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Long-Term Modeling of Wind Energy in the United States

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June 2007

Prepared for the U.S. Department of Energy
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PNNL Research Report

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Abstract

Improved representations of wind energy have been developed for the O^bJECTS MiniCAM integrated assessment modeling framework. Two stages of this development are described. The first version of this wind model was expanded globally and used for the CCTP scenarios, and that version of the model and results are documented here in Sections 2 and 3. In the CCTP scenarios wind accounts for between 9% and 17% of U.S. electricity generation by 2095. Climate forcing stabilization policies tend to increase projected deployment. Accelerated technological development in wind electric generation can both increase output and reduce the costs of wind energy. In all scenarios, wind generation is constrained by its costs relative to alternate electricity sources, particularly as less favorable wind farm sites are utilized. These first scenarios were based on exogenous resource estimates that do not allow evaluation of resource availability assumptions. In Section 4, we describe a more detailed representation of wind energy that we have subsequently developed that uses spatial resource information and explicit wind turbine technology characteristics. A description of this new model and results for the United States are presented.

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1. Introduction

This report provides an update on modeling of wind energy within the O^{bj}ECTS MiniCAM at the Joint Global Change Research Institute (JGCRI). Started in FY 2004, the project aims to use integrated assessment modeling to understand the potential role of wind generation in the future market for electricity. A particular focus is to understand the potential role of wind technologies in the context of potential carbon constraints including interactions with other electric and non-electric technologies. Version 1 of this project was implemented for the U.S. in 2004 for U.S. DOE office of Energy Efficiency and Renewable Energy (EERE). The model was later expanded to global coverage under the Global Energy Technology Strategy Program (GTSP), and applied to scenarios developed for the U.S. Climate Change Technology Program (CCTP) and Climate Change Science Program (CCSP). Work on a more detailed representation of wind (“Version 2”) continued while the CCTP and CCSP scenarios were being developed, and a preliminary version of this model has been implemented. The successive stages of development are described in this report.

1.1. Overview of O^{bj}ECTS MiniCAM

Integrated assessment modeling at JGCRI integrates an economic system perspective with technological detail. The O^{bj}ECTS MiniCAM is a partial equilibrium model of global energy, economy, agriculture/land-use, and climate change that assesses the upcoming century in 15-year timesteps. Each timestep is solved for an equilibrium condition where supplies equal demands for all goods. The current version of the model uses an object-oriented structure, allowing the capability to create and refine individual sectors of the model (Kim et al. 2006). By virtue of this flexibility, as well as its scale and time frame, it is well-suited to explore the strategic role of energy technologies.

In the O^{bj}ECTS MiniCAM, technologies are incorporated by allowing an endogenous selection between competing available technologies, using a cost-based logit formulation. Models are calibrated to historical data for 1990 and 2005, and both existing and new technologies can compete to supply energy services in the future. Assumptions about potential technological change and other characteristics relevant to the deployment of the technologies are informed by present knowledge and available research.

1.2. Application of O^{bj}ECTS MiniCAM to wind energy

Key characteristics of the MiniCAM modeling approach are flexibility, transparency, and reasonable execution time. While analysis focused on short-term developments in the energy system would tend to use a very high level of detail, this technique is not appropriate for modeling on the time scales of decades to a century. Instead, our approach focuses on broad features of the energy system, such as technology and the drivers of market demands. The impacts of plausible changes in policies, technological development, and other scenarios can then be assessed by comparative analysis.

Our goal in this project is to build on the best existing work to develop a representation of wind energy that can simulate a wide range of future wind energy market characteristics, and capture the interactions between wind generation and the rest of the energy system. Version 1 was initially developed for the U.S. and later applied to all regions of the world. Version 2 of our wind energy system currently focuses on the U.S., but will be applied to other world regions depending on the availability of suitable wind resource data. This report starts with a schematic overview of Version 1 of the wind model, followed by a presentation of results from the scenarios made for the CCTP. Section 4 details the present work on Version 2, and the report concludes with a summary of future directions.

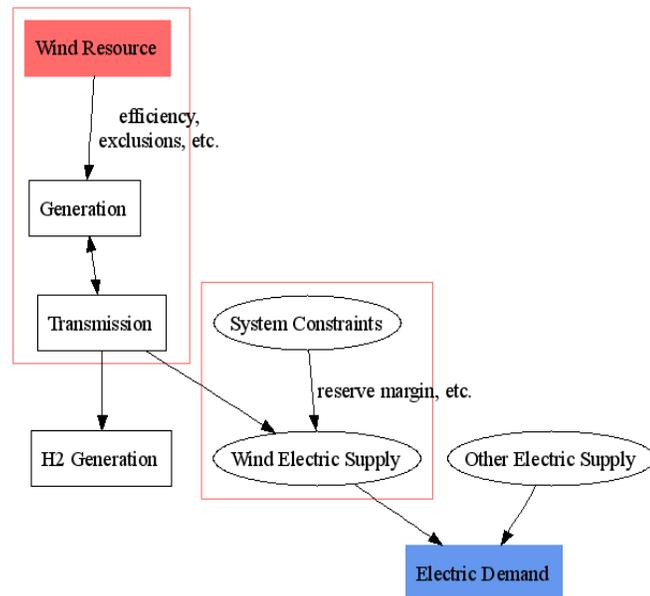


Figure 1.1: Simplified schematic of the wind electric system.

A simplified representation of the wind energy system within the O^{bj}ECTS MiniCAM is shown in Figure 1.1. The model for wind electric generation was separated into two primary components (red boxes): wind generation and transmission, and integration of the power into the rest of the electric system. Additional reserve requirements were stipulated based on a formulation developed by the National Renewable Energy Laboratory (NREL 2006a).

Version 1 of the wind model uses a simplified representation of wind generation and transmission based on exogenous cost curves. The more detailed version developed later uses explicit spatial data to develop an endogenous representation of wind generation and transmission.

2. Wind Supply in O^{bj}ECTS MiniCAM Version 1: Exogenous Supply Curves

2.1. Wind Generation and Transmission

In our first version of the wind model, wind generation and transmission was based on supply curves published by the International Energy Agency Greenhouse Gas Programme (IEAGHG 2000). The curves detail wind generation in a given year as a function of the marginal cost of electricity generation, derived from a GIS model of wind generation costs at every cell in a gridded database for each region. Costs at each cell were calculated from the quality of wind resources, turbine capital and operating costs,

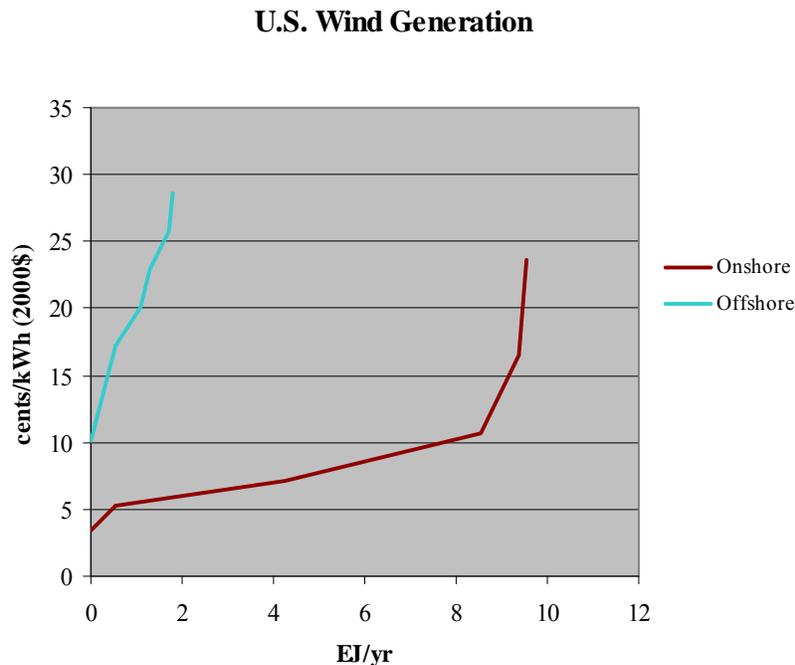


Figure 2.1: U.S. Wind energy supply curves from the IEAGHG (2000) for 2005 as adjusted to 2005 technology characteristics.

distance to electric transmission and distribution networks, and costs of building additional transmission lines and grid reinforcement.

The IEAGHG report presented separate supply curves for off-shore, large on-shore and small on-shore wind generation. In our analysis we have used large on-shore and off-shore supply curves. We have adjusted the data from the original report to account for improved wind turbine characteristics as detailed in the EERE FY2006 GPRA report (NREL 2005). These characteristics include wind turbine capital costs, operation and maintenance costs, and capacity factors. Because technological improvement was assumed to take place over time, the supply curves were adjusted for each 15-year timestep. This is detailed in Section 3.1.

The supply curves used for 2005 in Version 1 for the U.S. are shown in Figure 2.1. Comparisons with other resource assessments for the United States indicate that these curves could be pessimistic regarding U.S. wind resource potential (Cadogan 2006). The reasons for these differences are not clear, given that the resource data appear to be similar (Figure 4.5 in IEAGHG 2000 appendix A). One potential difference is the 0.15 MW/km^2 large-scale regional capacity limit that was applied in the IEAGHG report. Note that this limit applies to average wind density over some large region, not the density of wind turbines in an individual wind farm. This limit was based on social acceptability in Denmark, a limit that is not likely to be appropriate for more sparsely populated areas, such as much of the mid-western United States. Our spatially-based wind analysis (Section 4) is intended to directly examine these issues.

2.2. *Electric System Integration*

Because of the intermittency of the wind resource, wind additions to electric generation require greater ancillary services for integrating them into the electric system than would generation from dispatchable energy sources such as fossil fuels, hydroelectricity or nuclear power. These ancillary services include additional operating reserves and additional reserve capacity to compensate for potentially diminished contributions from wind to long-term planning reserve margins. For these initial efforts at modeling wind in more detail, we have focused on the impact of wind on operating reserve requirements.¹ Following the formulation used in the National Renewable Energy Laboratory WinDS model (NREL 2006a), we have modeled the operating reserve constraint by requiring:

$$(2.1) \quad \text{Additional Operating Reserve} = k \sqrt{\left(\frac{\text{NormalReserve}}{k}\right)^2 + \sigma^2 W^2} - \text{Normal Reserve}$$

In this equation, Normal Reserve refers to the operating reserve requirement that would apply to load supplied by dispatchable electric generation sources. Wind generation and its variance are W and σ^2 , respectively, while k is a constant specified to determine the tolerance limit of the operating reserve requirement². An intermittent energy resource such as wind adds variability into the system and, therefore, requires additional reserve capacity to maintain system stability. Equation 2.1 specifies the amount of operating reserves, which we have assumed to consist of additional quick start reserve capacity that would need to be provided as wind penetration increases. Equation (2.1) assumes that wind variance is uncorrelated with demand variance.

The cost of wind power therefore increases with output according to the supply curve (Figure 2.1) and ancillary requirements that increase with wind energy's share of total electricity generated. In this model, there are no pre-set limits to wind market penetration; wind deployment is limited only by competition with alternative electric generation technologies.

Note that the OBJECTS MiniCAM is a dynamic-recursive model, so that all parameters are for the current period. The model iterates values for the current period until markets are cleared and any trial values converge. Values such as those in Equation (2.1), for example, will be consistent for each time period. Values from previous periods are not used.

¹ Our model focuses on energy, and does not currently have an explicit capacity market or reserve margin constraint, though we have a new project to address this issue. However, our current approach focusing on electric generation does implicitly derate wind capacity's contribution to reserve margins to its average capacity factor.

² For example, in a Normal distribution, setting k to 3 would result in an upper tolerance limit such that 99.9% of values would be below that limit.

3. Wind in the CCTP Model Scenarios

This section presents wind modeling results from two scenarios from the O^bJECTS MiniCAM, developed in support of the CCTP strategic planning process (Clarke et al. 2006). The impacts of four carbon policies and a reference (no policy) case are examined initially in a scenario of reference technological development, and then compared with several scenarios of advanced technological development.

The policies correspond to four emissions trajectories analogous to those of Wigley et al. (1996) that ultimately lead to stabilization of atmospheric CO₂ concentrations at four different levels. The strategy allows for emissions reductions to take place in a flexible manner with respect to time and place, with the goal of minimizing the net present value of global emissions reductions costs. The four emissions pathways, assumed to be implemented in 2020, ultimately stabilize total greenhouse gas forcing. For purposes of this paper, we refer to the scenarios using their reference technology CO₂ concentration stabilization levels of 450 ppmv, 550 ppmv, 650 ppmv, and 750 ppmv.³

In this report, we focus on two technology scenarios, the reference case and the “New Energy Backbone” (hereafter NEB) scenario, which incorporates accelerated development of wind energy technologies. Note that substantial technological development is assumed to take place in the reference case. In NEB, however, additional technological improvements are assumed for renewable energy sources and nuclear energy, which have an impact on the market penetration of wind.

3.1. Future Wind Technology Assumptions

The technological development assumed to take place in the reference technology scenario is based on improved turbine and wind farm design. Wind resource availability and variance are assumed constant in the future. While technologies related to electricity transmission and distribution are assumed to improve, such improvements apply to all forms of electricity generation, and as such, are assumed not to influence the economics of wind relative to alternatives.

The technology scenarios for wind energy generation were drawn from EERE projections (NREL 2006), and are shown in Table 3.1". Capacity factors are assumed to increase while capital costs decrease in both the Reference and NEB cases. These changes increase the amount of energy available from a given wind site, and decrease the cost of wind-generated electricity. The net effect is a decrease in the cost of wind-generated electricity, relative to 2005, of 30% in 2050, and 35% in 2095 in the Reference case. The respective net decrease in wind electricity costs in the NEB case were 62% and 70% in

³ Stabilization in these scenarios was defined in terms of the radiative forcing from the “Kyoto” suite of greenhouse gases: CO₂, N₂O, CH₄, PFCs, HFCs, SF₆, and other long-lived fluorinated gases. The radiative forcing stabilization levels were constructed so that, under reference technology, the resulting CO₂ stabilization levels were 450 ppmv, 550 ppmv, 650 ppmv, and 750 ppmv. In the advanced technology scenarios, because of additional reductions in the emissions of non-CO₂ GHGs, the CO₂ concentrations can increase roughly 5 ppmv above these levels.

Table 3.1: Reference and NEB (“New Energy Backbone,” an advanced case) assumptions of capacity factors, capital costs, and resource variance for land-based and offshore wind generation.

	Reference			NEB	
	2005	2050	2095	2050	2095
Capacity factors					
Land-based	0.387	0.450	0.450	0.504	0.504
Offshore	0.387	0.427	0.427	0.451	0.451
Capital costs (\$/kWh)					
Land-based	0.046	0.031	0.029	0.022	0.020
Offshore	0.078	0.039	0.036	0.032	0.029
Wind resource variance	0.30	0.30	0.30	0.25	0.25

2050 and 2095. As well, in the NEB case, wind resource variance was assumed to decrease, due to more geographically dispersed wind generation and more advanced techniques for managing the variance of the resource.

3.2. *The Electricity Market*

To put the wind electric market in a broader context, we first present the projected growth in electricity production during the upcoming century. As shown in Figure 3.1A, global electricity production is projected to increase by nearly 400% between 2005 and 2095, which far outpaces the population growth over this period, assumed to be 34% (based on UN 2005 and MEA 2005). This trend is driven by mostly worldwide economic development, and increased electrification of buildings and industry.

Stabilization policies, by leading to increased fuel costs, result in decreased electricity production over time, relative to the reference (no policy) case (Figure 3.1), although the actual share of electricity with respect to other end-use fuels may increase. Between 2020 and 2050, the response to the policies is monotonic: more stringent policies induce lower levels of electricity production. However, by 2095, the more stringent policy cases (450 and 550 ppm) actually show increased electricity production relative to the less stringent policy cases. This is because emissions reduction strategies often entail increased electricity use, as electricity can be less carbon-intensive than alternatives. Wind power plays a role in this CO₂ reduction strategy, and we will return to this point later.

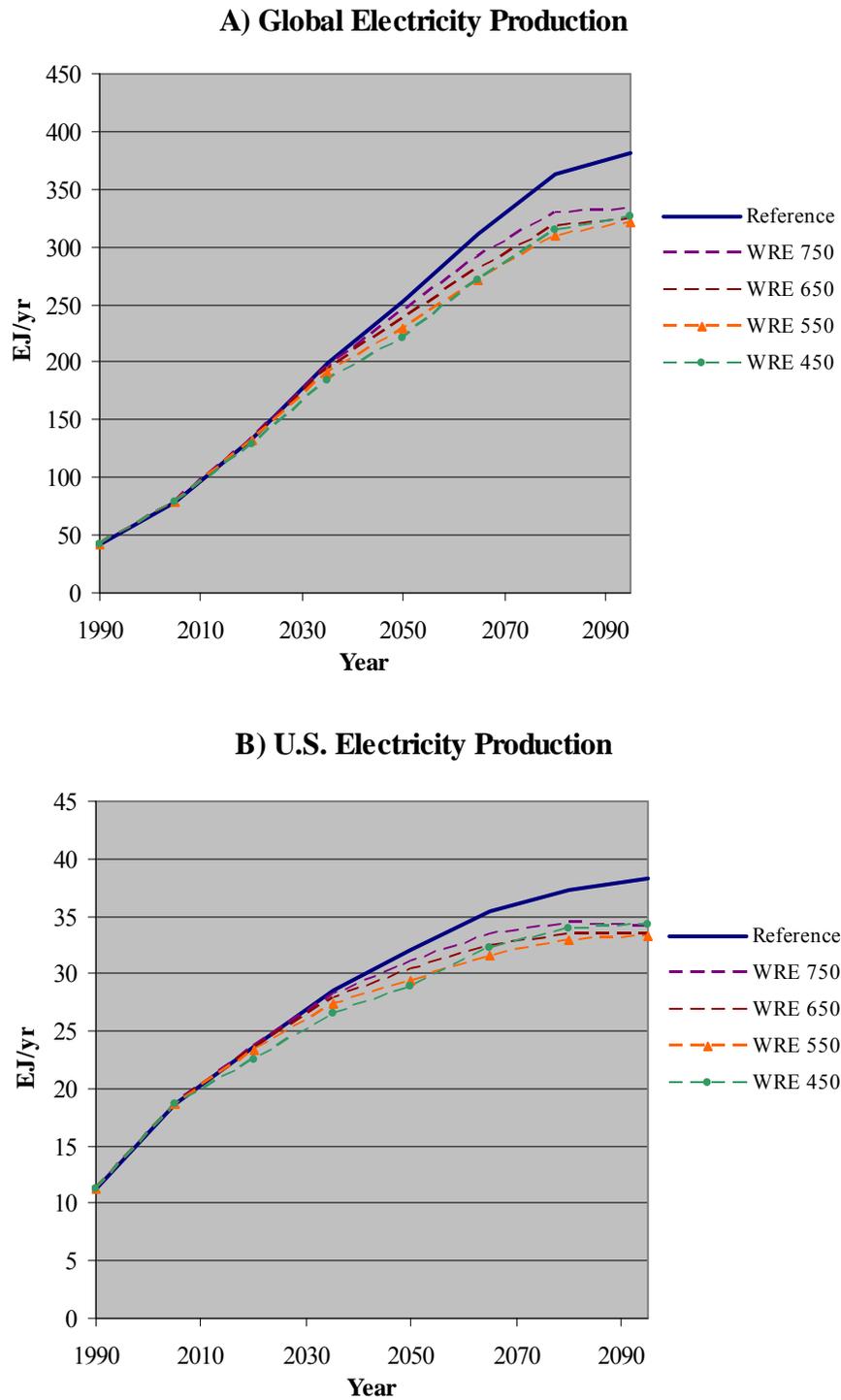


Figure 3.1: Global (A) and U.S. (B) electricity production, in four CO₂ stabilization policies and a reference (no policy) case. (1 EJ = 277.8 TWh)

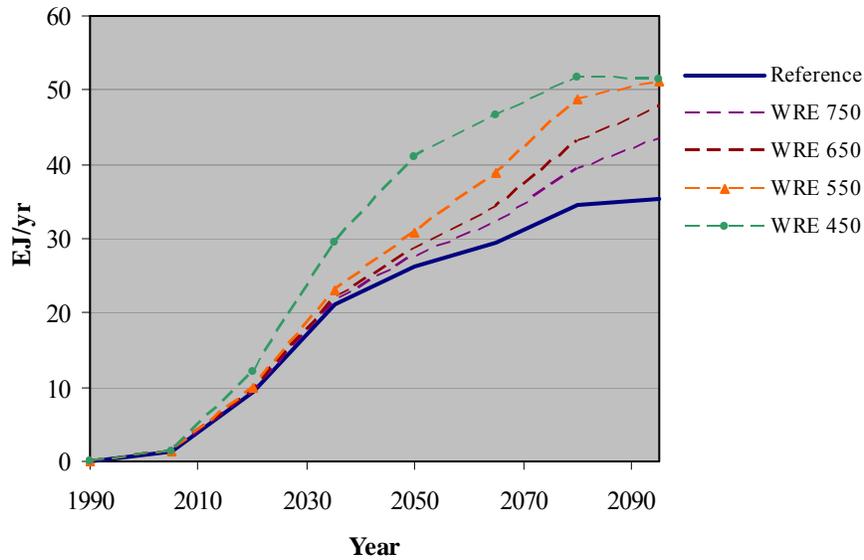
3.3. *Wind Electric Generation in a Reference Technology Scenario*

Lower wind production costs over time (Section 3.1) relative to costs for other technologies drive an increase in wind electric production over the century (Figure 3.2). Absent a carbon policy, wind accounts for 9% of electric generation in 2095, both globally and in the U.S. Nearly all (> 99%) of this production is onshore, because although some favorable locations are used, there is less available off-shore wind at costs comparable to on-shore costs (see Figure 2.1).

Wind generation, as a carbon-neutral electricity source, stands to increase in deployment under all stabilization levels (Figure 3.2). Stabilization policies lead to an increase in deployment of wind generation, as wind can substitute for carbon-emitting technologies in electricity production. Globally, the 450 ppmv case shows a 46% increase in annual wind power production by 2095 as compared to the reference case, accounting for 16% of total electricity generation (see Figure 3.2A). In the U.S., the policies induce increases in wind generation until 2050, at which point the 450 ppmv scenario results in a 74% increase in wind generation relative to the reference (no policy) case (Figure 3.2B). However, after this time, there are no further increases in wind generation for the 450 ppmv policy scenario, and by 2095, it has converged with 550 ppmv scenario. Even in the 450 ppmv scenarios, offshore production globally and in the U.S. in 2095 only accounts for 2% of total wind generation.

The deployment of wind is an important component of the global response to emissions constraints. As shown in Figure 3.1, the more stringent stabilization policies accelerate the electrification trend already projected to take place absent any policy. The reason for this shift is that electricity can be produced in part by carbon-neutral technologies such as wind turbines, and as such, electricity can be a less carbon-intensive alternative than competing technologies. This positive feedback between carbon-neutral electricity production and substitution of electricity for fossil fuels in end-use applications is an important technological strategy for meeting emissions requirements, and one in which wind can play a significant role.

A) Global Wind Electric Generation



B) U.S. Wind Electric Generation

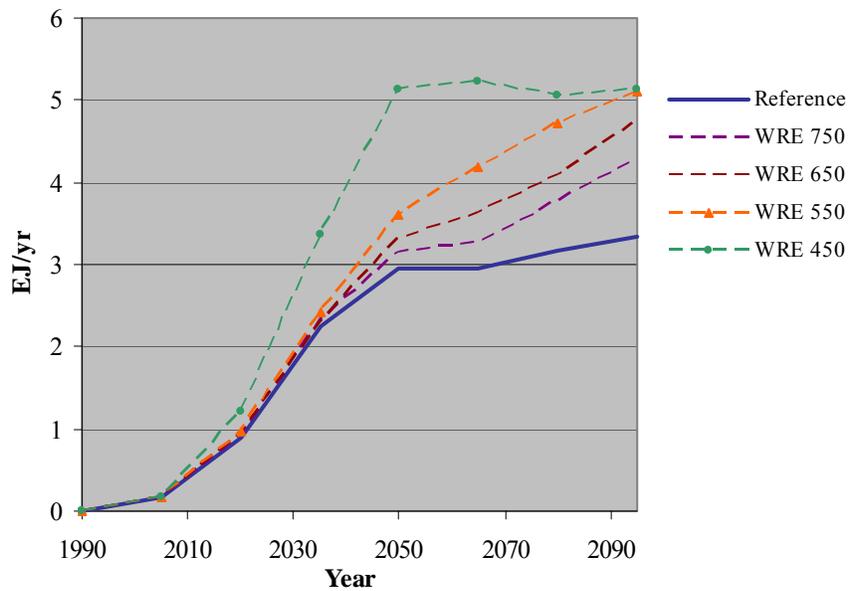


Figure 3.2: Global (A) and U.S. (B) total wind electric generation (offshore + onshore), 1990-2095, under four CO₂ stabilization policies and a reference case.

The role of wind is constrained by the costs of wind energy generation relative to other available technologies. As wind deployment expands, generation costs can be expected to increase due to the use of less economical resources (Figure 2.1), and due to increasing

ancillary costs. In the 450 ppmv scenario for the U.S., shown in Figure 3.2B, generation reaches a plateau in 2050, after which further increases are small. This is driven by increasing marginal costs of wind generation, and by electricity prices, which also plateau in 2050 in the 450 ppmv stabilization scenario (as electric generation is increasingly decarbonized in this scenario and not further affected by the increasing carbon prices). In the emissions pathway prescribed by this stabilization scenario, 2050 has the sharpest decrease in emissions from the preceding period of all eight periods. It therefore marks a turning point in the fuel mix of electricity generation, which undergoes a transition from coal and gas combined-cycle to more expensive alternatives, particularly nuclear, renewables, and fossil fuels with carbon capture and storage. After this year, further changes in the fuel mix are minor, and as a result prices remain relatively stable. The dependence of wind electric generation on electricity prices highlights the large role that wind generation costs play in determining future wind electric potential.

The cost of wind generation is the sum of generation and ancillary costs, each of which increase as a function of total wind electricity generation. These costs over time for the U.S. are detailed in Figure 3.3. As shown in Figure 3.3A, generation costs increase over time, as the assumed decreases in wind turbine costs are outweighed by deployment of less economical resources as wind generation expands, a trend induced by electricity prices. Similar to electricity prices, marginal costs for wind energy generation and ancillary costs (Figure 3.3B) in the 450 ppmv scenario peak in 2050.

These results indicate that wind deployment in the U.S. in this scenario is not limited by a finite resource, but rather by the economics of wind generation relative to costs of other electric generation technologies. In all stabilization policy cases, a premium is placed on wind-produced electricity, allowing for wind electricity generation at higher costs than in the no-policy case. For instance, in 2095, generation costs are increased by 12% (750 ppm) to 27% (450 ppm), relative to the reference (no policy) case. Because costs relative to competing fossil and non-fossil generation options limit deployment, technological improvements that lower costs can play an important role in the future U.S. wind electric market.

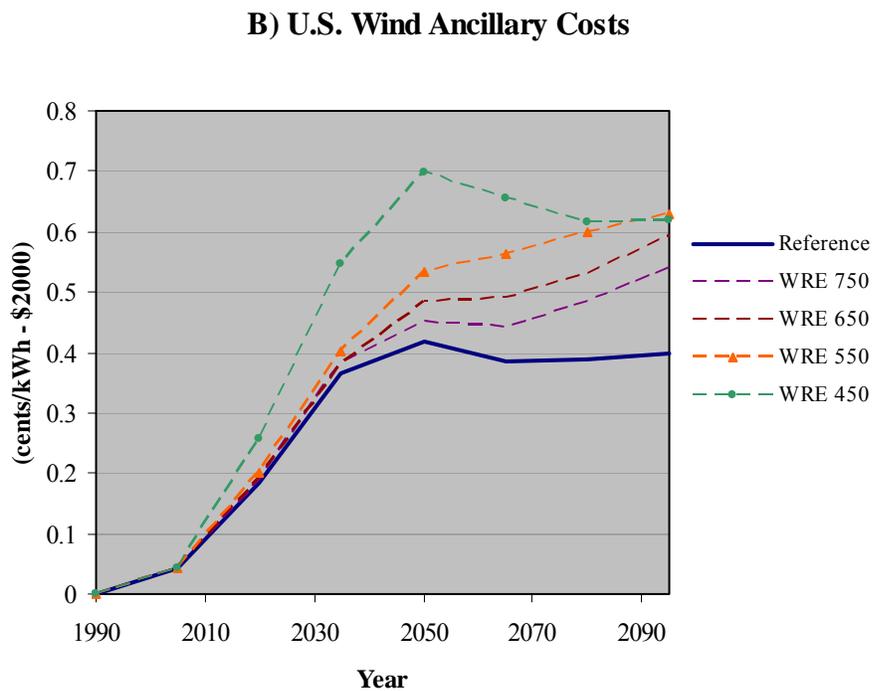
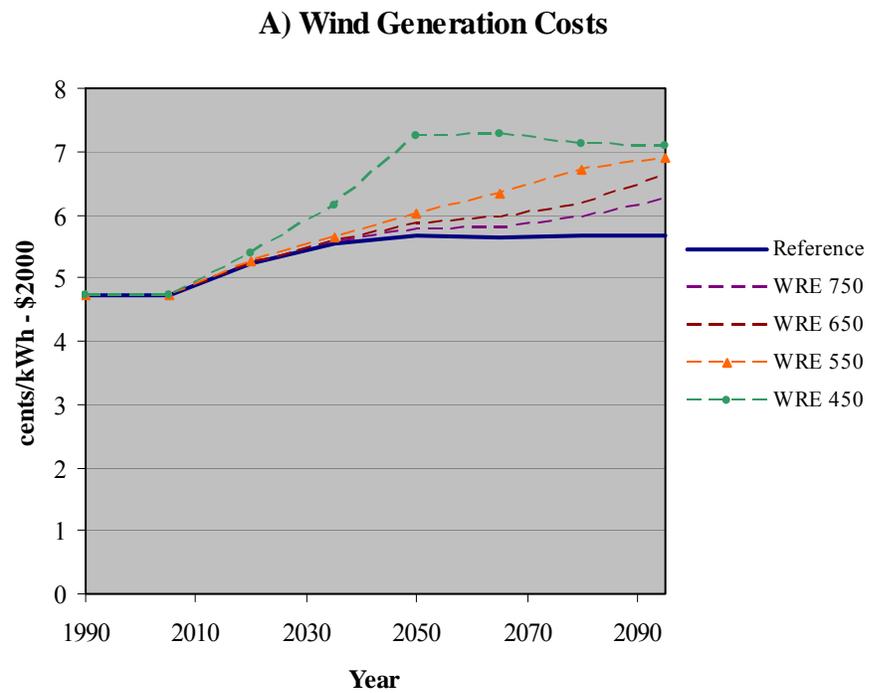


Figure 3.3: Marginal cost of U.S. wind electricity generation 1990 – 2095, broken down into generation cost (A) and ancillary costs (B) for additional operating reserve capacity, under four CO₂ stabilization policies and a reference case.

3.4. *U.S. Wind Electric Generation in Advanced Technology Scenarios (NEB)*

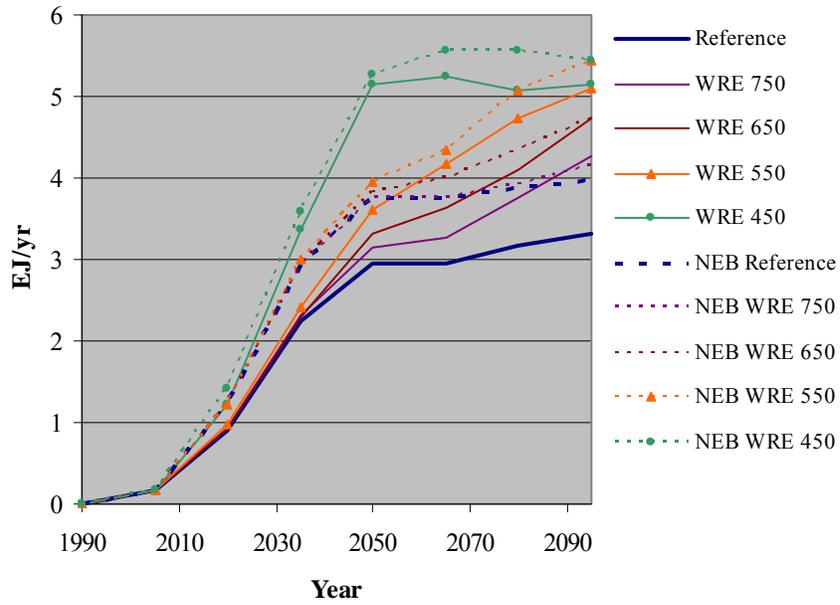
Section 3.3 examined the roles of stabilization policies in the market for wind electric generation, and pointed out that climate policies lead to increased wind production despite increases in marginal generation cost. In this section we address the role of technological development as a means to offset some of these costs. The advanced technology scenarios presented here (NEB) were developed in order to plausibly represent accelerated future technological gains in non-fossil energy sources, specifically nuclear, solar, and wind energy. In addition, the NEB scenarios include improvements in end-use energy intensity, increased opportunities to reduce non-CO₂ GHG emissions, and enhanced terrestrial carbon sequestration. In NEB, efficiency improvements in wind electricity generation are accelerated relative to the Reference case (see Section 3.1).

Because any changes in wind electric generation take place within the context of the electricity market as a whole, it is helpful first to note the effects of advanced technology on electricity production and costs. Electricity production with advanced technology in all year-policy combinations is similar to electricity production under reference technology, shown in Figure 3.1B.⁴ However, electricity prices decrease in NEB, due to accelerated development not only in wind but also in solar and nuclear technologies. Between 2050 and 2095, in the no-policy case, NEB shows a 5% to 8% decrease in electricity prices relative to the reference technology scenario. This decrease is between 11% and 25% for policy scenarios between 2050 and 2095. Lower electricity prices will tend to decrease wind deployment, while the effect of reduced costs of wind generation will tend to increase deployment. The net effect of NEB technology on wind generation across the policy scenarios is due to a combination of many assumptions.

U.S. wind electric generation across the two technology suites and five stabilization policy scenarios is shown in Figure 3.4A. In the absence of any carbon policy, NEB technology shows greater levels of wind generation than reference technology (20% in 2095). In carbon policy scenarios, wind generation also increases in NEB relative to reference technology, though to a lesser extent than without a policy, due to the advances described above in other non-fossil generation sources. However, the change in output is only one part of the effect of technological advances, as improved technology also decreases generation costs.

⁴ Due to the assumption of lower final energy demands in the NEB scenarios, electricity consumption in the no-climate policy NEB scenario is lower than in the no-policy reference technology scenario. Due to the combined effect of the advanced technologies in the NEB scenarios, however, electricity consumption in the NEB climate policy scenarios is generally slightly larger than electricity consumption in the corresponding reference technology climate policy scenarios.

A) U.S. Wind Generation



B) Marginal Cost and Wind Generation, 2095

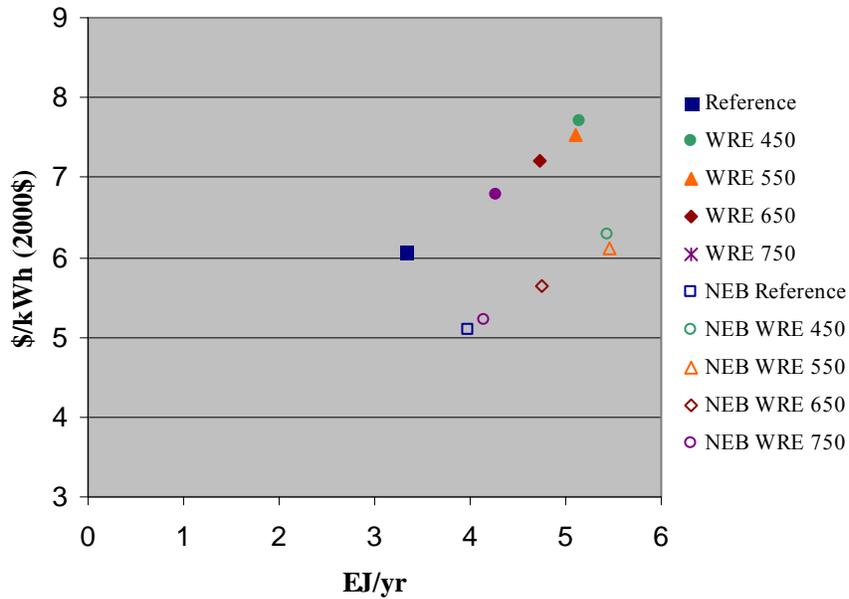


Figure 3.4: (A) U.S. wind generation across two technology suites (reference and NEB), in four stabilization policies and a reference (no-policy) case. (B) Marginal cost of wind electric production in the U.S. as a function of wind electric generation in 2095, by policy and technology scenario.

These effects are demonstrated in Figure 3.4B, which is derived from output in 2095. As shown, within either technology suite, marginal costs increase with generation, as would be expected from Figure 2.1 and Equation (2.1). However, NEB shifts the implied supply curve to the right. As such, even though wind generation does not necessarily increase in deployment, advanced technology is nevertheless important for reducing costs associated with meeting stabilization targets.

4. Wind Model Version 2: Explicit Wind Technology

In order to examine multiple scenarios and incorporate many possible future changes in technology, we have developed a model for wind energy generation and transmission costs in the U.S. based on spatially explicit data sets (“Version 2”). Our model was developed with high-resolution spatial datasets on U.S. wind resources combined with generation, exclusions, extant electricity infrastructure, and population. All aspects of the wind generation market shown in Figure 1.1 are modeled explicitly; exogenous supply curves are no longer used. Scenarios can now be run with varied assumptions, such as exclusions, transmission costs, or reserve margins. This allows exploration into the relative importance of each of these factors in determining potential future trajectories of the wind electric sector, and allows detailed comparison with other work. In general, the integrated assessment approach is best suited to examine a diversity of scenarios, rather than to develop one single optimal estimate.

This section describes our initial development of a resource-based wind generation model for the United States. The intention of this section is to provide an overview of the general approach we have taken so far for this project. The calculation details and parameter values used will be further refined and discussed with relevant experts as this project proceeds.

4.1. Wind Resources and Generation

4.1.1. Wind resources

The wind resource data used in this model were based on data developed by NREL and collaborators for the contiguous U.S. (NREL 2006b). Wind resource data consisted of high-resolution arcview data files for each state as downloaded from NREL (2006c). For the few states with no detailed data available, the older PNNL data (also downloaded from NREL) was used instead. A 0.5° grid was constructed for each wind class, with the fraction of each grid cell potentially available for wind generation specified from the wind resource data sets. Exclusions were then applied as described below.

The average wind speed for each wind resource class was assumed to be the midpoint of the range for that class. For example, class 5 wind resources are defined as having an average wind speed between 7.5 m/s and 8.0 m/s, and we assumed an average of 7.75 m/s across all class 5 areas. In addition to average wind speed, each resource is assigned an exponent for wind velocity increase with height. This is used to estimate the average wind speed at the hub height of the turbine.

4.1.2. Electric power output

The potential wind generation for any small region is determined by local air pressure, wind speed, and exclusions, defined as the portion of the region not suitable or acceptable for wind power production; this is detailed in Equation (4.1).

$$(4.1) \quad \text{Potential Wind Generation} = (\text{air pressure} \times f_{\text{turbine}}(\text{wind speed})) \otimes \text{exclusions}$$

[where \otimes stands for an integration over space.]

Air pressure and wind speed refer to the instantaneous values at the turbine, and f_{turbine} is the power production function of the turbine, detailed in Carlin (1997). Air pressure can be specified as an average for each wind resource class and area, although one average value was used for the present preliminary calculation. The power produced by an ideal turbine is proportional to wind speed cubed above a certain threshold speed, with a plateau at the maximum rated output of the turbine. In our analysis we have assumed that the probability density function of wind speed at any location follows a Rayleigh distribution (equal to the Weibull distribution with $k=2$; see appendix I). This assumption allows us to use average wind speed to calculate wind generation as in Equation (4.1), which requires instantaneous wind speed values. Calculations of power produced by idealized wind turbines are based on Carlin (1997), and are detailed in Appendix I. Actual electricity generation per time can be expressed as:

$$(4.2) \quad \text{Elec Power} = P_{R-B}(\text{Rating}, D, v_W) \times \epsilon_{\text{turbine}} \times \epsilon_{\text{nonturbine}} \times \epsilon_{\text{system}}$$

In Equation (4.2), P_{R-B} is the average power delivered by an ideal Rayleigh-Betz wind turbine with a finite power rating (Equation A-5), rotor diameter D , and average wind speed V_W . $\epsilon_{\text{turbine}}$ represents the efficiency of a real turbine relative to an ideal turbine, assumed to be 93% for wind speed classes 3-5 (average speeds between 6.4 and 8.0 m/s), and 89% for classes 6-7 (average speeds greater than 8.0 m/s; DOE/EPRI 1997). $\epsilon_{\text{nonturbine}}$ stands for efficiency with respect to losses not directly associated with turbines such as power conversion and turbine spacing losses, and is assumed to be 89% for wind speed classes 3-5 and 93.5% for classes 6-7. Finally, ϵ_{system} represents the system availability, assumed to be 98% in this analysis, in accord with DOE/EPRI (1997).

Wind turbine density, defined as the capacity of wind turbines per unit of land area, was specified as $5 \text{ MW}\cdot\text{km}^{-2}$, in accord with NREL (2006b). In general, turbines are spaced on the basis of multiples of turbine blade diameter, and because turbine rating tends to scale as the square of blade diameter, turbine density is roughly independent of turbine characteristics for a given spacing formula. If turbines are spaced too close together, then the wake from upwind turbines will lower the energy production of turbines downwind. For instance, we assume, as in DOE/EPRI (1997), that class 4 wind sites with rectangular turbine arrays would result in a loss of 4% of farm energy in 2010, while no array losses were assumed for class 6 wind sites.

4.1.3. Exclusions

Geographic areas may not be suitable for wind power production due to social factors, physical constraints, or prior land designation incompatible with wind power development. For instance, turbines should not be located immediately adjacent to homes for safety reasons, aesthetic impacts, and noise.

In general, the physical exclusion criteria have been initially chosen to be similar to those used in calculations used in the NREL WinDS model. Inland bodies of water are excluded, due to the social valuation of waterfront property and water-based recreation, and due to the logistical difficulty of their development for wind power. Slopes greater than 20% are similarly excluded for logistical challenges.

All public lands and nature preserves are excluded, with the exception of Department of Defense and Forest Service lands. A 50% exclusion was applied to all DoD lands, and likewise to Forest Service lands not specifically designated as wilderness, study, conservation, or roadless areas. This allows for the possibility that future wind power development may take place on some of these lands.

In our initial calculation we exclude areas with population densities greater than 321 people/km², assumed to be urban or threshold urban areas. For areas with population densities less than this, maximum turbine density is assumed to be a negative linear function of the population density. At densities less than 50 people/km², no population-induced constraint to turbine density is applied.

Figure 4.1 shows a preliminary calculation of the resulting distribution of available land area, by wind speed class, for classes 3 to 7. As shown, available land area for wind power development decreases with increasing speed class. Because the higher speed classes have the highest capacity factor (power generation), there will be a trade-off between site quality and availability (and thus power transmission costs), which will be further examined in Section 4.2.

4.2. Wind Generation and Transmission (Grid Connection) Costs

For integrated assessment modeling of wind energy, it is necessary to have an estimate of the potential power generation as a function of cost, appropriately averaged over time and space. To estimate the cost, there are three primary costs considered, shown in Equation (4.3): the costs of the wind turbine (relative to electricity generation), the transmission costs, and grid reinforcement costs.

$$(4.3) \quad \text{Wind Cost} = \text{Generation} + \text{Grid Connection} + \text{Grid Reinforcement Costs}$$

Grid reinforcement costs, including potentially building new lines directly to load centers, become a particularly important component of the equation as wind penetration, relative to the overall load level, increases. These costs have not been included in our work to date, although a discussion of a potential approach is given below (Section 4.4).

4.2.1. Wind generation turbine costs

Wind generation costs can be broken down into wind turbine capital and operating costs, generally expressed as costs per MW of capacity per year. However, for IA modeling the relevant cost is per unit of electricity generated, not MW of capacity. This is shown in Equation (4.4):

$$(4.4) \quad \text{Wind Generation Cost} = \text{Levelized Wind Farm Cost (\$)} / \text{Elec Generation}$$

To calculate this cost we used the amortized capital cost of a wind turbine plus operation and maintenance costs. This was calculated as the sum of the annual financing on turbine

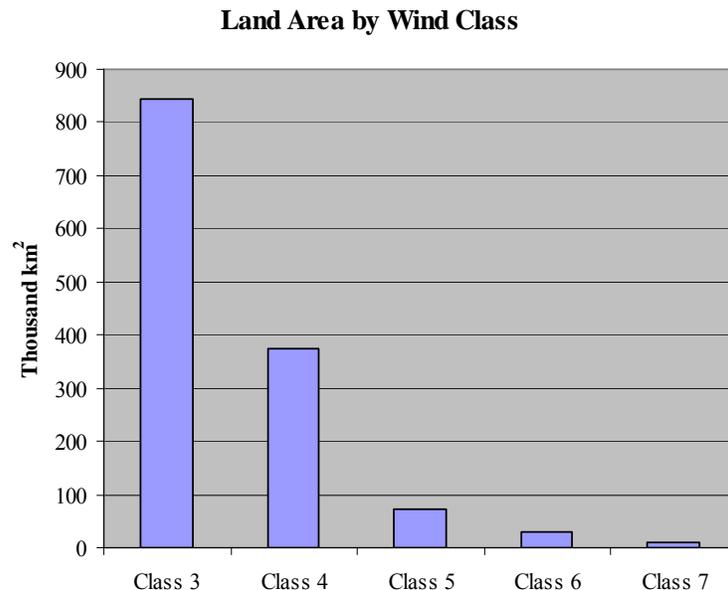


Figure 4.1: Total land area available for development for wind generation in the U.S., by wind speed class.

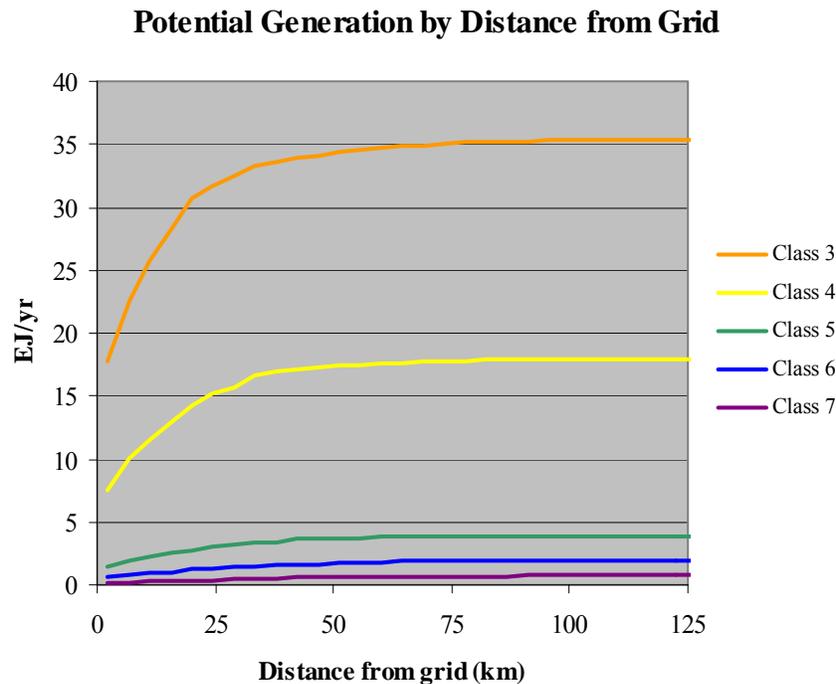


Figure 4.2: Cumulative wind generation for wind classes 3 to 7 as a function of distance from the grid. For this calculation turbine ratings were assumed to be 1 MW with a hub height of 63.5 m and a blade diameter 58.0 m.

capital costs, and annual operating costs. Electricity generation from each turbine will be calculated for each wind speed class using Equation (4.2).

4.2.2. Transmission and grid connection

The next primary component of wind energy cost is the *additional* cost of power transmission and grid connection, in excess of costs for other electric energy sources. Transmission and distribution costs that are generic to any electric power delivered to users are not considered in the wind component of electricity production in the model.

To calculate the grid connection cost, we need to know the cost of the electric lines per unit of distance, and the distance required to connect to the grid from any point. To estimate the distance to the grid, we used GIS data for the U.S. electricity transmission and distribution network from the Platts PowerMap database (Platts 2001).

Figure 4.2 shows a preliminary estimate of the cumulative potential generation (EJ/yr) as a function of distance from the grid for all available areas in the U.S. with wind speed Class 3 or higher. As shown, total generation decreases with increasing wind speed classes, despite greater production per unit of land area for the higher speed classes. This is because of the large differences in the total land area available by speed class (Figure 4.1). Note that 75% of the total potential generation for the U.S. is on land within 20km

of a grid connection. Note also that the maximum production, 75 EJ/yr, is far greater than the 12 EJ/yr implied by the IEAGHG supply curve used as the basis of Version 1 of the wind model (Figure 2.1).

A next step for further refinement is to integrate electric demand load centers into this analysis, so that costs for grid reinforcement or the construction of new lines can be estimated. Such grid reinforcement or expansion will be necessary under situations where existing grid does not have sufficient capacity to transmit wind power to load centers. To do this, we are considering the use of gridded population distributions and a value for average electricity consumption per person. A threshold electric demand (perhaps expressed as cumulative kWh integrated outward from the wind site) would then be set to define what constitutes a load center. We will then be able to estimate the length of either new transmission lines or reinforcement of existing lines necessary to connect wind resources to load centers.

4.2.3. *New wind generation model summary*

Wind generation costs are determined by wind turbine capital costs, turbine characteristics such as turbine losses, turbine rating, and hub height combined with resource characteristics. Within each grade of wind resource, the area of land with that resource is classified by distance to the existing transmission and distribution grid. The input to the model is a smoothed curve of cumulative area as a function of distance to grid, such as those shown in Figure 4.2. Total wind supply cost for each resource is calculated as the sum of wind generation cost plus grid connection costs.

Using this approach, wind supply is endogenously determined as a function of technology and resource assumptions. Wind costs and generation are computed for each wind resource class. As wind supply increases, additional reserve capacity is required as per Equation (2.1).

In our most recent analysis, wind technology descriptions were drawn from the latest NREL projections (NREL 2007). Our reference and advanced cases correspond to the NREL reference and program cases, respectively. Capital costs for wind turbines are summarized in Table 4.1. Capital costs for wind turbines decrease significantly through to the end of the century, with larger decreases in the advanced technology case.

Table 4.1: Capital cost assumptions for wind turbines in units of 2004\$ per kW of rated output.

Year	Class 4		Class 6	
	<i>Reference</i>	<i>Advanced</i>	<i>Reference</i>	<i>Advanced</i>
2005	1167	1167	1167	1167
2020	1040	946	961	818
2035	1014	862	948	777
2050	998	839	935	747
2065	983	827	921	736
2080	968	814	907	725
2095	954	802	894	714

The input parameters for the latest wind model are described in Appendix II.

4.3. *New wind model results*

The improved wind model was run with a standard base (no-climate policy) case in order to compare results with the previous version using exogenous cost curves. Figure 4.3 shows the fraction of U.S. electricity production that wind accounts for in the reference and advanced wind technology scenarios. As shown, wind accounts for 24% of electricity production in the reference scenario, and 37% in the advanced. In both scenarios, the market share of wind increases rapidly until 2050, after which the rate of increase declines. This is because total electricity demand continues to increase through the end of the century, but the most economical sites for wind power production are used first, causing increases in price as generation increases. As such, future wind development becomes less economical compared with alternative electricity production technologies.

This process is further detailed in Figure 4.4 (reference technology scenario shown). In 2020, the majority of wind is produced on Class 6 land, but as these sites are exhausted, Class 5 land is developed, accounting for the majority of wind production in 2035 and 2050. From 2065 through 2095, Class 4 sites produce the majority of wind electric

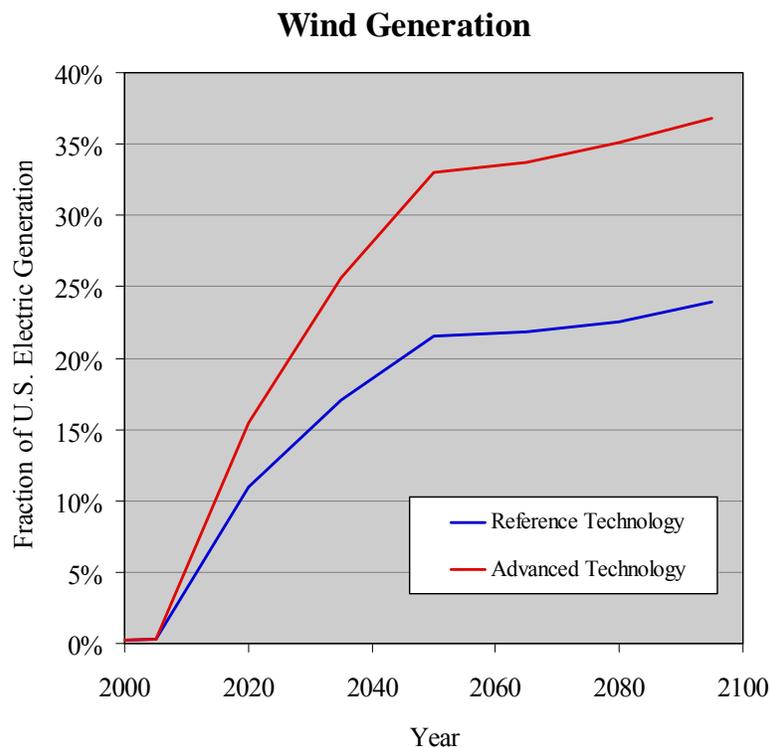


Figure 4.3: Fraction of U.S. electricity generation that is produced by wind power in two wind technology scenarios, 2005-2095.

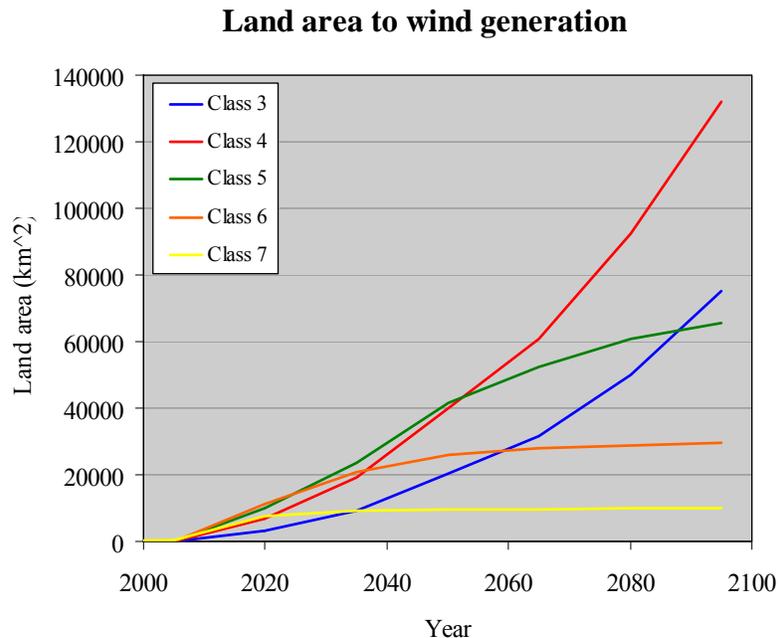


Figure 4.4: Land area used in the five wind speed classes in the reference wind technology scenario, 1990-2005.

energy. In 2095 under the reference case, most available land with wind speed classes 5, 6, and 7 is used for wind power production (88%, 94%, and 99%, respectively), while only 31% of Class 4 and 7% of Class 3 land is used. This suggests that further wind power deployment can continue for some time, albeit at higher costs. This also suggests that wind potential will be sensitive to assumptions about exclusions, particularly land availability at the higher speed classes.

In order to test the sensitivity to transmission costs, four scenarios were run, with transmission line construction and maintenance costs multiplied by factors of 5, 10, 20, and 50. These factors were used because it was assumed that transmission line capital costs under-represent the total costs and barriers of building new transmission lines (obtaining rights of way, litigation, etc.), and it isn't known how costly or difficult it will be to build new transmission lines in the upcoming century.

Figure 4.5 shows the impact of the transmission costs on the penetration of wind electricity in the advanced technology scenarios. Even when transmission line costs are increased by a factor of 50, wind power still accounts for 25% of the electricity production in 2095. The multiplier factors are arbitrary, but show that the penetration of wind power is at least moderately sensitive to access to adequate transmission capacity. The effect of transmission access is even greater than suggested in this result because grid reinforcement costs, which could potentially include what would be, in effect, the construction of new lines, was not included in this calculation. The availability of sufficient transmission capacity, and the ability to construct sufficient additional capacity, is an important issue that needs to be better quantified.

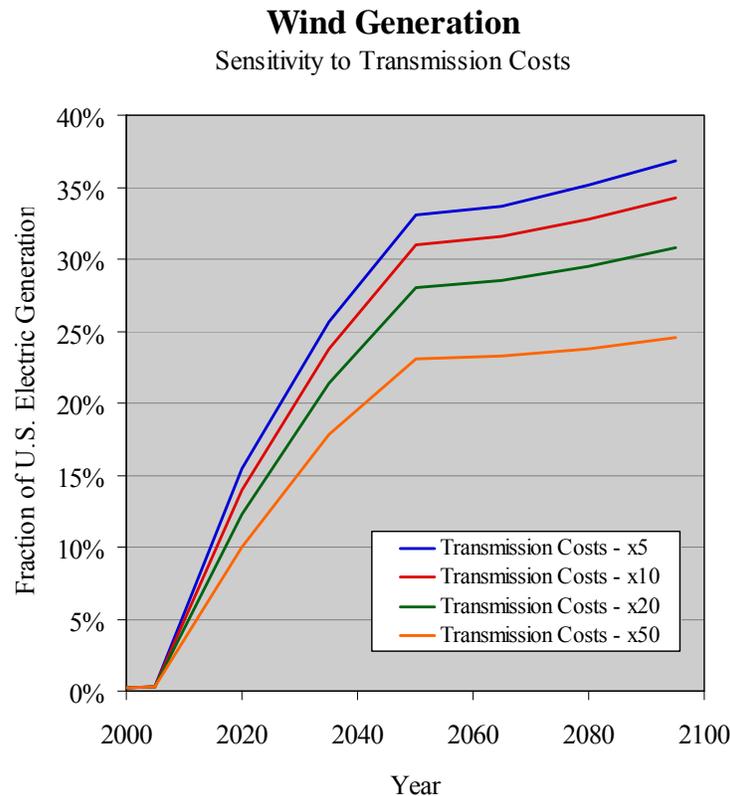


Figure 4.5: Wind generation in the advanced wind technology scenario, at four different levels of transmission costs. The base cost for connecting to transmission lines is multiplied by the factor shown (x5, x10, x20 and x50) in order to represent, in a generic manner, possible barriers or opposition to the construction or siting of transmission lines.

4.4. *Potential improvements*

The representation of wind can be improved in a number of areas. One area of particular importance is the need for transmission capacity as wind penetration increases. One method of parameterizing this is to construct an estimate of the distance to load centers for each grid point. This would allow the inclusion of the additional cost of connecting directly to load centers as penetration of wind increases and the otherwise existing grid capacity is not sufficient to transmit additional wind generation. This could be parameterized in terms of the fraction of total electricity supplied by wind, implicitly assuming that transmission capacity generally increases with demand. Results from the WinDS model suggest that by the time wind generation reaches 10% of total electric

generation, most new wind plants are constructed with new lines.⁵ (Note, however, that the definition of a new line in the WinDS model is slightly different than that used here).

A second area of improvement will be to add off-shore wind generation. This will require incorporating data on off-shore wind resources. A combination of current NREL estimates and perhaps incorporating some NASA data may be sufficient for this purpose. The calculation of distance to load centers described above would be necessary. It would then be possible to examine tradeoffs between different off-shore technologies and resource areas (near vs more distant, but deeper, off-shore areas, for example).

Wind variance in the current version is simply read-in as a constant. The capability for calculating wind variance for an individual turbine as a function of turbine characteristics can easily be implemented. What will take a bit more work is to incorporate the effect of de-correlation of wind output variance as turbines are spread over a wider distance. The appropriate spatial scale to evaluate wind variance needs to be better defined – which would likely be a function of assumptions about the level of grid interconnection between regions.

Another area of improvement would be to represent the loss of wind output as the penetration of wind increases due to factors such as mismatch with demand or transmission line congestion. As wind turbine prices fall it may be economically attractive to over build wind knowing, for example, that the full potential for wind generation at nighttime may not be used. (This could be mitigated by the provision of energy storage technologies, which are being incorporated in current work.) The more detailed results from the WinDS model would be useful guides to the magnitude of such effects.

With some of these basic modeling capabilities in place, some further regional desegregation of wind resources may be warranted. For example, high resource areas in the mid-west that are far from major load centers could be separated into their own resource classification. A portion of these resources could be used locally, with the majority of the resource requiring significant transmission infrastructure for utilization. Again, the more detailed WinDS results would provide useful guidance.

One capability that would assist in the modeling of wind energy is a representation of the electric system that distinguishes time of day, given that wind has diurnal characteristics that would affect its integration into the electric system. Such a representation is under development and we will integrate the wind generation model described here into the new representation of the electric system within the model framework.

Finally, it will be useful to further consider how to better represent the issues raised by high penetration (> 20%) of wind generation in the electricity system (preferably in conjunction with NREL researchers). We want to assure that system reliability has been adequately accounted for in the model representation. Our current work to incorporate a

⁵ W. Short - personal communication. Spreadsheet results from WinDS analysis AEO2005-GPRA07.

basic representation of electric system load segments (peak, intermediate, baseload) may facilitate any necessary model refinements.

4.4.1. Data Needs

The calculation of wind energy potential requires data on wind resources, wind turbine characteristics, potential exclusions, and electric transmission costs. Good wind resource data exists for most windy regions of the United States, but comprehensive wind resource data for the globe is lacking. This would be needed to expand this model to global coverage. In order to incorporate off-shore wind generation in the United States, off-shore wind resource data will be needed.

Transmission is a difficult issue to model and better data on transmission line costs and, in particular, better information on the barriers to the construction of transmission lines are needed.

5. Summary

Version 1 of the wind supply model, as applied in the CCTP scenarios, demonstrated that wind stands to become an important component of the national and global energy portfolio over the next century. Climate policies will generally increase wind generation, with the amount depending on the relative costs of wind and other technologies. In these scenarios, wind accounts for between 9% and 17% of global electricity generation in 2095, depending on policy and technology scenarios. In stringent policy scenarios, the generation of carbon-neutral electricity paired with enhanced electrification will be a technological strategy for reducing costs associated with CO₂ stabilization. Market penetration of wind is limited by economic competition, not resource constraints.

The analysis used for the CCTP scenarios, however, was based on supply curves that appear to be pessimistic in their estimation of the available resource and generation costs for the U.S., which may have led to a general under-estimation of the role of wind power in the future electricity market. We have, therefore, developed a more detailed wind energy representation based on explicit resource data and technology descriptions, which we have referred to in this report as Version 2. At this stage, wind appears capable of supplying a far greater proportion of U.S. electricity needs, perhaps up to nearly 40% by 2095, although this is a preliminary result with a number of important effects not included.

Now that a new resource-based wind model (i.e., Version 2) has been implemented, we can develop scenarios with different assumptions regarding exclusions, turbine capital and operating costs, or transmission and distribution costs and constraints. The model will then be more flexible and transparent in its assumptions, and capable of integrating new data as it becomes available.

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Appendix I

The equations below are derived from Carlin (1997).

Weibull Distribution

The one parameter Weibull distribution is:

$$(A-1) \quad f(x) = \frac{\beta}{c} \left(\frac{x}{c}\right)^{\beta-1} e^{-\left(\frac{x}{c}\right)^\beta}$$

The mean of the distribution is:

$$(A-2) \quad \bar{x} = c \cdot \Gamma\left(\frac{1}{\beta} + 1\right)$$

where Γ is the gamma function.

If we assume that the wind speed has a distribution with a shape parameter of 2, also known as a Rayleigh distribution, then the mean wind speed is:

$$(A-3) \quad \begin{aligned} \bar{x} &= c \cdot \Gamma(1.5) = \left(\sqrt{\pi}/2\right)c \\ &\text{or} \\ c &= \bar{x}/a = 2\bar{x}/\sqrt{\pi}; \quad a = \sqrt{\pi}/2 = 0.88623 \end{aligned}$$

Therefore, the wind distribution for a mean wind speed of \bar{x} is

$$(A-4) \quad f(v) = \left(\frac{\pi v}{2\bar{x}^2}\right) e^{-\pi\left(\frac{v}{2\bar{x}}\right)^2}$$

Wind Power from an Idealized Turbine

From Carlin (1997), we have the average power of a perfectly efficient (“Rayleigh-Betz” turbine) in a wind with a Rayleigh distributed wind as

$$(A-5) \quad \bar{P} = \int \left[\frac{1}{2} \rho A C_p v^3 \right] \left[\frac{2v}{c^2} e^{-(v/c)^2} \right] dv$$

where the first term in brackets is the power generated by a wind turbine and the second term is the probability density for a Rayleigh distributed wind. The ideal maximum extractable power, known as the Betz limit, has a coefficient of $C_p = 16/27$. At this limit, the integral evaluates to:

$$(A-6) \quad \bar{P}_{RB} = \rho \left(\frac{2}{3} D \right)^2 \bar{V}^3$$

where D is the diameter of the rotor and \bar{V} is the average wind speed. The capture coefficient (CC) for a real wind turbine is defined as the wind power relative to this maximum value.

For a more realistic turbine, the power up to a finite cutout speed is:

$$(A-7) \quad CC_{\text{finite cutout}}(x_f) = \text{Erf}(x_f) - \frac{4}{3\sqrt{\pi}}(x_f) \left(x_f^2 + \frac{3}{2}\right) e^{-x_f^2}$$

Where x_f is the cutout speed as a multiple of the weibull distribution characteristic speed c , or in terms of the average wind speed:

$$(A-8) \quad x_f = \left(\frac{\sqrt{\pi}}{2} \right) \frac{v_f}{v_{ave}}$$

For a turbine with a finite power rating (x_r), the capture coefficient is:

$$(A-9) \quad CC_{\text{finite power}}(x_r, x_f) = CC_{\text{finite cutout}}(x_r) + \frac{x_r^3}{3/4\sqrt{\pi}} \left(e^{-x_r^2} - e^{-x_f^2} \right)$$

Appendix II

The input parameters for the detailed version of the O^{bj}ECTS wind model (“Version 2”) are as follows:

Wind Resource

Any number of wind resources can be used in the model. Each wind resource is characterized as the total area (km²) and an average wind speed, distributed with a power-law logistic curve representing distance to the distribution grid. The cumulative area within each resource class is described by

$$Area(distance) = TotalResourceArea \cdot \frac{distance^{dist-exponent}}{midpoint - distance^{dist-exponent} + distance^{dist-exponent}} \quad (1)$$

where the *midpoint-distance* is mid-point of the distribution. The *dist-exponent* is adjusted to give the best fit to the cumulative resource curve.

The input parameters for each wind resource are:

	units	Wind speed class				
		3	4	5	6	7
<i>TotalResourceArea</i>	km ²	845595	373646	72946	31204	9929
<i>midpoint-distance</i>	km	6.59	9.23	11.55	15.15	27.70
<i>dist-exponent</i>	unitless	1.57	1.82	1.89	1.83	2.94
<i>AverageWindSpeed</i>	m/s	6.7	7.25	7.75	8.4	9.95
<i>AirDensity</i>	g/m ³	1.225	1.225	1.225	1.225	1.225
<i>ReferenceHeight</i>	m	50	50	50	50	50
<i>WindVelocityExponent</i> ¹	unitless	0.21	0.2	0.19	0.18	0.17

1 Exponent for power-law change in wind velocity with height

Wind Technology

The wind technology is described in section 4. In the model implementation, each technology is generally allowed to use any wind resource. It would also be possible to have more than one technology compete for a given wind resource.

The parameters for each technology are listed below. The values correspond to 2005 values in the reference case shown, with the reference grid connection costs (5 times the capital cost).

	units	value
RotorDiameter	m	58
TurbineHubHeight	m	63.5
TurbineDensity	MW/km ²	5
TurbineRating	MW	1.5
gridConnectionCost	\$/km/MW	7500

CapitalCost	\$/kW	see Table 4.1	based on rated capacity
FCR	1/yr	0.171	fixed charge rate
OM	\$/kW/yr	27.60	based on rated capacity
CutOutSpeed	m/s	30	
WindFarmLoss	unitless	0.12	fractional loss from turbine to grid
TurbineDerating	unitless	0.07	fractional difference between ideal and actual turbine
