTION 1.2.3: Improve multi-scale complex flow models. Conduct a measurement campaign; improve understanding of complex terrain; develop integrated models linking large-scale climatology, meso-scale meteorological processes, micro-scale terrain, and wind plant array effects.	Experimental data and computational models that define the effects of turbine wakes, complex terrain, and complex meteorological phenomena on wind plant flows.	Foundational understanding of complex flows in wind plants, which enables improved power plant design and energy production forecasting.	2014	2030

ACTION 1.2.1: Improve remote sensing techniques.

Remote sensing techniques are needed to collect the detailed intra-wind plant data needed to fully characterize wind plant flows, and to support resource assessment efforts. As turbine hub heights continue to grow, conventional meteorological towers become costly and impractical. Additional research is required to transition remote sensing measurements from the realm of scientific inquiry to “bankable” data with sufficient reliability to support large investment decisions. The performance of these systems must be completely characterized in a wide variety of terrain and weather conditions so their performance is fully understood. A key activity for this task is the development of internationally-accepted standards for these new measurement technologies.

ACTION 1.2.2: Optimize the siting of turbines in a wind power plant.

The aerodynamic interactions between wind turbines in a large-scale wind plant can reduce the power output of the plant by 10–15%. Additionally, the effects of any complex terrain features present at the site can further reduce the plant’s power production. Improved numerical simulation tools are needed to accurately calculate these effects, enabling wind plant design to mitigate these adverse effects and produce maximum power in a wide variety of atmospheric conditions. A data-gathering campaign is required to develop and validate the accuracy of the numerical simulation tools.

ACTION 1.2.3: Improve multi-scale complex flow models.

Generating wind power is basically a combination of large-scale weather processes and the detailed aerodynamic flow of wind through a turbine rotor. This process is not well understood. A combined experimental and theoretical investigation is required to provide insight into the fundamental physical processes, and to develop numerical simulation tools that can successfully model this complex system. This model is the foundation for many of the other actions in this roadmap. Therefore, development of this model should be initiated immediately. A substantial effort is also required to validate the results of the model for a wide range of wind plant configurations and atmospheric characteristics.

ACTION 1.3: Characterize Offshore Wind Resources. *Collect and analyze data to characterize offshore wind resources and external design conditions for all coastal regions of the United States, and to validate forecasting and design tools and models at heights at which offshore turbines operate.*

DELIVERABLE: Resource maps, forecasting tools, weather models, measurement stations, and technical reports documenting physical design basis.

IMPACT: Improved offshore research and development (R&D) strategy and accelerated offshore wind deployment.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 1.3.1: Characterize offshore wind resource and external design conditions. Validate at heights in which offshore turbines operate. Establish reference facilities to provide high-quality scientific observations and measurements.	Resource maps, forecasting tools, weather models, measurement stations, and technical reports documenting the physical design basis.	Accelerated adoption of offshore technology due to lower project risk and uncertainty.	2014	2030
ACTION 1.3.2: Accelerate development and acceptance of innovative remote measurement systems. Examples are buoy-based profiling Lidar and fixed scanning Lidar.[1]	Validation studies and peer-reviewed articles leading to certified, bankable procedures for remote sensing and profiling.	Reduction in cost and deployment time for site-specific resource characterization; acceptance of next-generation measurement practices; alternatives to bottom-fixed tall towers.	2014	2030
ACTION 1.3.3: Create offshore monitoring for metocean data collection. Establish high-intensity, benchmark metocean measurement and research facilities in strategic offshore locations.	An offshore monitoring network and multi-year validated datasets, accessible to multiple stakeholders.	Improved understanding of physical metocean conditions at higher spatial resolution; advanced modeling capabilities for dynamic processes and land-sea-air interactions; reduced uncertainty in wind plant design and performance.	2014	2030
ACTION 1.3.4: Improve offshore datasets for extreme events. Develop improved datasets of “extreme” event metocean statistics, including joint probabilities (e.g., wind and wave).	Maps, statistics and classifications of extreme events, values, and return periods for wind, waves, and other metocean phenomena.	Reduced uncertainty in plant design; reduced financing and insurance costs.	2014	2030
ACTION 1.3.5: Create archives and collaborative frameworks for data. Develop workable frameworks for collaborative private–public data sharing and research.	Archiving for offshore data, implemented according to contemporary standards; case studies and sample legal agreements for sharing metocean data collected by the private sector.	Expanded access to metocean data to address scientific barriers and advance knowledge.	2014	2030

ACTION 1.3: Characterize Offshore Wind Resources. *Collect and analyze data to characterize offshore wind resources and external design conditions for all coastal regions of the United States, and to validate forecasting and design tools and models at heights at which offshore turbines operate. (cont.)*

DELIVERABLE: Resource maps, forecasting tools, weather models, measurement stations, and technical reports documenting physical design basis.

IMPACT: Improved offshore research and development (R&D) strategy and accelerated offshore wind deployment.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 1.3.6: Improve wake modeling. Evaluate plant wakes and impacts on adjacent wind turbines and wind plants; advance wake and energy prediction models.	Quantitative studies and technical papers.	Improved turbine and plant layouts for optimum energy production; improved energy forecasting; improved turbine reliability; reduced wake-induced loads.	2014	2030
ACTION 1.3.7: Enhance resource maps and other models for offshore. Develop improved models for resource characterization and forecasting.	Improved model physics; models validated in the offshore environment for a full range of atmospheric and oceanographic conditions; reports and journal articles.	Higher confidence and accuracy from validated resource maps; improved inflow characterization for turbines and wind plant design; improved forecasting for wind plant operations.	2014	2030

ACTION 1.3.1: Characterize offshore wind resource and external design conditions.

Measurement campaigns are required to gather the scientific data needed to develop and validate detailed models of offshore wind characteristics. Knowledge of wind characteristics is required to effectively design offshore wind plants and accurately predict their power production. The measurement campaigns will be required at all offshore wind areas of the United States, including the Gulf of Mexico, Atlantic, Great Lakes, and Pacific. Reference facilities must be established to provide the necessary high-quality scientific data. These high-quality field measurements can be used to validate the numerical simulations that provide the needed spatial and temporal resolution.

ACTION 1.3.2: Accelerate development and acceptance of innovative remote measurement systems.

One of the largest barriers to offshore resource characterization is the high cost of tall meteorological masts needed to characterize wind conditions; the land-based norm is not readily transferable to water environments. At an offshore site, the cost of free-standing, offshore meteorological masts can be roughly two times their land-based counterparts in shallow water. These masts may not be feasible in deeper waters where floating wind turbines might be deployed. Permitting requirements for fixed meteorological towers are demanding and can take one to two years to satisfy.

Technological alternatives are needed to overcome these hurdles. Surface-based remote sensing technologies, including profiling, scanning, and floating versions of light detection and ranging, or Lidar, systems are essential for viable and bankable alternatives to mast-based measurement programs for offshore wind. Accelerated development and validation of new technologies like Lidar will enable collection of reliable offshore wind data for offshore research and commercial projects.

ACTION 1.3.3: Create offshore monitoring for metocean data collection.

Data needs and modeling efforts require detailed knowledge of the marine atmospheric boundary layer, the air-sea interface, and the subsurface ocean/lake water profile. Regional initiatives in strategically sited metocean measurement and research facilities are the most cost-effective approach to addressing several knowledge gaps in a concentrated fashion. Regional data sets available to the public are desirable in areas where offshore wind turbines might be deployed. The measurement environment should span the full water and atmospheric column, more than 150 meters above the surface. The deployed systems should complement and validate low-intensity, low-cost, standardized metocean monitoring systems (buoys) in intervening areas.

ACTION 1.3.4: Improve offshore datasets for extreme events.

Design criteria for offshore structures as established by the International Electrotechnical Commission, American Petroleum Institute, and other organizations include 50-, 100-, and possibly 500-year return periods for extreme wind and wave events. Due to the lack of long-term measurements in U.S. waters, existing probability statistics for extreme conditions contain a high degree of uncertainty. As evidenced by severe weather events in recent years, climatological statistics for extreme event probabilities derived solely from historical records may need to be revised. More reliable statistics for extreme event probabilities, derived from a combination of new observations and modeling approaches, are needed to reduce the need for large uncertainty margins in system design, which will lead to lower investment risk and costs.

ACTION 1.3.5: Create archives and collaborative frameworks for data.

For the foreseeable future, each offshore project will require a minimum of one year's worth of on-site metocean monitoring as part of the design and energy assessment process. Most offshore project development is expected to be financed by the private sector, which implies that the metocean data collection will be privately held as well. Given the critical importance of observational data to advance the greater industry's understanding of the offshore environment, there would be substantial value in finding ways for privately held dat2014a to be shared, either partially or in full, with the research community and other stakeholders. Mechanisms for data sharing should be designed, while respecting the competitive interests of developers.

ACTION 1.3.6: Improve wake modeling.

The understanding of wake impacts on turbine fatigue loads and energy production is more challenging for offshore projects because they are generally larger in scale than their land-based counterparts. Also, surface roughness and atmospheric stability regimes are significantly different. Due to their relative simplicity, current commercial wake modeling tools cannot accurately simulate wake development, propagation, and dissipation behavior for large arrays. This results in undesirably high levels of prediction uncertainty. Improved wake modeling is needed to better optimize turbine layouts and mitigate wake-induced impacts and uncertainties on project performance and reliability. Wake modeling advancement will enable projects yielding higher energy and lower operations and maintenance (O&M) costs.

ACTION 1.3.7: Enhance resource maps and other models for offshore.

In addition to more observational data, there is a need for improved modeling capabilities to accurately interpolate and extrapolate information from a limited number of stations to broader areas while representing important dynamic offshore processes. These processes include complex land-sea-air interactions that play a vital role in sea breeze circulations, low-level jets, thermal profiles and stability, and other marine boundary-layer phenomena. Given the evolution of increasingly taller hub heights and larger rotor diameters, wind turbines are becoming increasingly exposed to potentially significant flow discontinuities across their swept areas. Models will play an important role in both resource characterization and operational forecasting.

M.2 Wind Plant Technology Advancement

ACTION 2.1: Develop Next-Generation Wind Plant Technology. *Develop next generation wind plant technology for rotors, controls, drive trains, towers, and offshore foundations for continued improvements in wind plant performance and scale-up of turbine technology. (cont.)*

DELIVERABLE: Wind power systems with a lower cost of energy.

IMPACT: Reduced energy costs for U.S. industry and consumers . Increased wind deployment nationwide.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 2.1.1: Develop cost-effective turbine technology for very low wind speeds. High-capacity-factor wind turbines with tall towers and large blades are a critical part of this initiative.	Cost-effective wind energy in low-wind-speed sites.	Greater geographic diversity of wind energy supply, easing political barriers and the need for new transmission lines.	2014	2030
ACTION 2.1.2: Develop larger wind turbines. Develop technology for a new generation of much larger turbines that overcome cost and logistics barriers. A focus for this effort should be the design and manufacture of very large blades and towers, while overcoming logistical challenges such as transportation and installation.	Large, affordable turbines.	Significant reduction in siting and permitting challenges; lower bill of materials, balance of system, and O&M costs; significant reduction in the number of turbines needed to meet deployment goals.	2014	2040
ACTION 2.1.3: Develop advanced rotors. Use stronger, lighter materials to enable larger rotors; improve aerodynamic designs, novel rotor architectures, active blade elements, aeroelastic tailoring, sweep, noise reduction devices, active aerodynamic controls, and downwind, lower solidity rotors.	Rotors with increased energy capture, lighter weight, and lower noise.	Lower cost of energy, reduced deployment barriers.	2014	2040
ACTION 2.1.4: Improve drive train and power electronics. Create advanced generator designs; use alternative materials for rare earth magnets and power electronics; improve grid support through power electronics; improve reliability of gearboxes.	Increased power conversion system efficiency and reliability; reduced cost.	Increased overall wind plant efficiency.	2014	2030

ACTION 2.1: Develop Next-Generation Wind Plant Technology. *Develop next generation wind plant technology for rotors, controls, drive trains, towers, and offshore foundations for continued improvements in wind plant performance and scale-up of turbine technology. (cont.)*				
ACTION 2.1.5: Develop advanced control systems. Develop advanced control systems that reduce structural loads on turbines, increase energy capture, and operate the wind plant in an integrated manner to increase efficiency and support grid stability.	Next-generation control systems that increase power production and improve grid stability.	Lower cost of energy, improved grid stability.	2014	2035
ACTION 2.1.6: Develop tall towers. Develop taller towers that reach higher wind speeds aloft and enable larger rotors, but are not constrained by logistics.	Much taller towers that can be efficiently transported to wind plants.	Increased energy capture for a given land area, allowing development of lower wind speed sites.	2014	2030
ACTION 2.1.7: Develop next-generation foundations and installation systems. New foundation designs that will efficiently support the taller towers described in Action 2.1.6 are needed for both land-based and offshore turbines. New installation systems must be developed to mitigate the limitations of conventional crane technologies.	Cost-effective foundation and turbine installations.	Lower cost of energy, increased developable area.	2014	2030
ACTION 2.1.8: Deploy demonstration projects. Support and deploy full-scale demonstration projects for key advanced offshore technologies in various geographic regions.	Full-scale turbine technology in demonstration projects that showcase offshore wind technology.	Reduced investor and public perception of risks; initiation of infrastructure development.	2014	2020
ACTION 2.1.9: Develop advanced support structures. Innovate to produce offshore support structures that avoid high construction costs and enable mass production.	Low-cost piles, jackets, foundations, and installation methods.	Efficient mass production and deployment methods; reduced project costs and vessel bottlenecks.	2014	2030
ACTION 2.1.10: Develop new turbine technology systems. Research and develop cost-effective technology for floating wind turbines.	Cost-effective wind turbine technology that can be deployed in water depths up to 700 meters.	Increased siting options and lower levelized cost of electricity (LCOE).	2014	2050
ACTION 2.1.11: Evaluate solutions to ice loading. Develop technology to mitigate ice loading for freshwater ice floes.	Cost-effective wind turbines (fixed and floating) designed to withstand extreme ice loading in cold regions of the United States.	Increased siting options and lower LCOE.	2014	2030

ACTION 2.1: Develop Next-Generation Wind Plant Technology. *Develop next generation wind plant technology for rotors, controls, drive trains, towers, and offshore foundations for continued improvements in wind plant performance and scale-up of turbine technology. (cont.)*				
DELIVERABLE: Wind power systems with a lower cost of energy. **IMPACT:** Reduced energy costs for U.S. industry and consumers . Increased wind deployment nationwide. **KEY THEMES:** Reduce Wind Costs; Expand Developable Areas **MARKETS ADDRESSED:** Land, Offshore				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 2.1.12: Devise strategies to bolster offshore systems against hurricanes. Develop wind turbine systems and design strategies to address offshore wind deployment in hurricane-prone areas.	Cost-effective wind turbine systems designed and certified to withstand extreme tropical cyclone events.	Increased siting options and lower LCOE.	2014	2025
ACTION 2.1.13: Improve distributed wind technology. Optimize technology design for low to moderate wind resources, where distributed wind applications are typically located.	Lower-cost distributed wind turbines for low wind speed locations.	Much lower LCOE at moderate wind speed sites.	2014	2020

ACTION 2.1.1: Develop cost-effective turbine technology for very low wind speeds.

One of the most important new technologies for wind power is the development of much larger rotors for a given power-rating turbine. This permits increased energy capture and capacity factors, lowering the cost of energy. These larger rotors, and corresponding taller towers, permit the cost-effective development of sites with lower average wind speeds than was previously economical. This technology trend should be continued, allowing wind power to be economically competitive across the United States.

ACTION 2.1.2: Develop larger wind turbines.

The total number of wind turbines required for the *Wind Vision Study Scenario* can be significantly reduced by continuing the development of much larger machines, both in terms of electrical capacity and physical size. Key technologies for turbine growth are segmented rotor blades that can be easily transported to the wind plant and then assembled on site, and a similar technology being developed for on-site assembly of larger-diameter towers.

Since the wind power industry began in the early 1980s, the average capacity of wind turbines has increased almost 50 times. This growth in turbine size is indicative of the tremendous cost savings that have been realized by the industry since it began, largely due to fewer turbines generating the same plant output. The benefits of larger turbines are inherent in both land-based and offshore wind plants, but the challenges for land-based wind are different and turbine growth has not kept pace with offshore.

Today, the average offshore wind turbine being deployed has grown to nearly 4 megawatts (MW), and this growth is expected to continue. As evidence, almost every turbine manufacturer in the offshore wind market is developing a 5-MW to 8-MW wind turbine, and the industry forecasts the development of 10-MW wind turbines in the near future. These new machines are specifically designed to operate offshore. They also embody a unique set of offshore technology challenges that the industry is working to overcome. These technologies include rotor designs that implement advanced blade composite materials, assembly techniques, inspection, advanced blade testing, downwind rotor operation, and a new vein of advanced control methods and mechanisms. Drive trains are becoming more reliant on direct-drive and medium-speed generators with permanent magnets and advanced power electronics that can operate at very low speeds and overcome the reliability concerns of conventional gear-driven systems.

ACTION 2.1.3: Develop advanced rotors.

Many opportunities exist for continued improvements in rotor technology. Lower noise airfoil and rotor designs can be developed to increase the developable land area in the United States. Advanced materials can be used to reduce weight and structural loads, and enable larger rotor diameters. Active aerodynamic controls on the blades can be used to reduce operational fatigue loads on the entire turbine system, and sophisticated aeroelastic tailoring can be used to passively reduce the structural loads on the entire wind turbine structure.

ACTION 2.1.4: Improve drive train and power electronics.

Continued development is needed to reduce costs and improve the reliability and efficiency of the drive trains and power conversion systems that turn the rotor's rotational power into electrical power. Technological development of conventional multi-stage geared approaches, medium-speed systems, and direct-drive architectures—each of which has advantages—should be continued. High-flux permanent magnets can improve the efficiency of all three configurations. Efforts to develop alternatives to the existing rare-earth technologies should be pursued. New materials for power conversion electronics, such as silicon carbide, can increase efficiency and eliminate the need for complex liquid-cooling systems.

ACTION 2.1.5: Develop advanced control systems.

Advanced control systems that minimize turbine structural loads have been key contributors to the development of today's generation of much larger rotors. The continued development of these control systems in the future will likely take advantage of additional sensors, such as the forward-looking Lidar system that comprehensively senses the wind characteristics upstream of the rotor. An additional opportunity is the development of integrated wind plant control systems that operate all of the wind turbines in a synergistic manner to increase power production and reduce fatigue loads. These wind plant controls can also actively control the power output characteristics of the plant to promote grid stability.

ACTION 2.1.6: Develop tall towers.

Taller towers are the necessary complement to larger rotors. Taller towers also provide access to the stronger winds that exist at higher elevations above the ground. They are key to the cost-effective development of lower-wind-speed sites. Logistic constraints limit the maximum diameter of tower sections that can be transported over land, however, causing the cost of tall towers to increase disproportionately. For these reasons, innovations that permit increased on-site assembly of towers are needed.

ACTION 2.1.7: Develop next-generation foundations and installation systems.

The fabrication and installation costs of offshore foundations and support structures have led to higher costs for offshore wind technology. Offshore costs can be lowered considerably by reducing construction time and dependency on high-priced, heavy-lift vessels, as well as through technology innovations, mass production, and standardization of the support structure. This opportunity will guide the development of advanced offshore foundations and substructures. For land-based turbines, new foundation designs are needed to efficiently support the taller towers to be developed per Action 2.1.6.

ACTION 2.1.8: Deploy demonstration projects.

As of 2013, the industry has not yet deployed any full-scale offshore turbines in the United States. This lack of experience causes a perception that such installations are high-risk. A key need is to deploy and successfully demonstrate state-of-the-art offshore wind technology to determine the extent to which today's technology is reliable and can withstand environmental conditions in the United States. The U.S. Department of Energy has initiated an Offshore Wind Advanced Technology Demonstration Program,[2] which is scheduled to deploy three independent pilot offshore wind projects using full-scale commercial turbines. Developers will receive assistance to offset the initial risk of being first-of-a-kind. In exchange, the public will receive a first-hand account of actual offshore wind turbine performance.

ACTION 2.1.9: Develop advanced support structures.

Offshore foundations and support structures have followed a conservative path, leveraging the experience of the oil and gas industry, which has led to more than 7 gigawatts of successful offshore wind deployments worldwide. The support structure and cost of offshore construction, however, have contributed much of the higher cost of offshore wind technology, where 70% of the capital expenditures are non-turbine costs. Industry projections indicate that offshore costs can be lowered considerably by reducing construction time at sea and dependency on high-priced, heavy-lift vessels, and by mass producing and standardizing the support structure.

ACTION 2.1.10: Develop new turbine technology systems.

More than 60% of the gross resource potential for offshore wind is over water deeper than 60 meters. Deep water is also further from shore, where impacts are lower and wind resources are more abundant. Costs have been shown to increase with depth for fixed-bottom systems, so foundation costs for these systems are expected to be higher as depths increase beyond 60 meters. Floating offshore wind system costs, however, may not increase as rapidly with water depth.

New technologies that can operate at greater depths are emerging, leveraging oil and gas experience. They have the potential to match the costs of existing fixed-bottom systems and, with innovations in moorings and manufacturing, they may actually be able to achieve lower costs. New floating technology standards and certification procedures need to be created and adopted to provide guidance to technology and offshore wind system developers.

ACTION 2.1.11: Evaluate solutions for ice loading.

More than 500 gigawatts of gross U.S. resource potential can be found in the Great Lakes, where winter ice sheets introduce another engineering challenge for offshore wind turbines. Ice floes can introduce high-dynamic loading on the tower and support structure, which must be anticipated and taken into consideration during the design. Designs to resist ice loading from various sources are needed to allow wind turbines in the Great Lakes. These designs could deploy systems on individual towers to deflect ice sheets or treat the whole wind plant using perimeter ice defense systems. Standards and certification procedures to evaluate long-term ice load cases need to be drafted, validated and adopted to provide guidance to technology and offshore wind system developers.

ACTION 2.1.12: Devise strategies to bolster offshore systems against hurricanes.

Hurricanes frequently affect the U.S. coastline, particularly from Cape Cod, Massachusetts, to Galveston, Texas, as well as in Hawaii. Extreme hurricane conditions can exceed the limits of an offshore wind turbine designed using current wind turbine standards and practices. New design approaches and operating strategies need

2 See *http://energy.gov/eere/wind/offshore-wind-advanced-technology-demonstration-projects* for more information.

to be created to guard offshore wind turbines against these extreme events and, in turn, lower the risk for offshore deployment in hurricane-prone regions. Hurricane resiliency may lead to hurricane-class turbines under international standards, and further adoption of proven codes used by the oil and gas industries.

ACTION 2.1.13: Improve distributed wind technology.

By optimizing design tools and next-generation wind technology for distributed wind resources, several cost factors of distributed wind could be addressed. Advanced technology represents a significant opportunity to increase energy capture and reduce installed system and maintenance costs, especially technology that addresses low to moderate wind resources typical in distributed wind locations. For example, most medium-sized turbines used in distributed wind applications are based on 20-year-old designs and are slated for high wind resource, low-turbulence environments. Developing new designs for distributed wind turbines would lower several costs, including the levelized cost of electricity.

ACTION 2.2: Improve Standards and Certification Processes. *Update design standards and certification processes using validated simulation tools to enable more flexibility in application and reduce overall costs.*

DELIVERABLE: Certification processes that provide the required level of reliability while remaining flexible and inexpensive.

IMPACT: Lower overall costs, increased reliability, and reduced barriers to deployment.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 2.2.1: Create flexible certification processes. Eliminate needless conservatism. Enable efficient, custom design and certification process. Validate standards using modern turbines and test data. Establish a reliability basis for standards.	Lower cost and more flexible certification processes.	Custom wind turbine designs that can be efficiently brought to market, lowering the cost of energy.	2014	2040
ACTION 2.2.2: Define actual operating conditions. Develop a thorough understanding of actual operating conditions within a wind plant to enable turbine and component designs suitable for these conditions.	An accurate design basis for the development and certification of advanced technology.	Reduction in cost; increased reliability.	2014	2030
ACTION 2.2.3: Foster international collaboration and consistency. Enhance international collaboration in R&D and standardization, make standards internationally consistent, conduct large-scale testing, and improve wind integration. Exchange best practices. Sustain efforts to validate standards using open data. Formalize a gap-discovery and tracking processes for standards. Enable risk-based standards, design and certification.	Uniform certification processes worldwide.	Lower cost and reduced time to develop and certify new technologies.	2014	2050

ACTION 2.2.1: Create flexible certification processes.

The standards for wind power systems should be revisited and updated. The foundation for the next generation of standards should be based on systematic reliability, while simultaneously providing designers and manufacturers the flexibility to optimize the systems for specific sites without excessive recertification costs or delays. The next generation of certification standards can be developed following a comprehensive campaign to measure structural loads and validate the accuracy of the industry's simulation tools for the full range of operational conditions experienced over the lifecycle of the system.

ACTION 2.2.2: Define actual operating conditions.

The standards currently in use were developed with a focus on the operational conditions for a single turbine. This occurred well before the modern U.S. trend of installing large arrays of turbines in a single wind power plant. The current standards address the altered operational environment in the interior of a wind power plant in a superficial manner. They do not rigorously address the details of this interior environment. A field measurement campaign is needed to inform the next generation of standards with respect to the actual operational conditions in the interior of a large array of wind turbines.

ACTION 2.2.3: Foster international collaboration and consistency.

Developing and approving revised international standards for the certification of wind power systems takes many years. A sustained focus will be needed to achieve the goals of greater flexibility and lower costs while increasing reliability. The development of the next generation of standards will require collaboration among the wind industry, research laboratories, and national authorities around the globe. Coordination of national, state, and local permitting processes is required to make the new standards consistent among the many authorities with jurisdiction over the permitting process.

ACTION 2.3: Improve and Validate Advanced Simulation and System Design Tools. *Develop and validate a comprehensive suite of engineering, simulation, and physics-based tools that enable the design, analysis and certification of advanced wind plants. Improve simulation tool accuracy, flexibility, and ability to handle innovative new concepts.*

DELIVERABLE: Reliably accurate predictions of all characteristics of existing and novel wind turbine and wind plant configurations.

IMPACT: Improved technical and economic performance, increased reliability, and reduced product development cycle time.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 2.3.1: Create a load validation campaign. Measure structural loads; validate simulation tools; develop technologies to reduce operational and non-operational loads. Address all normal and fault conditions required for certification and prediction of life and reliability.	A complete assessment of the accuracy of structural load predictions for all conditions.	Increased confidence in predicted structural loads; reduced need for costly excess structural margins.	2014	2030
ACTION 2.3.2: Develop a wind plant systems engineering design tool. Develop robust wind plant design tools that enable adaptation of wind power plant design to specific local conditions (e.g., cold climates and low-wind sites), grid connection costs, local atmospheric conditions, and complex terrain.	Integrated design capability for an entire wind plant.	Reduction in cost, increased reliability, increased areas for deployment of customized wind plant designs.	2014	2025
ACTION 2.3.3: Develop aeroelastic analysis for wind plants. Develop integrated simulation of aerodynamics and structural dynamics of all turbines in a large-scale wind plant. This requires high-performance computing capability with physics-based simulation that computes energy capture and structural dynamics of an entire wind plant.	Computational capability for aerodynamics and structural dynamics of an entire wind plant.	Increased energy capture and increased reliability.	2014	2025

ACTION 2.3.1: Create a load validation campaign.

A comprehensive validation campaign is needed to define the accuracy, strengths, and weaknesses of today's simulation tools for a wide range of modern wind energy systems. This effort will directly support development of the next generation of certification standards described in Action 2.2. It will also support the identification of key opportunities and needs for improvements in the suite of simulation tools. A broad collaborative effort by academia, research laboratories, and the wind industry can then develop the specific improvements identified in the validation campaign.

ACTION 2.3.2: Develop a wind plant systems engineering design tool.

The focus of simulation tool development is shifting away from exclusive attention to the wind turbine and towards a comprehensive modeling capability for an entire wind plant. A systems engineering tool needs to be developed to provide a physics-based, comprehensive techno-economic model for the wind plant system. The tool must properly account for the physical interactions between the many components of that system. This capability can then be used to further optimize wind power plants for improved economic performance.

ACTION 2.3.3: Develop aeroelastic analysis for wind plants.

Simulation tools that can calculate the detailed aerodynamic and structural dynamic behavior of wind turbines have been evolving for decades. These tools provide a strong capability for the analysis of individual wind turbines. Consistent with the trend of considering the entire power plant as a system, these aeroelastic simulation tools need to be extended to accurately compute the detailed aerodynamic and structural dynamic behavior of all the turbines in a wind power plant, including aerodynamic, control system, and electrical system interactions among the individual machines. These simulation tools also need to have the flexibility to address novel configurations. This is a significant computational challenge requiring high-performance computing resources for a complete solution.

ACTION 2.4: Establish Test Facilities. *Develop and sustain world-class testing facilities to support industry needs and continued innovation.*				
DELIVERABLE: Cost-effective, publicly available test facilities for all critical wind plant subsystems. **IMPACT:** Lower cost of energy from increased reliability, reduced product development time, and support of innovative technology development. **KEY THEMES:** Reduce Wind Costs **MARKETS ADDRESSED:** Land, Offshore				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 2.4.1: Expand field test facilities. Increase the electrical capacity and available land area of field testing facilities at the National Renewable Energy Laboratory and Texas Tech University to support the development of the next generation of much larger wind turbines.	Field test facilities that support future needs for scientific research and innovative product development and certification.	Improved quality of scientific research and shortened product development timelines.	2014	2025
ACTION 2.4.2: Establish component and subsystem testing laboratories. Develop laboratory facilities that can test the full range of wind plant subsystems in realistic environmental conditions. Testing the interactions between subsystems is a critical capability.	Laboratory facilities that support the development of innovative subsystems and U.S. manufacturing competitiveness, and permit systematic testing to meet reliability objectives.	Reduction of costs, increased reliability, increased U.S. manufacturing competitiveness.	2014	2025

ACTION 2.4.1: Expand field test facilities.

Field test facilities are essential for scientific research, the development of innovative new turbines, and the certification of market-ready systems. The existing field testing facilities in the United States are not adequate for the coming generation of much larger turbines. The field test facility at the National Wind Technology Center, with its harsh flow and controllable grid interface, could be increased in both electrical capacity and in land area to support the growing need. The electrical capacity could also be increased at the complementary Scaled Wind Farm Technology, or SWiFT, field test facility at Texas Tech University, and the site's capabilities could be expanded to support wind plant aerodynamics and control research.[3]

ACTION 2.4.2: Establish component and subsystem testing laboratories.

No publicly-available facilities exist in the United States to support testing of the many subsystems in a wind turbine and wind plant. Such a facility is needed to support reliability improvements in these subsystems, and to permit a robust laboratory testing program for the development of subsystem innovations. The complex interactions between subsystems are frequently the root cause of reliability issues. This facility could provide the capabilities needed to examine these interactions in a realistic and controlled environment.

3 The National Wind Technology Center and the Scaled Wind Farm Technology site are both U.S. Department of Energy facilities.

ACTION 2.5: Develop Revolutionary Wind Power Systems. *Invest R&D into high-risk, potentially high-reward technology innovations.*				
DELIVERABLE: A portfolio of alternative wind power systems with the potential for revolutionary advances. **IMPACT:** Lower cost of energy, mitigation of deployment barriers. **KEY THEMES:** Reduce Wind Costs **MARKETS ADDRESSED:** Land, Offshore				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 2.5.1: Develop innovative designs. Encourage and enable the emergence of new, innovative designs in the wind industry and the wind research community through public/ private partnerships. Demonstrate promising technologies in laboratory and field tests. Support should transition from public to private sources as commercial prospects grow.	A portfolio of revolutionary wind power systems that explore new technological pathways.	Alternative approaches to wind power generation that will provide access to challenging sites.	2014	2050

ACTION 2.5.1: Develop innovative designs.

The conventional wind turbine configuration—a three-bladed, horizontal-axis rotor operating upwind of a tubular tower, with variable-pitch and variable-speed—has proven to be a robust and cost-effective arrangement. Alternative configurations need to be rigorously assessed, however, to ensure that their potential advantages and disadvantages are completely understood. Examples of alternative configurations include downwind rotor, floating vertical axis wind turbines, and airborne wind power systems. Public support is needed for the early stage investigations of these concepts, as the new technologies are too immature to receive the sustained support needed for a complete investigation. As the technologies mature and clear advantages over existing configurations are confirmed, further development will naturally transition to private sources.

M.3 Supply Chain, Manufacturing and Logistics

ACTION 3.1: Increase Domestic Manufacturing Competitiveness. *Increase domestic manufacturing competitiveness with investments in advanced manufacturing and research into innovative materials.*

DELIVERABLE: New information, analysis tools and technology to develop cost-competitive, sustainable, domestic wind power supply chain.

IMPACT: Reduced capital cost components, increased domestic manufacturing jobs and capacity, increased domestic technological innovation, and economic value capture.

KEY THEMES: Reduce Wind Costs; Increase Economic Value for the Nation

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 3.1.1: Conduct competitiveness assessments. Conduct comprehensive global manufacturing competitiveness assessments to inform future investments and manufacturing technology development.	Reports and tools to assess the competitiveness of U.S. manufacturers in a global context, including analysis of the cost-benefit of various manufacturing and trade policies.	Information and tools to guide investment and inform policy leading to improved domestic wind manufacturing competitiveness.	2014	2020
ACTION 3.1.2: Develop innovative manufacturing technology. Develop and deploy new manufacturing technology to increase domestic innovation and productivity.	Manufacturing technology innovation and commercialization through individual organizations and Industry-led consortia.	Increased domestic manufacturing competitiveness, capacity, and structure to innovate and commercialize next-generation technologies in the United States.	2014	2050
ACTION 3.1.3: Scale manufacturing capacity. Enable domestic manufacturers to scale up to competitively produce next-generation wind technology.	Access to capital and information to allow domestic manufacturers to upgrade equipment and facilities, and commercialize new manufacturing technologies capable of producing wind turbine components of sufficient size and quantity.	Reduced component cost; improved throughput and capacity.	2014	2020
ACTION 3.1.4: Improve supply chain efficiency through cross-industry synergies. Identify cost reduction opportunities along the supply chain from raw materials through fabrication.	Information exchange of the common needs of wind and complementary industries for raw materials, material forms, and fabrication capabilities, which would reduce input costs up the supply chain.	Diversified, sustainable, and more cost-competitive supply chains, especially in steel, cast iron, composite materials, and intermediate forms.	2014	2025

ACTION 3.1.1: Conduct competitiveness assessments.

Thorough surveys and analyses are needed to understand the competitive cost structure of U.S. and foreign suppliers, as is an assessment of the trade and manufacturing policies that are in place globally and driving competitive differences. This information will serve as a baseline to expand U.S. wind supply-chain value capture and domestic competitiveness. The data and tools developed can be used to inform new policies that support U.S. manufacturers and help industry prioritize key investments in manufacturing R&D and the use of capital, which will improve domestic manufacturing competitiveness [1].

ACTION 3.1.2: Develop innovative manufacturing technology.

Competitiveness assessments can guide and prioritize specific manufacturing technology that can be developed and deployed to improve the cost structure of U.S. manufacturers. Some technology development could be conducted by individual manufacturers through a combination of internal, government, and other funding sources to produce a competitive advantage through proprietary processes and technologies. Other more fundamental technology development could be conducted more collaboratively by industry-led consortia to address common manufacturing needs, much like the organization SEMATECH (from Semiconductor Manufacturing Technology) does for the semiconductor industry. The various Institutes for Manufacturing Innovation established through the White House's National Network for Manufacturing Innovation initiative could also serve as valuable forums to exchange knowledge, facilitate innovation, and develop technologies across industries and institutions that don't otherwise collaborate. Wind industry participation in these Institutes, such as the Clean Energy Manufacturing Innovation Institute for Composite Materials and Structures, and the Next Generation Power Electronics National Manufacturing Innovation Institute, will allow industry to benefit from these resources.

Regardless of the research and development model, the importance of a competitive, domestic manufacturing industry to support long-term innovation cannot be overlooked [2, 3]. The close interaction between manufacturing and R&D staff is a primary catalyst for inventing, developing and commercializing new technologies domestically. A report from the President's Council of Advisors on Science and Technology notes that, "Manufacturing has driven knowledge production and innovation in the United States by supporting two-thirds of private sector R&D and by employing scientists, engineers, and technicians to invent and produce new products [4]." It will be crucial to have a competitive domestic manufacturing industry to help develop and commercialize the many technologies that will be needed for on-going pursuit of the *Wind Vision Study Scenario.*

ACTION 3.1.3: Scale manufacturing capacity.

Innovation alone cannot increase domestic competitiveness; these new technologies will have to be commercialized in the nation's factories. Deploying new manufacturing technologies or even current state-of-the-art equipment in new or retooled facilities requires access to capital, which can be a significant barrier to U.S. manufacturers. This is especially true in the small and medium-sized businesses that make up a significant portion of the domestic supply chain. Sufficient capital from public and private sources is critical to enabling domestic manufacturers to match and exceed the capabilities and capacity of foreign competition and manufacture the quantity, quality and physical scale of next-generation wind plant technology [2]. Analysis tools are needed to support the development of effective financial policies that can ensure domestic manufacturers can scale up to meet the objectives of the *Wind Vision Study Scenario.*

ACTION 3.1.4: Improve supply chain efficiency through cross-industry synergies.

Even with highly productive, advanced manufacturing facilities, much of the cost of manufacturing is embedded in the raw materials and sub-assemblies that serve as inputs to the top-tier manufacturers. Opportunities exist in steel mills, foundries, and fiber composite suppliers to produce new standardized material forms that can reduce costly, labor-intensive processes like welding or composite layup and infusion that put domestic manufacturers at an inherent disadvantage due to the higher cost of labor in the United States. If done in coordination with synergistic industries like aerospace, automotive, and offshore oil and gas, this new production would incent material suppliers with a diverse and sufficient market to retool or expand capacity.

ACTION 3.2: Develop Transportation, Construction and Installation Solutions. *Develop transportation, construction, and installation solutions for deployment of next-generation, larger wind turbines.*

DELIVERABLE: Transportation, construction, and installation technology and methods capable of deploying next-generation, land-based and offshore wind.

IMPACT: Reduced installed turbine capital costs and deployment of cost-effective wind technology in more regions of the country.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 3.2.1: Develop transportation best practices. Develop best practices to enable the safe, reliable, and cost-effective transportation of wind components over land.	Guidelines developed through the coordination of industry, state, and local officials to identify and develop best practices for transportation of current and future wind components.	Clarity on transportation constraints across states to guide improved logistics planning and design of new components for transportability.	2014	2020
ACTION 3.2.2: Develop innovative transportation, construction, and installation technologies. Develop innovative transportation, construction, and installation technologies to meet the needs created by next-generation wind turbine technology.	Analysis of primary infrastructure and logistics challenges of larger wind turbines. Technology development and demonstration to validate potential solutions.	Validated innovative construction and assembly techniques to reduce cost and enable deployment of next-generation wind technology to access new resources on land and offshore.	2014	2025

ACTION 3.2.1: Develop transportation best practices.

As components increase in size and weight, the limitations of ground transport from factory to installation site become more pressing, especially for land-based systems [5]. Issues include safety, maintaining the integrity of the public infrastructure, and increased cost of components designed according to transportation constraints rather than optimized for performance. Industry and state and local government agencies need to assess the key issues and develop best practices to support improved logistics planning and clarify transportation constraints. This will enable original equipment manufacturers (OEMs) and transportation and logistics companies to develop new component designs and logistics solutions to ensure larger turbines can be deployed cost-effectively.

ACTION 3.2.2: Develop Innovative transportation, construction, and installation technologies.

New construction and installation techniques, materials, and equipment will be needed to install next-generation wind plant technologies. Concepts that could address some of the challenges presented by larger, heavier components, such as on-site manufacturing and assembly of towers or other components, will need to be demonstrated before being widely deployed. Dedicated technology demonstration sites, independent of commercial projects, could provide a venue to test new construction and installation technologies without incurring added risk to commercial projects. Proving out a new construction material or installation method can reduce risk and provide confidence to ensure new ideas can be deployed and financed.

ACTION 3.3: Develop Offshore Wind Manufacturing and Supply Chain. *Establish domestic offshore manufacturing and supply chain, and port infrastructure.*				
DELIVERABLE: Increased domestic supply of offshore wind components and labor. **IMPACT:** Increased economic growth in major offshore ports and regional manufacturing centers. **KEY THEMES:** Increase Economic Value for the Nation **MARKETS ADDRESSED:** Offshore				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 3.3.1: Establish offshore wind deployment levels sufficient to sustain the supply chain. Commit to offshore wind deployment levels that can support and sustain the supply chain needed to reduce cost and, in turn, drive additional deployment.	Strong domestic supply of offshore wind components and labor to support a sustainable U.S. wind manufacturing construction and service industry.	Increased economic growth in major offshore ports and regional manufacturing centers, and lower cost through supply chain industrialization.	2014	2030
ACTION 3.3.2: Support manufacturing supply chain development and use. Conduct regional supply chain asset mapping based on likely build-out of Wind Energy Areas. Create an online directory.	Comprehensive database of component manufacturing capabilities, locations, and gaps.	Understanding of gaps and ability to inform existing suppliers of offshore wind market opportunities; ability to inform developers and investors of the full range of available supply chain options.	2014	2020
ACTION 3.3.3: Create a network of U.S. port facilities. Develop, upgrade, and maintain a network of U.S. port facilities to support offshore wind manufacturing deployment and service.	New manufacturing facilities developed in close proximity to ports and quayside (i.e., ship loading and unloading platforms) service operations.	Reduced capital costs for new offshore wind facilities and increased regional job growth.	2020	2030

ACTION 3.3.1: Establish offshore wind deployment levels sufficient to sustain the supply chain.

As the U.S. offshore sector approaches deployment; issues of manufacturing capacity, skilled workforce, and maritime infrastructure requirements are coming into sharper focus. Studies commissioned by the U.S. Department of Energy in 2013–2014 provide an excellent knowledge base for considering strategic approaches to planning, promoting, and investing in necessary industrial-scale assets in a cost-effective, efficient manner. Specifically, this work addresses port readiness [6][4]; manufacturing, supply chain, and workforce [7]; and vessel needs [8] under a variety of deployment assumptions through 2030.

There is a wide range of economic development and job creation opportunities associated with offshore wind development. The United States has significant existing assets, which are currently used by other industries or underutilized, that can be deployed in support of offshore wind development. Development of the necessary manufacturing base, workforce, and maritime infrastructure to support a viable offshore wind industry will

4 Related port readiness tool available at *http://www.offshorewindportreadiness.com/*

require integrated public and private sector vision, commitment, and investment.

European experience illustrates the significant impact that supply chain gaps and vessel shortages can have on project cost and risk management [9]. It also shows the dangers of losing economic development advantage in the competitive, global offshore wind market through lack of strategic investment and planning [10]. Supply chain efficiencies have been targeted in the United Kingdom as a key opportunity for lowering the cost of offshore wind power [9]. Roadmap actions 3.3.2 and 3.3.3 are aimed at using lessons from the European Union to position the United States to realize offshore wind power's full economic development potential.

Commitment to significant, achievable offshore wind deployment levels is a necessary precursor to investment in new manufacturing facilities, workforce development, and port infrastructure to support the offshore wind industry. Because the majority of offshore wind development will occur in areas managed by the U.S. Department of the Interior through the Bureau of Ocean Energy Management, and the offtake markets are managed by state governments, the key participants to initiate this action are public sector agencies, in consultation with relevant stakeholders. All other suggested roadmap actions assume this development strategy is pursued.

ACTION 3.3.2: Support manufacturing supply chain development and use.

The offshore sector will use some aspects of the existing land-based wind supply chain. However, larger components intended specifically for offshore use, including foundation technologies, will likely require facilities located near ports. An estimated regional market of 300 megawatts per year will be necessary to support a turbine manufacturer [7].

Industrial infrastructure is primarily a function of market demand. The project-by-project approach of supply chain mobilization that is necessary for the first offshore wind projects will not be an effective or efficient process in planning for industry-scale deployment. The United States needs to develop offshore wind manufacturing infrastructure capabilities at key offshore wind port facilities to enable cost efficiency and maximize economic development benefits. The scale of deployment needed to support significant private sector investment in new manufacturing facilities, port improvement, and purpose-built vessel construction is likely to occur regionally rather than state by state.

A comprehensive database of the capabilities of component manufacturers available in each of five offshore wind development regions is needed to help communicate needs and opportunities.[5]

ACTION 3.3.3: Create a network of U.S. port facilities.

Significant port infrastructure is in place throughout the potential offshore wind development regions. Most ports currently meet the standards necessary to support O&M; however, staging ports will generally require investment to increase load-bearing capacity to accommodate nacelles and foundations. The state governments of Massachusetts, New Jersey, and North Carolina are investing in port infrastructure to accommodate anticipated first-stage projects. The most expensive improvement is typically quayside soil-bearing to support jack-up barges. Ports will be strategic hubs in the offshore wind construction process; all manufacturing and transport logistics will transit through them. The ability for offshore staging ports to engage multiple industries will be beneficial, especially as the industry ramps up through initial projects that may have gaps in construction activity [9].

It is estimated that a given port can support the activities associated with approximately 500 megawatts of capacity during the installation phase. When regional construction projections are mapped out over time, the results suggest that a minimum of one to four staging ports will be required per region. A minimum of approximately four O&M ports will be needed; however, the actual number of O&M ports required will depend on the specific project locations.

---

5 This activity has already been conducted in several states.

M.4 Wind Power Performance, Reliability, and Safety

ACTION 4.1: Improve Reliability and Increase Service Life. *Increase reliability by reducing unplanned maintenance through better design and testing of components, and through broader adoption of condition monitoring systems and maintenance.*				
DELIVERABLE: Reduced uncertainty in component reliability, and increased economic and service lifetimes. **IMPACT:** Lower operational costs and financing rates. Increased energy capture and investment return. **KEY THEMES:** Reduce Wind Costs **MARKETS ADDRESSED:** Land, Offshore				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 4.1.1: Update maintenance and replacement patterns. Transition from service-life to condition-based component maintenance and replacement.	Condition-based monitoring technology and intelligence built into future turbine models.	Reduced component failures through remote detection, which enables proactive decision-making by operators.	2014	2020
ACTION 4.1.2: Conduct design research and accelerated life testing. Improve design standards and accelerated life testing of componentry to simulate operating environments.	Testing centers and published research that improve the accuracy of component and turbine reliability testing and certifications.	Better understanding of long-term O&M costs and potential replacement and remanufacturing expenses that may be incurred in out-years of equipment lifetimes.	2014	2030
ACTION 4.1.3: Design offshore turbines and turbine systems for reliability. Develop high-reliability turbine systems that reduce offshore service requirements.	Turbines and turbine subsystems designed and tested for higher reliability using proven methods.	Offshore O&M plant costs reduced to land-based levels on a per megawatt basis.	2014	2050

ACTION 4.1.1: Update maintenance and replacement patterns.

Running components until they fail can result in costly downtime, replacements and repairs. Condition-based monitoring technology provides operators with intelligence and advance warning of component wear and tear, which can allow operators to make proactive decisions on maintenance and replacements. With such data, operators can plan and schedule repairs to coincide with weather or production windows to reduce costs and turbine downtime. Condition-based monitoring technology can also save technician time by reducing the frequency of technician turbine inspections and troubleshooting. Although condition-based monitoring sensors are becoming inexpensive, much work remains to develop predictive analysis methodologies that convert the raw sensor data into actionable maintenance alerts.

ACTION 4.1.2: Conduct design research and accelerated life testing.

Most existing certification standards lack a specific reliability basis. Developing a reliability component to certification standards could drive significant changes to product development. Another knowledge gap is an understanding of actual operating conditions, particularly in the interior of a wind plant. Collecting more field data and developing better algorithms that simulate such conditions could contribute to improved reliability designs in future turbines.

ACTION 4.1.3: Design offshore turbines and turbine systems for reliability.

Offshore wind turbines currently use many techniques for O&M and service that were developed for land-based systems. Offshore wind turbines are more difficult and costly to repair than their land-based counterparts, however, so the value proposition for more sophisticated repair and failure prevention strategies is much greater. Reliability and service strategies need to be integrated into turbine designs. Condition-based monitoring systems need to become more intelligent to provide accurate remote diagnostics.

ACTION 4.2: Develop a World-Class Database on Wind Plant Operation under Normal Operating Conditions. *Collect wind turbine performance and reliability data from wind plants to improve energy production and reliability under normal operating conditions.*

DELIVERABLE: Database of wind turbine performance and reliability data representing the U.S. fleet.

IMPACT: Lower unplanned maintenance costs, lower financing and insurance rates, and increased energy production.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 4.2.1: Collect and analyze field data to understand the specific mechanisms that cause early failure and what those failures cost.	Broad, national data sets that collate component failure information across OEMs and operators (e.g., the Blade Reliability Collaborative, Gearbox Reliability Collaborative, and the Continuous Reliability Enhancement for Wind Database and Analysis Program).	Higher component, turbine, and plant reliability through improved OEM designs that help owner/operators anticipate and avoid failure modes and conditions.	2014	2030
ACTION 4.2.2: Publish aggregated reliability statistics with regular updates.	An online, publicly available database of turbine performance, availability, and repairs.	Database against which owners, operators, and OEMs can benchmark their equipment and operating practices.	2014	2050

ACTION 4.2.1: Collect and analyze field data to understand the specific mechanisms that cause early failure and what those failures cost.

Operators and OEMs collect vast amounts of data on the performance of existing wind turbines in the field through real-time monitoring and analysis. This information is generally held privately, making it difficult for smaller industry players and outsiders in the financial community and public sector to have accurate insights into the performance and reliability of turbine equipment. Creating and maintaining national data sets; such as the Gearbox Reliability Collaborative, Blade Reliability Collaborative, and the Continuous Reliability Enhancement for Wind (known as CREW); can assist in providing the public and others outside the industry with factual, transparent information on turbine performance and reliability. Such groups can support coordination and sharing of best practices among industry players.

ACTION 4.2.2: Publish aggregated reliability statistics with regular updates.

Reliability analyses that attempt to improve the understanding of the existing situation must establish a baseline performance, identify performance drivers, and determine root causes. A national reliability benchmark remains highly desirable for the wind industry, to assist with its objectives of maximizing power performance yield;

decreasing financial risk and uncertainty; and understanding reliability trends across turbine models, turbine components, geographical locations, and age. Quantitative findings, modeling and statistical analyses can be incorporated into published benchmark data reports that are designed to increase industry confidence, particularly for those who do not have access to privately held data.

ACTION 4.3: Ensure Reliable Operation in Severe Operating Environments. *Collect data, develop testing methods, and improve standards to ensure reliability under severe operating conditions including cold weather climates and areas prone to high force winds.*

DELIVERABLE: High availability and low component failure rates in all operating environments.

IMPACT: Lower unplanned maintenance costs, lower financing and insurance rates, and increased energy production.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 4.3.1: Create and maintain national datasets on performance and reliability. Collect and analyze field data from wind plants in severe operating environments to understand the conditions under which each component operates and the specific mechanisms that cause early failure.	Broad, national data sets that collate component failure information across OEMs and operators (e.g., the Blade Reliability Collaborative and Gearbox Reliability Collaborative).	Higher component, turbine and plant reliability through improved OEM designs that help owner/operators anticipate and avoid failure modes and conditions.	2014	2030
ACTION 4.3.2: Create a Distributed Wind Reliability Database. Create and maintain a performance/reliability database for distributed wind projects.	An online, publicly available database of turbine performance, availability, and repairs.	Accurate tracking and reporting of distributed wind system performance, reliability, and safety issues; record of progress with wind technology and applications, as well as early indication of specific issues.	2014	2050

ACTION 4.3.1: Create and maintain national data sets on performance and reliability.

Operators and OEMs collect vast amounts of data on the performance of existing wind turbines in the field through real-time monitoring and analysis. This information is generally held privately, making it difficult for smaller industry players and outsiders in the financial community and public sector to have accurate insights into the performance and reliability of turbine equipment. Creating and maintaining national data sets, such as those identified in Action 4.2.1, can provide valuable information on performance and reliability. Action 4.3.1 provides a specific focus on reliability data under severe operating conditions.

ACTION 4.3.2: Create a distributed wind reliability database.

While much research and data collection focus on project O&M costs and events for wind plants, parsing out O&M costs for distributed wind projects is challenging, and no industry-standard reporting method currently exists. Lack of information about performance and availability of technology is one of the main roadblocks to wider deployment of distributed wind. A comprehensive database consisting of information on the performance and reliability of nationwide distributed wind projects would provide a valuable record of progress with wind technology and applications, as well as early indications of specific issues, while reducing uncertainty about distributed wind. The database would be publicly available and accessible online. It would include turbine performance, availability, and repairs, as well as accurate tracking and reporting of system performance, reliability, and safety issues.

ACTION 4.4: Develop and Document Best Practices in Wind O&M. *Develop and promote best practices in O&M strategies and procedures for safe, optimized operations at wind plants.*

DELIVERABLE: Regular updates to the American Wind Energy Association O&M Recommended Practices document and other industry-wide documents.

IMPACT: Consistency and improvement of O&M practices and transferability of worker skills.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 4.4.1: Collaborate with trade organizations and other agencies to improve workplace safety and practices. Coordinate with agencies that can help ensure worker safety practices are disseminated and adopted across the industry.	Maintained and sustained collaboration with the Occupational Safety and Health Administration to expand safety awareness and training for wind technicians, and to educate Occupational Safety and Health Administration employees on wind industry safety practices and standards.	Continuous improvement in workplace safety performance and the safety reputation of the industry.	2014	2030
ACTION 4.4.2: Identify and adopt O&M practices that reduce disruption to wind plant neighboring communities and wildlife. Conduct related research on wind plant interactions with the local environment and communities.	Research on operational practices that minimize disruption to wildlife, neighboring communities, and other local concerns.	Wind power in operation as a good neighbor in local communities.	2014	2030

ACTION 4.4.1: Collaborate with trade organizations and other agencies to improve workplace safety and practices.

Wind plants are interesting workplace environments that pose an array of unique conditions for workers, including high voltage work, extreme weather conditions, and working at heights. Given these conditions, adherence to best practices in worker safety is of paramount importance. Continued collaboration with agencies, such as the Occupational Safety and Health Administration and coordination administered by trade organizations like the American Wind Energy Association, can ensure that worker safety practices are disseminated and adopted across the industry, which helps protect the safety of the workforce and the reputation of the industry overall.

ACTION 4.4.2: Identify and adopt O&M practices that reduce disruption to wind plant neighboring communities and wildlife.

After siting and permitting approvals are complete, it is the owner/operator who interacts with the neighboring community for the next 20-plus years of plant operation. Research on wind plant interaction with wildlife, and impact on public health and local communities should continue. The findings of this research must be continually considered for incorporation into existing O&M practices. Adopting such practices can improve local acceptance of wind power plants and reduce negative impact on wildlife and neighboring areas.

ACTION 4.5: Develop Aftermarket Technology Upgrades and Best Practices for Repowering and Decommissioning. *Develop aftermarket upgrades to existing wind plants and establish a body of knowledge and research on best practices for wind plant repowering and decommissioning.*				
DELIVERABLE: Aftermarket hardware and software upgrades to improve operational reliability and energy capture, along with reports and analyses on wind repowering and decommissioning. **IMPACT:** Increased energy production and improved decision-making for aging wind plant assets, including repowering, to avoid greenfield development costs. **KEY THEMES:** Reduce Wind Costs **MARKETS ADDRESSED:** Land				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 4.5.1: Create component retrofits and upgrades that enable improved performance and/or reliability. Conduct third-party research to validate for improved performance and reliability.	Third-party research and publications analyzing performance and cost-effectiveness of component upgrades.	Increased energy production and reliability through improved componentry.	2014	2030
ACTION 4.5.2: Create a body of knowledge on wind plant repowering and decommissioning practices. Research and publish information on repowering, decommissioning, and service life extension.	Analytical tools that support comparing the costs and benefits of repowering, retiring, or continuing to operate a wind plant.	Optimized production of current and future wind plants.	2014	2030

ACTION 4.5.1: Create component retrofits and upgrades that enable improved performance and/or reliability.

An array of aftermarket upgrades is available for wind plant owners and operators today. Options range from software control updates to Lidar-based devices that collect more advanced wind speed measurement and directional data. These upgrades all have the potential to increase the energy production of existing wind plant assets and improve reliability. There is insufficient information, however, to validate the performance and value provided by many of these aftermarket upgrades. Research should be conducted by neutral third parties to provide trusted information on the performance and cost-effectiveness of various aftermarket upgrades. This information can then be used to validate whether retrofits and upgrades will improve performance and reliability.

ACTION 4.5.2: Create a body of knowledge on wind plant repowering and decommissioning practices.

The majority of the U.S. fleet of wind turbines was installed after 2005, with a few exceptions of older turbines from the 1980s in California and Hawaii. As these turbines approach the end of their useful life (generally around 20 years), owners and operators will face the decision of whether to retire the equipment, repower the site with new turbines, or extend the operating life of the existing turbines. There is currently limited cost–benefit analysis for these investment decisions or best practices in plant repowering and decommissioning in general. Research and publications on the costs and techniques used for plant decommissioning, plant repowering, and turbine service life extension will be important to establish a body of knowledge on the subject that supports cost-effective, environmentally-sensitive decisions for wind plant owners and operators.

M.5 Wind Electricity Delivery and Integration

ACTION 5.1: Encourage Sufficient Transmission. *Collaborate with the electric power sector to encourage sufficient transmission to deliver potentially remote generation to electricity consumers and provide for economically efficient operation of the bulk power system over broad geographic and electrical regions.*

DELIVERABLE: Studies, methodologies, and validated tools that inform cost-effective, reliable electricity delivery from wind power and all other generation types.

IMPACT: Increased transmission, reduced electricity costs, and increased wind generation with less curtailment.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 5.1.1: Conduct cost-benefit analysis. Perform cost and benefit analysis of new transmission designs to determine whether a given design is promising, and whether alternating-current-only or alternating current/direct current hybrid options make sense.	Cost-benefit analyses of candidate transmission additions with appropriate recommendations on subsequent action.	Increased development of cost-effective transmission, resulting in increased ability to integrate renewable generation.	2014	2030
ACTION 5.1.2: Analyze system dynamics. Develop methods to analyze system dynamics, including voltage and frequency performance, synthetic inertia and system stability, and determine the technical and economic basis for utilization of advanced wind power control schemes.	A full range of analytic models, market structure options, and best practices showing how the characteristics and capabilities of advanced solid-state-coupled renewable resources interact with conventional generators and automatic generation control, and how the new control capabilities of the renewable resources can best be used.	Integration of high penetrations of renewable generation at minimal cost, while maintaining power system reliability.	2015	2040
ACTION 5.1.3: Reduce jurisdictional barriers. Develop an institutional framework to reduce barriers to transmission across multiple jurisdictions when there is a net benefit to society.	An institutional framework allowing for effective multi-state transmission development that benefits society.	Relief of bottlenecks in developing the transmission needed for reliable power system operation and for integrating large amounts of wind power.	2015	2025

ACTION 5.1: Encourage Sufficient Transmission. *Collaborate with the electric power sector to encourage sufficient transmission to deliver potentially remote generation to electricity consumers and provide for economically efficient operation of the bulk power system over broad geographic and electrical regions. (cont.)*				
ACTION 5.1.4: Develop and build systems to aggregate power from multiple offshore projects. Propose strategies to aggregate multiple projects onto common interconnects.	An efficient method for delivering power from large-scale offshore wind plants to coastal grid interconnects.	Reduced capital requirements and environmental impacts; more orderly delivery of power to coastal grids, resulting in reduced offshore wind costs.	2020	2050

ACTION 5.1.1: Conduct cost-benefit analysis.

Analysis is needed to determine whether new transmission technologies and network designs will increase reliability, allow more wind generation to be delivered to load, and be cost-effective. Cost-benefit analysis of new transmission designs is needed to determine whether a given design is promising, and whether alternating-current-only or alternating current/direct current hybrid options make sense. Studies to develop alternative transmission network designs that balance a range of technical, economic, and regulatory issues will promote the economic development of wind generation. Study results will inform stakeholders about alternative transmission network designs and provide the foundation for building new transmission.

ACTION 5.1.2: Analyze system dynamics.

New analytical methods are required to accurately represent the characteristics and capabilities of advanced solid-state-coupled wind, solar, and storage devices. These methods will provide the ability to properly analyze the power system to ensure reliability, while minimizing costs and fully exploiting control capabilities of advanced devices. Once models are available for relevant devices and components, it will be possible to develop methodologies and best practices to use the advanced control capabilities offered by solid-state-coupled wind, solar, and storage devices to enhance power system reliability and mitigate any identified adverse conditions. This will both increase power system reliability and enable the economic integration of larger amounts of wind generation. Areas of particular interest include system dynamics, synthetic inertia, and system stability.

ACTION 5.1.3: Reduce jurisdictional barriers.

Long transmission lines that cross multiple-state jurisdictional boundaries can be particularly difficult to site. A framework that identifies and quantifies benefits for all participants can help facilitate acceptance. Developing an institutional framework that allows for the development of economically justified multi-state transmission will help relieve bottlenecks and reliably integrate larger amounts of wind generation.

ACTION 5.1.4: Develop and build systems to aggregate power from multiple offshore projects.

Under the *Wind Vision Study Scenario*, several gigawatts of offshore wind projects will be deployed by 2050. If each project is required to provide a radial transmission line and separate interconnect, competing use conflicts may arise, likely resulting in higher costs for offshore wind. Proposed strategies to aggregate multiple projects onto common interconnects would result in lower costs and a more orderly delivery of power to coastal communities. Regulators and utilities can work with offshore wind developers to seek the most efficient and reliable solutions.

ACTION 5.2: Increase Flexible Resource Supply. *Collaborate with the electric power sector to promote increased flexibility from all resources including conventional generation, demand response, wind and solar generation, and storage.*

DELIVERABLE: Analysis of flexibility requirements and capabilities of various resources. Frequent assessments of supply curve for flexibility. Implementation of cost-effective rules and technologies.

IMPACT: Reduced wind integration costs, reduced wind curtailment, improved power system efficiency and reliability.

KEY THEMES: Reduce Wind Costs, Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 5.2.1: Increase industry understanding. Increase understanding of integrating wind power into the power system so flexibility needs can be understood.	Government and industry involvement in workshops and related activities to deliver the results of analysis and modeling.	Understanding among the power system industry of wind integration impacts and means to address challenges. Understanding among regulators of integration impacts and challenges.	2014	2025
ACTION 5.2.2: Develop flexibility methods and models. Develop methods, models, metrics, and targets for assessing flexibility needs.	Methods, models, metrics, and targets that can be used to assess the need for, and supply of, flexibility.	Availability of tools and approaches to quantify flexibility needs to help accommodate high levels of wind generation on the bulk power system.	2015	2025
ACTION 5.2.3: Develop flexibility supply curves. Develop and update flexibility supply curve data so that cost-effective solutions can be identified.	Periodic and regular assessments of the current suite of technologies that can provide flexibility to the power system, including the associated costs. Regular assessment, e.g., every two to three years, will ensure that new technologies and costs are included in the analysis.	Relevant information provided to the power system industry and regulators regarding the potential sources and costs of flexibility—both in generation and demand response; identification and adoption of cost-effective flexibility solutions in the bulk power system.	2015	2050
ACTION 5.2.4: Increase demand response. Develop inventory of potential demand response resources organized by equipment type, aggregate resource size, resource capability, and location.	Increased use of demand response as a flexible resource to help maintain system balance.	Additional source of flexibility that can help cost-effectively maintain system balance with high levels of wind energy.	2015	2050

ACTION 5.2: Increase Flexible Resource Supply. *Collaborate with the electric power sector to promote increased flexibility from all resources including conventional generation, demand response, wind and solar generation, and storage. (cont.)*				
ACTION 5.2.5: Analyze new market designs. Analyze the effect of new, innovative market designs, such as performance-based rates for frequency regulation per Federal Energy Regulatory Commission Orders 755 and 784, and the role of scarcity pricing and its intersection with capacity markets.	Operating and market rules that do not hinder access to the existing physical flexibility. (Without this, physical flexibility can be stranded and unavailable to the power system operator.)	Increased effectiveness of physical resources to provide needed flexibility.	2015	2050
ACTION 5.2.6: Evaluate direct and indirect economic benefits of offshore wind. Evaluate all direct and indirect economic benefits of offshore wind, including savings to ratepayers from peak-coincident, price-suppression impacts.	Studies of the direct and indirect economic benefits of offshore wind, including savings to ratepayers from peak-coincident, price-suppression impacts in various coastal transmission systems.	Educated public and decision-makers, including appellate courts, with regard to the economic value of offshore wind; facilitated approval of power purchase contracts.	2014	2050

ACTION 5.2.1: Increase industry understanding.

Power system engineers evaluate reliability requirements based on the capabilities and limitations of conventional generators. Assistance is required to understand that the increased flexibility offered by both existing and advanced technologies can be utilized to increase reliability, decrease costs, and facilitate greater wind generation penetration. Advanced generation provides increased flexibility, faster and more accurate ramping, lower minimum loads, and increased cycling capability. Demand response and storage can provide a response that is faster than the conventional generation governor response. Industry understanding of new capabilities is required before these resources will gain acceptance. Activities such as DOE and industry workshops are useful for delivering the results of analysis and modeling.

ACTION 5.2.2: Develop flexibility methods and models.

Technology-neutral metrics are required to quantify specific reliability requirements so that new technologies can be utilized in place of and alongside conventional technologies. Modeling and simulation are required to determine the needed metrics. Developing industry-accepted tools will facilitate power system planners and operators in accommodating high levels of wind generation on the bulk power system through greater deployment of advanced, flexible resources.

ACTION 5.2.3: Develop flexibility supply curves.

The full suite of flexible resources cannot be utilized unless system operators are aware of the available resource pool and its capabilities to provide each type of reliability response. Flexibility supply curves should initially be developed by researchers and then transferred to utilities. Regular updates will enable the identification and implementation of cost-effective solutions.

ACTION 5.2.4: Increase demand response.

Demand response is increasingly shown to be capable of providing the full range of reliability response from cycles to hours. Advantages of this approach for wind generation include reducing the need for conventional generation, generation minimum loads, and wind curtailment, all while enabling greater wind penetration, maintaining reliability, and lowering power system costs. Developing an inventory of potential demand response resources (industrial, commercial, and residential) organized by equipment type, aggregate resource size, resource capability, and location will help speed full utilization. Improved communications, monitoring and control can reduce the cost of demand response implementation. Greater understanding of demand response capabilities will expand the range of demand response services that power system operators actively access.

ACTION 5.2.5: Analyze new market designs.

Operating and market rules need to be examined and perhaps revised so that they do not inadvertently hinder access to the physical flexibility that is potentially available from demand response and other flexibility resources. Appropriate market incentives can motivate demand response while reducing power system and wind integration costs. Specific examples include performance-based rates for frequency regulation per Federal Energy Regulatory Commission Orders 755 and 784, the role of scarcity pricing, and the intersections with capacity markets. Revenue adequacy for conventional generation should also be addressed.

ACTION 5.2.6: Evaluate direct and indirect economic benefits of offshore wind.

The current levelized cost of offshore wind does not reflect all direct and indirect economic factors that may impact the cost to ratepayers. Methods of land-based grid integration and forecasting need to be extended to offshore grid systems and include unique attributes of offshore wind, such as locational-marginal-price benefits, capacity value (in general and during peak demand), grid congestion, and the aggregation of multiple wind power facilities into common shore-based interconnects.

Research indicates that offshore wind tends to be more consistent during periods of peak summer electricity demand along the East Coast [11]. Power from offshore turbines with low fuel cost would be dispatched first, offsetting the cost of more expensive peak generators. One study estimated that the savings to New England ratepayers over the proposed 25 years of operation of the Cape Wind project off Cape Cod, Massachusetts, could total more than $7 billion [12,13]. This analysis was acknowledged in approvals of the Cape Wind power purchase contract by the Massachusetts Public Utility Commission and the state Supreme Court [14].

ACTION 5.3: Encourage Cost-Effective Power System Operation with High Wind Penetration. *Collaborate with the electric power sector to encourage operating practices and market structures that increase cost-effectiveness of power system operation with high levels of wind power.*

DELIVERABLE: Coordination of wind integration studies at the state and federal levels and promulgation of practical findings, especially to entities with less wind integration experience.

IMPACT: Increased wind integration levels, appropriate amounts of operating reserves, reduced curtailment, and lower integration costs.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 5.3.1: Improve market and reliability rules. Identify and eliminate inappropriate limitations on flexibility embedded in current market and reliability rules.	Alternative standards and rules to mitigate inappropriate limitations on wind generators and advanced technologies providing reliability services.	Reduced barriers for new technologies to supply energy and ancillary services; elimination of inappropriate limitations on new technology market entry.	2015	2030
ACTION 5.3.2: Improve understanding of wind integration issues. Increase industry understanding of wind power system integration and develop appropriate operating practices and market rules, while ensuring rules are technologically neutral.	Enhanced understanding of how to economically maintain power system reliability while accommodating increasing amounts of wind generation.	Scientific background necessary to help promulgate operating practices like sub-hourly energy scheduling and balancing over larger areas; potential to dramatically reduce wind integration costs.	2015	2025

ACTION 5.3.1: Improve market and reliability rules.

Market and reliability rules, including North American Electric Reliability Corporation standards, were developed based on the characteristics and limitations of conventional generators. The capabilities and limitations of technologies such as wind, solar, demand response, and storage were not considered because these technologies were not significant participants when the rules were developed. Forcing such technologies to emulate existing technologies simply to conform to historical rules is inefficient. Identifying and eliminating inappropriate limitations on flexibility embedded in current market and reliability rules will facilitate increased penetration of wind power while increasing power system reliability. Costs will also be reduced as the full capabilities of new technologies are exploited.

ACTION 5.3.2: Improve understanding of wind integration issues.

Power system planners and operators require assistance in understanding the impact increased wind generation will have on their systems. Some systems have little or no wind capacity, and therefore offer little or no experience about operating a power system with wind generation. Systems with significant amounts of wind do offer experience, but cannot offer certainty about higher penetrations. Assistance is required to help power system planners and operators convert research results concerning higher penetrations of wind generation into best operating practices. Topics of interest include sub-hourly energy scheduling and balancing, larger balancing areas, and utilizing the response and control capabilities offered by solid-state-coupled devices like advanced wind turbines, solar PV, storage, and advanced demand response.

ACTION 5.4: Provide Advanced Controls for Grid Integration. *Optimize wind power plant equipment and control strategies to facilitate integration into the electric power system, and provide balancing services such as regulation and voltage control.*

DELIVERABLE: Advanced wind turbine and wind plant controls that can be used to provide voltage support, regulation, synthetic inertial response, and frequency regulation by wind plants. Bulk power market designs and/or tariffs are necessary to pay for these services.

IMPACT: Allows power system operator access to additional flexibility from wind plants, when it is economical or necessary for reliability. This will reduce cost and increase reliability.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 5.4.1: Develop advanced active power controls. Encourage incentives for use of advanced turbine and plant control technologies and strategies.	Optimized wind turbine and plant control strategies to facilitate reliable, coordinated bulk power system operations and planning. Action 5.3.1 is a companion action because it provides market signals for the services needed for reliability and economic operation.	Increased wind generation through less curtailment, increased power system reliability, and lower operating costs.	2014	2030

Action 5.4.1 Develop advanced active power controls.

The latest generation of wind turbines has increasingly adopted advanced controls that allow the wind turbine to respond to control signals. Wind turbines can often respond to automatic generation control, frequency response via appropriate droop settings, system disturbances using synthetic inertial response, and even economic dispatch signals. These abilities are not routinely provided because of the lack of market signals, which means there is no incentive to provide these services. In addition, these controls will evolve from turbine-level to wind plant-level, allowing for more economic and reliable operation. The evolution of these controls must be matched by the evolution of bulk system market design.

ACTION 5.6: Improve Distributed Wind Grid Integration. *Improve grid integration of and increase utility confidence in distributed wind systems.*

DELIVERABLE: Modeling tools and information that utilities can use to evaluate integration of distributed wind into distribution systems.

IMPACT: Improved distributed wind power integration and delivery into distribution systems and increased utility confidence in this integration.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 5.6.1: Develop distributed system modeling tools. Collaborate with the Utility Variable-Generation Integration Group and similar organizations, such as those supporting smart grid initiatives, to update distributed system modeling tools.	New modeling tools that include all types of distributed generation and advanced grid support capabilities.	Improved wind power integration and delivery in distribution systems.	2014	2020
ACTION 5.6.2: Improve communication and control capabilities. Increase grid support capability (low-voltage ride-through and line-fault ride-through functions), including communications and control.	A new edition of Institute of Electrical and Electronics Engineers (IEEE) 1547. Updated distribution system modeling tools.	Improved wind power integration and delivery into distribution systems.	2014	2020
ACTION 5.6.3: Inform utilities of integration possibilities. Educate utilities on the technical characteristics, limitations, and benefits of integrating increased levels of variable generation from distributed wind systems.	Information and outreach to electric utilities on characteristics, limitations and benefits of distributed wind systems.	Improved collaboration and engagement.	2014	2020

ACTION 5.6.1: Develop distributed system modeling tools.

Increased collaboration by the distributed wind community with industry stakeholder groups, such as the Utility Variable-Generation Integration Group, smart grid organizations, and those supporting smart grid initiatives, will increase the exchange of ideas on advanced distributed system modeling. Working with these organizations, as well as supporting research on distributed system modeling and analysis, could allow the distributed wind community to facilitate lower cost, streamlined distributed generation models leading to optimized planning. Reducing costs and increasing confidence in distributed wind integration through better distribution system modeling tools, informed utilities, and standards development will improve distributed wind deployment.

ACTION 5.6.2: Improve communication and control capabilities.

As distributed energy's share in the nation's generation mix increases, the need for improved communication and control capabilities becomes more evident. Specific standards covering grid support capability, including low-voltage or low-frequency ride-through functions, as well as communications and control for interconnecting distributed resources with electric power systems [15], would support a wider application of wind power. Developing a new revision of IEEE 1547 is important for establishing a framework for distributed generation that supports the grid and allows improved wind power integration and delivery into distribution systems.

ACTION 5.6.3: Inform utilities of integration possibilities.

Utilities are a key partner for wider use of wind power in the United States. Utilities, however, are often unaware of the latest technologies supporting the integration of distributed wind. A dedicated outreach effort aiming to inform utilities of the integration possibilities and educating them on the technical characteristics, limitations, and benefits of increased levels of variable generation from distributed wind systems will allow them to make more educated decisions about strategies and business plans for renewable energy.

M.6 Wind Siting and Permitting

ACTION 6.1: Develop Mitigation Options for Competing Human Use Concerns. *Develop impact reduction and mitigation options for competing human use concerns, such as radar, aviation, and maritime shipping and navigation.*

DELIVERABLE: A better understanding of the impacts of wind development and appropriate mitigation options leading to streamlined site assessment and trusted hardware and software technology solutions that address the most pressing competing use conflicts.

IMPACT: Decreased impact of all wind technologies allowing project developers to site wind projects while limiting competing public use impacts.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 6.1.1: Develop better understanding of wind turbine and radar interactions. Conduct research to understand and mitigate wind turbine impact on existing radar systems.	A strong understanding of the impact of wind turbines on existing radar systems and communally accepted mitigation strategies for these limitations.	Consensus understanding of radar/wind turbine interactions and a known course of action to address the problems associated with them.	2014	2020
ACTION 6.1.2: Reduce potential wind turbine and radar interaction. Implement approved minimization and mitigation strategies for radar systems with high impact on current or expected wind development.	To the extent possible, replacement of all outdated radar systems that are having the highest impact on current and potential near-term wind development.	Minimization of wind-radar impacts; continued wind development with minimal radar performance impacts.	2015	2025
ACTION 6.1.3: Address issues of aircraft safety and public perception. Test and demonstrate improved lighting and aircraft avoidance systems to ensure safe compliance with the Federal Aviation Administration 500-foot height requirement.	Technology, regulation, and systems that address wind turbine height concerns over most of the nation.	Confidence for developers and manufacturers to install the most cost-effective technology available without fear of uncertain regulatory processes.	2014	2020

ACTION 6.1: Develop Mitigation Options for Competing Human Use Concerns. *Develop impact reduction and mitigation options for competing human use concerns, such as radar, aviation, and maritime shipping and navigation. (cont.)*				
ACTION 6.1.4: Alter existing or design new shipping routes. Develop transportation and shipping routes consistent with offshore wind power to optimize the safe coexistence of offshore wind and maritime commerce.	A study that recommends appropriate adjustments to existing shipping lanes or new routes to minimize interference with proposed Wind Energy Areas.	Increased number of viable sites for offshore wind development.	2014	2050

ACTION 6.1.1: Develop better understanding of wind turbine and radar interactions.

Wind turbine interactions with aircraft and weather radar systems have been a safety and security concern for several years and have been a driving concern for developers of new wind facilities in the United States and abroad. Progress has been made to develop and streamline a process to determine if a proposed wind project is likely to impact existing radar systems. Accommodating future wind power growth in the United States, however, will require an expanded understanding of radar/wind turbine interaction. This understanding will lead to new technologies to minimize and mitigate interference impacts. Although studies are underway and software tools are being developed to mitigate current concerns, more information is needed on the exact nature of the impact of different wind technologies, radar systems, and operational conditions.

An example of recent progress is the work of the third Interagency Field Test and Evaluation of Wind Turbine-Radar conducted by the Federal Aviation Administration, DOE, the U.S. Department of Defense and other U.S. government agencies. This study completed operational field tests to better understand the physical and electromagnetic interference between radar systems and wind plants. Data from these tests will be used to help assess near-term mitigation options and develop long-term mitigation techniques. If deployment levels approach those outlined in the *Wind Vision Study Scenario*, additional expanded work to understand longer-term wind turbine and radar impacts will be needed.

ACTION 6.1.2: Reduce potential wind turbine and radar interaction.

A number of approaches are being considered to mitigate the impact of wind plants on radar. The first is careful upfront planning and siting of wind plants so that little or no interference is caused to nearby radars. This approach is being used by regulating authorities working with wind plant developers. This technique takes time because it often requires lengthy and iterative applications for study, which focus results on a simple pass/fail analysis. Another approach is to upgrade the affected radars or introduce new filtering and advanced processing tools to sort wind turbine clutter from actual aircraft. These radar upgrades, however, are still unable to completely resolve the interference issues, partly because of the complexity of the interaction.

Another approach is to reduce the scattering from the turbine. This can be done by applying radar cross-section minimization techniques, such as shaping, and radar-absorbing materials to the wind turbine. Yet another promising approach is to deploy specialized, high-resolution Doppler "fill in" radars that just cover the wind plant in question. These are being developed with the intention of differentiating aircraft or other targets from the wind plant itself. Other techniques, including multi-static radar, have also been suggested.

ACTION 6.1.3: Address issues of aircraft safety and public perception.

The expanded wind deployment examined in the *Wind Vision Study Scenario* must take into account the safety of commercial and recreational aviation. Excessive aircraft safety requirements on wind, however, will either eliminate locations that could support wind development or add to the overall cost of power produced by wind plants.

Support for expanded wind development will require a combination of technology approaches, permitting support, the development of tools and systems to ensure there is no adverse impact, and education for people and organizations in both the wind and aviation industries. Addressing aviation safety and public perception, along with wind and radar system interference issues (Actions 6.1.1 and 6.1.2), will provide improved wind turbine siting information and avoidance technology. The goals are to ensure and improve aircraft safety. It is essential that the wind and aviation industries take a collaborative, proactive and consultative approach to addressing ongoing and newly identified issues.

ACTION 6.1.4: Alter existing or design new shipping routes.

Shipping lanes exist along the entire length of the U.S. seacoast, affecting all potential wind energy areas in the Atlantic, Pacific, Great Lakes, and Gulf of Mexico. For example, competition with existing shipping lanes reduced the initial Maryland Wind Call Area from a potential of 30 lease blocks to nine lease blocks because there was no clear process for assessing impacts of wind development. The U.S. Coast Guard oversees a study of all shipping lanes, known as the Atlantic Coast Port Access Route Study,[6] to evaluate current and future shipping needs. Maritime commerce and safety are national priorities. Strategies to accommodate shipping needs will contribute to expanded offshore wind development.

6 *http://www.uscg.mil/lantarea/acpars/*

ACTION 6.2: Develop Strategies to Mitigate and Minimize Siting and Environmental Impacts. *Develop and disseminate relevant information as well as minimization and mitigation strategies to reduce the environmental impacts of wind plants, including impacts on wildlife.*

DELIVERABLE: Accurate information and peer-reviewed studies on actual environmental impacts of wind power deployment, including on wildlife and wildlife habitat.

IMPACT: Decreased environmental impact by all wind technologies, improved understanding of the relative impact of wind development, defined methodologies to assess potential impacts and risks, and shorter and less expensive project deployment timelines.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 6.2.1: Improve understanding of wildlife and habitat impacts. Develop and disseminate relevant information on wildlife and habitat impacts, including cumulative impacts in relation to other activities within the ecosystem.	Information and peer-reviewed studies on the actual wildlife and habitat impacts of wind power deployment in relation to other energy production, which can be used and shared through a variety of platforms.	Improved understanding of the relative impact of wind development; shorter and less expensive project deployment timelines.	2014	2050
ACTION 6.2.2: Develop strategies to reduce wildlife impacts. Develop, test and conduct research on strategies to mitigate, avoid, minimize, or compensate for impacts to wildlife.	Proven technologies and strategies that will reduce wind power impacts on wildlife.	Decreased wildlife impact by all wind technologies; shorter and less expensive project deployment timelines.	2014	2050
ACTION 6.2.3: Develop a funding pool for wildlife research. Implement a shared funding pool from industry, government, and other interested parties to fund wildlife research administered by an independent third party with appropriate oversight.	Fact-based research, mitigation practices, and independent analysis on key wildlife impacts.	Expansion of industry- and government-based research that is credible and independent of undue influence from interested parties.	2014	2050
ACTION 6.2.4: Perform strategic assessment of offshore wind. Conduct strategic environmental assessments to inform siting and add to the knowledge base for future permitting of offshore wind projects.	Assessments that provide baseline environmental data for offshore wind needed by federal and state governments to inform siting, permitting, and marine spatial planning efforts.	Increased knowledge of which marine resources may be at risk in certain locations; reduced permitting timelines and risk for projects.	2014	2030
ACTION 6.2.5: Continue monitoring environmental impacts. Continual monitoring of environmental and wildlife impacts to assess changes and their potential impacts.	Periodic updates of known environmental impacts, targeting market and impact assessments.	Improved understanding of known impacts, as well as their evolution over time due to changes in technology, markets and affected species.	2014	2050

ACTION 6.2.1: Improve understanding of wildlife and habitat impacts.

As wind development has expanded, more information is available on the environmental impacts of wind deployment. Significant gaps exist, however, in the industry's understanding of potential impacts. Regulators and local decision-makers often cite a lack of scientifically credible information as an issue. The cumulative impacts of wind development on particular species need to be understood and made available. In some cases, this information is available but not easily accessible; in other cases, a great deal of data may have been collected for a specific wind facility but is not publicly available. Where information about impacts exists, it will take effort to convert that information into a form identified stakeholders can use. It will also require effort to ensure that data can be used more broadly to conduct regional- or national-scale impact assessments. Engagement at multiple levels will be needed to respond to the expanding wind industry and changes in potentially impacted species.

Some potential environmental impacts of wind development have been studied, but either the results are not publicly documented or they are site-specific. As discussed in Chapter 2, broad wildlife and habitat impacts have been identified, but only limited public, peer-reviewed documentation of the actual impacts is available. Understanding the potential impact of wind deployment will reduce development risk for land-based wind, and for offshore and distributed wind. Such impact assessments are most effective when provided by a trusted, third-party source. Without active industry engagement on this topic, public and regulatory pressures will likely increase as deployment moves toward new areas or areas with known environmental issues.

ACTION 6.2.2: Develop strategies to reduce wildlife impacts.

Even appropriately sited wind development can have negative impacts on local wildlife, primarily avian and bat species. Although significant work has been done to develop avoidance, minimization and mitigation strategies for certain wildlife impacts, continued and expanded efforts are needed to allow substantial expansion of wind deployment. Most efforts have aimed at avoiding potential impacts on a site-specific basis. The industry is also funding tools that could be applied either at a specific wind project or at other locations. With programs such as lead shot abatement or electrical pole retrofits, potential impacts can be offset. Each minimization and mitigation option must undergo rigorous long-term assessment, testing and validation before it can be considered acceptable by regulatory organizations—a time-intensive and costly process.

As technology and the status of species change and deployment expands into new areas with different environmental sensitivities, additional strategies will need to be developed, tested and implemented.

ACTION 6.2.3: Develop a funding pool for wildlife research.

Wind industry research on the environmental impacts of development focuses on specific areas or species and may not be widely coordinated with other research activities or openly accessible to potential stakeholders. An expanded degree of credibility and broader access to data resources could be provided by organizations independent of direct influence by any specific sector of the industry (i.e., turbine manufacturers, development companies, federal agencies, and state agencies). Such organizations could gather existing research, and identify and address potential wildlife and habitat impacts. These organizations could create impartial organizational structures, set up and implement credible independent screening and peer review processes, address issues that may be difficult for specific industry sectors, and further expand the credibility of results. The organizations would require a long-term funding base that would cover organizational costs and support a robust research agenda. Such a research agenda would likely be carried out by a small internal staff and trusted external contractors. The implementation of this concept as a public and private partnership would strengthen the credibility of any results and provide a process for expanded collaboration on domestic public impact research.

ACTION 6.2.4: Perform strategic assessment of offshore wind.

The permitting and leasing processes for offshore wind are tied to understanding the potential environmental impact, primarily through National Environmental Policy Act (NEPA) compliance and assessment of environmental effects of installations. On the Outer Continental Shelf, the Bureau of Ocean Energy Management—in consultation with resource agencies—determines the level of NEPA documentation needed in accordance with the current state of knowledge and thresholds of proposed impacts and benefits.

NEPA requires an "appropriate" level of environmental review for various activities. The Bureau of Ocean Energy Management has interpreted this to mean an Environmental Impact Statement or an Environmental Assessment for Site Assessment Plans or Construction and Operation Plans (30 CFR 585.14[c], 585.613[b], 585.628[b]). The Bureau of Ocean Energy Management explained "appropriate" NEPA review when issuing its Final Rule: "ensure that environmental analysis for [Outer Continental Shelf] renewable energy proposals is proportional to the scope and scale of each proposal, is effectively tiered to programmatic NEPA documents, and efficiently incorporates other publicly available information by reference ... ensure that mitigation and monitoring information informs future decision-making processes."[7]

The lack of information about specific issues related to the marine environment and coastal communities has slowed the NEPA process. As new environmental studies and environmental assessments are completed, the results could be incorporated in future NEPA reviews. For example, the Bureau of Ocean Energy Management Environmental Assessment and Finding of, "No Significant Impacts for Site Assessment Activities in the Mid-Atlantic Wind Energy Areas" concluded that any future site assessment activities consistent with those studied in this environmental assessment would not require future NEPA reviews before implementation. As more NEPA reviews are conducted and experience is gained with new offshore technologies, it will become appropriate to execute less comprehensive NEPA reviews under the NEPA statute. This will expedite the permitting process.

So far, much of the cost for filling gaps in knowledge has been borne by offshore wind project developers, which has slowed offshore wind development. Peer-reviewed, publicly available environmental studies are needed to assist in building the knowledge base and closing information gaps.

ACTION 6.2.5: Continue monitoring environmental impacts.

The national wind market has changed rapidly in the decade leading up to 2014, from both technology and deployment standpoints. Continued evolution is likely if the deployment levels of the *Wind Vision Study Scenario* are implemented. Changes in understanding or regulation of the impacts of the U.S. energy system on all wildlife species will also affect perception of any potential impact, changing whether mitigation measures are more or less necessary. As part of this ongoing development, understood impacts will change and new impacts will be identified. Ongoing assessments of existing and potentially new environmental impacts will need to be implemented to ensure that informational outreach and research activities target concerns identified by key deployment stakeholders.

7 Bureau of Ocean Energy Management Final Rule, 74 Federal Register 19643, April 29, 2009.

ACTION 6.3: Develop Information and Strategies to Mitigate the Local Impact of Wind Deployment and Operation. *Continue to develop and disseminate accurate information to the public on local impacts of wind power deployment and operations.*				
DELIVERABLE: Accurate information and peer-reviewed studies on the impacts of wind power deployment that can be used and shared through a variety of platforms. **IMPACT:** Decreased impact by all wind technologies, defined methodologies to assess potential impact, and shorter and less expensive project deployment timelines. **KEY THEMES:** Expand Developable Areas **MARKETS ADDRESSED:** Land, Offshore, Distributed				
ACTION	**DELIVERABLE**	**IMPACT**	**BEGIN**	**END**
ACTION 6.3.1: Document and disseminate public information on public impact. Develop and disseminate relevant information to the public on impacts, including economic impacts, and the social and economic value of power system externalities.	Information and peer-reviewed studies on the actual impact of wind power deployment that can be used and shared through a variety of platforms to inform the public.	Improved understanding of the relative impact of wind development; shorter and less expensive project deployment timelines.	2014	2025
ACTION 6.3.2: Develop mitigation strategies. Devise, test, and research strategies to mitigate (avoid, minimize, or compensate for) public impact.	Proven technologies and strategies that will reduce the impact of wind power on local populations.	Decreased impact by all wind technologies.	2014	2025
ACTION 6.3.3: Establish a funding pool for public impact research. Implement a shared funding pool from industry, government, and other interested parties to fund public impact research administered by an independent third party with appropriate oversight.	Fact-based research, mitigation practices, and independent analyses on key public impacts.	Expansion of industry- and government-based research that is credible and independent of influence from interested parties.	2014	2050
ACTION 6.3.4: Continue monitoring public Impact. Execute ongoing monitoring of public impact to assess changes in social understanding and comprehend the potential impacts of that change.	Periodic updates of known public impacts targeting market, public perceptions, and impact assessments.	Improved understanding of known impacts, as well as their evolution over time due to changes in technology, markets and public perception.	2014	2050

ACTION 6.3.1: Document and disseminate public information on public impact.

As wind development expands, more information is becoming available on the local community impacts of wind deployment. However, there are gaps in the level of understanding of potential impacts. The general public and local decision makers often cite a lack of scientifically credible information as an issue. In some cases, this information is available but not readily accessible; in others, the information is not conclusive. Where information does exist, it should be made readily available in a form that is understandable for identified stakeholders. Continued and increased engagement at multiple levels will be needed given the expanding nature of the industry. If wind development becomes commonplace in specific regions, a tipping point may occur and outreach efforts may no longer be needed.

Industry has identified a host of public impacts from wind power. Some research has been done to understand these impacts, but, in most cases, impacts have not been documented. As discussed in Chapter 2, public impacts such as turbine noise, economic development, economic value of power system externalities, and public safety have been identified for specific projects. However, minimal public, peer-reviewed documentation of the actual impacts is available. For example, longitudinal studies of the long-term community impacts of wind development have never been undertaken. Such an assessment would be helpful in understanding the impact of local wind development and useful to communities considering local development.

Full understanding of the potential impact of wind deployment at all levels is needed: land-based, offshore, and distributed. If provided by a trusted third-party source, this understanding will reduce development timelines, costs, and implied development risk. Active industry engagement is necessary to reduce public acceptance pressures, which will likely increase as deployment moves into new areas and closer to higher population areas.

ACTION 6.3.2: Develop mitigation strategies.

As noted previously, even appropriately sited wind development can have negative impacts from the perspectives of some stakeholders. As wind deployment expands into new areas closer to population centers, there is an increasing likelihood for negative impacts to be highlighted. With that in mind, the wind industry continues to fund tools that help identify potential negative impacts and support development of related minimization or mitigation options. Some of these mitigation strategies are technology-specific, while others could be developed and implemented more broadly. Even with industry efforts underway, a wider engagement is needed to address both current and potential future public impact issues.

ACTION 6.3.3: Establish a funding pool for public impact research.

The broader wind industry; including turbine manufacturers, development companies, federal agencies, state agencies, and trade associations; conducts research about the public impacts of wind power. Each organization and its research can be viewed differently by potential stakeholders. Although each sector of the wider industry will continue to fund research addressing its specific interests, research independent of direct influence from any sector of the industry would lend an increased degree of credibility to the results. Such research should be conducted by an organization(s) with a mission to identify and address potential negative public impact. This organization or organizations would be able to develop an impartial organizational structure, implement credible independent screening and peer review processes, and address issues that may be difficult for specific industry sectors. This effort would require a long-term funding base, which would not only cover organizational costs, but also support a robust research agenda that would likely be carried out by a small internal staff and trusted external contractors. This implementation as a public and private partnership would strengthen the credibility of any results and provide a process for expanded collaboration on domestic public impact research.

ACTION 6.3.4: Continue monitoring public impact.

The national wind market has changed rapidly in the decade leading up to 2014, from both technology and deployment standpoints. If the deployment levels discussed in the *Wind Vision Study Scenario* are successfully pursued, the rate of change in both technology and deployment practices will continue to develop and evolve. Changes in social understanding of wind development will also impact perception of any potential impact, changing whether mitigation measures are more or less necessary. As part of this ongoing development, known impacts will change and new impacts will be identified. Ongoing assessments of existing and potentially new public impacts will need to be implemented to ensure that informational outreach and research activities target concerns identified by key deployment stakeholders.

ACTION 6.4: Develop Clear and Consistent Regulatory Guidelines for Wind Development. *Streamline regulatory guidelines for responsible project development on federal, state and private lands, as well as in offshore areas.*

DELIVERABLE: Defined regulatory guidelines for the deployment of offshore, land-based and distributed wind turbines, developed in collaboration with the wind industry to provide comprehensible and geographically consistent regulations for the deployment of wind technologies.

IMPACT: Allows developers to clearly understand the processes to deploy wind technologies on federal, state, or private lands, thus reducing costs.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 6.4.1: Encourage regulatory process for wind development on federal lands. Encourage federal regulatory consistency for development on federal lands, including a defined pathway for both wind and transmission that is consistent, based on peer-reviewed science, and incorporates an appropriate evaluation of risk.	A clear and well defined permitting process for development on federal lands.	Reduced investment costs, shorter development times, and consistent development pathways.	2014	2020
ACTION 6.4.2: Create a model deployment framework. Development of a consensus-based, wind power deployment framework that summarizes best practices, defined studies, and standard development considerations and that can be used as a non-binding template for future development of offshore, land-based and distributed wind.	A model development framework for deployment of all wind technologies.	More consistent deployment with wider public acceptance of the process, lower costs, and shorter deployment timelines.	2014	2020
ACTION 6.4.3: Create a streamlined leasing and permitting process for offshore wind. Decrease the regulatory timeline and complexity for offshore wind, while maintaining a high level of safety for the public and environment, consistent with existing statutes.	A streamlined leasing and permitting process to eliminate redundant pathways. Demonstration of an efficient process through successful project deployments.	A more consistent and efficient regulatory framework; lower costs and shorter deployment timelines.	2014	2020
ACTION 6.4.4: Increase available sites to accommodate growth of offshore wind. Support the identification of offshore wind power development zones in state and federal waters, allowing timely build-out of offshore wind capacity to meet *Wind Vision Study Scenario* levels.	Additional Atlantic wind energy area designations; use of competitive leasing auctions to open additional sites, including those in deeper water, as well as the Pacific Ocean and Gulf of Mexico.	Increased number of available commercial sites to enable the expansion of offshore wind deployment across the United States.	2018	2030

ACTION 6.4: Develop Clear and Consistent Regulatory Guidelines for Wind Development. *Streamline regulatory guidelines for responsible project development on federal, state and private lands, as well as in offshore areas. (cont.)*				
ACTION 6.4.5: Implement a consistent, streamlined permitting process for distributed wind. Engage local and state governments in improving the permitting process and enacting certification requirements for distributed wind technologies.	Consistent state and local permitting, including certification requirements, for distributed wind technologies.	Expanded distributed wind deployment through streamlined siting and permitting approval processes; removal of artificial barriers to deployment.	2014	2020

ACTION 6.4.1: Encourage regulatory process for wind development on federal lands.

Investors and wind developers deploy capital and resources in areas with more certain returns or lower identified risks. Wind resources span public and private lands, but wind developers have traditionally invested in development on private land, where the regulatory process and cost for permits are understood. The wind industry has faced several challenges on public lands that have discouraged investors. Oil and gas leases have tended to get processed ahead of wind leases, and even permits for single meteorological towers have experienced lengthy processing times. Environmental assessment processes have been lengthy and inconsistently administered among the decentralized federal field offices.

Wind power development on U.S. public lands has significant potential, and policymakers have acknowledged this opportunity by prioritizing the development of renewable energy, including wind, on public trust lands. Development on private lands, however, has greatly outpaced development on public lands. Activities such as streamlining the process for meteorological tower permits and the overall regulatory approach toward wind power development on federal lands would create a more predictable process and open millions of acres of public land (usually in less-populated parts of the country) for wind power development. As with private land, measures such as those outlined in Action 6.2 would be used to minimize and mitigate environmental effects.

ACTION 6.4.2: Create a model deployment framework.

Conceptually, the process for developing wind projects is fairly well understood, and some elements of the process have been documented in best practice guides and handbooks. Still, the actual process for deploying distributed and land-based projects is not an entirely well-defined process, and the process for offshore wind deployment is even less defined. The lack of defined and consistent development frameworks results in widely different project development processes and different results. For this reason, there is no clear process to define what types of tests or considerations are important for wind deployment, such as noise or flicker analysis, community engagement steps, or guidelines on when to initiate dialog with different development stakeholders. Issues that are driven through defined regulatory processes, such as the assessment of environmental impacts, are typically better understood due to the outside regulatory process. A deployment framework may not be necessary for large development companies working with communities experienced with wind development. If neither party has this experience, however, the lack of a process can result in non-optimal projects. For instance, important items may be dismissed or skipped because of a lack of project knowledge by one or more project participants.

A non-mandatory framework that is widely available and well-documented would provide a basic structure for project development. This framework would provide recommendations on studies that should be undertaken, community engagement steps, and deployment best practices. This framework would also identify potential regulatory overlaps or complications, in hopes of reducing project development timelines. Although there would be no attempt to mandate its use, the development of a defined process could result in reduced development timelines, less contention about what steps should be undertaken, and a lower overall cost for the development process. This action would be completed in conjunction with other recommended actions described in this document, such as Actions 6.4.1 and 6.4.5.

ACTION 6.4.3: Create a streamlined leasing and permitting process for offshore wind.

The regulatory and permitting process for offshore wind power crosses jurisdictional territories for multiple state and federal agencies, as well as local permitting authorities. The process is largely untested given the small number of permitted offshore wind projects to date. The offshore environment is also complex, with little known about the potential interactions of habitats and species with the installation and operation of wind turbines. Marine animals and habitats may interact with offshore wind turbines, and offshore turbines may encounter different avian species than those common around land-based wind plants. Regulators are working to integrate and apply existing laws and regulations to offshore wind technology where there is a higher degree of uncertainty. Many key agencies and authorities must now become proficient with this new technology. Applying laws and the need to gain proficiency in the technology are contributing to long offshore permitting timelines, estimated to be from five to seven years. This lengthy process, combined with the uncertainty and risk of getting a permit, drives up offshore wind project costs and prevents installations from moving forward.

Efficient coordination between state and federal agencies is critical for an emerging offshore wind industry to succeed in the United States. The permitting and siting process for offshore projects would benefit from increased engagement among offshore wind developers, regulators and other stakeholders. For example, military practice areas, shipping lanes, recreational fishing and boating, and commercial fishing can all have a significant impact on offshore wind siting and operations. Much progress has been made to better define and streamline the permitting process, yet redundant and complex permitting pathways and procedures still exist. If these are addressed in a collaborative process including all interested parties, permitting of offshore wind projects will be more efficient.

ACTION 6.4.4: Increase available sites to accommodate growth of offshore wind.

Available offshore wind sites can be expanded by increasing access to areas currently not being considered for development. Providing access to transmission through proposed private ventures, and creating predictable, straightforward permitting processes, would open significant potential for the U.S. offshore wind market. The waters off the U.S. coasts are busy and contribute to the livelihood of many people. As such, conversations about the use of state and federal waters for offshore wind development are complex and potentially contentious. A highly collaborative approach offers the best opportunity to devise mutually acceptable solutions and increase available sites for offshore wind deployment.

ACTION 6.4.5: Implement a consistent, streamlined permitting process for distributed wind.

Smaller-scale distributed wind projects have historically been grouped with large-scale, land-based wind projects for various zoning and permitting requirements. Small wind systems are typically considered to be outside of existing zoning, permitting and electrical interconnection rules, so they require exceptions. Small wind projects also do not have economies of scale or the same level of impact as larger land-based wind projects, and are often burdened by expensive and time-consuming permitting requirements. Resolving these issues would allow distributed wind to fit more easily into existing permitting, zoning, and electrical interconnection requirements.

Some work could be expanded to support small wind deployment. Work by the National Association of Counties and the Distributed Wind Energy Association was aimed at reducing permitting barriers for distributed wind while protecting resident interests. The resulting report, "County Strategies for Successfully Managing and Promoting Wind Power," was published in 2012 in conjunction with the Distributed Wind Energy Association's

Small Wind Model Zoning Ordinance [16,17,18]. As part of this report, the National Association of Counties conducted extensive research to learn and share best practices from county governments on regulating wind power systems. The report suggests that counties research wind technologies and adopt a wind power engagement strategy before public inquiries to ensure efficient government processes and adherence to planning objectives [18]. Further work could be undertaken to define expanded governance approaches for appropriate deployment of small wind systems, outline special or conditional use requirements, and identify appropriate small wind permitting and zoning requirements, including height, setbacks, lighting, aesthetics, and fees.

ACTION 6.5: Develop Wind Site Pre-Screening Tools. *Develop commonly accepted standard siting and risk assessment tools allowing rapid pre-screening of potential development sites.*

DELIVERABLE: A single or series of interlinked siting tools or frameworks that support wind turbine siting.

IMPACT: Decrease permitting time while easing permitting processes, leading to lower project development costs with improved siting and public acceptance.

KEY THEMES: Reduce Wind Costs

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 6.5.1: Develop verified tools to support wind turbine siting and assessment. Building from the base of tools that are currently used to support siting decisions, develop additional methods, tools, or validation approaches to support siting decisions.	A set of siting support tools that address key siting issues (such as sound, visual impact, flicker, and economic impacts) that are known to be accurate.	A higher degree of trust in and expanded availability of proven and accurate siting and impact assessment tools; reduced project development timelines and costs.	2014	2020
ACTION 6.5.2: Investigate challenging siting issues for complex or unique siting locations. Development of tools, methodologies, research, and deployment processes that will support the expanded deployment of wind technologies on isolated grids and under extreme conditions.	Research, tools, applications, and demonstration activities that support the use of wind power in high value, small market applications.	Expanded deployment of wind in extreme or remote locations.	2014	2020
ACTION 6.5.3: Develop offshore wind spatial planning tools and methods. Develop methods and tools for spatial planning to meet economic, social and environmental objectives, all with the objective of ensuring appropriate deployment of offshore wind technologies.	Screening tools to support siting decision processes.	Decreased permitting time and streamlined permitting processes; lower cost project development; improved siting and general public acceptance.	2014	2020
ACTION 6.5.4: Provide analysis and modeling tools for offshore wind. Develop analysis and modeling tools for determining risk to navigation and the potential impacts of plants on marine radars.	Accurate, validated models that predict navigational impacts of offshore wind turbines on radars.	Reduced navigation risk due to radar interference; facilitation of siting of offshore wind projects; increased marine safety.	2014	2020

ACTION 6.5: Develop Wind Site Pre-Screening Tools. *Develop commonly accepted standard siting and risk assessment tools allowing rapid pre-screening of potential development sites. (cont.)*				
ACTION 6.5.5: Develop distributed wind resource and modeling tools. Accurately characterize distributed wind resources and benchmark current models against desired capabilities.	High-resolution, physics-based models that can characterize distributed wind resources in highly complex lower elevation environments.	Physics-based simulation of the flow characteristics that enable reliable assessment of turbine performance and reliability.	2014	2020
ACTION 6.5.6: Reduce the cost of distributed wind assessment tools. Develop lower cost site assessment and analysis tools.	Virtual meteorological tower capability and low-cost remote sensing validation procedures and equipment. Reliable computer tools linked to existing 30-meter wind maps that are flexible enough to input micro-siting blockages, such as trees and buildings.	Improved understanding of wind resources where turbines are used in distributed applications; reduced uncertainty in distributed wind system performance; reduced time and cost to identify and eliminate poor sites; improved identification of productive locations.	2014	2020

ACTION 6.5.1: Develop verified tools to support wind turbine siting and assessment.

Many tools provide understanding of the viability, impacts, and benefits of wind development. These include visualization tools that offer an accurate depiction of wind facilities and economic assessment tools, allowing a community, state or region to better understand the economic impacts of wind development. Other tools and data sets help developers and regulators screen large areas based on wind resource, land type, and a large number of competing uses or other conditions, including transmission or areas of environmental sensitivity. These tools, however, are not used in a coordinated way, and may not be validated or proven to offer firm results.

The creation of improved or validated siting tools, methods, and approaches could simplify and build confidence in the wind development process by reducing or eliminating some of the associated risks. Since many of the tools currently used across the industry were privately created, this process would require the establishment of a viable validation framework, as well as close partnerships with industry. A set of high-quality but simple, publicly-accessible tools could be made available for the most common community concerns, such as visual representation, flicker, economic impact, and noise propagation. With these tools, community members could conduct their own basic assessments of potential wind power impacts and gain improved confidence in the overall development process.

ACTION 6.5.2: Investigate challenging siting issues for complex or unique locations.

In locations where land access, grid interconnection, and siting conflict issues are minimized, wind project development can proceed using a relatively well-understood process. There are locations in which this development process is not as clear, however, such as sites with isolated grids or microgrids where wind contributions can be unusually high (e.g., islands), or in areas of high potential conflict. In some cases, additional requirements can be met by focusing on existing guidelines. In other cases, more detailed technical research and/or the development of tailored technology will be required to meet specific needs.

Initial investigations into the deployment of wind technologies in isolated grids and complex locations would be the focus in this action. Additional topics could include the installation of wind turbines on capped landfills to support municipal wind development and the development of low environmental impact small wind turbines for installations on sensitive lands.

ACTION 6.5.3: Develop offshore wind spatial planning tools and methods.

The marine spatial planning process is an important element of large-scale, offshore wind development. Consideration of offshore wind in the myriad of competing and complementary ocean uses is complex and still lacks cohesion across U.S. coastal regions. Federal involvement would help link marine spatial planning efforts (at state and federal levels) with candidate sites for offshore wind power. Selecting candidate sites and analyzing potential cumulative effects will involve mapping available wind resources and other attributes for successful offshore wind development. It will also involve scientific assessments of vulnerable marine resources along the U.S. coastline with compatible and conflicting areas of public use. Marine spatial planning efforts could support and inform a coordinated process among existing regulatory authorities with regional priorities and integrated spatial data. Federal involvement, expanded coordination across all levels of government and other affected parties, technical expertise, and financial resources throughout the entire siting and permitting process would help ensure adequate participation by stakeholders and the use of the best science, as well as all known and available best practices.

ACTION 6.5.4: Provide analysis and modeling tools for offshore wind.

Marine-band radars (S-band and X-band) are non-Doppler radars used for collision avoidance and navigation at sea. Because these bands differ from those used on land, proposed offshore wind projects will utilize different assessment protocols and mitigation approaches for radar interference than those applied to land-based wind plants. Each offshore wind project will present varied conditions, such as ambient marine and weather conditions, typical radars being used, and the specific configuration of the proposed wind array. These elements must be evaluated in order to inform a navigational risk assessment for the particular types of vessels using the waterway. Current modeling tools and analysis methods are insufficient for these unique offshore conditions.

ACTION 6.5.5: Develop distributed wind resource and modeling tools.

Improving distributed wind resource characterization is a crosscutting opportunity to reduce the levelized cost of electricity; increase stakeholder confidence; reduce customer acquisition costs; and improve grid planning, operation, and power quality. This process requires accurately characterizing distributed wind resources and benchmarking current models against desired capabilities, such as high-resolution, physics-based models that work in highly complex, lower elevation environments. Better resource and modeling enables properly-sited distributed wind turbines and mitigates financial risk.

ACTION 6.5.6: Reduce the cost of distributed wind assessment tools.

R&D emphasis on characterizing distributed wind resources and developing reduced cost assessment tools will increase the accuracy of performance predictions, in turn ensuring more realistic economics for wind developers and electricity consumers. Reducing the cost of site assessment and analysis tools includes developing virtual assessments of meteorological tower capability and low cost, remote-sensing validation procedures and equipment. Further advances, especially in the area of reliable computer tools linked to existing 30-meter wind maps, could add flexibility and reduce micro-siting blockages such as trees and buildings. These improved energy resource characterization and assessment tools would support understanding of wind resources where turbines are used in distributed applications, reduce uncertainty in distributed wind system performance, reduce the time and cost to identify and eliminate poor sites, and allow potentially productive areas to be identified.

M.7 Collaboration, Education, and Outreach

ACTION 7.1: Provide Information on Wind Power Impacts and Benefits. *Increase public understanding of broader societal impacts of wind power, including economic impacts; reduced emissions of carbon dioxide, other greenhouse gases, and chemical and particulate pollutants; less water use; and greater energy diversity.*

DELIVERABLE: Information and peer-reviewed studies delivered in a stakeholder-targeted method that provides accurate information on the impacts and benefits of wind power independently and in relation to other energy choices.

IMPACT: Retention or expansion of areas open to wind development; decreased fear and misconceptions about wind power; lower project deployment costs and timelines; all leading to more wind installations, better public relations, and lower costs of power.

KEY THEMES: Expand Developable Areas; Increase Economic Value for the Nation

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 7.1.1: Engage with key stakeholders. Involve key stakeholders and proactively provide information on wind impacts and benefits through venues such as publications, electronic and social media, workshops, and organized outreach.	Science-based, impartial information and peer-reviewed products that are packaged for various national audiences using a range of outreach venues, which can also be repurposed by state or regional organizations.	Increased understanding of the impacts and benefits of wind development; more and lower cost wind installations.	2014	2030
ACTION 7.1.2: Convene organizations to support engagement on local wind power issues. Institute state or regional efforts to gather, analyze, and distribute information and data regarding the impacts of wind power plants, including environmental, socioeconomic, public acceptance, and radar-related.	Regional- or state-level delivery of informational and educational products, targeted at local stakeholders, addressing local challenges to wind development.	Better and lower-cost decisions about local project development.	2014	2030
ACTION 7.1.3: Develop consensus-based organizations to support appropriate wind deployment. Implement a national, consensus-based organization(s) to help facilitate discussions on wind-related impacts and provide negotiated paths forward in the implementation of best practices at the regional, state, or federal levels.	An independent organization(s) that will build consensus around appropriate wind deployment methodologies at the regional or state level.	Implementation of consensus-based wind deployment approaches that fairly recognize stakeholder concerns and encourage decisions grounded in science-based information.	2014	2030

ACTION 7.1.1: Engage with key stakeholders.

Stakeholders in decisions about all types of wind development need concise and accurate information on the known impacts of wind development. Without unbiased, science-based information, stakeholders are unable to consider potential positive and negative impacts of expanded development that would allow them to make educated decisions about the appropriate deployment of wind technologies. The definition of key stakeholders can vary greatly, from land owners and county commissions to state and federal regulators. Outreach methods will differ by stakeholder group but could include printed publications, electronic and social media, presentations at topical conferences, webinars, workshops, and direct outreach. Outreach through credible, influential groups will also be required to cover the broad base of stakeholders, especially given the range of viewpoints represented.

ACTION 7.1.2: Convene organizations to support engagement on local wind power issues.

Although considered in a national context throughout this report, the decision to deploy wind technologies is largely a local decision discussed at the county or state level. As with any development, local decisions for wind deployment are driven by local considerations. Outsiders such as wind developers or state regulatory personnel may be treated with some degree of suspicion. The development of local or regional organizations that can address local concerns related to environmental, socioeconomic, public acceptance, aviation, and other impacts of wind power plants will help communities make balanced assessments of the positive and negative impacts. Local and regional entities will also be able to develop locally relevant content, which will have the most impact when addressing local concerns.

ACTION 7.1.3: Develop consensus-based organizations to support appropriate wind deployment.

As with any new development in the power sector, wind development comes with a host of impacts to the local area and to the wider electrical system. As a result, wind development can include interaction with many stakeholders with sometimes conflicting interests. Consensus-based organizations that can help facilitate discussions on wind-related impacts and address diverging interests early in the process are needed. This will provide negotiated paths forward in the implementation of best practices at the regional, state, and federal level, which is needed to support the deployment levels outlined in the *Wind Vision Study Scenario*. Such efforts should be broad-based and, to the extent possible, inclusive of all entities affected by the expanded deployment of appropriately sited wind development.

ACTION 7.2: Foster International Exchange and Collaboration. *Foster international exchange and collaboration on technology R&D, standards and certifications, and best practices in siting, operations, repowering, and decommissioning.*

DELIVERABLE: Expanded international collaboration including information sharing, joint research, and staff exchanges allowing expanded education about wind power and expert collaboration from across the wind industry.

IMPACT: Expanded understanding of the benefits of wind power across the energy sector; expanded cross-industry collaboration on pressing research topics.

KEY THEMES: Reduce Wind Costs; Expand Developable Areas

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 7.2.1: Support wind turbine certification and improve wind turbine standards. Continue support for turbine certification programs and develop specific standards, while making International Electrotechnical Commission and other national standards consistent for all wind turbine technologies.	Continuous updates of all wind turbine standards.	Continuously improved load modeling, reliability, and safety testing for all wind turbine frames; increased number of certified turbines; minimized divergence of national and international standards.	2014	2050
ACTION 7.2.2: Continue international research collaboration. Expand multi-national research through ongoing work with organizations such as the International Energy Agency, bilateral partnerships, and research collaborations.	Collaborative research projects that bring together worldwide technical experts from all sectors to address the most pressing wind power-related research questions.	Reduced total energy cost from wind technology by addressing the most significant technical, production, and deployment questions faced by the industry.	2014	2030
ACTION 7.2.3: Continue international collaboration to address wind deployment challenges. Work with and through organizations, such as the International Renewable Energy Agency, bilateral partnerships, development banks, and international donor organizations, to expand multi-national technical assistance and outreach about appropriate deployment of wind technologies.	Science-based, impartial information and peer-reviewed products packaged for various international audiences using a range of outreach venues, combined with active technical assistance in all areas of wind deployment, from resource assessment through long-term operations.	Expanded international wind market; possible increased demand for U.S. exports; increased rate of technology development; lower costs; greater environmental benefits.	2014	2040

ACTION 7.2.1: Support wind turbine certification and improve wind turbine standards.

Although wind technology has reached a relatively high level of technical acceptance, it is not universally accepted. This is especially true for newer technologies, such as lower wind speed components, offshore wind, and distributed wind. Even though standards and certifications for larger land-based wind systems exist, the industry is still immature. With rapid technology advancement, standards are typically in need of constant review to ensure they meet the current industry needs. As U.S. companies continue to look toward export markets to support expanded manufacturing growth, especially in the distributed wind market, there is the need to ensure parity with domestic, international, and other national standards so that U.S. technology can compete globally. It is also important to ensure that international manufacturing does not undercut the U.S. market, especially with inferior products that could, in turn, impair the credibility of wind technology. Continued support for international wind turbine certification and standards development will be required to allow active participation by U.S.-based experts in the private and public sectors for all wind technologies.

ACTION 7.2.2: Continue international research collaboration.

Although vibrant, the global wind industry remains small when compared to other energy industries. As the market grows, greater collaboration will be needed to address ongoing technical challenges, especially increasingly larger wind components, deployment into less-developed markets such as offshore, and an expanding market for distributed wind technologies. To allow the commercial and industrial sectors to address these challenges, the wind industry will need to go beyond relatively simple information exchange (successfully implemented by the International Energy Agency Wind program) and fully embrace collaborative, international R&D across industry, academia, and research laboratories. Specific activities would include implementation of multi-funded, cross-border research projects on topics of common interest; increased use of the limited, existing testing infrastructure; and broader collaboration to support the next generation of larger testing facilities. Expanded researcher and academic exchanges—for example, permanent researcher-in-residence programs at all significant national laboratories worldwide—would allow private and public researchers and educational professionals to share ideas and the results of their most recent research, thus enhancing the diffusion of new ideas and solutions. Expanded international collaboration on the development of wind power research agendas would also be helpful.

ACTION 7.2.3: Continue international collaboration to address wind deployment challenges.

Expanded knowledge of the applicability of wind technology and how to address the most pressing deployment challenges of integration, public acceptance, environmental impact, radar, and other competing uses are not unique to the United States. Knowledge gained from research in other countries, primarily Europe, Canada, and Australia, has provided valuable insight into the potential impacts of wind development and expands research done in the U.S. market. Beyond activities in the International Energy Agency Wind program portfolio, further bilateral or multi-lateral research that can bolster U.S. findings or build from impactful research conducted in other countries to enhance understanding of U.S. deployment strategies could support wind power deployment.

Collaboration with organizations such as the International Renewable Energy Agency can bring the experience base from the United States to other developing markets, expanding wind development in general and growing the potential for U.S. export markets. Higher wind deployment will allow for not only increased research and resulting lower costs, but also the opening of additional export markets for U.S. manufacturing. This will help stabilize the U.S. wind industry and allow increased industry-wide efficiency improvements.

M.8 Workforce Development

ACTION 8.1: Develop Comprehensive Training, Workforce, and Educational Programs. *Develop comprehensive training, workforce, and educational programs, with engagement from primary schools through university degree programs, to encourage and anticipate the technical and advanced-degree workforce needed by the industry.*

DELIVERABLE: A highly skilled, national workforce guided by specific training standards and defined job credentials to support the growth of the wind industry.

IMPACT: A sustainable workforce to support the domestic and as appropriate the expanding international wind industry.

KEY THEMES: Reduce Wind Costs; Increase Economic Value for the Nation

MARKETS ADDRESSED: Land, Offshore, Distributed

ACTION	DELIVERABLE	IMPACT	BEGIN	END
ACTION 8.1.1: Develop a foundation for a national wind workforce. Develop the foundational knowledge to address wind-focused training, workforce, and educational infrastructure, ensuring ongoing engagement from primary schools through university degree programs to encourage and anticipate the technical and advanced-degree workforce needed by the wind industry.	Analysis and research products that will help identify improvement opportunities, leading to new, highly skilled wind professionals entering the workforce.	Better understanding of industry workforce needs, training standards, and existing educational programs that will lower costs, increase system reliability, improve worker safety, and reduce the negative impacts of deployment.	2014	2040
ACTION 8.1.2: Develop robust wind education programs for primary and secondary levels. Develop and implement primary and secondary education programs that not only introduce more people to the impacts and benefits of wind power but also engage students of all types to enter all levels of the wind power workforce.	Engaging, standards-based wind power educational materials, curricula, activities, and teacher training programs that help support a general understanding of wind.	Increased interest in wind power at primary and secondary education levels, leading to expansion of the national wind workforce over time.	2014	2030
ACTION 8.1.3: Develop technical training programs for wind. Build a robust network of community college, vocational, apprenticeship, and organizational technical centers; develop and implement programs supporting technically-minded individuals who are interested in working in the wind industry.	A nationally coordinated and recognized, multi-level educational infrastructure to support the training and continued development of technical workers for the wind industry.	An adequate number of highly skilled and competently trained technical workers to support the long-term growth of the wind industry.	2014	2025

ACTION 8.1: Develop Comprehensive Training, Workforce, and Educational Programs. *Develop comprehensive training, workforce, and educational programs, with engagement from primary schools through university degree programs, to encourage and anticipate the technical and advanced-degree workforce needed by the industry. (cont.)*				
ACTION 8.1.4: Create a robust higher education infrastructure. Provide a broad range of advanced degreed individuals to support the needs of the wind industry; develop and implement university-level educational programs across the spectrum of wind industry professional needs.	Nationally coordinated and recognized, multi-level educational infrastructure to provide workers with the advanced degrees that the wind industry needs.	Enough highly skilled and competently trained professionals to support the long-term growth of the wind industry.	2014	2030
ACTION 8.1.5: Train and certify distributed wind assessors. Develop a program for training and certifying distributed wind site assessors.	A certification program for distributed wind site assessors.	Skilled practitioners to support the growth of the industry; reduced sales acquisition costs.	2014	2020
ACTION 8.1.6: Formalize distributed wind installer training. Develop a program for training and certifying distributed wind installers.	A certification program for distributed wind installers.	Skilled practitioners to support the growth of the industry, improved consumer confidence in systems, and improved quality of installations.	2014	2020
ACTION 8.1.7: Develop and implement offshore wind workforce training programs. Create and continuously update training modules to reflect technology changes, market conditions, and lessons learned.	Offshore workforce training modules and updates; ongoing analyses and assessments of gaps in training programs, facilities, and training requirements.	A workforce with the skills required to expand offshore wind using domestic workers.	2014	2020

ACTION 8.1.1: Develop a foundation for a national wind workforce.

Efforts are underway to support and expand wind industry workforce development options and better understand the wind industry's workforce development needs. Various industry groups and educational organizations have already implemented workforce development programs. Activities are also supported by DOE's Wind and Water Power Program, the National Renewable Energy Laboratory, the American Wind Energy Association, the U.S. Department of Labor, and the National Science Foundation. Many of these efforts are conducted in an uncoordinated fashion, however, with typically few direct ties to defined levels of expertise. Educational organizations and, in some cases, interested local parties are also implementing activities. One of the first needs is to obtain better understanding and coordination of the defined workforce and educational needs for this sector.

ACTION 8.1.2: Develop robust wind education programs for primary and secondary levels.

The active engagement of students at the primary and secondary levels not only introduces more people to the impacts and benefits of wind power, but also "primes the pump" of the wind power workforce at all levels. Educational work in the STEM topics—Science, Technology, Engineering and Math— including energy and wind technologies specifically, should be made available to students at the kindergarten (K)–12 level so that they will have the skills and interest to enter the renewable energy workforce. There is also a need to ensure that more minorities and women of all backgrounds are engaged in science and math education and supported in pursuing careers in technology fields, and this is most likely to be successful if it happens at an early age.

ACTION 8.1.3: Develop technical training programs for wind.

The development of programs at community colleges, vocational centers, and direct technical centers will support a vast majority of the individuals who will join the wind industry. In many cases, these institutions focus on people with technical skills and professional development, developing or expanding skills needed to work in the land-based, offshore, and distributed wind markets. Expanded needs for worker education and safety become more critical in the technical training fields. This is particularly true given the development of offshore wind plants, which will impose additional training requirements, and the expansion of the distributed wind market, which will mean a need for more site assessors, installers, and maintenance providers. Although the wind industry will continue to play a critical role in worker training programs, expanded collaboration to ensure a universal understanding of the required skills and defined achievement levels will improve the quality of the workforce overall and allow expanded worker flexibility and development.

ACTION 8.1.4: Create a robust higher education infrastructure.

Many of the skills required for the successful long-term development of the wind industry, from engineering to business, call for individuals with advanced degrees [19]. The need to reduce the cost of wind systems, especially in the offshore and remote environment, will require expanded research and deployment innovation. These activities will, for the most part, be driven by individuals with advanced degrees at organizations that can focus on long-term, high-risk innovative strategies; i.e., research universities and laboratories. Given the limited number of university programs that provide graduate degrees in wind-related fields and the extended lead time that it takes to develop high levels of technical proficiency in a specific field, the near-term expansion of university-level programs in the wind sector is of high importance. University programs also need to include some level of direct collaboration or interaction with industry in order to connect students with the most pressing challenges facing the industry, as well as to provide industry with knowledge of cutting-edge academic research.

ACTION 8.1.5: Train and certify distributed wind assessors.

Having a well-trained base of assessors for distributed wind will lead to several immediate and long-term benefits for the deployment of distributed wind. Skilled practitioners, able to effectively use assessment and analysis tools, will, among other things, reduce sales acquisition costs, leading to lower total costs of projects. In the long run, developing a program for training and certifying distributed wind site assessors will support the growth of the industry.

ACTION 8.1.6: Formalize distributed wind installer training.

A formalized wind turbine installer program covering the technological and physical attributes, as well as the science, of wind turbines will benefit the distributed wind industry. Certification programs for installers will improve consumer confidence in distributed wind systems and raise the overall quality of installations. Developing a program for training and certifying installers will also create a more skilled workforce of practitioners, supporting the growth of the industry.

ACTION 8.1.7: Develop and implement offshore wind workforce training programs.

Given commonalities in turbine technologies, there are many common training needs for land-based and offshore wind plant workers. There are, however, significant differences in risks, regulatory framework, and inspection and enforcement protocols between land-based and offshore wind. While land-based wind workers might drive to and from a construction site in a pick-up truck, a lengthy ocean transit in specially designed vessels or helicopters is the norm for offshore workers. When the weather prohibits safe transfer and transit, the offshore worker may be required to take shelter in the turbine. The specific risks associated with offshore activities must be mitigated by training specifically designed for offshore construction, operations, and maintenance.

The offshore wind industry can learn many lessons from the offshore operations experience of the oil and gas industry, including the safe transfer of large work crews. The implementation of effective safety and environmental management systems is an important part of these lessons learned.

As the United States approaches construction of its first offshore wind plant, there is a need for well-trained and properly certified offshore workers. Training programs that meet this demand require the creation of a framework for offshore wind O&M technicians. In addition, short-service construction workers and vessel operators must have clear pathways to obtaining training and certification in order to work in the offshore renewable energy industry.

As the offshore wind industry continues to grow, training venues must not only keep pace with demand but also continuously update training modules to reflect advances in technology and lessons learned.

M.9 References

[1] *U.S. Wind Energy Manufacturing and Supply Chain: A Competitiveness Analysis.* DE-EE-0006102. Work performed by Global Wind Network, Cleveland, OH. Washington, DC: U.S. Department of Energy, June 2014. Accessed Oct. 10, 2014: http://energy.gov/eere/downloads/us-wind-energy-manufacturing-supply-chain-competitiveness-analysis.

[2] Berger, S. *Making in America: From Innovation to Market.* Cambridge, MA: MIT Press, 2013. Accessed Feb. 3, 2015: http://mitpress.mit.edu/books/making-america.

[3] Wessner, C.W.; Wolff, A.W., eds. *Rising to the Challenge: U.S. Innovation Policy for the Global Economy.* Washington, DC: National Academies Press, 2012. Accessed Feb. 3, 2015: www.nap.edu/openbook.php?record_id=13386.

[4] *Report to the President on Capturing Domestic Competitive Advantage in Advanced Manufacturing.* Report to the President. Washington, DC: President's Council of Advisors on Science and Technology, July 2012; 70 pp. Accessed Feb. 3, 2015: http://www.manufacturing.gov/amp.html.

[5] Cotrell, J.; Stehly, T.; Johnson, J.; Roberts, J.O.; Parker, Z.; Scott, G.; Heimiller, D. *Analysis of Transportation and Logistics Challenges Affecting the Deployment of Larger Wind Turbines.* NREL/TP-5000-61063. Golden, CO: National Renewable Energy Laboratory, 2014. Accessed Dec. 19, 2014: www.nrel.gov.

[6] Elkinton, C.; Blatiak, A.; Ameen, H. *Assessment of Ports for Offshore Wind Development in the United States*. Document 700694-USPO-R-03. Work performed by GL Garrad Hassan America, San Diego, CA. Washington, DC: U.S. Department of Energy, March 2014. Accessed Dec. 19, 2014: http://energy.gov/eere/wind/downloads/wind-offshore-port-readiness.

[7] Hamilton, B.; Battenberg, L.; Bielecki, M.; Bloch, C.; Decker, T.; Frantzis, L.; Karcanias, A.; Madsen, B.; Paidipati, J.; Wickless, A.; Zhao, F. U.S. *Offshore Wind Manufacturing and Supply Chain Development.* DE-EE0005364. Work performed by Navigant Consulting for U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. Burlington, MA: Navigant, Feb. 22, 2013; 191 pp. Accessed Feb. 3, 2015: http://energy.gov/eere/wind/downloads/us-offshore-wind-manufacturing-and-supply-chain-development.

[8] *Assessment of Vessel Requirements for the U.S. Offshore Wind Sector.* Work performed by Douglas-Westwood, Kent, UK, for U.S. Department of Energy (DOE). Washington, DC: U.S. DOE, 2013. Subtopic 5.2 of U.S. Offshore Wind: Removing Market Barriers grant opportunity under Funding Opportunity Announcement 414, 2013. Accessed Dec. 19, 2014: http://energy.gov/eere/wind/downloads/assessment-vessel-requirements-us-offshore-wind-sector.

[9] *Offshore Wind Cost Reduction Pathways Study.* London: The Crown Estate, May 2012. Accessed Dec. 19, 2014: http://www.thecrownestate.co.uk/energy-and-infrastructure/offshore-wind-energy/working-with-us/strategic-workstreams/cost-reduction-study/.

[10] *Offshore Wind Project Timelines 2013.* London: Renewable UK and Crown Estate, 2013. Accessed Dec. 20, 2014: http://www.renewableuk.com/download.cfm?docid=63B303B4-425D-4CD3-B032A0A4F109E42C.

[11] Bailey, B.; Wilson, W. "The Value Proposition of Load Coincidence and Offshore Wind." *North American Windpower,* January 2014. https://www.awstruepower.com/knowledge-center/articles/.

[12] "Analysis of the Impact of Cape Wind on New England Energy Prices." CRA Project No. D15007-00. Work performed for Cape Wind Associates by Charles River Associates. Boston: CRA, 2010; 13 pp. Accessed Feb. 3, 2015: http://www.crai.com/uploadedFiles/Publications/analysis-of-the-impact-of-cape-wind-on-new-england-energy-prices.pdf?n=944.

[13] "Update to the Analysis of the Impact of Cape Wind on Lowering New England Energy Prices." CRA Project No. D17583-00. Work performed for Cape Wind Associates by Charles River Associates. Boston: CRA, 2012.

[14] *Alliance to Protect Nantucket Sound, Inc., vs. Department of Public Utilities.* 461 Massachusetts 166, Docket DPU 10-54. National Grid and Cape Wind Association, 2010.

[15] "Standard for Interconnecting Distributed Resources with Electric Power Systems." IEEE 1547 Working Group, 2014. Accessed Dec. 20, 2014: http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

[16] "DWEA Model Zoning Ordinance, Final." Flagstaff, AZ: Distributed Wind Energy Association (DWEA), 2012.

[17] "Distributed Wind Model Zoning Ordinance." Flagstaff, AZ: Distributed Wind Energy Association, February 2014.

[18] Lang, J.; Wasser, C.; Jenkins, J.; DiFrancisco, L. *County Strategies for Successfully Managing and Promoting Wind Power: Implementing Wind Ordinances in America's Counties.* Distributed Wind Energy Association Planning and Zoning Committee Issue Brief. Washington, DC: National Association of Counties, 2012. Accessed Feb. 3, 2015: http://www.naco.org/programs/csd/Pages/County-Strategies-for-Successfully-Managing-and-Promoting-Wind-Power.aspx.

[19] Leventhal, M.; Tegen, S. *A National Skills Assessment of the U.S. Wind Industry in 2012.* NREL/TP-7A30-57512. Golden, CO: National Renewable Energy Laboratory, 2013. Accessed Dec. 19, 2014: http://www.nrel.gov.

Appendix N: Contributors

The U.S. Department of Energy (DOE) acknowledges the authors, reviewers, and various contributors listed below, each of whom contributed to this report. The DOE Wind and Water Power Technologies Office (WWPTO) managed the project in collaboration with the American Wind Energy Association and the Wind Energy Foundation. These three organizations solicited the participation of the wind industry and other expertise. Expert input for the project was provided by members of 11 Task Forces, a Senior Peer Review Group, and an External Review Group comprising senior managers from wind, electric power, non-governmental organizations, and government organizations involved with wind power and the energy and electricity sectors. Overall project coordination was carried out by DOE.

This technical report is the culmination since May 2013 of contributions from more than 250 individuals and more than 50 organizations representing DOE, the wind industry, the electric power sector, environmental stewardship organizations, and four major national laboratories (Lawrence Berkeley National Laboratory, the National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and Sandia National Laboratories). Contributions and support from these participants were important throughout the development of this report.

Various offices within DOE and other federal agencies also provided counsel and review throughout the effort. The DOE Office of Energy Efficiency and Renewable Energy was a principal internal adviser. DOE's Office of Energy Policy and Systems Analysis and Office of Electricity Delivery and Energy Reliability also provided input. DOE WWPTO consulted with the other DOE energy program technology offices—including solar, geothermal, hydroelectric, fossil, and nuclear energy—and the U.S. Energy Information Administration to obtain the best available information on characteristics for those technologies. DOE WWPTO also coordinated with other federal agencies, such as the U.S. Department of the Interior's (DOI's) Bureau of Ocean Energy Management and the National Oceanic and Atmospheric Administration (NOAA). Eleven task forces conducted analyses, prepared sections of this report, and provided valuable guidance during the final review processes. Lead authors and main advisors for each chapter are shown in **bold**.

The final version of this document was prepared by the U.S. Department of Energy.

Overall Direction

Wind Vision Project Management

Jose Zayas (DOE Lead)	**U.S. Department of Energy**
Jessica Lin-Powers (Co-Lead)	**National Renewable Energy Laboratory**
Richard Tusing (Co-Lead)	**New West Technologies, LLC**
Edgar DeMeo	**Renewable Energy Consulting Services, Inc.**
Ed Eugeni	**SRA International, Inc.**
Elizabeth Salerno	formerly American Wind Energy Association
Darlene Snow	formerly Wind Energy Foundation
Emily Williams	American Wind Energy Association

Report Lead Editors and Coordinators

Ed Eugeni (Co-Lead)	**SRA International, Inc.**
Patricia Weis-Taylor (Co-Lead)	**PWT Communications, LLC**
Coryne Tasca (Co-Lead)	**SRA International, Inc.**
Alexsandra Lemke (Communications Lead)	**National Renewable Energy Laboratory**
Joelynn Schroeder (Art Director)	**National Renewable Energy Laboratory**
Mark Swisher (Designer)	**National Renewable Energy Laboratory**
Alfred Hicks (Designer)	**National Renewable Energy Laboratory**
Edgar DeMeo	**Renewable Energy Consulting Services, Inc.**
Jessica Lin-Powers	**National Renewable Energy Laboratory**
Richard Tusing	**New West Technologies, LLC**
Fredric Beck	SRA International, Inc.

Senior Peer Review Group

The Senior Peer Review Group played an important role by reviewing key messages of the document during its development and providing important constructive comments and strategic input as the work progressed.

Jose Zayas (DOE Lead)	**U.S. Department of Energy**
Gabriel Alonso	EDP Renewables North America, LLC
Angela Anderson	Union of Concerned Scientists
Chris Brown	Vestas American Wind Technology, Inc.
Patrick Barry Butler	University of Iowa
Jamie Rappaport Clark	Defenders of Wildlife
Tom Kiernan	American Wind Energy Association
Keith Longtin	General Electric Energy
Peter Mandelstam	Arcadia Windpower, Ltd.
Andy Ott	PJM Interconnection
Susan Reilly	Renewable Energy Systems Americas, Inc.
Brian Smith	National Renewable Energy Laboratory
James Walker	EDF Renewable Energy

Lead Authors and Contributors

Executive Summary: Overview & Key Chapter Findings

Eric Lantz (Co-Lead)	**National Renewable Energy Laboratory**
Richard Tusing (Co-Lead)	**New West Technologies, LLC**
Edgar DeMeo	Renewable Energy Consulting Services, Inc.
Jessica Lin-Powers	National Renewable Energy Laboratory
Trieu Mai	National Renewable Energy Laboratory
Patricia Weis-Taylor	PWT Communications, LLC
Ryan Wiser	Lawrence Berkeley National Laboratory
Jose Zayas	U.S. Department of Energy

Chapter 1: Introduction to *Wind Vision*

Richard Tusing (Lead)	**New West Technologies, LLC**
Edgar DeMeo	**Renewable Energy Consulting Services, Inc.**
Eric Lantz	**National Renewable Energy Laboratory**
Jessica Lin-Powers	**National Renewable Energy Laboratory**
Trieu Mai	National Renewable Energy Laboratory
Ryan Wiser	Lawrence Berkeley National Laboratory
Jose Zayas	U.S. Department of Energy

Chapter 2: Wind Power in the United States: Recent Progress, Status Today, and Emerging Trends

Ed Eugeni (Lead)	**SRA International, Inc.**
Ian Baring-Gould	**National Renewable Energy Laboratory**
Fort Felker	**National Renewable Energy Laboratory**
Michael Milligan	**National Renewable Energy Laboratory**
Walt Musial	**National Renewable Energy Laboratory**
Brian Naughton	**Sandia National Laboratories**
Alice Orrell	**Pacific Northwest National Laboratory**
Josh Paquette	**Sandia National Labratories**
Ryan Wiser	**Lawrence Berkeley National Laboratory**
Kathy Belyeu	Consultant
Mark Bolinger	Lawrence Berkeley National Laboratory
Arielle Cardinal	National Renewable Energy Laboratory
Tessa Dardani	National Renewable Energy Laboratory
Maureen Hand	National Renewable Energy Laboratory

Chapter 2: Wind Power in the United States: Recent Progress, Status Today, and Emerging Trends *(cont.)*

Brendan Kirby	Consultant
Jessica Lin-Powers	National Renewable Energy Laboratory
Jeff Logan	National Renewable Energy Laboratory
Paul Veers	National Renewable Energy Laboratory
Emily Williams	American Wind Energy Association
Jose Zayas	U.S. Department of Energy

Chapter 3: Impacts of the *Wind Vision*

Eric Lantz (Co-Lead)	**National Renewable Energy Laboratory**
Trieu Mai (Co-Lead)	**National Renewable Energy Laboratory**
Ryan Wiser (Co-Lead)	**Lawrence Berkeley National Laboratory**
Ian Baring-Gould	**National Renewable Energy Laboratory**
Mark Bolinger	**National Renewable Energy Laboratory**
Austin Brown	**National Renewable Energy Laboratory**
Garvin Heath	**National Renewable Energy Laboratory**
David Keyser	**National Renewable Energy Laboratory**
Jordan Macknick	**National Renewable Energy Laboratory**
Dev Millstein	**Lawrence Berkeley National Laboratory**
Walt Musial	**National Renewable Energy Laboratory**
Alice Orrell	**Pacific Northwest National Laboratory**
Alberta Carpenter	National Renewable Energy Laboratory
Stuart Cohen	National Renewable Energy Laboratory
Maureen Hand	National Renewable Energy Laboratory
Thomas Jenkin	National Renewable Energy Laboratory
Brendan Kirby	Consultant
Venkat Krishnan	National Renewable Energy Laboratory
Jeff Logan	National Renewable Energy Laboratory
Jennifer Melius	National Renewable Energy Laboratory
Michael Milligan	National Renewable Energy Laboratory
Andrew Mills	Lawrence Berkeley National Laboratory
David Mulcahy	formerly National Renewable Energy Laboratory
Brian Naughton	Sandia National Laboratories
Arman Shehabi	Lawrence Berkeley National Laboratory
Patrick Sullivan	National Renewable Energy Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Richard Tusing	New West Technologies, LLC
Jose Zayas	U.S. Department of Energy

Chapter 4: The *Wind Vision* Roadmap: A Pathway Forward

Edgar DeMeo (Lead)	**Renewable Energy Consulting Services, Inc.**
Ian Baring-Gould	**National Renewable Energy Laboratory**
Frederic Beck	**SRA International, Inc.**
Fort Felker	**National Renewable Energy Laboratory**
Maureen Hand	**National Renewable Energy Laboratory**
Michael Milligan	**National Renewable Energy Laboratory**
Walt Musial	**National Renewable Energy Laboratory**
Brian Naughton	**Sandia National Laboratories**
Alice Orrell	**Pacific Northwest National Laboratory**
Josh Paquette	**Sandia National Laboratories**
Ryan Wiser	**Lawrence Berkeley National Laboratory**
Jessica Lin-Powers	National Renewable Energy Laboratory
Richard Tusing	New West Technologies, LLC
Jose Zayas	U.S. Department of Energy

Appendix A: Glossary

Patricia Weis-Taylor (Lead)	**PWT Communications, LLC**

Appendix B: Summary of *20% Wind Energy by 2030*

Edgar DeMeo (Lead)	**Renewable Energy Consulting Services, Inc.**

Appendix C: Regulatory Agencies

Ian Baring-Gould (Lead)	**National Renewable Energy Laboratory**

Appendix D: Wind Project Development Process and Costs

Ian Baring-Gould (Lead)	**National Renewable Energy Laboratory**
Suzanne Tegen	National Renewable Energy Laboratory

Appendix E: Domestic Supply Chain Capacity

Brian Naughton (Lead)	**Sandia National Laboratories**
Jason Cotrell	**National Renewable Energy Laboratory**
Steven Quade	**Blattner Energy, Inc.**

Appendix F: Test Facilities

Patricia Weis-Taylor (Lead)	**PWT Communications, LLC**

Appendix G: Regional Energy Deployment System (ReEDS) Model—Additional Inputs and Assumptions

Trieu Mai (Lead)	**National Renewable Energy Laboratory**
Eric Lantz	**National Renewable Energy Laboratory**
David Mulcahy	**formerly National Renewable Energy Laboratory**
Stuart Cohen	National Renewable Energy Laboratory
Venkat Krishnan	National Renewable Energy Laboratory

Appendix H: *Wind Vision* Wind Power Technology Cost and Performance Assumptions

Kathy Belyeu (Co-Lead)	**Consultant**
Maureen Hand (Co-Lead)	**National Renewable Energy Laboratory**
Donna Heimiller (Co-Lead)	**National Renewable Energy Laboratory**
Stuart Cohen	National Renewable Energy Laboratory
Eric Lantz	National Renewable Energy Laboratory
Trieu Mai	National Renewable Energy Laboratory
David Mulcahy	formerly National Renewable Energy Laboratory
Owen Roberts	National Renewable Energy Laboratory
George Scott	National Renewable Energy Laboratory
Aaron Smith	National Renewable Energy Laboratory
Ryan Wiser	Lawrence Berkeley National Laboratory

Appendix I: JEDI Model Documentation

David Keyser (Lead)	**National Renewable Energy Laboratory**
Suzanne Tegen	**National Renewable Energy Laboratory**
Eric Lantz	National Renewable Energy Laboratory
Ryan Wiser	National Renewable Energy Laboratory

Appendix J: Life-Cycle GHG Emissions and Net Energy Metrics

Garvin Heath (Lead)	**National Renewable Energy Laboratory**
Alberta Carpenter	**National Renewable Energy Laboratory**
Ryan Wiser	Lawrence Berkeley National Laboratory

Appendix K: Water Usage Reduction, Supplemental Results

Jordan Macknick (Lead)	**National Renewable Energy Laboratory**
Stuart Cohen	**National Renewable Energy Laboratory**
David Mulcahy	formerly National Renewable Energy Laboratory
Ryan Wiser	Lawrence Berkeley National Laboratory

Appendix L: Health and Environmental Impact Methods

Dev Millstein (Lead)	**Lawrence Berkeley National Laboratory**
Trieu Mai	National Renewable Energy Laboratory
Ryan Wiser	Lawrence Berkeley National Laborat

Appendix M: Detailed Roadmap Actions

Edgar DeMeo (Lead)	**Renewable Energy Consulting Services, Inc.**
Ian Baring-Gould	**National Renewable Energy Laboratory**
Fort Felker	**National Renewable Energy Laboratory**
Jessica Lin-Powers	**National Renewable Energy Laboratory**
Michael Milligan	**National Renewable Energy Laboratory**
Walt Musial	**National Renewable Energy Laboratory**
Brian Naughton	**Sandia National Laboratories**
Alice Orrell	**Pacific Northwest National Laboratory**
Josh Paquette	**Sandia National Laboratories**
Ryan Wiser	**Lawrence Berkeley National Laboratory**
Ed Eugeni	SRA International, Inc.

Appendix O: Geographic Impacts of Wind Technology Research and Development

Eric Lantz (Lead)	**National Renewable Energy Laboratory**
Jennifer Melius	National Renewable Energy Laboratory
Billy Roberts	National Renewable Energy Laboratory
Owen Roberts	National Renewable Energy Laboratory

Contributing Task Force Members

Market Data and Analysis and Scenario Modeling Task Forces

Eric Lantz (Co-Lead)	**National Renewable Energy Laboratory**
Trieu Mai (Co-Lead)	**National Renewable Energy Laboratory**
Ryan Wiser (Co-Lead)	**Lawrence Berkeley National Laboratory**
Elizabeth Salerno (Project Coordinator)	**formerly American Wind Energy Association**
Richard Tusing (Project Coordinator)	**New West Technologies, LLC**
Rajan Arora	Renewable Energy Systems Americas, Inc.
Sam Baldwin	U.S. Department of Energy
Fredric Beck	SRA International, Inc.
Dave Berry	Clean Line
Mark Bolinger	Lawrence Berkeley National Laboratory
Austin Brown	National Renewable Energy Laboratory
Alberta Carpenter	National Renewable Energy Laboratory
Stuart Cohen	National Renewable Energy Laboratory
Steve Clemmer	Union of Concerned Scientists
Sam Enfield	MAP Royalty, Inc.
Mike Finger	EDP Renewables
Patrick Gilman	U.S. Department of Energy
Michael Goggin	American Wind Energy Association
Juan Gutierrez	Siemens
Bruce Hamilton	Navigant Consulting, Inc.
Maureen Hand	National Renewable Energy Laboratory
Garvin Heath	National Renewable Energy Laboratory
Donna Heimiller	National Renewable Energy Laboratory
Mike Horn	General Electric Energy
Thomas Jenkin	National Renewable Energy Laboratory
Geoff Keith	Synapse
Willet Kempton	University of Delaware
David Keyser	National Renewable Energy Laboratory
Venkat Krishnan	National Renewable Energy Laboratory
Nick Lenssen	Vestas
Jeff Logan	National Renewable Energy Laboratory
Jordan Macknick	National Renewable Energy Laboratory
Trieu Mai	National Renewable Energy Laboratory
Michael McManus	Siemens
Jennifer Melius	National Renewable Energy Laboratory
Andrew Mills	Lawrence Berkeley National Laboratory

Contributing Task Force Members *(continued)*

Dev Millstein	Lawrence Berkeley National Laboratory
Jason Minalga	Invenergy
David Mulcahy	formerly National Renewable Energy Laboratory
Brian Naughton	Sandia National Laboratories
Nick Nigro	Center for Climate and Energy Solutions
Ryan Pletka	Black & Veatch
Sandra Sattler	Union of Concerned Scientists
Matt Schuerger	Energy Systems Consulting Servies, LLC
Melissa Seymour	Iberdrola
Arman Shehabi	Lawrence Berkeley National Laboratory
Patrick Sullivan	National Renewable Energy Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Jurgen Weiss	The Brattle Group
Ed Weston	Great Lakes Wind Network
Emily Williams	American Wind Energy Association
Aaron Zubaty	Map Royalty, Inc.

Wind Plant Technology Task Force

Fort Felker (Lead)	**National Renewable Energy Laboratory**
Paul Veers (Deputy)	**National Renewable Energy Laboratory**
Edgar DeMeo (Project Coordinator)	**Renewable Energy Consulting Services, Inc.**
David Blittersdorf	All Earth Renewables
Sandy Butterfield	Boulder Wind
Joel Cline	U.S. Department of Energy
Steve Dayney	Senvion
Bob Gates	Consultant
Melinda Marquis	NOAA/ Earth System Research Laboratory
Wayne Mays	Iberdrola
Charudatta Mehendale	General Electric Energy
John Meissner	New West Technologies, LLC
Margaret Montanez	Vestas
Mike Outtne	EDP Renewables
Josh Paquette	Sandia National Laboratories
Will Shaw	Pacific Northwest National Laboratory
Kevin Standish	Siemens – R&D
Case Van Dam	University of California

Contributing Task Force Members *(continued)*

Operations and Maintenance, Performance, and Reliability Task Force

Josh Paquette (Lead)	**Sandia National Laboratories**
Jessica Lin-Powers (Project Coordinator)	**National Renewable Energy Laboratory**
Kevin Alewine	Shermco
Matt Burt	Renewable Energy Systems Americas, Inc.
Joshua Crayton	Rope Partners
Ashley Crowther	Romax
Matt Daly	General Electric
Kevin Devlin	Iberdrola
Bill Erdman	DNV GL
Jonathan Glessner	H&N Electric
Daniel Griffith	Sandia National Laboratories
Brian Hayes	EDP Renewables
Craig Houston	DNV GL
Jon Keller	National Renewable Energy Laboratory
Matt Malkin	DNV GL
Tom Marek	Moventus
Ruth Marsh	DNV GL
Suzanne Meeker	General Electric
Thomas Mills	Vestas
Lars Moller	Global Energy Services
Robert Poore	DNV GL
Krys Rootham	Edison Mission
Shaun Sheng	National Renewable Energy Laboratory
Eric Stanfield	Rope Partners
Peter Wells	UpWind Solutions
Emily Williams	American Wind Energy Association
Gary Wolfe	Gamesa

Manufacturing and Logistics

Daniel Laird (Lead)	**Sandia National Laboratories**
Brian Naughton (Deputy)	**Sandia National Laboratories**
Jessica Lin-Powers (Project Coordinator)	**National Renewable Energy Laboratory**
Doug Cairns	Montana State University
Jason Cotrell	National Renewable Energy Laboratory
Peter Duprey	Broadwind Energy

Contributing Task Force Members *(continued)*

Cash Fitzpatrick	U.S. Department of Energy
Juan Gutierrez	Siemens
John Hensley	American Wind Energy Association
Steve Lockard	TPI Composites
Dan McDevitt	Nordex
John Norton	NRG Energy
Mihir Patel	Logisticus
Vikash Patel	Logisticus
Derek Petch	National Renewable Energy Laboratory
Frank Peters	Iowa State University
John Purcell	Leeco Steel
Steve Quade	Blattner Energy
Terry Royer	Winergy
Robbin Russell	Signal Energy
Richard Tusing	New West Technologies, LLC
Ed Weston	Great Lakes Wind Network
Ryan Wiser	Lawrence Berkeley National Laboratory

Project Development and Siting

Ian Baring-Gould (Lead)	**National Renewable Energy Laboratory**
Mark Jacobson (Deputy)	**National Renewable Energy Laboratory**
Ed Eugeni (Project Coordinator)	**Sra International, Inc.**
Darlene Snow (Project Coordinator)	**formerly Wind Energy Foundation**
Tabor Allison	American Wind Wildlife Institute
Abby Arnold	American Wind Wildlife Institute
Mike Arquin	KidWind
Alan Axworthy	Distributed Wind Energy Association
Jonathan Bartlett	U.S. Department of Energy
Ray Brady	DOI Bureau of Land Management
Andria Copping	Pacific Northwest National Laboratory
Fara Courtney	U.S. Offshore Wind Collaborative
Sam Enfield	MAP
Michael Ernst	Tetra Tech
Ian Evans	American Wind Wildlife Institute
Julie Falkner	Defenders of Wildlife
Patrick Gilman	U.S. Department of Energy
Joe Grennan	Renewable Energy Systems Americas, Inc.

Contributing Task Force Members *(continued)*

Ben Hoen	Lawrence Berkeley National Laboratory
Susan Holmes	National Oceanographic and Atmospheric Administration
Mike Horn	General Electric Energy
Christy Johnson-Hughes	U.S. Fish and Wildlife Service
John Kostyack	National Wildlife Federation
Simon Mahan	Southern Alliance for Clean Energy
Ruth Marsh	DNV GL
Jon Miles	James Madison University
Brian Miller	BEM Int'l LLC
Rick Miller	EDF Renewable Energy
Dave Minster	Sandia National Laboratories
Walt Musial	National Renewable Energy Laboratory
Dorthe Nielsen	Vestas
Shalini Ramanathan	Renewable Energy Systems Americas, Inc.
Derek Reiman	EDP Renewables
Roby Roberts	EDP Renewables
John Rogers	Union of Concerned Scientists
Mick Sagrillo	Sagrillo Power & Light
Karin Sinclair	National Renewable Energy Laboratory
Mary Spruill	KidWind
Jennifer States	formerly Pacific Northwest National Laboratory
Gene Takle	Iowa State University
James Walker	EDF Renewable Energy
Stu Webster	Iberdrola

Transmission and Integration

Michael Milligan (Lead)	**National Renewable Energy Laboratory**
Brendan Kirby (Deputy)	**Consultant**
Edgar DeMeo (Project Coordinator)	**Renewable Energy Consulting Services, Inc.**
Tom Acker	Northern Arizona University
Mark Ahlstrom	WindLogic
Steve Beuning	Xcel
Bob Bradish	American Electric Power
Jay Caspary	Southwest Power Pool
Charlton Clark	U.S. Department of Energy
Paul Denholm	National Renewable Energy Laboratory

Contributing Task Force Members *(continued)*

Don Furman	Iberdrola
Jimmy Glotfelty	Cleanline
Jay Godfrey	American Electric Power
Michael Goggin	American Wind Energy Association
Rob Gramlich	American Wind Energy Association
Jeff Hein	Xcel
Ben Karlson	Sandia National Laboratories
Warren Lasher	Electric Reliability Council of Texas
Clyde Loutan	California Independent System Operator
Trieu Mai	National Renewable Energy Laboratory
David Maggio	Electric Reliability Council of Texas
Melinda Marquis	National Oceanic and Atmospheric Administration
Mike McMullen	Midcontinent Independent System Operator
Nick Miller	General Electric Energy
Andrew Mills	Lawrence Berkeley National Laboratory
Dale Osborn	Midcontinent Independent System Operator
Brian Parsons	Western Grid Group
Kris Ruud	Midcontinent Independent System Operator
Steve Saylors	Vestas
Ken Schuyler	PJM Interconnection
J. Charles Smith	Utility Variable-Generation Integration Group
Beth Soholt	Wind on the Wires
Cameron Yourkowski	Renewable Northwest

Offshore Wind

Walt Musial (Lead)	**National Renewable Energy Laboratory**
Arielle Cardinal (Deputy)	**National Renewable Energy Laboratory**
Ed Eugeni (Project Coordinator)	**SRA International, Inc.**
Bruce Bailey	AWS TruePower
Kevin Banister	Principle Power Inc.
Jen Banks	Southeastern Coastal Wind Coalition
Ron Beck	Tetra Tech
Catherine Bowes	National Wildlife Federation
Sebastian Chivers	PMSS USA
Andrea Copping	Pacific Northwest National Laboratory
Fara Courtney	US Offshore Wind Collaborative
Dennis Duffy	Cape Wind

Contributing Task Force Members *(continued)*

Michael Earnst	Tetra Tech
Simon Geerlofs	Pacific Northwest National Laboratory
Todd Griffith	Sandia National Laboratories
Rudy Hall	Keystone Engineering
Bruce Hamilton	Navigant Consulting, Inc.
Mary Hunt	Georgia Tech University
Willett Kempton	University of Delaware
Jim Lanard	Offshore Wind Development Collaborative
Eric Lantz	National Renewable Energy Laboratory
Kevin Lindquist	Renewable Energy Systems Americas, Inc.
Tracy Logan	Bureau of Ocean Energy Management
Chris Long	American Wind Energy Association
Peter Mandelstam	Arcadia Offshore LLC
Meghan Massaua	New West Technologies, LLC
Greg Matzat	U.S. Department of Energy
Stephanie McClellan	University of Delaware
Markian Melnyk	Atlantic Wind Connection
Thomas Mills	Vestas
Karsten Moeller	Siemens Offshore Wind Americas
Thomas Mousten	Siemens Offshore Wind Americas
Charlie Nordstrom	Glosten Associates
Gary Norton	SRA International, Inc.
Brian O'Hara	Southeastern Coastal Wind Coalition
Doug Pfeister	Offshore Wind Development Collaborative
Will Shaw	Pacific Northwest National Laboratory
Aaron Smith	National Renewable Energy Laboratory
Bryan Stockton	ML Strategies, LLC
Katarina Svabcikova	Siemens Offshore Wind Americas
Richard Tusing	New West Technologies, LLC
Larry Viterna	Nautica Windpower
Lorry Wagner	Lake Erie Energy Development Corporation
Joel Whitman	Whitman Consulting Group

Contributing Task Force Members *(continued)*

Distributed Wind

Alice Orrell (Lead)	**Pacific Northwest National Laboratory**
Richard Tusing (Project Coordinator)	**New West Technologies, LLC**
Bret Barker	U.S. Department of Energy
Larry Flowers	American Wind Energy Association
Trudy Forsyth	Wind Advisors Team
Nikolas Foster	Pacific Northwest National Laboratory
Jennifer Jenkins	Distributed Wind Energy Association
Robert Preus	National Renewable Energy Laboratory
Heather Rhoads-Weaver	eFormative Options, LCC
Val Stori	Interstate Turbine Advisory Council

Roadmap Development

Edgar DeMeo (Lead)	**Renewable Energy Consulting Services, Inc.**
Richard Tusing (Project Coordinator)	**New West Technologies, LLC**
Darlene Snow (Project Coordinator)	**formerly Wind Energy Foundation**
Jeff Anthony	formerly American Wind Energy Association
Ian Baring-Gould	National Renewable Energy Laboratory
Jon Chase	Vestas
Seth Dunn	General Electric Energy
Fort Felker	National Renewable Energy Laboratory
Don Furman	Wind Energy Foundation (Board Chair)
Simon Geerlofs	Pacific Northwest National Laboratory
Rob Gramlich	American Wind Energy Association
Maureen Hand	National Renewable Energy Laboratory
Mark Higgins	U.S. Department of Energy
Daniel Laird	Sandia National Laboratories
Eric Lantz	National Renewable Energy Laboratory
Michael Milligan	National Renewable Energy Laboratory
Walt Musial	National Renewable Energy Laboratory
Alice Orrell	Pacific Northwest National Laboratory
Josh Paquette	Sandia National Laboratories
Susan Reilly	Renewable Energy Systems Americas, Inc.
Roby Roberts	EDP Renewables
Brian Smith	National Renewable Energy Laboratory
James Walker	EDF Renewable Energy

Contributing Task Force Members *(continued)*

Greg Wetstone	TerraGen
Ryan Wiser	Lawrence Berkeley National Laboratory

Communications and Outreach

Alexsandra Lemke (Lead)	**National Renewable Energy Laboratory**
Jessica Lin-Powers	**National Renewable Energy Laboratory**
Darlene Snow	formerly Wind Energy Foundation
Noah Golding	Energetics, Inc.
Liz Hartman	U.S. Department of Energy
Peter Kelley	American Wind Energy Association
John Kostyack	Wind Energy Foundation
Stephanie Shuff	Energetics, Inc.
Richard Tusing	New West Technologies, LLC
David Ward	American Wind Energy Association

External Reviewers

Although feedback was provided by these individuals, DOE is ultimately responsible for content in this report.

Michael Brower	**AWS Truepower**
Jason Dedrick	**Syracuse University**
Andy Geissbuehler	**Alstom Power**
Charles Gray	**NARUC**
Jérôme Guillet	**Green Giraffe**
Hannele Holttinen	**VTT Technical Research Centre of Finland**
Henning Kruse	**European TPWind (Siemens)**
Jim Lyons	**Novus Energy**
Amir Mikhail	**Consultant**
David Olsen	**CA-ISO**
Larry Pearce	**Governors' Wind Energy Coalition**
Steve Sawyer	**Global Wind Energy Council**
Walter Short	**Consultant**
Dan Shreve	**MAKE Consulting**
Jamie Simler	**Federal Energy Regulatory Commission**
Randy Swisher	**Consultant**
Aidan Tuohy	**Electric Power Research Institute**
Thomas A. Wind	**Wind Utility Consulting**

Additional Supporting Editors

Linda Bevard	PWT Communications, LLC
Michelle Dorsett	PWT Communications, LLC
Sophia Latorre	PWT Communications, LLC
Cezanne Murphy-Levesque	PWT Communications, LLC
Catherine Steiner	PWT Communications, LLC

This page is intentionally left blank

Appendix O: Geographic Impacts of Wind Technology Research and Development

Reducing the cost of wind energy is a key theme of the Wind Vision Roadmap. Continued incremental reductions could allow the benefits of the *Study Scenario* to be realized with reduced costs and greater long-term savings. Aggressive cost reductions could enable electric sector savings to be realized, relative to the *Baseline Scenario*, in the 2020 and 2030 timeframe.

Technology research and development is a key driver of cost reductions. Advanced materials, advanced wind turbine and plant controls, and increased knowledge of intra-plant wakes and airflows are expected to increase turbine and plant-level energy production, minimize plant losses and downtime, enable new and improved construction practices, and support enhanced plant and electric power system operation. Manufacturing innovations are anticipated to complement these advancements by eliminating or reducing key transportation and logistics constraints and enabling new and improved construction and installation practices.

In addition, advancements in wind technology are notable for their ability to reduce the geographic constraints of the technology. This is achieved through increases in energy production per dollar invested, which opens previously marginal resource areas to development. These geographic impacts provide the business community, utility-sector, and public with more options in terms of siting and locating wind plants to achieve a given wind energy outcome. Moreover, by increasing the amount of land area that can support commercial wind development, wind power may be able to provide local economic development in those communities and regions where the power is being consumed, better avoid sensitive wildlife habitat, and reduce dependence on new transmission infrastructure.[1]

Appendix O provides additional context about this opportunity by detailing the impacts of wind technology advancement on the amount of land area that can achieve a net capacity factor of at least 30% (i.e., land area with a net capacity factor ≥ 30%). Quantitative comparisons illustrate changes in technology achieved between 2008 and 2013, as well as for the future, assuming technology development that is in the near-term commercialization pipeline. A brief discussion of the long-term (2050) future is also included in this appendix.

O.1 Technology Impacts Since 2008

Wind technology has undergone a step-change in terms of turbine and plant-level productivity, with accompanying reductions in the cost of energy [1, 2, 3]. Changes in productivity have resulted from a combination of increased rotor diameter and higher hub heights [1, 2, 3].[2] Recent rotor-driven impacts are enabled by design improvements in blades that allow for expanded rotor size with relatively few impacts throughout the rest of the turbine and limited incremental material costs. From a geographic perspective, the increase in rotor size observed in the market, particularly for low-wind-speed sites, increases the amount of land area able to achieve a net capacity factor of at least 30%[3] by 68% (1.1 million km^2). Figure O-1 illustrates this change, showing the land area that meets this criteria using state-of-the-art technology in 2008.

---

1 The value associated with cost improvements for relatively low-wind-speed sites in terms of reduced transmission costs are represented, in part, in the *Study Scenario* 2050 wind deployment results, whereby states including Louisiana, Mississippi, Alabama, and Georgia are each observed to have economic wind deployment serving regional load growth, under *Study Scenario* conditions (i.e., 10% wind energy by 2020, 20% by 2030 and 35% by 2050).

2 Wiser and Bolinger [3] illustrate that average rotor diameter has increased from approximately 80 m in diameter in 2008 to nearly 97 m in 2013. This represents an increase in rotor diameter of just over 20% and an increase in rotor-swept area of nearly 50%.

3 The 30% net capacity factor threshold is consistent with historical fleet-wide, operating-average wind capacity factor [3]. Although, increased turbine productivity would, under equivalent wind resource conditions, drive an increase in observed capacity factors, the confounding trend of siting wind power plants in lower quality wind resource areas (as well as the lag time between technology commercialization and technology deployment) has resulted in fleet-wide capacity factors remaining relatively flat with time. Accordingly, the 30% net capacity factor is applied here as a proxy for potentially viable commercial development. Actual development will depend on additional market, policy, and other factors.

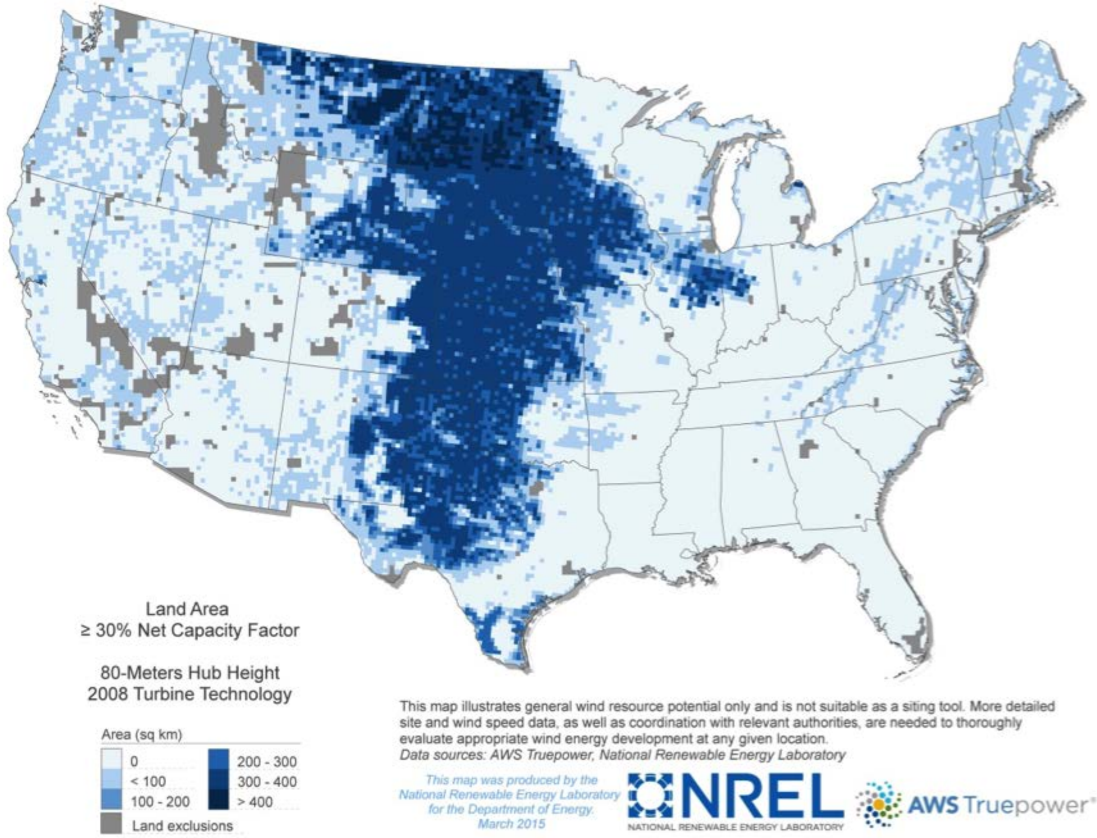


Figure O–1. Land area achieving a minimum 30% net capacity factor by grid cell, based on state of the art technology circa 2008

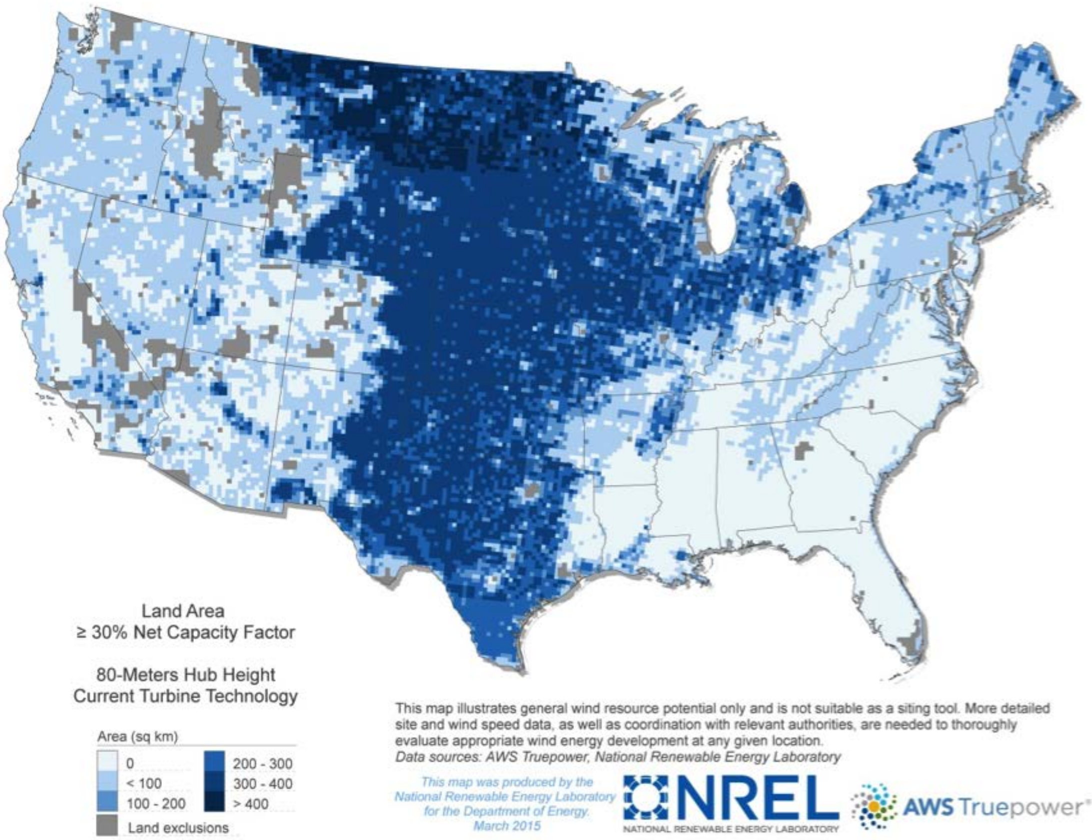


Figure O–2. Land area achieving a minimum 30% net capacity factor by grid cell, based on state of the art technology circa 2013

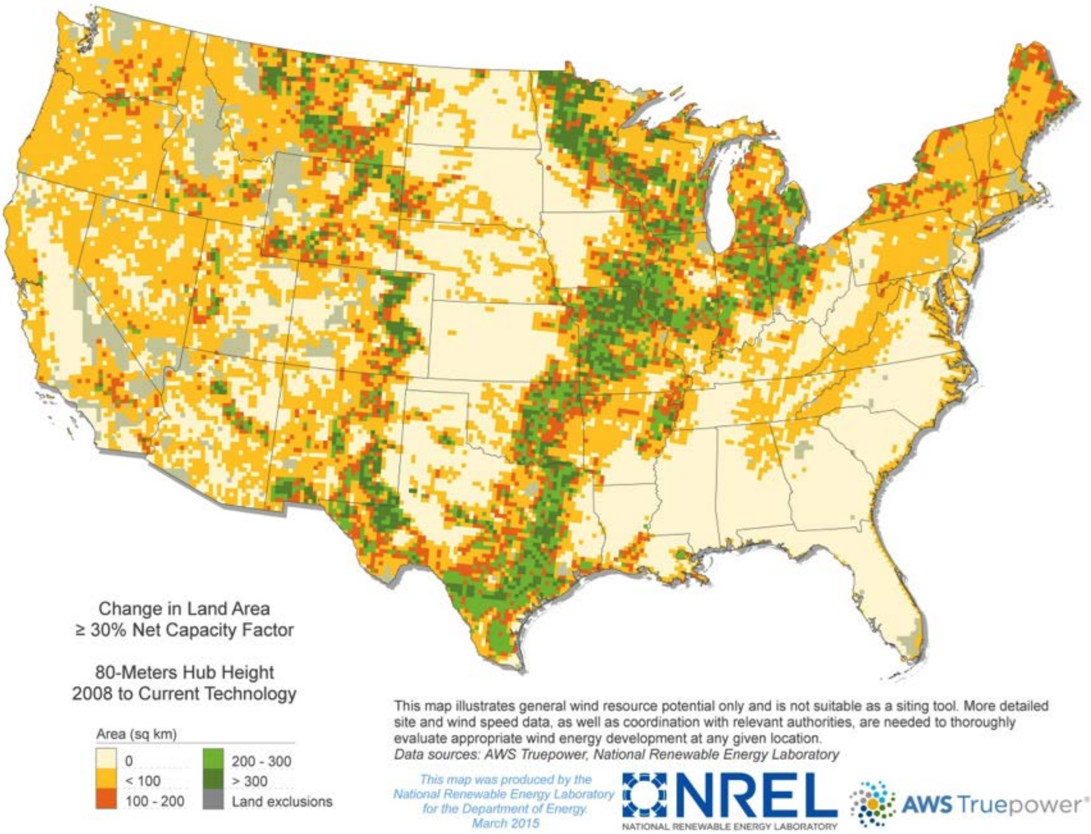


Figure O–3. Change in land area achieving a minimum 30% net capacity factor, based on state of the art technology circa 2008 and 2013

O.2 Future Impacts

Innovations are currently under development that would allow future turbine rotors to continue to grow to even larger diameters; the realization of these technologies would allow the turbine to maximize energy production at the wind speeds that occur with the highest frequency (often at wind speeds lower than rated power). In addition, consistent with longer-term historical trends, continued hub height increases are also expected beyond current national averages of 80-meter [4]. Hub height growth will allow the requisite ground clearance to be achieved for large rotor machines but also moves the turbine into higher quality resource conditions as one moves to higher above ground levels where the wind resource experiences reduced surface disruptions. Both of these innovation opportunities would support even greater expansion of the land area able to support a net capacity factor of 30% or above.

Focusing first on the implications of increased hub height, Figure O-4 illustrates the impact on land area achieving a minimum net capacity factor of 30% from taking a current turbine on an 80-meter (m) tower and simply placing it on a 110-m tower (i.e., a 110-m hub height). Figure O-5 illustrates the impact of placing current technology on a 140-m tower. Figure O-6 illustrates the change in land area resulting from the 140-m tower opportunity relative to the current technology (2013) estimates at 80-m. As is shown, land area achieving the 30% net capacity factor threshold is increased by 24% (0.7 million km^2) from the increase to a 110-m hub height and by 42% (1.2 million km^2) from the increase to a 140-m hub height, relative to the current technology 80-m estimates.

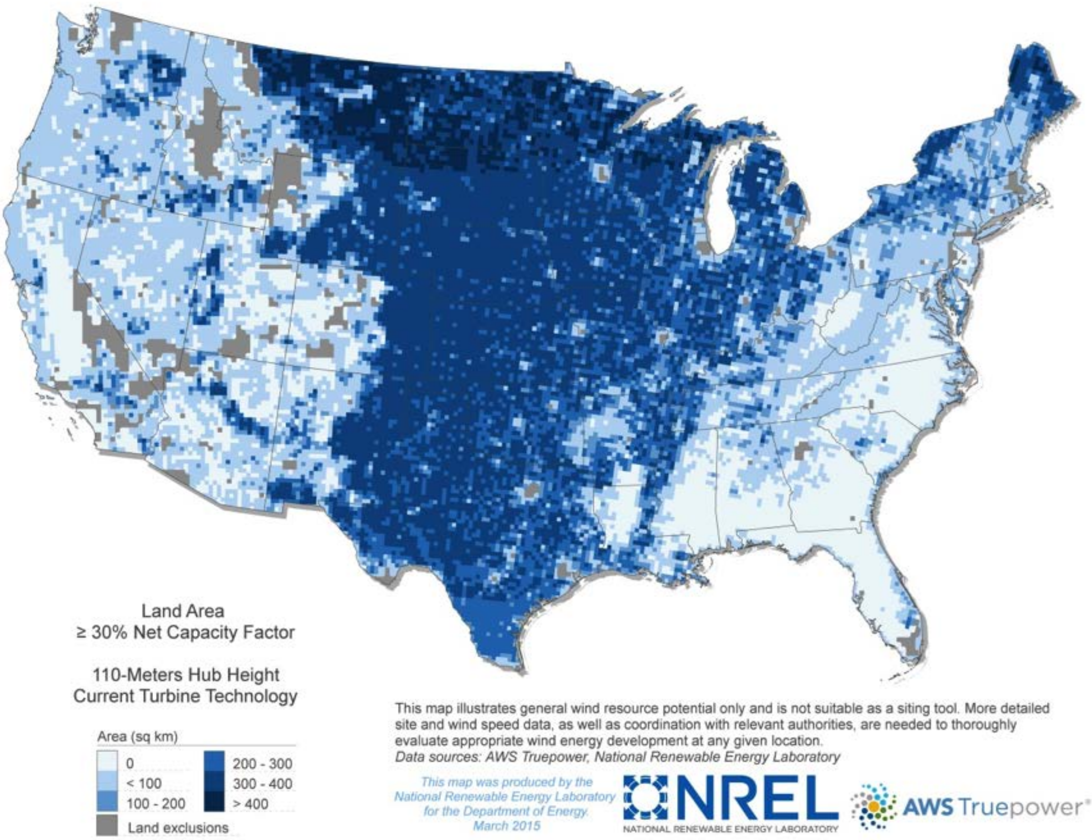


Figure O–4. Land area achieving a minimum 30% net capacity factor by grid cell, based on state of the art technology circa 2013 and assuming a 110-m tower

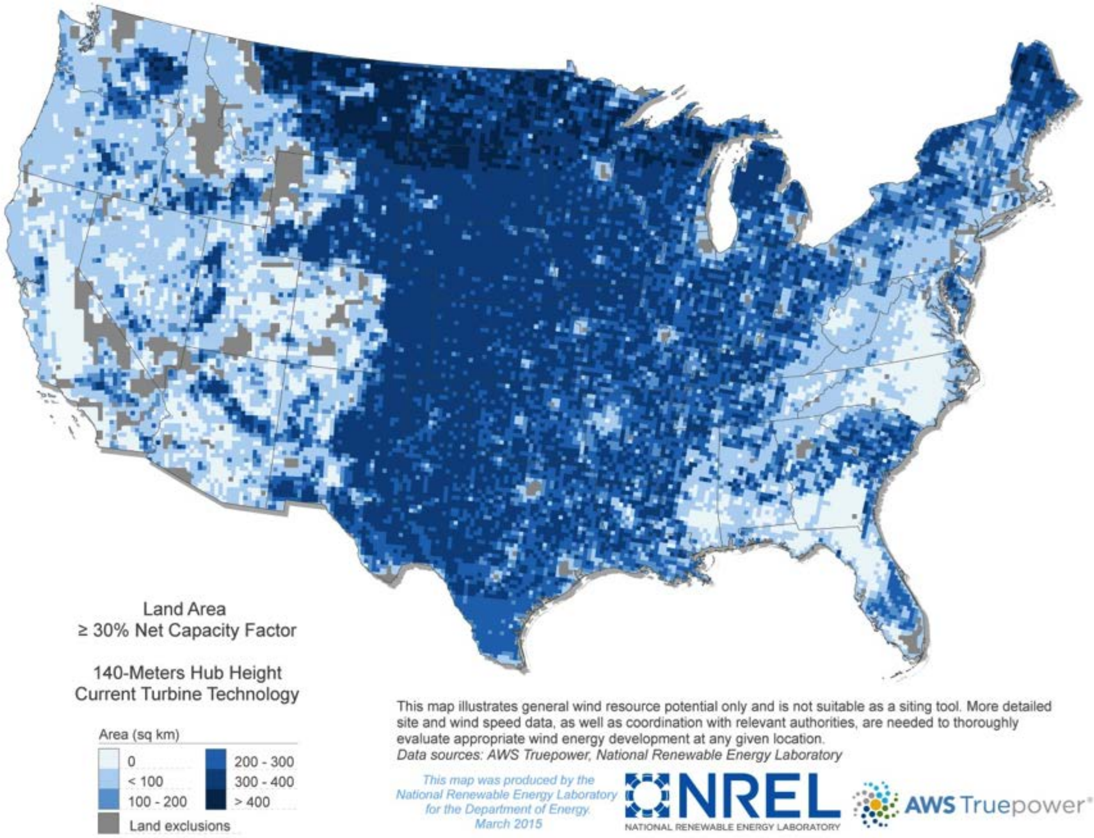


Figure O–5. Land area achieving a minimum 30% net capacity factor by grid cell, based on state of the art technology circa 2013 and assuming a 140-m tower

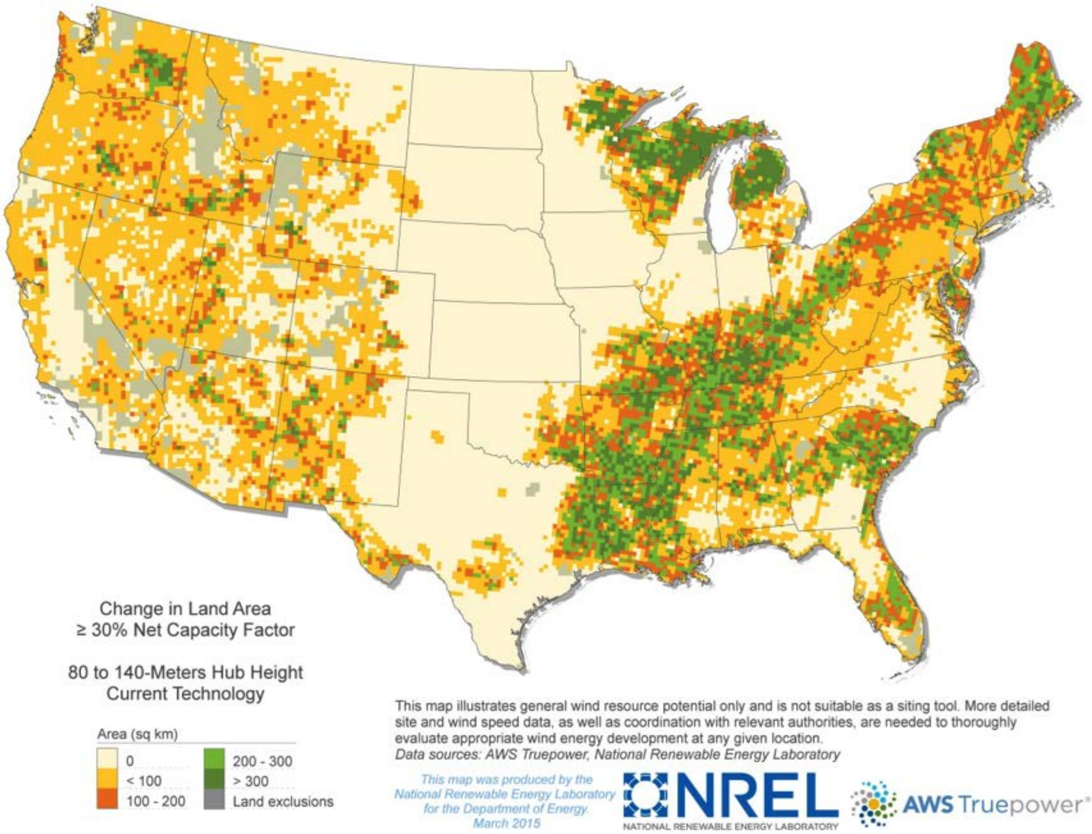


Figure O–6. Change in land area achieving a minimum 30% net capacity factor, based on state of the art technology circa 2013 and change from 80-m to 140-m hub heights

Now focusing on impacts from advanced turbines, assuming innovations currently under development, expected, near-term future impacts are estimated at 80-m, 110-m, and 140-m hub heights. As an example, estimates are derived from a conceptual "Next Generation" (Next Gen) wind turbine. This turbine increases rotor diameter up to 124 m (relative to a 2013 average of about 97-m) while holding average turbine nameplate capacity at 1.8 MW (relative to a 2013 average of 1.87 MW) [5, 3]. Such a change is expected to be feasible with commercial innovations in late-stage development and is not expected to trigger key transport or logistics constraints. This turbine would see an increase in turbine rotor swept area of approximately 1.4 times relative to 2008 and more than 60% relative to 2013.

Figure O-7 illustrates the land area achieving the 30% net capacity factor threshold noted above for this conceptual “Next Gen” turbine at an 80-m hub height. The resulting change in land area for this conceptual turbine relative to current 2013 technology and holding hub height constant at 80-m is 27% (0.8 million km^2)[4] The impacts of placing this “Next Gen” turbine on a 110-m and 140-m tower are shown in Figure O-8 and Figure O-9 and result in a 54% (1.5 million km^2) and 67% (1.9 million km^2) increase in land area, respectively, and relative to current technology 80-m estimates. The incremental increase in land area exceeding the 30% threshold as a function of both increased hub height and the move to the “Next Gen” concept turbine is shown in Figure O-10.

4 Although this suggests that technology advancements focused on rotor development have slightly greater impact on national level geographic expansion potential than a shift to the 110-m rotor diameter, it is also important to recognize that variability in key regional characteristics may alter the regional importance of such a result, relative to the national result.

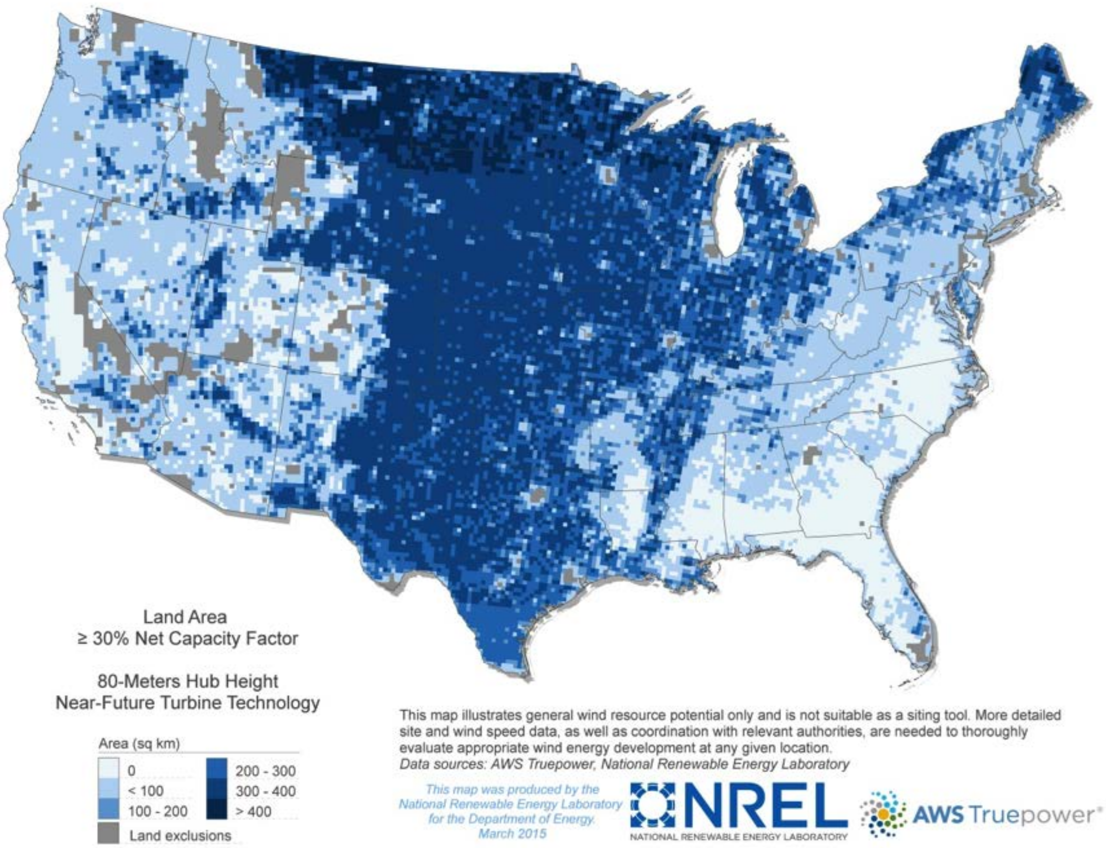


Figure O–7. Land area achieving a minimum 30% net capacity factor by grid cell, based on larger rotor designs and an 80-m hub height

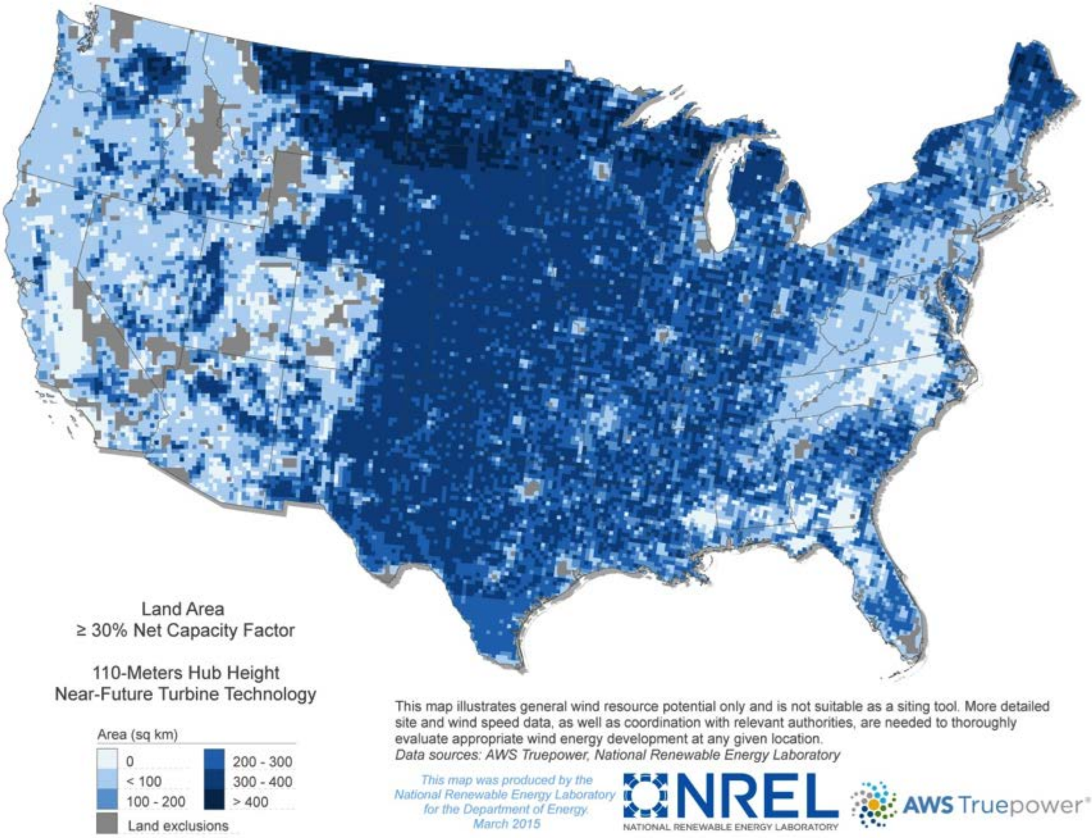


Figure O–8. Land area achieving a minimum 30% net capacity factor by grid cell, based on larger rotor designs and an 110-m hub height

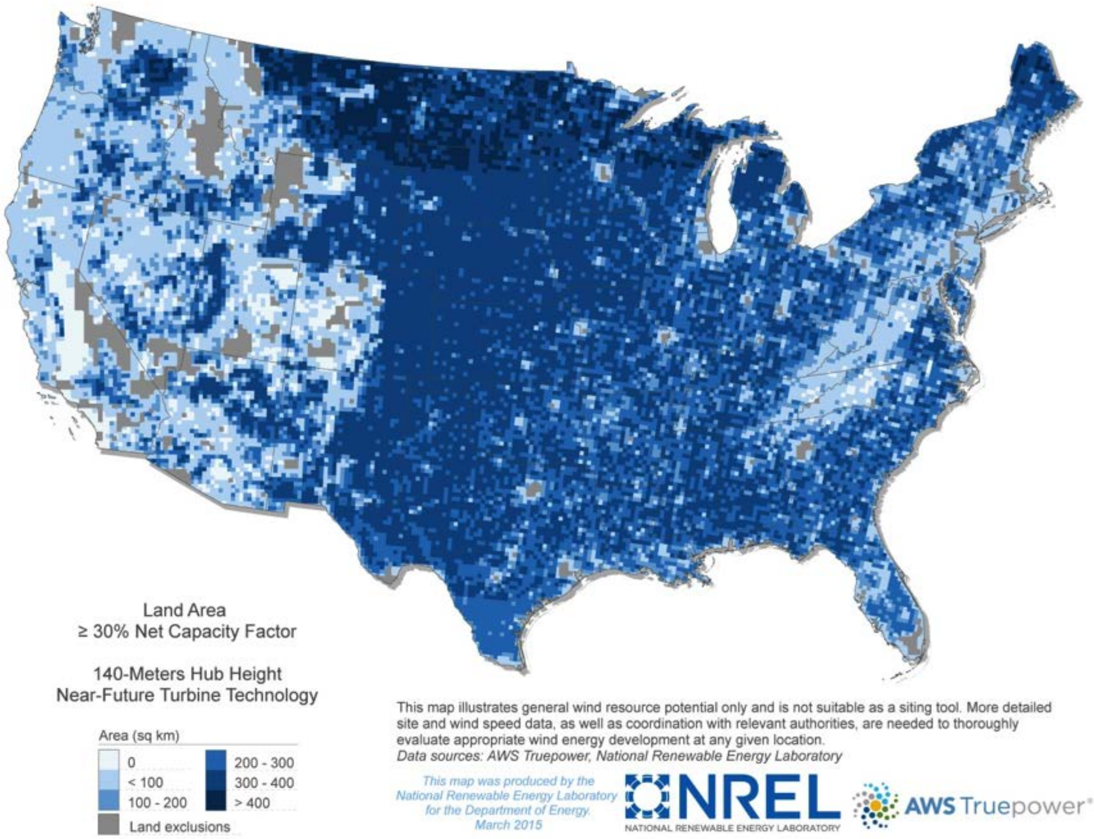


Figure O–9. Land area achieving a minimum 30% net capacity factor by grid cell, based on larger rotor designs and an 110-m hub height

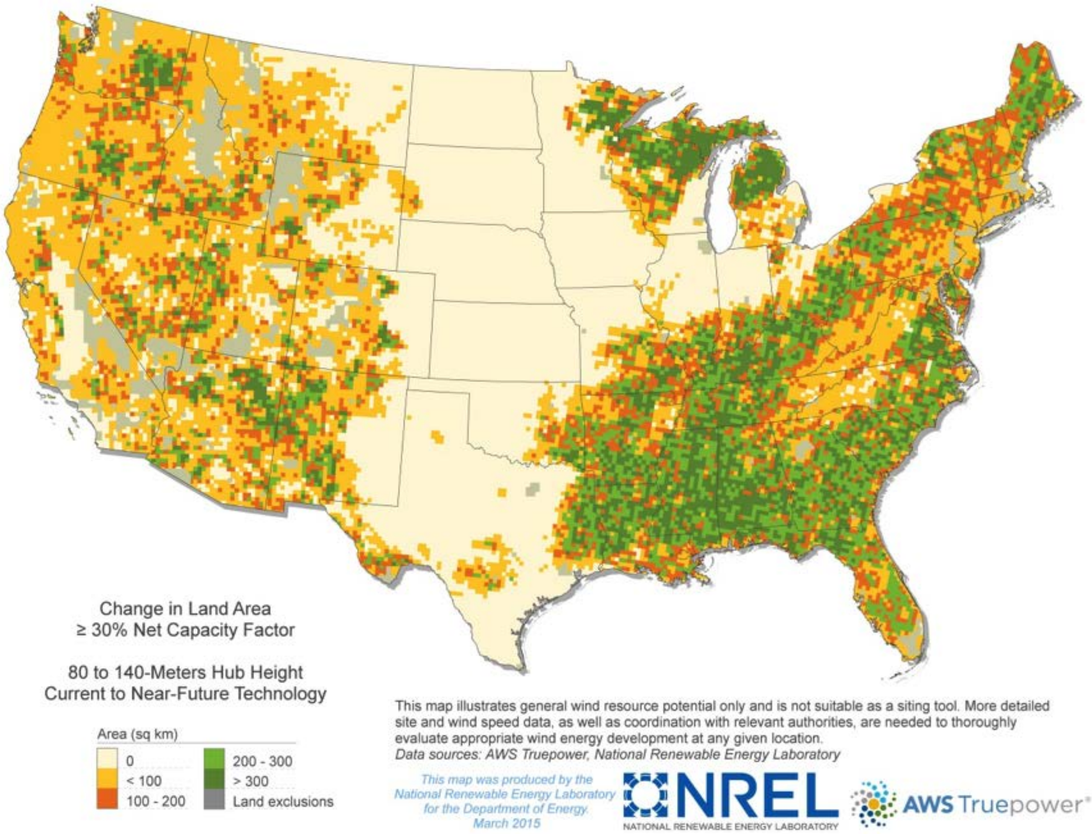


Figure O-10. Change in land area achieving a minimum 30% net capacity factor resulting from continued rotor growth and an increase to a 140-m hub height, relative to 80-m 2013 estimates

O.3 Discussion

Data presented in this appendix demonstrate that wind technology advancements (Table O-1) have already begun to affect the amount of land area that could potentially support a 30% or greater net wind capacity factor. Continued innovations could further expand this land area from current levels by more than 67% assuming hub heights of 140-m and continued incremental rotor growth. Since 2008, these advances have primarily expanded development opportunities in the West, Midwest, Northeast, and Mid-Atlantic. However, perhaps just as notably, much of the land area opened to potential new development as a function of future technology advancement lies in the regions of the Southeast, the East, Great Lakes and the Interior West (Figure O-10, Table O-2) large portions of which have previously been viewed as having insufficient resources for wind development.

Table O-1. Turbine Parameters Applied to Develop Land Area Estimates

	2008 Turbine Technology	Current Turbine Technology	Future Turbine Technology
Specific Power (W/m²)	400	210	150
Hub Height (m)	80	80, 110, 140	80, 110, 140

Viewed strictly in terms of impacts on the land area metric a substantial fraction of the increase in land area could be achieved by simply continuing rotor growth (Figure 11). At the same time, hub height growth to 110-m or 140-m would also bring an additional 21% and 32% increase in land area meeting the 30% net capacity factor threshold, respectively, and may be of relatively greater importance in regions with above average wind shear, such portions of the east. Although a coupling of the “Next Gen” turbine concept with increased hub heights results in land area exceeding the 30% net capacity factor threshold in nearly all regions of the country (Figure 9), continued incremental or disruptive innovations could further increase the cost viability of wind technology in these historically marginal regions.

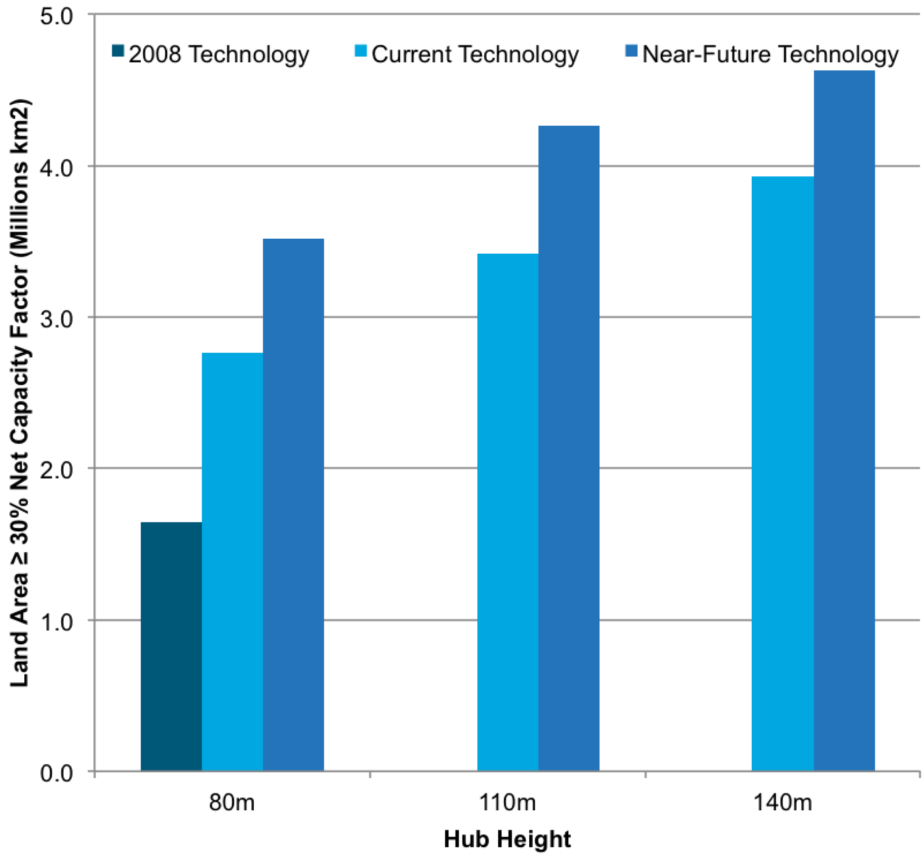


Figure O–11. Total land area achieving 30% net capacity factor or greater for 2008 technology, current technology, and future technology across hub heights

Table O-2. Change in Land Area Greater than or Equal to 30% Net Capacity Factor

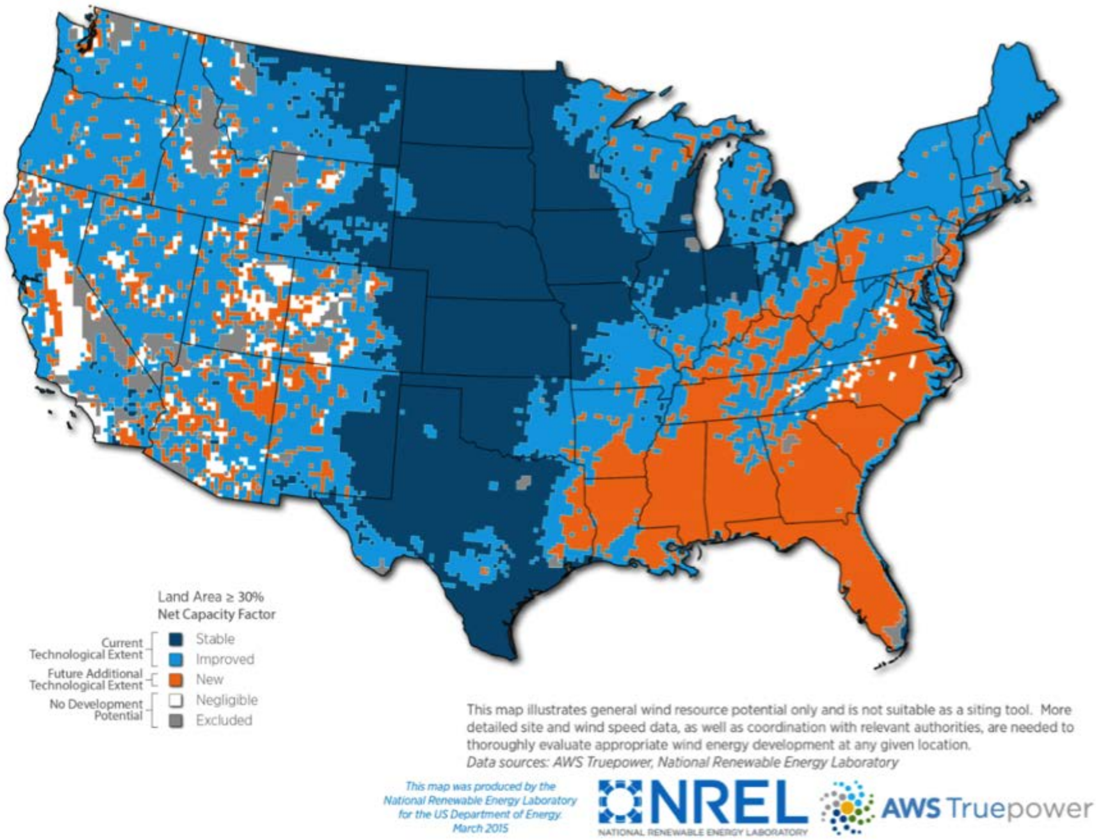
Hub Height	2008 Turbine Technology (million km^2)	Current Turbine Technology (million km^2)	% Change from 2008	Future Turbine Technology (million km^2)	% Change from Current
80 m	1.6	2.8	68%	3.5	27%
110 m		3.4	108%	4.3	54%
140 m		3.9	139%	4.6	67%

Notwithstanding the opportunity presented by technology improvement, key challenges must be overcome to realize this potential. First, the technical hurdles to achieving increased rotor size and tower height must be overcome. Second, these innovations must be realized in a manner such that the savings from reduced transmission needs and proximity to load exceed the incremental material, manufacturing, assembly, or transport cost associated with production and transport of larger wind turbine blades and towers. Finally, a series of regulatory, permitting, and siting barriers must be resolved. A great deal of public and private research and development attention and investment are already focused on solutions to the technology and cost challenges noted above. However, the latter issue of addressing and resolving regulatory, permitting, and siting barriers is somewhat more complex as it requires effort not only from within the wind power community but also from various local, state, and federal officials operating with varying levels of jurisdiction and authority.

Addressing regulatory, permitting, and siting barriers will require continued engagement from local, state, and federal officials already working on wind power and new engagement from officials and representatives in areas that are not currently affected by the technology. For example, stakeholders in the Southeast and parts of Interior West will need to evaluate and determine if areas that are expected to gain potential meet other environmental and public criteria for development. As well, increased hub heights to the level of 140-m or more are expected to push maximum turbine heights to more than 500 feet. Permitting turbines that exceed this height threshold will trigger increased scrutiny and engagement with the Federal Aviation Administration and the Department of Defense, and potentially, the development of new rules and regulatory policy. Despite these challenges however, technology advancements such as these will ultimately provide decision-makers with more sites to choose from in developing wind power specifically and low emissions renewable power generally. In principle, these increased options should facilitate more optimal decisions with respect to the siting of wind turbines around the nation as well as the preferred distribution of costs and benefits associated with wind power development.

O.4 Summary and Conclusions

Technology research and development is a key element of realizing the benefits of the *Study Scenario* with the minimal near-term costs and maximum long-term savings. Advanced technology can also open new regions to wind development, subsequently providing more opportunities for the business community, the utility sector and the public to deploy wind power in locations that are consistent with public and electric sector needs. Technology advancements since 2008 have increased the total land area that supports a 30% net capacity factor level or greater by nearly 70% with particularly noteworthy impacts in the West, Midwest, Northeast, and Mid-Atlantic. Continued incremental innovations in rotor size and hub height could further expand the land area achieving a 30% or greater net capacity factor by an additional 67% with impacts extending well into the Southeast, East, Great Lakes, and Interior West. Figure O-12 summarizes these results by illustrating the land area with sites that can achieve a 30% net capacity factor based on current (2013) technology, land area with potential today that sees increased potential with technology improvements, and new land areas achieving the 30% minimum net capacity factor as a function of technology advancement.



Note: Dark blue coloring identifies high quality wind resource areas that see no change in available land area meeting the 30% minimum net capacity factor threshold with technology advancement because the entire area is capable of achieving this threshold today. Light blue coloring identifies land area that meets the capacity factor threshold today but sees an increase in the proportion of the area able to achieve this threshold as a result of turbine and hub height improvements. Orange coloring identifies new land area able to achieve the minimum 30% net capacity factor level as a result of turbine and hub height improvements.

Figure O–12. Land area achieving a minimum 30% net capacity factor based on current (2013) technology, larger rotor designs and a 140-m hub height

Technology advancement provides the opportunity for wind power to expand to all U.S. states (Figure O-12). Key innovations needed to realize this opportunity include continued growth in rotor diameter in order to increase energy capture and increases in hub heights in order to capture better wind resource conditions at greater above ground level heights. As wind power technology continues to grow in scale and becomes increasingly viable around the nation, permitting, siting, and regulatory challenges will also require attention. Engagement with stakeholders at the local, state, and federal levels including agencies such as the Federal Aviation Administration and Department of Defense is expected to facilitate the constructive resolution of these challenges, while public and private sector research and development resources are currently working to resolve the remaining technical and cost hurdles needed to bring this future to fruition.

O. 5 References

[1] Wiser, R.; Lantz, E.; Bolinger, M.; Hand, M. "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects." WINDExchange presentation, Feb. 1, 2012. Washington, DC: U.S. Department of Energy Wind Program, Office of Energy Efficiency & Renewable Energy; 42 pp. Accessed Feb. 22, 2015: http://apps2.eere.energy.gov/ wind/windexchange/filter_detail.asp?itemid=3456.

[2] Lantz, E.; Wiser, R.; Hand, M. *IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2.* NREL/TP 6A20-53510. Golden, CO: National Renewable Energy Laboratory, 2012. Accessed Feb. 22, 2015: http://tinyurl.com/mzmm39m.

[3] Wiser, R.; Bolinger, M.; Barbose, G.; Darghouth, N.; Hoen, B.; Mills, A.; Weaver, S.; Porter, K.; Buckley, M.; Oteri, F.; Tegen, S. *2013 Wind Technologies Market Report.* DOE/GO-102014-4459. Washington, DC: U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, August 2014. Accessed Feb. 22, 2015: http://www1.eere.energy.gov/library/viewdetails. aspx?productid=6866&Page=9.

[4] Cotrell, J.; Stehly, T.; Johnson, J.; Roberts, J.O.; Parker, Z.; Scott, G.; Heimiller, D. *Analysis of Transportation and Logistics Challenges Affecting the Deployment of Larger Wind Turbines*. NREL/TP-5000- 61063. Golden, CO: National Renewable Energy Laboratory, 2014. Accessed Feb. 24, 2015: http://tinyurl.com/om5rla9.

[5] *Global Wind Turbine Trends 2013*. Market Report. Aarhus, Denmark: MAKE Consulting A/S, Dec. 18, 2013. Accessed March 3, 2015: http://www.consultmake.com/research-products?search=Global+Wind+Turbine+Trends+2013#researcharchive.

DOE/GO-102015-4557 • March 2015
Cover photos from iStock 30590690, 11765469

Wind Vision: A New Era for Wind Power in the United States

U.S. DEPARTMENT OF ENERGY