Carnegie Mellon University

CARNEGIE INSTITUTE OF TECHNOLOGY

THESIS

SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS

FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

TITLE: The Economics and Environmental Impacts of Large-Scale Wind Power in a Carbon Constrained World

PRESENTED BY: Joseph Frank DeCarolis

ACCEPTED BY THE DEPARTMENT OF: Engineering and Public Policy

ADVISOR, MAJOR PROFESSOR ______ DATE ______

DEPARTMENT HEAD ______ DATE ______

APPROVED BY THE COLLEGE COUNCIL

DEAN ______ DAT ______

(This page was intentionally left blank.)

Carnegie Mellon University

The Economics and Environmental Impacts of Large-Scale Wind Power in a Carbon Constrained World

A Dissertation Submitted to the Graduate School in Partial Fulfillment of the
Requirements for the Degree of

Doctor of Philosophy

in

Engineering and Public Policy

By

Joseph Frank DeCarolis

Pittsburgh, Pennsylvania

November 2004

(This page was intentionally left blank.)

Abstract

Serious climate change mitigation aimed at stabilizing atmospheric concentrations of CO_2 will require a radical shift to a decarbonized energy supply. The electric power sector will be a primary target for deep reductions in CO_2 emissions because electric power plants are among the largest and most manageable point sources of emissions. With respect to new capacity, wind power is currently one of the most inexpensive ways to produce electricity without CO_2 emissions and it may have a significant role to play in a carbon constrained world. Yet most research in the wind industry remains focused on near term issues, while energy system models that focus on century-long time horizons undervalue wind by imposing exogenous limits on growth. This thesis fills a critical gap in the literature by taking a closer look at the cost and environmental impacts of large-scale wind.

Estimates of the average cost of wind generation – now roughly 4¢/kWh – do not address the costs arising from the spatial distribution and intermittency of wind. Even when wind serves an infinitesimal fraction of demand, its intermittency imposes costs beyond the average cost of delivered wind power. This thesis develops a theoretical framework for assessing the intermittency cost of wind. In addition, an economic characterization of a wind system is provided in which long-distance electricity transmission, storage, and gas turbines are used to supplement variable wind power output to meet a time-varying load. With somewhat optimistic assumptions about the cost of wind turbines, the use of wind to serve 50% of demand adds ~1-2¢/kWh to the cost of electricity, a cost comparable to that of other large-scale low carbon technologies.

This thesis also explores the environmental impacts posed by large-scale wind. Though avian mortality and noise caused controversy in the early years of wind development, improved technology and exhaustive siting assessments have minimized their impact. The aesthetic valuation of wind farms can be improved significantly with better design, siting, construction, and maintenance procedures, but opposition may increase as wind is developed on a large scale. Finally, this thesis summarizes collaborative work utilizing general circulation models to determine whether wind turbines have an impact of climate. The results suggest that the climatic impact is non-negligible at continental scales, but further research is warranted.

(This page was intentionally left blank.)

Acknowledgements

First, I would like to dedicate this thesis to my undergraduate advisor at Clark University, Christoph Hohenemser. In the twilight of his professional career and despite great physical hardship, he took the time to impart his wisdom on energy and the environment – gleaned through decades of distinguished work – to an enthusiastic student.

I owe an enormous debt of gratitude to my thesis advisor, David Keith. I had high expectations entering Carnegie Mellon, and David has exceeded them. I have benefited tremendously not only from the depth and breadth of his knowledge but also his critical eye, all of which has slowly but surely made me into a better researcher. I also consider David a good friend – probably not something that many PhD students would offer about their advisor.

I also wish to thank my committee members: Alex Farrell, Granger Morgan, Jay Apt and Paul Gipe. Granger, Alex, and Jay have been supportive of my research and have offered insightful suggestions too numerous to count throughout my tenure at Carnegie Mellon. I sincerely thank Paul for joining the committee at a late stage, despite his busy schedule. I also wish to thank Hisham Zerriffi, a good friend and academic comrade, for providing advice and support.

I also want to thank my family: simply put, I would not be where I am today without your love and support. We have survived tragedy and celebrated triumphs, each experience made deeper and richer because we did it together. I also wish to thank Chrissy's family, who eased my longing for home by accepting me with open arms.

Most of all, however, I thank my wife Chrissy. I don't know how I would have persevered without her love, encouragement, and confidence in my ability to succeed. Meeting, falling in love, and marrying her during the past four years has dwarfed the importance of the PhD, the reason that brought me to Pittsburgh in the first place.

And finally, I want to thank my stepdaughter Elisa. She has also given me unconditional love and support, enduring many boring weekends and evenings while I worked. I know it must be hard for her to understand why any human being would want to sit in front of a computer day after day the way I have, especially over the last few months. I only hope that someday she may draw inspiration from my example, proving that you can reach any goal you set for yourself with hard work and perseverance.

This research was made possible through the generous support of the Carnegie Mellon Electricity Industry Center (CEIC). CEIC is jointly funded by Alfred P. Sloan Foundation and the Electric Power Research Institute and dedicated to addressing important challenges facing the electric power sector through interdisciplinary research.

(This page was intentionally left blank.)

Table of Contents

List of Tables xi

List of Figures xii

Chapter 1: The Future Role of Wind in the Electric Power Sector
1.1 Contribution of my Dissertation 1
1.2 Wind Power Today 4
1.3 Birth of the Modern Wind Industry 4
 1.3.1 The Danish Approach to Wind Power 6
 1.3.2 The American Approach to Wind Power 7
1.4 Wind Turbine Technology 8
1.5 Challenges Posed by Wind 12
 1.5.1 Intermittency of Wind Resources 13
 1.5.2 Spatial Distribution of Wind Resources 16
1.6 Lessons from Northern Europe? 18
1.7 The Future Role of Wind Power 20
1.8 CO_2 Mitigation in the Electric Power Sector 24
 1.8.1 Renewable Technologies 25
 1.8.2 Non-renewable Technologies 26
 1.8.3 System Architecture 28
 1.8.4 Environmental Impacts 29
1.9 Outline of the Thesis: Estimating the Cost and Environmental Impacts of Large-Scale Wind 30
1.10 References to Chapter 1 32

Chapter 2: The Cost of Wind's Intermittency: Is There a Threshold?
2.1 Chapter Overview 38
2.2 Managing Variability in Electric Power Systems 39
2.3 Defining the Cost of Wind's Intermittency 42
2.4 Review of Wind Integration Studies 49
2.5 Wind at Small Scale 51
2.6 Wind at Large Scale 56
2.7 Conclusions and Implications for Energy Modeling 58
2.8 References to Chapter 2 62

Chapter 3: Assessing the Cost of Large-Scale Wind
3.1 Chapter Overview 64
3.2 Previous Modeling Work 65
3.3 Model Numerics, Implementation, and Challenges 66
3.4 Model Description 69
3.5 Technologies in the Model 72
 3.5.1 Wind Turbines 72
 3.5.2 Gas Turbines 73
 3.5.3 Compressed Air Energy Storage (CAES) 76
 3.5.4 High Voltage Direct Current (HVDC) Transmission 78
 3.5.5 Assumptions About Scale 80
3.6 Wind Data and Site Geometry 80
3.7 Model Results 82

3.8 Exploring the Benefits of CAES 89
3.8.1 Description of a Reduced-Form Model 89
3.8.2 Cost Comparison with an H_2 System 92
3.9 Conclusions Drawn from the Model 95
3.10 References to Chapter 3 99

Chapter 4: Environmental Impacts of Wind Power
4.1 Chapter Overview 102
4.2 Avian Mortality 103
4.3 Noise 106
4.4 Aesthetic Impacts of Wind Farm Development 108
4.4.1 A Renewed Debate: Conservation versus Preservation 108
4.4.2 NIMBYism and Wind Power 110
4.4.3 Addressing Aesthetic Concerns 112
4.4.4 Aesthetic Considerations versus Land Requirements 116
4.5 Summary of Environmental Impacts and the Path Forward 118
4.6 References to Chapter 4 119

Chapter 5: The Climatic Impact of Wind Turbines
5.1 Chapter Overview 122
5.2 Wind in the Atmospheric Boundary Layer 123
5.3 Model Parameterization 124
5.4 The Relationship between Added Drag and Wind Farms 126
5.4.1 Power Dissipation in the Model 126
5.4.2 Relating Power Dissipated to Electricity Produced 127
5.5 GCM Results 131
5.6 Comparison of Direct and Indirect Climatic Effects 148
5.6.1 Defining a Metric 148
5.6.2 Estimating the Ratio of Direct to Indirect Climate Impacts 149
5.7 Conclusions 155
5.8 References to Chapter 5 157

Chapter 6: Thesis Conclusions and Future Work
6.1 Chapter Overview 160
6.2 The Costs of Wind's Variability: Is There a Threshold? 161
6.3 The Cost of Large-Scale Wind 162
6.4 Environmental Impacts from Wind 164
6.5 Future Work 165
6.5.1 Decarbonizing the Electric Power Sector 165
6.5.2 Wind 167
6.5.3 Clean Coal 170
6.5.4 Integration Issues 171
6.5.5 Proposed Modeling Work 172
6.5.6 Summary 174
6.6 References to Chapter 6 175

(This page was intentionally left blank.)

List of Tables

Table 2.1 – Summary of wind integration studies and their cost estimates for intra-hour load-following and regulation 50
Table 3.1 – Cost and efficiency parameters used in the optimization model 71
Table 3.2 – Carbon tax at which CAES and H_2 storage systems become cost-effective over GTCC 92
Table 4.1 – Comparative avian risk in the US 105
Table 4.2 – Comparison of different sounds with wind turbines 108
Table 5.1 – Estimates of α: the ratio of direct to indirect climatic impacts produced by wind power 155

List of Figures

Figure 1.1 – Power production from wind turbines versus wind speed 12
Figure 2.1 – Stylized picture of supply and demand 41
Figure 2.2 – Schematic illustration of the economics of intermittent wind 44
Figure 2.3 – Theoretical load duration curve 46
Figure 2.4 – Schematic illustration of the average cost of electricity versus the fraction of wind energy serving demand 48
Figure 3.1 − Illustration of the convergence problem 68
Figure 3.2 – Model geometry and map of US wind potential 70
Figure 3.3 – Optimal capacities as a function of carbon tax 84
Figure 3.4 – Marginal cost of carbon mitigation as a function of the fractional reduction in emissions 86
Figure 3.5 – The average cost of electricity as a function of the fractional reduction in emissions 88
Figure 3.6 – The four functions used in the reduced-form model 90
Figure 3.7 – Plot of cost derivative as a function of carbon tax 94
Figure 4.1 – Comparison of good and bad aesthetic designs for wind farms 115
Figure 5.1 – An energy extracting actuator disc, which is used as a simplified representation of a wind turbine 128
Figure 5.2 – Wind farm array and temperature response 133
Figure 5.3 – Energy dissipation versus drag 135
Figure 5.4 – Linear coefficient (slope) of climatic response in the NCAR linearity ensemble 137
Figure 5.5 – Mean climatic response over various masks versus δP 140
Figure 5.6 – Schematic illustration of the linear scaling assumption 144
Figure 5.7 – Surface temperature response ($\delta T_{2\,m\text{-}air}$) to two different spatial configurations of wind-farm array and δC_D 145
Figure 5.8 – Zonal measures of climatic response 147
Figure 5.9 – Hypothetical trajectories for carbon emissions and wind power for the next three centuries 151
Figure 5.10 – Hypothetical atmospheric concentration of CO_2 over the next three centuries 152

(This page was intentionally left blank.)

Chapter 1: The Future Role of Wind in the Electric Power Sector

1.1 Contribution of my Dissertation

How the costs and environmental impacts scale with increasing levels of wind on an electric power system is not well understood, yet these issues carry very serious implications for the long-term future of the wind industry and, more importantly, the ability of wind energy to mitigate climate change. Nearly all interest in the wind industry is currently focused on near-term details such as turbine design, system integration[1], wind subsidies, and fair rules for wind generators in deregulated markets[2]. While these are certainly important issues, long-term planning in the wind industry is not driven by the possibility of a strong constraint on future CO_2 emissions because there is no incentive to do so.

Part of the wind industry literature includes a rich set of analyses that examine the integration of wind power into existing electric power systems and their associated markets, often done in response to a national or regional policy initiative aimed at reducing greenhouse gas emissions or promoting renewables. Such analyses generally look no more than two decades ahead, assume that much of the existing electric power infrastructure remains in place, and generally do not consider the possibility of wind serving more than 20 percent of electricity demand. As such, these studies are limited in scope (e.g., Grubb, 1988; Hirst, 2001; Ilex and Strbac, 2002; Gardner, Snodin et al., 2003; Hirst and Hild, 2004). In addition, some wind integration studies do not accurately

[1] In fact, the journals *Wind Engineering* and *Wind Energy* are dedicated almost exclusively to wind turbine design, wind power electrical engineering, and grid integration issues.
[2] Several journals report important policy developments regarding wind, most notably *Wind Energy Weekly* (focusing on US developments) and *WindPower Monthly* (focusing on international developments).

treat the intermittency costs of wind because they neglect the degraded reliability stemming from the variability that wind adds to the system.

Likewise, there is a similarly rich set of analyses that examine the long-term economics of the CO_2-climate problem. These include energy models of the kind that participate in the Energy Modeling Forum, and Integrated Assessment models that embed energy system models with models of the climate system and the impacts of climate change to assess climate policy. These models often examine a century long time horizon, and include representations of technological change and economic growth. While these models often include wind, they cannot readily capture the dynamics of load and dispatch in electric power systems and markets (e.g., Edmonds et al., 2004). To avoid the complex grid operation issues that arise with the use of intermittent supply technologies, some integrated assessment models simply impose exogenous limits on the growth of wind (Smith, 2004).

My purpose is to examine the intellectual ground lying between the near-term studies that focus on integrating wind into existing systems and the long-term analyses based on energy system models. This dissertation aims to capture the temporal scope of integrated assessment models, but also represent the dynamics of load and dispatch in electric power systems. Of course, such an approach sacrifices detail for flexibility and generalness. Rather than providing specific policy recommendations, this thesis provides a general economic characterization of using wind to mitigate climate change. This thesis treats the spatial distribution and intermittency of wind as an economic rather than technical constraint, and therefore does not impose exogenous limits on the level of wind penetration. With this approach, cost estimates (in the form of supply curves) of mitigating carbon emissions with wind at high penetration levels are derived, which could be used in developing more accurate treatments of wind in long-duration comprehensive models aimed at understanding the cost of mitigating CO_2 emissions.

Wind also imposes unique environmental impacts, which include but are not limited to avian mortality, noise, and aesthetics. Concerted effort by the wind industry has lessened these impacts, although aesthetic perception of wind turbines in the landscape still presents an important challenge to the development of wind on a large-scale. This thesis also presents an environmental impact which to date has not received significant attention: wind turbines have a direct impact on climate by dissipating atmospheric kinetic energy. This thesis discusses how these various environmental impacts scale with installed wind capacity and identifies the impacts that present the greatest challenges to the deployment of large-scale wind under a carbon constraint.

This thesis focuses on three key questions that must be addressed in order to assess wind's potential role in a CO_2 constrained world.

- How does wind's intermittency affect the cost of electricity, and how does the cost scale with increasing levels of wind?
- How does the spatial distribution of wind resources in the US and abroad (requiring long-distance electricity transmission) change the cost of electricity from wind?
- How do the environmental impacts produced by wind scale and can these impacts severely limit the penetration of wind into electricity systems worldwide?

1.2 Wind Power Today

Global wind-power capacity is roughly 40 GW, with annual capacity additions approaching 8.2 GW and annual equipment sales exceeding $9 billion (AWEA, 2004). Construction of wind farms has been driven by government regulation or subsidies with steady declines in unit costs. Even so, at good sites, the average cost of wind is currently 4-6¢/kWh without credits or subsidies, and advances in turbine design may plausibly reduce the cost to 2-3 ¢/kWh in the near term (Bull, 2001; McGowan et al., 2001; McGowan and Connors, 2000). Due in large part to steady incremental design improvements, the lifetime of new wind turbines is now expected to be 20 to 30 years (DWIA, 2004). Although wind energy currently serves about 0.1 percent of total global electricity demand (Sims, Rogner et al., 2003), it has the fastest relative growth rate of any electric generating technology: capacity has increased by roughly 33 percent annually for the five years ending in 2002 (BTM Consult, 2003).

1.3 Birth of the Modern Wind Industry

The idea of harnessing wind energy to produce electricity is nearly as old as the electric power system itself: six years after Edison built New York City's Pearl Street Station in 1882, Charles Brush built the first wind mill designed to produce electricity. Brush's turbine consisted of 144 cedar planks with a diameter of 17 meters, had an output of 12 kW, and produced electricity for 20 years (DWIA, 2004). For the next century, wind turbines remained a hobby for self-motivated engineers and resourceful farmers, who built small-scale wind turbines – less than 10 kW – to power remotely located homes and farms that remained untouched by the spread of transmission and distribution lines.

The oil embargo of 1973 and the unstable US energy market over subsequent years led to a confluence of state and federal regulation that gave birth to the first utility-scale wind industry in the early 1980s. The Public Utility Regulatory Policies Act (PURPA) of 1978 (PL 95-617) was meant to diversify the national energy portfolio by forcing electric utilities to interconnect with and buy electricity from qualifying facilities – at the utilities' avoided cost. PURPA had important implications for the development of wind energy, because it set the rules that allow private developers and individuals to erect wind turbines and sell the output to electric utilities. In addition, the Powerplant and Industrial Fuel Use Act of 1978 (PL 95-620) prohibited utilities from building new plants that burned natural gas, although it exempted qualifying facilities from this restriction.

The oil embargo along with these previous federal laws had a significant impact in California, a state with 90 percent of its electricity supply derived from oil. The Iranian oil embargo struck as the state electricity demand was growing by 7 percent per year (Gipe, 1995, 33-34). When the California state legislature banned new nuclear power plants in 1976 until a suitable disposal option was found for nuclear waste (Simon, 2003), the only viable options left for meeting the increased electricity demand were new coal plants and/or renewable energy. With the environmental movement in full swing and a liberal state governor in office, favor was given to the latter. Under Governor Jerry Brown, California put in place generous tax incentives from 1981 to 1985 that created one of the first serious markets for wind energy. In addition to a 25 percent federal tax credit for investments and federal loan guarantees that could be applied to wind energy development, California offered an additional 25 percent state tax credit and gave corporations and partnerships involved in renewable energy projects the ability to issue tax-free bonds (Righter, 1996, 209).

When the California tax incentives took effect in 1981, many turbines only lasted a few years before major failures rendered them damaged beyond repair (Loiter and Norberg-Bohm, 1999). Although some improvement occurred, the average generation cost was roughly 40¢/kWh in the early 1980s (Bull, 2001). Despite the immature state of wind technology, the California market for wind farms was irresistible to investors searching for a sizable tax shelter. The result was a significant boom followed by a bust, and though many ventures in wind energy failed, the California experience had the effect of culling the industry of inferior technology and corrupt players, while injecting badly needed capital into research, development, and deployment of wind turbines. By the late-1990s, California held over 90 percent of installed wind capacity in the US (Loiter and Norberg-Bohm, 1999).

1.3.1 The Danish Approach to Wind Power

In 1973, Denmark faced similar challenges to California: imported oil met 95 percent of Danish electricity demand, which was growing by roughly 4 percent annually (Gipe, 1996, 51). Although Danish interest in wind-generated electricity was initially motivated by high oil prices, the motivation shifted over time to climate change mitigation (DEA, 1999). In the 1980s the Danish government mandated that Danish utilities pay 70-85 percent of the pretax retail rate for wind-generated electricity[3]. Including tax offsets for

[3] Throughout the 1980s and early 1990s, Danish utilities paid 85% of the pretax rate when buying electricity from cooperatives or owners of single wind turbines under 150 kW. For owners of larger turbines or cooperative members living outside the district where their wind turbines were installed,

electricity and carbon dioxide emissions, wind generators were receiving close to 0.13$/kWh for their electricity (Gipe, 1996, 51).

Nearly all Danish companies produced three-bladed, upwind machines that focused on conservative, heavy design. With little disagreement on fundamental design issues, there was a high degree of cooperation between Danish manufacturers in securing common parts, and effort was focused on incremental design improvements (Asmus, 2001, 125). And given the limited geographical extent of Denmark, Danish wind turbines were often directly serviced by the manufacturers, which allowed companies to fix problems and learn from mistakes quickly, both of which boosted confidence in potential investors (Gipe, 1995, 57). Danish taxpayers invested roughly $52 million with the modest goal of building smaller wind turbines for use in rural areas (Righter, 1996, 124). The Danish strategy proved more effective than anticipated: by 1985, the Danes were supplying 50 percent of the turbines installed in US wind farms (*ibid*, 218). Danish dominance continues to the present, with Danish manufacturers holding a 43.5 percent global market share as of 2002 (BTM Consult, 2003).

1.3.2 The American Approach to Wind Power

The U.S. government took the opposite approach to wind turbine design, providing $450 million in research and development funding between 1974 and 1990 to large aerospace firms, which were focused on building multi-MW, lightweight designs that would dramatically reduce cost and appeal to large utility monopolies (Asmus, 2001, 125). Design approaches in the US were varied, with both vertical and horizontal axis designs,

---

payment was 70% of the pretax retail rate (Gipe 1996, 60-61). These incentives clearly favored single owners or small cooperatives, which gave rise to the distributed nature of Danish wind farms.

different numbers of blades, and both upwind and downwind orientations for blades of horizontal-axis turbines. The federal research and design effort failed to produce a single commercially viable wind turbine, in large part because of the strategic failure of the aerospace industry to appreciate the difficulty of building robust turbines that could withstand years of abuse by the elements (*ibid.*, 125). The problem was exacerbated by the lack of a market in which to test early design concepts (Loiter and Norberg-Bohm, 1999).

1.4 Wind Turbine Technology

Given the relative success of Danish design, almost all commercially available modern wind turbines have a horizontal axis design with three blades mounted upwind. As with any technology, particular wind turbine designs represent a series of tradeoffs between cost and performance. Incremental design improvements over time have led to larger wind turbines that take advantage of economies of scale while maintaining or improving performance: in 1981 the average installed wind turbine size was 50 kW (McGowan et al., 2001, 3-12), compared with 1,087 kW in 2002 (BTM Consult, 2003), at the same time that the average cost of electricity from wind declined by 80 percent (Loiter and Norberg-Bohm, 1999). Economies of scale are particularly important for off-shore applications. For example, tripling the size of the wind turbine (500kW to 1.5MW) only increases the cost of the foundation and undersea cabling by 10-20 percent (DWIA, 2004). For off-shore applications, economies of scale along with stronger, more constant wind resources offset the added cost of foundations, maintenance, and grid connection, making the average cost of off-shore wind with currently available technology 5-6¢/kWh (McGowan et al., 2001, 3-18).

Wind turbine towers are usually one to one-and-a-half the rotor's diameter in height; for example, a 1 MW wind turbine with a 60 meter rotor diameter typically has a 60-80 meter tower (McGowan and Connors, 2000, 149-150). The tower height is an economic tradeoff between access to stronger, more constant winds, which improves economic performance, and the added cost of taller towers. The turbine blades and nacelle sit upon either truss or conical tubular towers. While truss towers are cheaper to build, tubular towers tend to be more aesthetically pleasing and also provide shelter for workers who must climb the tower to service the turbine (Gipe, 1995, 221). Virtually all MW class wind turbines are built with tubular towers.

To interconnect with the existing electric power system, wind turbines must be synchronized to the grid by producing power with the correct frequency and phase. A simple and straightforward design solution is to operate the wind turbine with fixed pitch blades at constant speed via an induction generator. Such a design sacrifices efficiency; however, because the angle of attack on the turbine blade changes with wind speed. As a result, optimal performance occurs only within a narrow range of wind speeds (McGowan et al., 2001, 3-12). The efficiency of constant speed turbines can be improved with active regulation of pitch via actuators in the blade root. With active pitch regulation, the blade angle can be changed with wind speed to preserve the optimal angle of attack, thereby increasing efficiency.

Another option is to allow the turbine to run at variable speed, which increases efficiency by maintaining a constant tip-to-wind speed ratio that maintains the optimal angle of attack at different wind speeds. Because the generator output has variable frequency, it must be rectified using thyristors or large power transistors, then converted back to smooth alternating current using an inverter with filters. Despite the complexity and added cost of this design, it conveys two important advantages beyond increased efficiency: variable speed operation allows the rotor to spin faster during gusts, which reduces peak torque and it allows for the control of reactive power, which is especially important in weak grids (DWIA, 2004).

The large torque loads on constant speed wind turbines created by wind gusts often result in gearbox failure. Low speed, multi-pole generators − similar to those used in hydroelectric plants − eliminate the need for a gearbox because the turbine rotor can be directly connected to the generator (McGowan et al., 2001, 3-14). Direct drive designs are employed by the German company Enercon in all their turbines, and utilize a specially designed ring generator. Direct drive generators significantly increase wind turbine availability by avoiding downtime created by gearbox failure.

Another important tradeoff is the amount of wind power captured versus the generator size. Because wind power is proportional to the cube of wind speed, turbine performance is highly sensitive to the sizing of the generator relative to the blades. While it is possible to arbitrarily increase the size of a generator with respect to a particular blade size, at some point the added cost of a larger generator is not justified by the infrequent high speed wind gusts that allow the generator to produce near or at its rated power. In practice, generators are sized in modern wind turbines to produce rated power between roughly 15 – 25 m/s. The torque on the rotor shaft must be held relatively constant in this wind speed region through stall or pitch regulation to prevent overloading the generator. Turbines with fixed-pitch blades are stall-regulated, whereby the blades enter aerodynamic stall by creating turbulence on the side of the rotor blade that is not facing the wind. With pitch regulation, the blade is actively pitched with actuators to reduce aerodynamic lift and maintain constant torque on the rotor shaft.

Below a particular wind speed, usually 4 m/s, the turbine blade does not produce enough torque on the generator shaft to overcome friction and start rotating. At intermediate wind speeds, typically between 4 – 15 m/s, the power produced by the generator varies cubically with the wind speed. At wind speeds exceeding roughly 25 m/s, the blades are stopped in order to prevent damage by either entering full aerodynamic stall or feathering the blades out of the wind. Figure 1.1 includes the power curves for a stall- and pitched- regulated wind turbine, and also demonstrates the hourly variability in wind speed. The variable nature of wind is apparent: most hourly wind speeds fall within the cubic region of the power curve, resulting in variable output, and several hourly wind speeds are below the cut-in threshold where the wind turbine doesn't produce power, resulting in intermittent power.

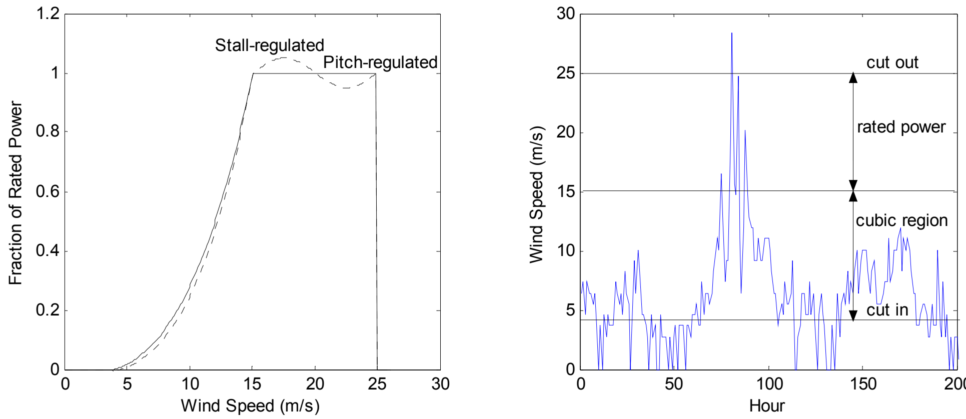


Figure 1.1 – Power production from wind turbines versus wind speed. The left panel represents stylized power curves for both a stall-regulated and pitch regulated wind turbine. The pitch-regulated wind turbine actively feathers the blade to control output, and the stall-regulated turbine has a fixed pitch but undergoes aerodynamic stall during higher winds, which passively limits output. The right hand panel is sample wind speed data from Sioux City, Iowa, with the different regions of the wind turbine power curve superimposed.

1.5 Challenges Posed by Wind

Because fossil resources can be physically transported to minimize electricity transmission costs and because fossil-based capacity is dispatchable, the generation cost dominates the total average cost of conventional capacity. While the average generation cost of wind is currently 4-6 ¢/kWh, two factors – the spatial distribution and intermittency of wind resources – raise the cost of wind above the average cost of electricity from a single turbine. Studies that assume the economics of wind can be represented by the cost of generation alone produce misleading results. For example, Jacobson and Masters (2001) estimate the cost of electricity from wind to be 3-4 ¢/kWh and argue that wind is currently cheaper than coal, when health externalities are factored into the cost of coal. However, their analysis does not account for the additional costs associated with wind that arise from long distance electricity transmission (to compensate for mismatch between the spatial distribution of wind resources and demand) and backup capacity and/or storage systems (to compensate for the mismatch in temporal distribution of supply and demand). While these costs arise at any scale, their influence on the economics of wind power grow rapidly as wind serves a larger fraction of demand.

The absolute annual growth of wind power generation now exceeds that of hydro, but is still an order of magnitude smaller than for natural gas-fired electricity. The lack of wind capacity expansion in absolute terms is explained by the cost imposed by the spatial distribution and intermittency of wind resources. With conservative assumptions about the income from wind generators in the US: 3¢/kWh for utility or market-based energy payments, a 1.5¢/kWh federal production tax credit for wind energy, and a conservative 0.5¢/kWh green power premium, wind generators should break even at ~5 ¢/kWh. If wind generation costs are 4 ¢/kWh in wind class 4 or 5 areas, producers should make substantial profits and wind should dominate new electric capacity in windy states. No such boom is observed; wind generates only ~0.2% of US electricity and accounts for only 1% of capacity additions in the last 5 years (EIA, 2003a). Even in the five windiest states in the US, wind only serves between 0.001 – 3.6% of state electricity demand, far below its potential (EIA, 2004; AWEA, 2004).

1.5.1 Intermittency of Wind Resources

Current wind farm capacities are small relative to the overall generation capability within the control area they serve, so system operators treat wind power as negative load and compensate variable wind output by using standard control procedures (Richardson and McNerney, 1993). In addition to the variable nature of wind energy, it is relatively unpredictable more than a few hours in advance. Inaccurate wind forecasts complicate economic dispatch of hourly scheduled energy, particularly when wind serves a large fraction of demand, because the system operator is forced to balance the risk of wind not meeting its scheduled output against the risk of committing too much slow-start capacity (Milligan, 2000). It is important to note that wind is fairly predictable over a daily timescale, and that accurate wind speed forecasts provide an important tool to system operators scheduling energy. As wind farms increase in size relative to the control area, the amplitude of power fluctuations from intermittent wind energy increases, making it increasingly difficult for system operators to utilize limited reserve to compensate for periods of low wind power output (Richardson and McNerney, 1993). It is important to note that adding an intermittent power source to an electric power system to meet growing demand will affect reliability and decrease reserve margins even when the intermittent sources serve a very small fraction of demand. As will be discussed in Chapter 2, the cost to deal with wind's intermittency scales smoothly and monotonically from infinitesimal to large-scale wind.

If wind were to serve a third of demand under a strong constraint on carbon emissions, cost-effective management of intermittency would become a central issue for electric infrastructure and associated markets. Intermittency can be mitigated by constructing storage facilities or backup capacity integrated with large wind farms and/or by adding reserve capacity to the wider grid. Storage and backup reduce the imbalance penalties paid by wind generators to the system operator, but add to the cost of the wind project whereas managing intermittency elsewhere in the grid will decrease the average price paid to the wind farm operator. Intermittency will raise overall costs under either scenario. In the work described in this thesis, market mechanisms are ignored, and solutions are found that minimize overall costs and intermittency.

Increasing the price-responsiveness of demand on a short timescale is a potentially important method to offset the cost of wind's intermittency. Several options exist for making demand more responsive to price. First, residential customers can be provided with real-time monitors that track energy consumption and price; but demand response is weak, particularly at the short timescales of economic dispatch. A recent experiment with electricity monitoring devices in Japanese households, for example, found that monitor usage had very modest impacts on energy conservation: each day a household accessed the monitor, daily electricity usage decreased by -1.5% on average (Matsukawa, 2004). A second, and likely more effective option, is to encourage residential customers to allow system operators to control appliance loads. Modeling work that employs refrigerators in the UK as responsive loads demonstrates that the aggregation of load-responsive appliances can offer some of the benefits of spinning reserve, provide operational flexibility by delaying the fall in frequency at times of imbalance, and provide considerable frequency smoothing when operated in conjunction with wind power (Short, 2003). Third, and likely most important, are the options that arise for commercial and industrial loads in liberalized electricity markets. For example, customers can submit price-responsive demand curves in day-ahead markets for energy and ancillary services that provide the system operator with increased flexibility in matching supply with demand (Hirst, 2002).

All else equal, responsive demand will reduce the need for reserves, lowering overall electricity supply costs; and, all else equal, wind power will increase the need for reserves. The interactions between these effects have not been explored: it is possible, for example, that the marginal cost of wind's intermittency will be roughly independent of demand responsiveness.

1.5.2 Spatial Distribution of Wind Resources

The second challenge posed by wind is the spatial distribution, and often remote location, of high-quality, large-scale wind resources. Current windfarm installations in both the US and abroad have generally been sited in strong wind resources close to preexisting transmission infrastructure. Wind sites near demand centers are not likely exploitable on a large scale for two reasons. First, these resources tend to be of lower quality such that when wind is used at sufficient scale to exploit economies of scale in long distance transmission lines, it will be more economical to import electricity from distant high quality wind sites. Second, the high quality wind sites that do exist near demand centers are often in environmentally sensitive areas and/or areas where there will be significant public opposition. In the US, the controversy surrounding the Cape Wind project is testimony to the uproar created by proposals aimed at building wind farms in an area that is both a popular recreational center and environmentally sensitive (Grant, 2002; Ziner, 2002). Undeveloped areas near demand centers suitable for wind development, such as mountain ridges and coastal areas, tend to be naturally popular recreational areas of significant importance to local residents.

If wind were used to serve a significant fraction (e.g., one third) of US electricity demand, then the need for cheap land, low population densities, and strong wind resources would likely dictate that the bulk of the wind capacity be located in the remote, windy regions of the Great Plains and transmitted via long-distance transmission lines to demand centers. There is no shortage of capacity: under moderate land use constraints on wind farm siting, 12 Midwestern states could supply 4 times the current US electricity demand (Grubb and Meyer, 1993).

The problem of overlapping federal, state, and local jurisdictions compounded by the lack of regulatory incentive to build new lines in restructured electricity markets makes transmission line construction a very difficult and uncertain prospect in the US. This analysis ignores these near-term regulatory issues, and only considers the construction and material costs to build such long distance transmission lines in the future.

Constructing long-distance transmission lines to utilize the best wind resources also provides the opportunity to build geographically dispersed wind turbine arrays, which can decrease the intermittency of the aggregate wind energy system. Geographic dispersion of turbine arrays over sufficiently large areas on the order of 1000 km can increase the reliability of wind by averaging wind power over the scale of prevailing weather patterns. Kahn (1979) quantified the reliability benefit of geographically dispersed wind turbine arrays using California data. While the main point of the paper is that the geographical dispersal of turbine arrays improves the aggregate reliability, the ratio of effective load carrying capability to wind turbine capacity indicates that the diversity benefit reaches diminishing returns when the model is extended beyond Northern California to the entire Pacific region (Kahn, 1979). Subsequent studies have looked at the diversity benefit of distributing wind sites across other US states (Milligan and Artig, 1998; Milligan and Factor, 2000). Recently, the diversity benefit was demonstrated by comparing the average wind power output across 1 (in Kansas), 3 (across Kansas), and 8 (spanning Kansas, New Mexico, Texas, and Oklahoma) wind sites (Archer and Jacobson, 2003). In addition, a European study noted a significant diversity benefit when wind power output is aggregated across Europe, Central Asia, and North Africa (Czisch and Ernst, 2001).

1.6 Lessons from Northern Europe?

The impact of the spatial distribution and intermittency of wind depends on the existing transmission and generation infrastructure, and the resulting costs are not well understood in cases where wind serves more than a small fraction of demand. While Denmark and parts of Germany have wind serving more than 20% of demand, their experience does little to resolve uncertainties about the costs imposed by intermittent wind resources for at least two reasons. First, both are connected to large power pools that serve as capacity reserve for wind. Second, the multiplicity of wind energy subsidies and absence of efficient markets, particularly markets for ancillary services, makes it difficult to disentangle costs.

Denmark only comprises about 10 percent of the annual electricity demand of countries in the Nordic Power Exchange – Denmark, Finland, Norway, and Sweden (Pedersen, 2002). Hydropower is a significant fraction of the Nordic Power Exchange; notably Norwegian electricity supply is almost 100 percent hydro and Swedish supply is roughly 50 percent hydro (*ibid.*). There is a strong synergy between hydro and wind: hydro can be dispatched on short timescales to compensate for variations in wind power, and wind power conserves water resources by displacing a portion of the hydro output.

Sørensen (1980) indicates that all of Denmark's electricity needs could be met on average with wind energy – assuming shortfalls could be met by Norwegian hydro. Because excess wind-generated electricity in Denmark would also be exported to Norway to conserve water resources, the resultant impact on Norwegian reservoir levels would be minimal (Sørensen, 1980). Transmission interconnections from Western Denmark to Sweden, Germany, and Norway amount to roughly 1700 MW, which is ~70 percent of average Danish electric power demand and enables significant power sharing (Eltra, 2003).

Despite the advantage of a large power exchange to draw from, there are indications that high wind penetrations[4] in Western Denmark (including the Jutland peninsula and the island of Funen) are already having adverse impacts. To date, the maximum load is 3800 MW and minimum load is 1150 MW (Jackson, 2004). On the supply side, over 1400 MW is decentralized combined heat and power (CHP) and 2360 MW is wind (*ibid.*). Eltra, the transmission system operator in western Denmark, is required to buy all electricity from both wind and CHP plants because they are designated as "priority power" (*ibid.*). During the winter, CHP plants often run at full capacity to keep up with heat demand, and Eltra must buy the accompanying electricity whether it is needed or not. A system containing significant fractions of wind and CHP present unique problems for the system operator because electricity production is tied to the weather in two ways: wind speed and temperature. Eltra is on the brink of becoming a weak system, whereby transmission bottlenecks and energy balance problems are resulting from the

[4] Throughout this thesis, the level of "wind penetration" specifically refers to the fraction of wind energy serving electricity demand.

high penetration of wind energy - in fact, utilities in Jutland were asked in 2002 to close 120 MW of wind capacity (Christiansen, 2002).

Even in Germany, which leads the world in installed wind capacity at 14.2 GW, system planners have only just started to consider how much reserves are adequate to cover the variability in wind supply (Knight, 2004). Without a clear plan to deal with intermittency, new research is required to assess the cost and level of new operating reserves required to buffer variable wind while maintaining a consistent reliability standard. Since the US and many other nations have no large power pool to draw from, the challenges posed by intermittent wind must be addressed sooner than in the Danish and German contexts.

1.7 The Future Role of Wind Power

The use of fossil fuels to produce electricity has generated significant concern about resource scarcity and environmental impacts, and has led to an intense interest in a cleaner, securer, and more sustainable electricity supply. More specifically, the generation of electricity presents several environmental and human health concerns related to the impacts of mining and drilling, air pollution, and climate change; and the global distribution and supply of fossil fuel resources also raises vital concerns regarding fuel price, national energy security, and reliance on nonrenewable resources. It is important to assess the strategic value of wind energy in light of these concerns, given the current and likely state of future electric power systems.

The argument that wind enhances energy security has lost much its saliency since the oil crisis in 1973. While oil still presents the most serious geopolitical concerns regarding energy security, the fraction of oil-based generation in the global electric power sector decreased from 23% in 1977 to under 10% in 1999 (EIA, 2002, 131). Likewise in the US, oil met 16.8% of electricity demand in 1973 but declined to 2.3% by 2002 (EIA, 2003b, 224). While oil will remain an important fuel source for electric generators in the oil rich nations of the former Soviet Union and Middle East, future wind projects can not be expected to significantly impact future oil supplies.

Natural gas now plays a more significant role than oil in electricity generation, with the global consumption of natural gas to fuel efficient gas turbines for electricity generation to double by 2020 (IEA, 2002, 43). With an estimated – albeit highly speculative – global reserve/production ratio of roughly 60 years (BP, 2003) and 72 percent of the proven reserves located in the Middle East and Former Soviet Union (IEA, 2002, 45), the future development of a global liquefied natural gas market may result in high fuel prices and potential security concerns analogous to the current oil market. With significant uncertainty over the future price of natural gas, wind can provide a hedge against high gas prices. However, if energy security is the overriding concern, then for many nations, coal provides sufficient security in the electric power sector at lower cost. The reserve/production ratio for coal is about 200 years globally, and 250 years in the U.S. (BP, 2003).

Despite assertions to the contrary (NREL, 2002; UCS, 2003), wind is unlikely to become a competitive means to achieve reductions in air pollution. If air pollution reduction is the goal, then deep reductions in air pollutants can be achieved by retrofits to existing coal facilities at costs of order 1¢/kWh (Rubin, Kalagnanam et al., 1997).

Wind's primary role will be to mitigate climate change by reducing carbon dioxide emissions in the electric power sector. Anthropogenic climate change is one the most serious long-term environmental challenges facing the world. Working Group II of the Intergovernmental Panel on Climate Change (IPCC) concludes that "the stakes associated with projected changes in climate are high" (McCarthy et al., 2001). Expected impacts of climate change include changes in ocean circulation; sea level; the water cycle; carbon and nutrient cycles; air quality; the productivity and structure of natural ecosystems; the productivity of agriculture, grazing, and timber lands; and the geographic distribution, behavior, abundance, and survival of plant and animal species, including vectors and hosts of human disease (*ibid.*). Although small changes in temperature will produce both positive and negative effects that vary geographically, the effects will grow increasingly negative as the temperature increases, and the effects will have a disproportionate impact on the world's poor who are more susceptible to the effects of climate change because they possess less adaptive capacity than the rest of the developed world.

The possibility of abrupt climate change is most alarming, whereby the nonlinear climate system may undergo rapid change (on a decadal timescale) in response to external forcing (Houghton et al., 2001). While the climatological record presents evidence of abrupt climate change, for example the rapid cooling during the Younger Dryas period 13,000 year ago, it is not possible (given our limited knowledge of climatological processes) to determine whether anthropogenic influence can trigger abrupt climate change (National Research Council, 2002). Schwartz and Randall (2003) outline a worst-case scenario of abrupt climate change in which the thermohaline circulation of the North Atlantic eventually shuts down, which would cause a rapid cooling of Europe and much of the Northern Hemisphere and a dramatic drop in rainfall over many key agricultural areas and population centers. The report suggests that the potential effects of abrupt climate change present significant concerns for US security, as affected nations exceed their own reduced carrying capacity and conflicts over resources and mass migration erupt (Schwartz and Randall, 2001).

In order to stabilize atmospheric concentration at twice the pre-industrial level of 280 ppm, an average of roughly 20 TW of carbon-neutral primary power will be required over the next century, assuming business-as-usual growth defined by the IS92A scenario of the IPCC (Hoffert et al., 1998). For comparison, the current primary energy burn rate is only ~11 TW. Avoiding significant impacts from anthropogenic climate change will require research and development of carbon-neutral energy technologies on an unprecedented scale. Since, with respect to new capacity, wind is currently one of the most inexpensive ways to produce electricity without CO_2 emissions, it is imperative to estimate the contribution that wind energy can make to the elimination of greenhouse gas emissions.

The timing of serious regulatory constraints on CO_2 emissions remains profoundly uncertain. However, uncertainty in timing should not be mistaken for uncertainty of action. Even John Browne, Group Chief Executive of British Petroleum, writes of climate change "…if we are to avoid having to make dramatic and economically destructive decisions in the future, we must act soon" (Browne, 2004). When such constraints arrive, the electric sector will likely need to deliver deeper proportional reductions in emissions than elsewhere in the economy. There are several reasons to expect that the electricity sector will be a key target for carbon mitigation. Centralized ownership and management of electric power plants, which are the largest and most manageable point sources of CO_2 emissions, make regulation easier to implement in an industry that already has considerable experience with the regulation of emissions (Johnson and Keith, 2004). In addition, electric utilities represent captive markets: regardless of the regulations, utilities can not feasibly operate outside national borders and transport their commodity to market. If serious efforts are made to slow climate change, then the US electric sector will likely need to cut CO_2 emissions in half within the next quarter century. Wind power may play a pivotal role in reducing CO_2 emissions from electric power generation.

The rapid worldwide growth in wind capacity has been driven by environmentally motivated taxes, credits, and other regulatory incentives. Absent such incentives, wind will not likely achieve substantial penetration into worldwide electricity markets, despite the continued declining costs of wind turbines, in part because of the costs imposed by remoteness and intermittency. A key assumption of this analysis is that the single most important driver for future wind development will be a constraint on CO_2 emissions. Under a strong carbon constraint, it is likely that wind will compete effectively with other means of reducing electric sector carbon emissions such as coal with carbon capture and sequestration or nuclear.

1.8 CO_2 Mitigation in the Electric Power Sector

There is no panacea for eliminating CO_2 emissions in the electricity sector. Because wind is a viable CO_2 emissions-free technology, a more accurate assessment of the cost of mitigating electric sector CO_2 emissions using wind is important to the economics of climate change mitigation. Other renewable options include hydro, photovoltaics, and biomass. Non-renewable alternatives for reducing CO_2 emissions include fuel switching to less carbon-intensive fuels, improved efficiency (both demand- and supply-side), carbon capture and sequestration from fossil units, and nuclear. Each of these technological alternatives possesses a unique set of benefits, limitations, and costs. Although this thesis focuses on wind, the potential efficacy of these other options is briefly discussed below.

1.8.1 Renewable Technologies

Among renewable technologies – most notably wind, biomass, solar, and hydro –wind and biomass show the most potential for growth. Despite continued growth in hydroelectric installations in the developing world (EIA, 2003a, 105), limited resources and growing environmental concerns are likely to severely limit the long-term role that hydro can play in climate change mitigation. Even if installed hydroelectric capacity were to double worldwide, it would still only make a small contribution to CO_2 mitigation. The direct use of solar energy to generate electricity is currently confined to small off-grid applications because the cost of electricity from photovoltaic panels is roughly 20 ¢/kWh (Bull, 2001), and projections for advanced solar thermal systems are still higher than the current cost for wind (Dracker and De Laquil, 1996). Despite the current high costs, advances in materials science make the long-term potential of photovoltaics a realistic possibility.

Biomass, unlike hydro and solar, has the potential to play a leading role in the reduction of carbon emissions in the electric power sector. According to Metz et al. (2001), the technical potential for global biomass energy crop production in 2050 could reach 12.5 TW from 1.28Gha of available land, a land area that is slightly less than the amount of currently cultivated land worldwide. Capital investment in a high pressure, direct gasification combined-cycle plant for electricity production is expected to be roughly 1000 $/kW by 2030, with operating costs, including fuel supply, reaching 3.12 ¢/kWh (*ibid.*). If this projection proves accurate, biomass gasification would become an inexpensive carbon-neutral technology. In the near term, biomass cofiring in existing coal plants can reduce electric sector carbon emissions by 5% at a low cost of 25±20 $/tC (Robinson et al., 2003), and a biomass-IGCC system with a carbon capture and sequestration can produce net negative emissions at projected costs of 7-8 ¢/kWh (Rhodes and Keith, *forthcoming*).

1.8.2 Non-renewable technologies

Coal-based generators that employ carbon capture and sequestration are also expected to play a role in providing electricity with lower specific carbon emissions than the current generating system. There are several options for separating carbon from coal. To capture carbon post-combustion, CO_2 can be removed form the flue gas through a chemical absorption method. Post-combustion carbon capture is complicated by the low concentrations of CO_2 in the flue gas, resulting from high ambient concentrations of nitrogen in the air feed (Herzog, 2001). An oxyfuel approach, which uses an air separation plant to produce oxygen that is fed to the power plant to be used in combustion, simplifies capture by yielding higher concentrations of CO_2 in the flue gas (*ibid.*). Because combustion with oxygen yields unmanageably high temperatures given current technology, some of the flue gas would be recycled to moderate the temperature (*ibid.*). Another option is to partially oxidize coal to create a synthesis gas. The synthesis gas can be made to undergo a water-gas shift reaction to form CO_2 and H_2, with the former being captured and the latter being burned as a carbon-free fuel in a combustion turbine (Parson and Keith, 1998).

Once the CO_2 has been separated using one of the separation methods described above, it can be sequestered in large reservoirs. Reservoirs capable of sequestering of order 10^2-10^4 GtC for thousands of years include the ocean, deep saline formations, depleted oil and gas reservoirs, and coal seams (Herzog, 2001; Parson and Keith, 1998). Carbon capture and sequestration is possible today and adds roughly 2 ¢/kWh to the cost of electricity if 90 percent of the carbon is captured and sequestered (Herzog, 2001), similar to the cost of other electric generation technologies with low carbon emissions (Johnson and Keith, 2004). The continued use of coal as a central generating technology in a low-carbon world also maintains energy security for many nations, as the global reserve/production ratio for coal is over 200 years globally (BP, 2003).

Another alternative to reduce carbon emissions in the electric power sector is nuclear. Over the next 20 years, nuclear power capacity is expected to grow by a modest 9 GW, with plant construction in the developing world offsetting plant retirements in the developed world (EIA, 2002, 91). On a life-cycle basis, the greenhouse gases emitted per kWh from nuclear is two orders of magnitude less than for fossil-based electricity generation and comparable to renewables (Metz et al., 2001, 240). Despite the maturity of nuclear technology, capital costs remain high: currently 1700-3100 $/kW, rendering it uncompetitive with combined-cycle gas turbines in places where natural gas infrastructure already exists (*ibid.,* 240). However, under a strong constraint on carbon emissions and higher natural gas prices, nuclear could play a key role in climate change mitigation. In order for nuclear power to emerge as important player in the electric power sector, four basic challenges must be met: cost, safety, proliferation, and waste (Ansolabehere, 2003, 3). The saliency of Chernobyl and Three Mile Island as well as new security concerns that have emerged post 9/11 also present a significant ongoing public relations challenge to the nuclear industry, which stagnates potential growth.

1.8.3 System Architecture

Deep reductions in carbon emissions in the electric power sector will not be accomplished with a single generating technology; rather, it is likely that a few dominant technologies will emerge as the most cost-effective way to mitigate carbon emissions. Conventional coal and nuclear are fundamentally baseload technologies, which given their thermal constraints can not ramp output quickly to follow changes in load or wind power output, and will be of less value in a wind-dominated system. All else equal, the cost of wind intermittency will be less if the generation mix is dominated by gas turbines (low capital costs and fast ramp rates) or hydro (fast ramp rates) than if the mix is dominated by nuclear or coal (high capital costs and slow ramp rates).

If wind is employed as a strategy to achieve deep reductions in electric sector emissions, then it will likely be competing with gas turbines and other technologies capable of fast ramping and low emissions. The rapid growth in gas turbine capacity is likely to continue as a cost-effective near-term measure to curb carbon emissions, thereby supplanting older coal capacity and making the economics increasingly attractive for wind. In addition, if future fossil-based plants are designed with the coexistence of intermittent renewables in mind, then integrated gasification combined-cycle plants with carbon capture and sequestration can be designed to store a portion of the hydrogen produced through gasification for use in combustion turbines that can ramp quickly to meet fluctuations in wind output.

1.8.4 Environmental Impacts

From an environmental standpoint, the fundamental limitation to wind and biomass is low power density. The environmental footprint of wind and biomass is much more diffuse than that from conventional sources. While some observers would suggest that land requirements for wind are a relatively small price to pay for an emissions-free energy source, others will complain that large-scale wind will disrupt the landscape with roads and transmission lines, while increasing bird kills and scarring vast tracts of land with unappealing structures. Although the impacts of conventional fossil generators are no less severe, they (in general) remain well-hidden from public view because they are spatially compact.

Also, as discussed in Chapter V of this dissertation, wind turbines, in addition to the well-characterized issues of avian mortality, aesthetics, and noise, may have a direct effect on the climate by dissipating additional kinetic energy inside the wind farm field. This climatic impact may be an important consideration in using wind energy to mitigate climate change.

On the other hand, coal poses well known risks including black lung disease, mining accidents, as well as the disruption and contamination of surface and ground water. In addition, air emissions – especially fine particulates – are a major cause of acid deposition, smog, visibility degradation, increased asthma, respiratory and cardiovascular disease, and mortality (Jacobson and Masters, 2001). Perhaps most significantly, the high carbon intensity of coal makes its combustion an important contributor to anthropogenic climate change. In addition, carbon capture and sequestration entails unique risks, including the inducement of seismic activity, the premature release of CO_2 from underground reservoirs, as well as potential negative health effects on animals and plants (Wilson et al., 2003). While natural gas is significantly cleaner, it still emits CO_2 and is subject to significant supply risk. Nuclear poses safety, proliferation, and waste disposal issues. Like wind, biomass is a diffuse resource; but unlike wind, requires the conversion of significant tracts of land for fuel. Preference depends subjectively on the relative importance of how these often incommensurate environmental impacts are weighted in relation to one another.

1.9 Outline of the Thesis: Estimating the Cost and Environmental Impacts of Large-Scale Wind

This chapter emphasizes the critical role that wind power could play in a carbon constrained world. However, there is a surprising lack of rigorous analysis focused on assessing the cost and environmental impacts of large-scale wind serving more than a quarter of electricity demand. The purpose of this thesis to estimate the cost and environmental impacts of large-scale wind in a framework that provides enough detail to capture the physical constraints imposed by the electric power system and natural environment but remains general enough to ensure broad applicability.

Chapter 2 addresses the issue of how variable wind affects grid operation. A common assertion – that variable wind imposes negligible costs below a certain threshold (usually expressed as fraction of wind energy serving demand) and significant costs above the threshold – is critiqued. The chapter posits how the cost of intermittency scales with the level of wind penetration, and addresses how the assumption of a static versus non-static electric power system affects the cost of electricity.

Chapter 3 builds on the assertions developed in the previous chapter regarding wind's intermittency. The chapter describes an optimization model that was constructed to estimate the cost of large-scale wind, in which the costs imposed by the remote location and intermittency of wind resources are included. Results from the greenfield system presented in this chapter provide an economic characterization of a wind system in which long-distance electricity transmission, storage, and gas turbines are used to supplement variable wind power output to meet a time-varying load.

While the previous chapter establishes that large-scale wind can be a cost-effective carbon mitigation option, it does not address the environmental impacts produced by wind power. Chapter 4 addresses three environmental impacts from wind that receive considerable attention in the wind industry: avian mortality, noise, and aesthetics. A significant amount of attention is dedicated to aesthetics in Section 4.4, since the ability to site wind turbine arrays will be a crucial determinant of wind's ultimate role in the electric power sector.

Chapter 5 introduces another environmental impact that has not been raised until recently: wind turbines can influence climate. While wind turbines mitigate climate change by displacing fossil fuels from the electricity supply, they may cause climate change through a separate mechanism by dissipating additional atmospheric kinetic energy within the wind farm field. The relative magnitude of these competing effects may determine wind's efficacy in mitigating climate change. This chapter describes collaborative work that utilizes two General Circulation Models (GCMs) to estimate how massive turbine arrays may affect important climatic variables.

Finally, Chapter 6 summarizes the key findings to create an overall picture of wind's role in a carbon constrained electric power sector. The chapter concludes with a proposal to extend the optimization model described in Chapter 3 to include fossil generation with carbon capture and sequestration.

1.10 References to Chapter 1

Ansolabehere, S. et al. (2003). "The Future of Nuclear Power." Massachusetts Institute of Technology, Cambridge, MA.

Archer, C.L. and Jacobson, M.Z. (2003). "Spatial and temporal distributions of U.S. winds and wind power at 80 m derived from measurements" *J. Geophys. Res.* 108 (D9), 4289, doi:10.1029/2002JD002076.

Asmus, P. (2001). *Reaping the Wind*: *How Mechanical Wizards, Visionaries, and Profiteers Helped Shape Our Energy Future*. Island Press, Washington, DC.

AWEA (American Wind Energy Association) (2004). *Global Wind Energy Market Report*. Washington, DC.

AWEA (American Wind Energy Association) (2004). *Wind Energy Projects in the U.S.* Website: www.awea.org/projects. Accessed on 2 February 2003.

BP (2003). *BP Statistical Review of World Energy*. British Petroleum, Egham, UK.

Browne, J. (2004) "What to Do About Global Warming." *Foreign Affairs*, 83(4): 20-32.

BTM Consult (2003). "International Wind Energy Development: World Market Update 2002" Ringkøbing, Denmark

Bull, S. (2001). "Renewable Energy Today and Tomorrow." *Proceedings of the IEEE*, 89(8): 1214-1226.

Christiansen, P. (2002). *Personal Communication*. Frederica, Denmark: Techwise.

Czisch, G. and Ernst, B. (2001). "High wind power penetration by the systematic use of smoothing effects within huge catchment areas shown in a European example." Presented at *Windpower 2001*, 3-7 June 2001, Washington, DC.

DEA (Danish Energy Authority) (1999). *Wind Power in Denmark: Technology, Policies and Results*. Copenhagen, Denmark.

Dracker, R. and De Laquil, P. (1996). "Progress Commercializing Solar-Electric Power Systems." *Annu. Rev. Energy Environ* 21: 371–402.

DWIA (Danish Wind Industry Association) (2004). Website: www.windpower.org. Accessed on 1 October 2004.

Edmonds, J., Clarke, J., Dooley, J., Kim, S.H. & Smith, S.J. (Forthcoming) "Stabilization of CO2 in a B2 World: Insights on The Roles of Carbon Capture and Disposal." *Energy Economics*.

EIA (US Energy Information Administration), Office of Energy Markets and End Use, US Department of Energy, (2003a). *Annual Energy Review 2002*. DOE/EIA-0384(2002). Washington, DC: US Government Printing Office.

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, US Department of Energy, (2003b). *Annual Energy Outlook 2003*. DOE/EIA-0383(2003). Washington, DC: US Government Printing Office.

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, US Department of Energy, (2002). *International Energy Outlook 2002*. DOE/EIA-0484(2002). Washington, DC: US Government Printing Office.

Eltra. (2003). *Annual Report 2003.* Fredericia, Denmark. Website: www.eltra.dk. Accessed on 20 September 2004.

Fairley, P. (2003). "Steady As She Blows" *IEEE Spectrum* 40(8): 35-39.

Gardner, P., Snodin, H., et al. (2003). "The Impacts of Increased Levels of Wind Penetration on the Electricity Systems of the Republic of Ireland and Northern Ireland: Final Report" Glasgow, Scotland: Garrad Hassan and Partners Limited.

Gipe, P. (1995). *Wind Energy Comes of Age*. Wiley, New York, NY.

Grant, S. (2002). "The Sound of Power Politics." *The Hartford Courant*. Hartford, CT. August 19, 2002.

Grubb, M.J. (1988). "The Economic Value of Wind Energy at High Power System Penetrations: An Analysis of Models, Sensitivities and Assumptions" *Wind Engineering* 12(1): 1-26.

Grubb, M.J. and Meyer, N.I. (1993). "Wind Energy: Resources, Systems, and Regional Strategies" *Renewable energy: sources for fuels and electricity* T. B. Johansson and L. Burnham (Eds.) Washington, DC: Island Press.

Herzog, H.J. (2001). "What Future for Carbon Capture and Sequestration?" *Environmental Science & Technology* 35(7): 148-153.

Hirst, E. (2001). "Interactions of Wind Farms with Bulk-Power Operations and Markets" Website: www.ehirst.com/publications.html. Accessed on 21 August 2003.

Hirst, E. (2002). "Price-Responsive Demand As Reliability Resources." Website: www.ehirst.com/publications.html. Accessed on 26 May 2004.

Hirst, E. and Hild, J. (2004). "The Value of Wind Energy as a Function of Wind Capacity." *The Electricity Journal*, July 2004.

Hoffert, M.I. et al. (1998). "Energy implications of future stabilization of atmospheric CO_2 content." *Nature* 35: 881-884.

Houghton, J.T., Ding, Y., et al. (eds.). (2001). *Climate Change 2001: The Scientific Basis: Contribution of Working Group I to the Third Assessment Report of the IPCC*. Cambridge, England: Cambridge University Press.

Ilex and Strbac, G. (2002). "Quantifying the System Costs of Additional Renewables in 2020." Ilex Energy Consulting, Oxford, UK.

Jackson, J. (2004). "Integrated in Practice But Not in Theory." *Windpower Monthly*, February, 2004.

Jacobson, M.Z. and Masters, G.M. (2001). "Exploiting Wind Versus Coal." *Science (Policy Forum)* 293: 1438.

Johnson, T.L. and Keith, D.W. (2004). "Fossil electricity and CO_2 sequestration: how natural gas prices, initial conditions and retrofits determine the cost of controlling CO2 emissions" *Energy Policy* 32: 367-382.

Kahn, E. (1979). “Reliability of Distributed Wind Generators” *Electric Power Systems Research* 2: 1-14.

Knight, S. (2004). “Shocking Claims on Reserve Requirements.” *Windpower Monthly*, February, 2004.

Loiter, J.M and Norberg-Bohm, V. (1999). “Technology policy and renewable energy: public roles in the development of new energy technologies.” *Energy Policy* 27(2): 85-97.

Matsukawa, I. (2004). “The Effects of Information on Residential Demand for Electricity” *The Energy Journal* 25(1): 1-17.

McCarthy, J.J., Canziani, O.F. et al. (eds.). (2001). *Climate Change 2001: Impacts, Adaptation, and Vulnerability Basis: Contribution of Working Group II to the Third Assessment Report of the IPCC*. Cambridge, England: Cambridge University Press.

McGowan, C., Finney, K., Peterson, T. and Hughes, E. (2001). "Renewable Energy Technical Assessment Guide – TAG RE: 2000." Palo Alto, California: Electric Power Research Institute (EPRI). Report no. 1000575.

McGowan, J.G. and Connors, S.R. (2000). “Windpower: A Turn of the Century Review” *Ann. Rev. of Energy Environ.* 25: 147-197.

Metz, B., Davidson, O., Swart, R. & Pan, J. (eds.). (2001). *Climate Change 2001: Mitigation: Contribution of Working Group III to the Third Assessment Report of the IPCC.* Cambridge, England: Cambridge University Press.

Milligan, M. and Artig, R. (1998) “Optimal Site Selection and Sizing of Distributed Utility-Scale Wind Power Plants.” *Proceedings of the 1998 International Conference of the International Association of Energy Economists*, pp. 312-322.

Milligan, M. (2000). “Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit” *Wind Energy* 3: 167-206.

Milligan, M. and Factor, T. (2000). “Optimizing the Geographic Distribution of Wind Plants in Iowa for Maximum Economic Benefit and Reliability” *Wind Engineering* 24(4): 271-290.

National Research Council, Committee on Abrupt Climate Change. (2002). “Abrupt Climate Change: Inevitable Surprises.” Washington, DC: National Academies Press.

NREL (2002). “Wind Powering America: Clean Energy for the 21st Century.” National Renewable Energy Laboratory, Golden, CO.

Parson, E.A. and Keith, D.W. (1998). "Fossil Fuel Without CO_2 Emissions." Science 282(5391): 1053-1054.

Pedersen, S.G. (2002). *Personal Communication*. Copenhagen, Denmark: Danish Energy Agency.

Rhodes, J.S. and Keith, D.W. (forthcoming). "Engineering-economic analysis of biomass IGCC with carbon capture and storage." *Biomass & Bioenergy*.

Richardson, D. and McNerney, G.M. (1993). "Wind Energy Systems" *Proceedings of the IEEE* 81(3): 378-390

Righter, R. (1996). *Wind Energy in America*. University of Oklahoma Press, Norman, OK.

Robinson, A.L. et al. (2003) "Assessment of Potential Carbon Dioxide Reductions Due to Biomass-Coal Cofiring in the United States." *Environmental Science & Technology* 37(22): 5081-5089.

Rubin, E.S., Kalagnanam, J.R., et al. (1997). "Integrated Environmental Control Modeling of Coal-Fired Power Systems." *Air & Waste Management Association* 47**:** 1180-1188.

Schwartz, P. and Randall, D. (2003). "An Abrupt Climate Change Scenario and Its Implications for United States National Security." Global Business Network, commissioned by the U.S. Defense Department.

Short, J. (2003). "Using 'responsive loads' to stabilise grid frequency" Master's thesis, Centre for Renewable Energy Systems Technology, Loughborough University, Leicestershire, UK.

Simon, R. (2003). "Senate Boosts Nuclear Power." Nuclear Power Research Institute, Washington, DC.

Sims, R.E.H., Rogner, H-H., et al. (2003). "Carbon emission and mitigation cost comparisons between fossil fuel, nuclear and renewable energy resources for electricity generation" *Energy Policy* 31:1315-1326.

Smith, S. (2004). *Personal communication*. April 20, 2004.

Sorensen, B. (1980). "A Combined Wind and Hydro System." Copenhagen, Denmark: Niels Bohr Institute, University of Copenhagen.

UCS (2003). "Coal Vs. Wind." *Union of Concerned Scientists.* Accessed 23 November 20003 from http://www.ucsusa.org/CoalvsWind/c01.html.

van Kuik, G.A.M. and Slootweg, J.G. (2001). "Wind Energy Harvest and Storage Strategies" Paper presented at the *VGB Conference*, December 2001, Brussels, Belgium.

Wilson, E.J., Johnson, T.L., and Keith D.W. (2003). "Regulating the Ultimate Sink: Managing the Risks of Geologic CO2 Storage." *Environmental Science & Technology* 37: 3476-3483.

Ziner, K.L. (2002). "Offshore Harvest of Wind Is Proposed for Cape Cod" *The New York Times*. New York, New York. April 16, 2002.

Chapter 2: The Cost of Wind's Intermittency: Is There a Threshold?

2.1 Chapter Overview

As noted in Chapter 1, the spatial distribution and intermittency of wind resources increase the cost of wind beyond the generation cost from a single wind turbine. Previous studies have either ignored the intermittency cost of wind or estimated the increased operating costs without addressing the need for additional capacity reserve to maintain pre-wind reliability levels. How intermittency affects the cost of wind has important implications for mid-term energy models such as NEMS and long-range integrated assessment models that examine pathways of technological development to mitigate climate change[5].

Section 2.2 provides a brief overview of electric power system operation, including the different timescales on which system operators must balance supply and demand. Section 2.3 outlines a method for estimating the intermittency cost of wind. Section 2.4 reviews wind integration studies that estimate the cost imposed by wind's intermittency. Section 2.5 critiques arguments that suggest the presence of a threshold (expressed as fraction of wind energy serving demand), below which wind's intermittency imposes negligible costs and above which it imposes substantial costs. Section 2.5 also discusses how small-scale, intermittent wind affects grid operation. Section 2.6 discusses the intermittency costs of large-scale wind, assuming that the generating mix changes as higher levels of wind penetration are achieved. Finally, Section 2.7 draws conclusions about how the cost of wind's intermittency scales with the

[5] Much of the work described in this chapter was originally written as a journal article and has recently been submitted to *The Electricity Journal* for publication.

level of wind penetration, and highlights the implications for the development of energy system and integrated assessment models.

2.2 Managing Variability in Electric Power Systems

Unlike conventional capacity, wind-generated electricity can not be reliably dispatched or perfectly forecasted, and exhibits significant temporal variability[6]. The variable nature of wind makes it less valuable to system operators than dispatchable power. In restructured electricity markets, for example, wind operators choosing to participate in markets for scheduled energy may have to settle schedule deviations at the real-time price, which decreases revenue (Hirst, 2001; Hirst and Hild, 2004). Such penalties are not simply arbitrary financial mechanisms, but reflect, however imperfectly, the cost of managing variations in wind output.

Even without wind, managing electric supply and demand requires sufficient flexibility to respond to time-varying demand, forecast inaccuracies, and contingencies. Three timescales concern system operators on a day-to-day basis: minute-to-minute, intra-hour (5-15 minute timescale), and inter-hour. System operators schedule energy each hour using economic dispatch to meet forecasted demand. The schedule is typically drawn up the day before scheduled dispatch. Sub-hourly differences between scheduled energy and forecasted demand during each hour are met by load-following units that can ramp output quickly to balance supply and demand. In restructured electricity systems, load-following units participate in a real-time (intrahour) market. For example, the New

[6] Wind can be considered quasi-dispatchable, because wind power can be curtailed when required. With fixed-pitch wind turbines, power can be dumped; and with variable-pitch wind turbines, the blades can be feathered to limit output. Thus wind can be dispatched in the negative direction only – power output can not be increased beyond the limit dictated by the prevailing wind speed.

York, New England, and PJM ISOs determine how much more or less capacity is needed for the next five minute interval and utilize their daily supply curves to issue price signals to the load-following units participating in their real-time market (Hirst, 2001). Typically, any generating unit deviating from its schedule must pay the imbalance at the real-time market-clearing price. Load-following units that participate in real-time markets are also known as spinning reserve because they are synchronized to the grid and either idle or operate at less than full capacity.

System operators employ an automatic generation control (AGC) system to manage minute-to-minute load imbalances – an ancillary service known as regulation. Units participating in AGC are equipped with governors that sense a change in frequency and automatically adjust the turbine valves, which allow the generator to change output rapidly. Intra-hour dispatch every few minutes allows the units providing regulation to return to their nominal set points. There are 3 important distinctions between regulation and load-following: (i) regulation takes places over a shorter timescale (minute-to-minute versus every several minutes), (ii) load centers have uncorrelated variability on the regulation timescale, but exhibit significant correlation with each other on the load-following timescale, and (iii) load-following changes often follow predictable diurnal cycles while regulation does not (Kirby and Hirst, 2000). These timescales are illustrated in Figure 2.1.

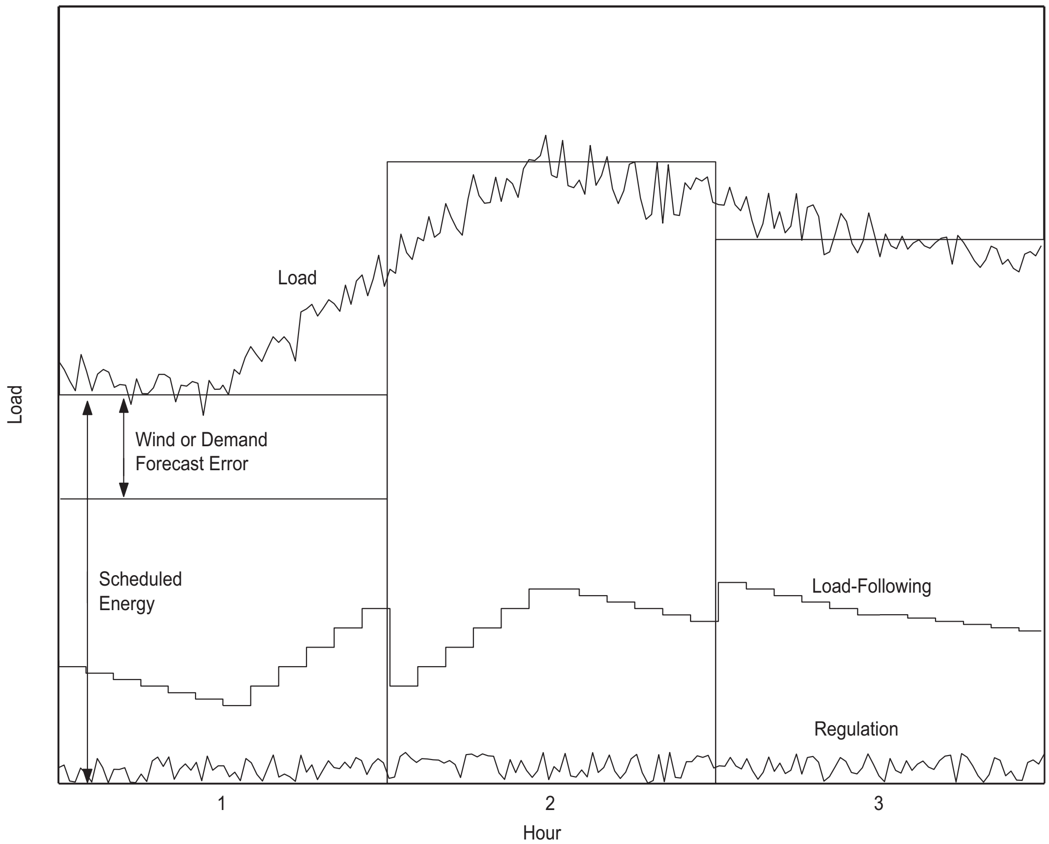


Figure 2.1 – Stylized picture of supply and demand. Demand is met by hourly scheduled energy, intra-hour load-following, and regulation. In most control areas, energy is scheduled ahead of time on an hourly basis using economic dispatch to meet forecasted demand. Load-following makes up for imbalances on a 5-15 minute timescale while regulation (AGC) corrects the minute-to-minute imbalances. Inaccuracies in forecasted demand and/or wind can increase the need for load-following capability.

In order to provide AGC and spinning reserve, some generating units must operate at lower power output than would be dictated by optimal economic dispatch without the requirement to follow changing loads; this adjustment forces the system operator to dispatch higher marginal cost units to make up the difference, which raises the average cost of electricity. Additional costs arise from the degraded efficiency that results when generators are operated at partial power or are forced to follow rapidly changing loads.

In addition to making minor corrections to load forecasts or small schedule deviations, system operators must also have enough generating capacity available to meet system contingencies, such as a forced outage of a particular generating unit or transmission line. Operating reserve, which consists of spinning and non-spinning reserves, represents capacity that can be dispatched within minutes to meet demand in the event of a system contingency such as failure of a generating unit. Non-spinning reserves consist of quick-start units that are not operating, but can be brought online in a matter of minutes. The requirements for operating reserves are generally set by deterministic criteria, such as a fraction of the forecasted maximum peak demand, to ensure that they are large enough to compensate the most likely or largest contingencies.

2.3 Defining the Cost of Wind's Intermittency

Given the complexity of modern electric power system operation, there are debates about how to estimate the cost of wind's intermittency and how to apportion the costs between wind generators and system operators. The purpose of this section is to define the total average cost of wind's intermittency in a simplified context, without respect to which parties should bear the cost. Suppose that a cost-free black box technology exists that has unlimited ability to store wind-generated electricity and can be dispatched without efficiency losses. Such a storage system would make wind perfectly dispatchable, while holding the capacity factor of the wind system constant. Assume that the average cost of electricity (including capital) in a system with such a dispatchable wind-storage system is C_s. In the same system, the cost of electricity with intermittent wind is higher and given by C_{si}. For a given amount of wind capacity on the system, the cost per kWh of wind's intermittency, C_I, would therefore be defined as:

$$C_I = C_{si} - C_s, \tag{2.1}$$

The intermittency cost arises from three sources: higher marginal costs for balancing, new reserve capacity required to maintain system reliability, and non-marginal intermittency costs that arise when the supply of wind energy exceeds demand. The non-marginal intermittency costs occur because as the level of wind penetration increases, an increasing fraction of wind energy exceeds demand and must be curtailed. The cost formulation given by (2.1) can be considered an upper bound because the intermittency cost is based on a comparison to perfectly dispatchable wind. The same formulation applied to steam-based generation technologies would also result in $C_I > 0$ because even though output from such technologies can be controlled, steam units can not be ramped quickly enough to meet changes in supply requirements on a short timescale and balancing costs would be incurred.

Suppose an electric power system without wind supplies electricity at an average cost C_0, while perfectly dispatchable wind (as described above) can be supplied at average cost C_w. If time-varying load is met by units with constant marginal cost and wind was dispatchable, then the average cost of power for the combined system, C_s, would be a simple linear combination of C_w and C_0 as the fraction of total power supplied by wind was increased. Figure 2.2 demonstrates how the intermittency cost of wind, C_I, scales as the fraction of wind serving demand increases.

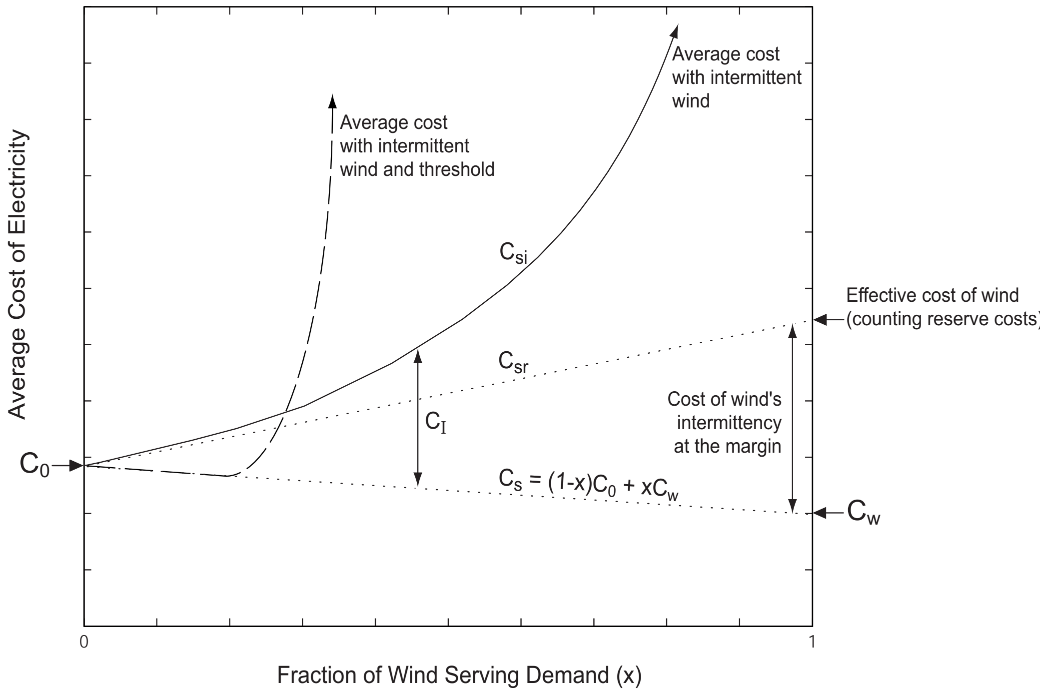


Figure 2.2 – Schematic illustration of the economics of intermittent wind. The vertical axis is the average cost of supplying demand, including both capital and operating costs. The horizontal axis is the total energy supplied by wind divided by the total supplied energy from all generating sources. In a system with dispatchable wind and constant marginal costs, the average cost of power for the combined system (C_s) is a simple linear combination of C_w and C_0 as the fraction of total power supplied by wind (x) was increased. Line C_{sr} includes both the generation cost of wind and the cost of reserve capacity for wind. The solid curve C_{si} shows the minimum cost of supplying demand with intermittent wind. C_s, C_{sr}, and C_{si} all assume that system reliability is held constant as the fraction of wind serving demand increases. C_{si} diverges upward from C_{sr} because as the level of wind penetration rises, the fraction of wind power that exceeds demand increases and must be curtailed. Several studies addressing the cost of wind power suggest that the cost of intermittency is negligible below some threshold beyond which it rises steeply, as illustrated in the dashed curve.

When the marginal costs of supply vary, the straight line linear combination of wind and existing plant (C_s) does not accurately represent the cost of electricity. In real electric power systems, the cost of electricity changes according to the merit order of dispatch. The units with lowest marginal cost are dispatched to meet baseload, cycling units with higher marginal cost are used to meet the shoulder portion of the load, and peaking units with the highest marginal costs are only dispatched to meet peak demand.

Because the theoretical wind-storage system described above, though dispatchable, would maintain the same capacity factor (roughly 30 percent) as intermittent wind, the wind system at low penetration levels should be dispatched to meet peak demand in order to displace the expensive peaking units. But as the fraction of wind on the system increases, wind will displace progressively lower marginal cost plants, which will result in declining marginal fuel savings from wind (Grubb and Meyer, 1993). Even with stratified generation costs, if it assumed that wind power is only installed to meet growing demand, then the average cost of power for the combined system would be still be a simple linear combination of C_w and C_0 as the fraction of total power supplied by wind was increased.

However, if dispatchable wind displaces progressively cheaper supply as the fraction of wind on the system increases, then the average cost of the combined system is no longer a simple linear combination of C_w and C_0. Suppose a theoretical system is represented by the load duration curve in Figure 2.3.

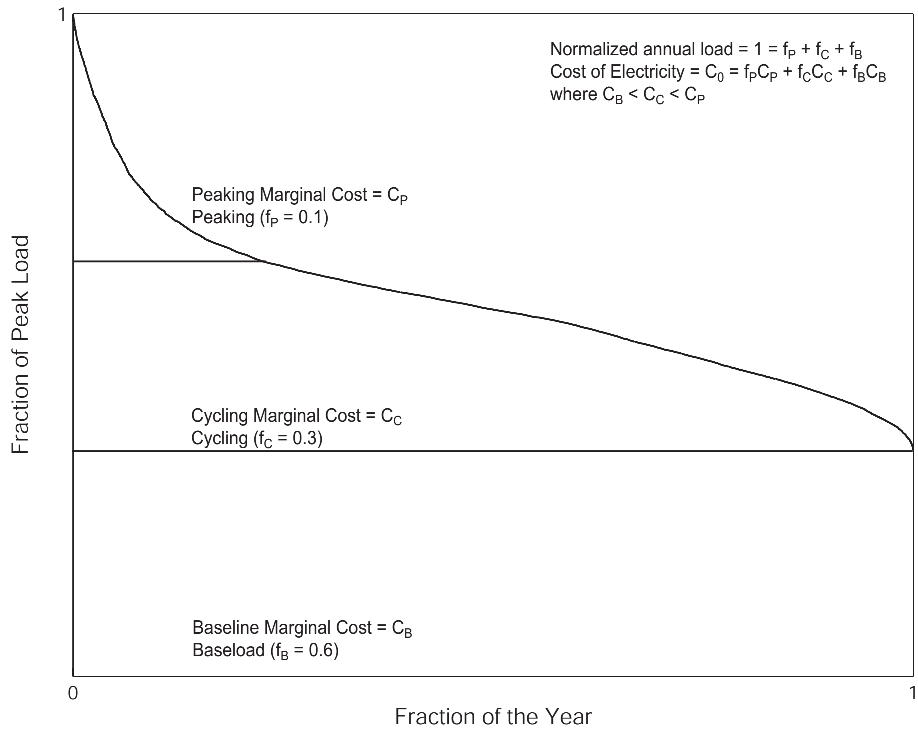


Figure 2.3 – Theoretical load duration curve, where the marginal costs of all units of the same type – baseload, cycling, or peaking – have the same marginal costs.

For simplicity, all generating units in this system can be classified as one and only one of the following: baseload, cycling, or peaking. In addition, all units in the same class have the same marginal cost. When wind is added to the system, the combined cost of electricity in the system can be expressed as:

$$C_0 = f_w C_w + \left(f_P - f_{w_P}\right)C_p + \left(f_C - f_{w_C}\right)C_C + \left(f_B - f_{w_B}\right)C_B\,, \qquad (2.2)$$

subject to the following constraints:

$$\begin{aligned} &f_w = f_{w_P} + f_{w_C} + f_{w_B} \\ &0 \le f_{w_P} \le f_P \\ &0 \le f_{w_C} \le f_C \\ &0 \le f_{w_B} \le f_B \end{aligned}$$

In the constraints above, $f_{w_P}, f_{w_C}, f_{w_B}$ are the fraction of peak, cycling, and baseload met by wind, respectively. The average cost of electricity for the combined system as the fraction of wind serving demand increases from zero to unity can be expressed as a piecewise linear function, whose shape depends on the relative costs of peaking, cycling, baseload, and wind. The stacked plots in Figure 2.4 demonstrate how the shape of the system average cost curve changes as the cost of wind relative to the other supply technologies is adjusted.

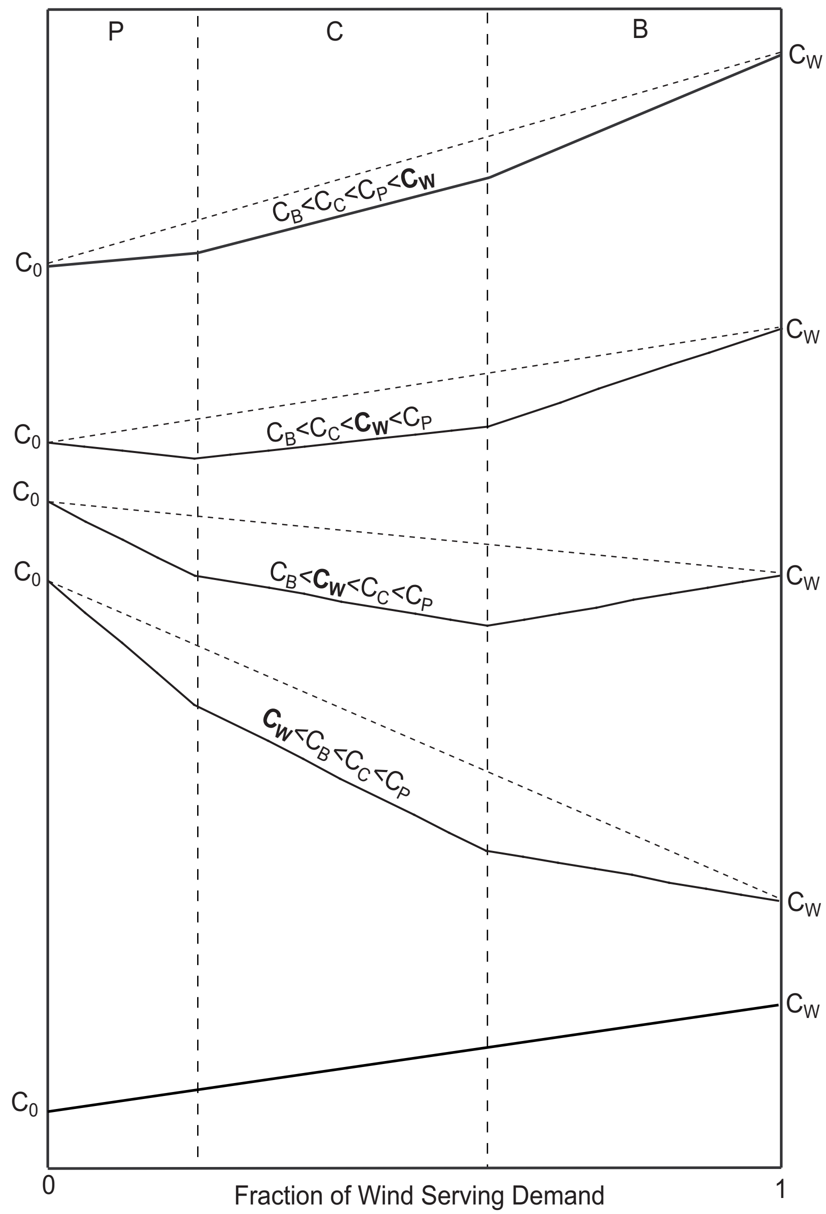


Figure 2.4 – Schematic illustration of the average cost of electricity versus the fraction of wind serving demand. In all cases, wind is assumed perfectly dispatchable. The line closest to the bottom represents the simplest case where wind always displaces existing capacity with the same marginal cost, or wind simply meets growing demand, leaving the rest of the system unchanged. The other curves demonstrate how the average cost of electricity changes if wind displaces increasingly lower marginal cost plants. In the 'P' region wind displaces peaking units, in the 'C' region wind displaces cycling units, and in the 'B' region wind displaces baseload units. The shape of the curve, determined by (2.2), depends on the cost of wind relative to the marginal costs of the other supply technologies.

Assuming that marginal costs vary with the merit order of dispatch, one of the curves in Figure 2.4 would replace the C_s line in Figure 2.2, depending on the relative cost of wind to the other supply technologies. Note that in each case shown in Figure 2.4 where the marginal costs vary, the combined cost of electricity versus the fraction of wind serving demand can always be described as a concave function. In the limit where each unit has a different marginal cost, the piecewise linear functions in Figure 2.4 would approach smooth concave functions. If wind could be dispatched first to displace the most expensive marginal cost units and then work down the merit order of dispatch as the fraction of wind on the system increases, the combined average cost of the system is always lower than assuming wind displaces units representing the average marginal cost of the system.

2.4 Review of Wind Integration Studies

There is a rich set of wind integration studies that estimate the system cost of managing the variability of small-scale wind power using electric dispatch models or detailed analysis based on supply, demand, and cost data for a particular control area. Because these analyses employ highly detailed representations of particular control areas, the results can be difficult to generalize. In addition, these analyses do not consider wind serving more than 30 percent of demand, assume that most of the existing infrastructure remains in place, and do not look more than 20 years into the future. See Table 2.1 for a comparison of cost results from these studies.

Table 2.1 – Summary of wind integration studies and their cost estimates for intra-hour load-following and regulation.

Study	Wind Serving Demand (~%)[a]	Regulation Cost (¢/kWh)	Intra-Hour Load-Following Cost (¢/kWh)
Hirst (2001)	0.08	0.005-0.03	0.07-0.28
Hirst (2002)	6	0.019	0.028
Hirst and Hild (2004)	2-25	0.1-0.4	0.0005-0.002
UWIG (2003)	2	negligible	0.41
Pacificorp (2003)	15	negligible	0.55
Ilex and Strbac (2002)	20-30	0.0015-0.002	0.0032-0.0034

[a] In cases where the fraction of wind serving demand was not given, it was estimated by dividing the product wind capacity and an assumed capacity factor of 35 percent by the average demand for power.

While the costs in Table 2.1 appear very low, there are two important caveats that prevent the extrapolation of these costs to future large-scale wind. First, with the exception of the UWIG study[7], none of these analyses include the cost of transmission. While existing wind farms have been sited close to preexisting transmission infrastructure, future wind farms will increasingly be located in more remote locations in order to utilize stronger winds, minimize public resistance by targeting less densely populated areas, and minimize environmental impact to sensitive environments. Particularly in the US, where the cost and planning uncertainties associated with building new transmission outweigh the incentives, the transmission system is rapidly approaching its capacity limits (Factor and Wind, 2002). As such, substantial installation of new wind capacity will almost certainly require new transmission lines.

Second, with the exception of the Ilex study, these analyses do not account for the cost of increased capacity reserve that is necessary to maintain the same level of pre-wind

[7] UWIG (2003) does account for the cost of new transmission, but does not specify the length or type of new lines.

reliability. Ilex and Strbac (2002) estimate that the cost of new reserve capacity to maintain reliability adds between ~0.5–1¢/kWh to the cost of wind, depending on the assumptions[8]. It is important to quantify all of the costs associated with wind, and determine how the costs scale with the level of wind installed in a system.

2.5 Wind at Small Scale

Several papers consider the regulation and balancing costs in Table 2.1 negligible, and suggest that small-scale wind does not require additional operating reserves to balance the variable output of wind. This leads several authors to conclude that there is a threshold below which wind has a negligible effect on grid reliability, and therefore imposes negligible costs (Richardson and McNerney, 1993; Grubb and Meyer, 1993; EWEA, 2003; van Kuik and Slootweg, 2001). Richardson and McNerney (1993) assert that "if the generation displacement provided by the wind turbines is within the power-handling capabilities of the load-following units, then wind turbines should not affect system stability." Grubb and Meyer (1993) claim that "with no significant measures taken either to make thermal units more flexible, or to predict wind energy better, then serious operational penalties could arise for wind contributions much above 10 to 15 percent of system energy," and also indicate that variability from wind at low levels of penetration are "drowned out by errors in predicting demand, so there is no operational penalty at low wind penetrations." The European Wind Energy Association (2003) claims

---

[8]The cost estimates for new reserve capacity by Ilex and Strbac (2002) are not included in Table 2.1. In the North Wind scenario with 20% renewables under high demand, the cost of new capacity to maintain reliability is 0.44¢/kWh (assuming wind is given a capacity credit) or 0.67¢/kWh (assuming no capacity credit for wind). In the North Wind scenario with 30% renewables under high demand, the cost of new capacity to maintain reliability is 0.59¢/kWh (assuming wind is given a capacity credit) or 0.85¢/kWh (assuming no capacity credit for wind). These calculations assume 1£ ≈ $0.60.

that "numerous assessments involving modern European grids have shown that no technical problems will occur by running wind capacity together with the grid system up to a penetration level of 20%." In another example, van Kuik and Slootweg (2001) claim that wind can serve 15-20% of electricity demand "without special precautions to secure grid stability." Finally, Milborrow (2004) claims that "in none of the countries which label wind power as problematic or expensive have technical issues been identified that would inhibit satisfactory operation of a network with up to 20 percent of its generation coming from wind power." The assumption of such a cost threshold is illustrated in Figure 2.2 by the dashed curve.

These studies implicitly assume that small-scale wind does not affect reserve capacity and does not have a measurable effect on grid operations. By this logic, wind's variability imposes no costs until it approaches the limit of the existing system's operating reserve capability. This assumption is unrealistic; however, because anything that adds variability to load or supply– even if uncorrelated with existing load –will impose additional costs if the same level of reliability (with or without wind) is to be maintained. If wind is a very small fraction of load then these costs will be small in absolute terms, but they may still be significant when compared to the cost of wind power itself.

It may be difficult, or impossible, to unambiguously partition the cost of wind's variability between various markets (day ahead, real-time, and regulation) and market participants (producers, consumers, and transmission operators); it is nevertheless possible, at least in principle, to assess the overall cost of wind's intermittency.

In practice, the costs of wind's intermittency means that the average cost of electricity in an optimally dispatched system that combines wind and conventional capacity will rise above the estimates derived from the simple linear combinations of average costs shown in Figure 2.4. The effective cost of wind power at the margin (that is, for infinitesimal amounts of wind power) is given by the derivative of the total cost curve (line C_{sr} in Figure 2.2), while the cost of wind's intermittency at the margin is the difference between C_{sr} and C_s. This difference represents the cost of capacity reserve for wind and can be expressed as $w \times C_R$, where w is the wind capacity and C_R is the average cost of reserve capacity[9].

Supporting the assertion that intermittency imposes increasing costs on the wider grid as the level of wind penetration increases, Hirst and Hild (2004) find that the revenue received by the wind generators declines smoothly and steadily as the percent of wind serving demand increases and attribute the declining payments to several factors: the addition of supply to a small control area, forecast errors, interhour variability, intrahour energy imbalance, and regulation.

When wind is a small fraction of demand operators (sensibly) manage its variability by treating it as negative load, but this does not mean that the cost of variable wind is negligible. Moreover, wind is in several respects more variable than typical loads. At the minute-to-minute or regulation timescale, AGC can be treated as a random variable with a gaussian distribution and mean of zero (Hudson and Kirby, 2001). For a sense of perspective, the regulation component is roughly 0.1% of total load in PJM

[9] The average cost of reserve capacity does not change assuming the capacity factor remains the same, and this is true assuming that the wind capacity factor remains relatively constant as the fraction of wind serving demand increases. Also, this formulation for the cost of reserve capacity is conservative, and possibly unfair to wind, because it assumes that wind does not receive any capacity credit.

(Hirst, 2001). For comparison, the regulation component for wind in isolation is much larger; one study demonstrates its decline from 10% - 6% of rated wind capacity (assuming a 3σ risk level) as the wind capacity grows from 10 to 100 MW (Hudson and Kirby, 2001). Another study performed in Germany finds that the regulation burden from wind declines from 4.5% to 1% of rated wind capacity (or 14.5% to 3% assuming a 3σ risk level), for wind capacities of 2.8 MW and 44.6 MW respectively (Ernst, 1999). The regulation required for wind grows more slowly than wind capacity because fluctuations on the minute timescale are weakly correlated. In the case of a single wind farm, the minute-to-minute change in each turbine's output is neither perfectly independent nor perfectly correlated with the other turbines. If several wind farms are scattered over a large control area, then the regulation requirement for each wind farm is roughly independent of the others, and the total regulation requirement would scale as the square root of the sum of squares of the regulation requirement from each of the wind farms. For small scale wind serving less than a few percent of demand, the growth in the regulation requirement for wind can be approximated as linear. But as the level of wind on the system increases, the regulation requirement grows slower than wind capacity and the regulation requirement per unit of wind energy decreases. As such, the cost of regulation – while important – is unlikely to place a strong economic constraint on the future growth of wind.

Wind is also more variable than typical loads at the inter-hourly load-following timescale, and this can lead to under-estimates of the cost of wind's variability. Milligan (2003), for example, employs the 3σ rule as a simple proxy to estimate the hourly load-following requirement for wind. (N.B., the actual amount of AGC and load-following capacity must be sufficient to meet NERC's CPS1 and CPS2 reliability standards respectively, which translates into a different capacity requirement for each system operator depending on the particular characteristics of the control area.) Analysis of PJM aggregate hourly load data suggests that load-following requirements have a sub-gaussian distribution in which the actual number of hours that exceed the 3σ-rule is much less than the 0.3% that would occur if the variability of load were normally distributed, making the 3σ-rule conservative for loads. Inter-hour changes in wind power, on the other hand, have a super-gaussian distribution[10]. This result suggests that Milligan's analysis may substantially underestimate the amount of load following capacity necessary to maintain system reliability because wind increases system variance and fattens the tail of the load-following distribution. More generally, it can not be assumed that wind power time series have the same statistical characteristics as load time series. While Hirst and Hild (2004) find that the imbalance charge for intrahour load-following is very modest, even with wind serving ~25% of demand, they acknowledge that reliability will be degraded but do not estimate the cost to upgrade reserves. The portion of aggregate variability attributable to wind ties up a fraction of the existing regulation and load-following capacity, which reduces the amount of reserve available for system contingencies. If reliability is held constant as wind power is added to the system to meet growing demand or replace retired units, this requirement for additional reserve capacity necessarily adds to overall costs. The cost of reserve capacity for wind is represented in

[10] Statistical analysis of PJM and simulated wind power time series was based on data described in Chapter 3. The hourly ramping requirements for PJM between 1997 and 2002 have a sub-gaussian distribution: only 0.09% of the hours fall outside the 3σ risk level, substantially less than the 0.3% predicted by a gaussian distribution. For comparison, the hourly differences in simulated wind power from 5 different wind sites exhibit a super-gaussian distribution, i.e. roughly 2 percent of the hourly load-following requirements for each wind site fall outside the 3σ limit. See Chapter 3, Section 3.4 for details on how the wind power time series was derived.

Figure 2.2 as the difference between C_s and C_{sr}. The cost of adding system reserve to cover the higher variance with wind is real and should be accounted for by system planners.

2.6 Wind at Large Scale

The discussion above assumed that, except for marginal additions to capital stock to cover AGC and load following, the electric power system remains static as wind is added. This assumption is reasonable for small amounts of wind, but as the fraction of wind serving demand increases, it becomes less plausible. Because wind serving a substantial fraction (e.g., more than a third) of demand will take several decades to achieve, the mix of generating units is likely to change significantly during this long period of wind development. Studies that assume wind will grow to serve 20 percent of demand or more while the existing infrastructure remains static may falsely produce a threshold. Any economic limit on the amount of large-scale wind in a given system will depend on how wind coevolves with the rest of the electric power system. All else equal, the cost of intermittency will be less if the generation mix is dominated by gas turbines (low capital costs and fast ramp rates) or hydro (fast ramp rates) than if the mix is dominated by nuclear or coal (high capital costs and slow ramp rates).

The effect of the existing generating mix on wind intermittency costs is illustrated by the Estonian power system. The generating capacity in Estonia is 2 GW, consisting mostly of oil shale and combined heat and power. A theoretical study that added 400 MW of wind to the thermal plants of Estonia found at least an 8-10 percent increase in fuel consumption and emissions due to the increased ramping requirements necessary to compensate intermittent wind; in some cases the net environmental gain from wind was negligible (Liik et al, 2004). It is important to note, however, that this study assumed a static system. A much different result could be obtained by assuming that new wind capacity will be added gradually to the Estonian system, and during that time fast-ramping capacity that can easily and cost-effectively buffer intermittent wind would also be installed. In many parts of the world, the rapid growth in gas turbine capacity is likely to continue, thereby supplanting older coal capacity and making the economics increasingly attractive for wind. In a non-static system, low cost reserve can be added to the wider grid to account for the increased variance from wind.

Three factors identified by Grubb (1988) lower the economic value of wind as the wind penetration level increases, assuming a static system: (i) the reduced cost of marginal fuels (increasing wind generally saves fuel from progressively lower fuel cost thermal plants as discussed in Section 2.3), (ii) operational losses (repeated plant starts or partial plant loading), and (iii) discarded wind energy (primarily due to operational constraints). Grubb defines two (somewhat arbitrary) penetration limits: (i) the marginal fuel savings have dropped by one-quarter and (ii) the marginal fuel savings have been halved. Grubb considers (i) to be an economic target and (ii) to be a "maximum credible penetration level." In terms of the percent of wind energy serving demand, Grubb finds that (i) is 17% and (ii) is 26% for the British system. However, Grubb assumes a static system, and the results would change significantly if the rest of the electric power system was free to change as well.

In Chapter 3 of this thesis, the cost of large-scale wind in a non-static system is investigated by modeling a greenfield system that assumes low capital costs for wind and utilizes distributed wind farms interconnected via long-distance transmission lines, storage, and gas turbines to meet a time-varying load under a carbon tax. A key conclusion from the modeling work is that the cost of dealing with the intermittency problem is reasonable and adds 1-2¢/kWh to the cost of wind serving 50% of demand. The cost of large-scale wind can be broken down into four components: generation, transmission, reserves, and non-marginal losses. The non-marginal losses occur because, even without operational constraints, wind's marginal contribution to serving load decreases as the fraction of wind energy serving demand increases. Because the energy available in the wind can not be dispatched, a large fraction of wind energy is wasted as supply exceeds demand. The effect of marginal losses can be seen in Figure 2.2, where the average cost of electricity with intermittent wind C_{si} diverges upward from C_{sr}.

2.7 Conclusions and Implications for Energy Modeling

Intermittent wind energy imposes real costs on grid operations, even at the scale of a single wind farm. It is posited here that these costs increase smoothly and monotonically as the fraction of wind serving demand increases. Studies that assume reserve capacity is free up to a certain threshold are not taking into account the degraded reliability stemming from increased system variance. Even at small scale, wind adds to variable load, which reduces reserve margins by forcing fast-ramping capacity to correct wind-induced imbalances. Threshold arguments for wind are likely to be overly optimistic at low wind penetration levels (by ignoring the degraded reliability stemming from wind intermittency), and overly pessimistic at high wind penetration levels (by assuming that serious operational penalties will suddenly arise in a static system). While it is imperative to consider the system reliability implications of wind at all scales, it is unlikely that the addition of operating reserve to the wider grid to counter variable wind will result in prohibitive costs. It is important to note that the costs imposed by large-scale wind serving more than a quarter of demand cannot be estimated by taking a static system view, but rather will depend on how the underlying system architecture changes over time as the amount of installed wind gradually increases.

An important underlying principle of this analysis is that electricity should be supplied with the same level of grid reliability with wind as without. While accepting a lower level of reliability could reduce the average cost of supplying electricity with wind power, lower reliability standards would enable roughly equivalent cost savings in the absence of wind. For the same reason, while increasing the responsiveness of demand could reduce the overall costs of electric power, such measures entail roughly equal benefits with or without wind. Increasing the responsiveness of demand may make sense, but it is misleading to argue that the costs of wind's intermittency can be reduced simply because lower electricity costs can be achieved by increasing demand-responsiveness or reducing reliability.

The most important driver for future wind development will likely be a constraint on carbon emissions. Centralized ownership and management, significant experience with regulation, and large, manageable point sources of CO_2 make the electric power sector a prime target for deep cuts in CO_2 emissions. Even with the added cost to deal with intermittency, wind is well-positioned to compete effectively against other generation technologies with low carbon emissions, and may emerge as a key generation technology under a carbon constraint. Yet the assumption of a penetration threshold for wind unfairly limits its role in energy system models.

The National Energy Modeling System (NEMS) is an energy-economy model of US energy markets, designed and implemented by the Energy Information Administration (EIA) and used to project the production, imports, consumption, and prices of energy for the midterm period through 2020. Because the EIA produces annual forecasts compiled in the *Annual Energy Outlook* and carries significant political importance, it is worth considering how wind is modeled in NEMS. NEMS imposes an exogenous limit on intermittent renewables by constraining them to serve no more than 40 percent of demand. To determine the amount of wind capacity to be installed, the NEMS considers capital costs (as well as cost reductions that stem from learning), capacity factor, capacity credit, seasonal variations in wind output, and the distance from existing transmission (EIA, 2004, 7; 42-50). Wind does not play a significant role in NEMS, in part because of the optimistic mid-term estimates of fuel costs, particularly natural gas: 3-5 $/GJ over the next 20 years (EIA, 2003, 77). While some studies, e.g. Clemmer et al. (2001), have modeled the impact of near-term RPS proposals in NEMS, it would be interesting and illustrative to impose a strong constraint on carbon emissions in the model to observe what happens to the level of wind penetration. In such a scenario, wind development would be unfairly limited because, at least in the current version of NEMS, the model is constrained to building wind farms located less than 20 miles from existing transmission (EIA, 2004, 42). With this transmission constraint, NEMS can not capture the likely possibility of large-scale wind from the central US being transmitted to major demand centers via HVDC transmission.

The role of wind in reducing CO_2 emissions over the long run (decades to a century or more) is addressed by energy-system models that attempt to compute the long run costs of reducing CO_2 emissions across all economic sectors and energy technologies. Such models are integral to so-called Integrated Assessment Models (IAMs) of climate change that play a central role in debates over long term climate policy. Such models must necessarily use highly simplified representations of electric power systems and therefore do not simulate the dynamics of electric system dispatch. These models often assume that there is a strong threshold beyond which wind power becomes uneconomic. In one of the most prominent of such models, for example, the fraction of electricity supplied by wind power is capped at 10 percent (Smith, 2004).

By imposing arbitrary (and generally small) caps on wind power's penetration such integrated assessment models may greatly understate the potential contribution of wind power to mitigating CO_2 emissions. The outputs of these models, which show comparatively small contributions from wind power, play important roles in debates about appropriate energy policies to manage climate change. It is important to objectively reassess wind's role through critical research on the implications of wind power's variability for large-scale electric power systems; research that connects the typically disparate communities of those who study near-term integration of wind power in existing markets with the community that does long-range energy modeling.

Future research on the intermittency cost of wind should include analysis of high resolution demand, supply, and wind power time series, consider plant retirement and the temporal development of the electric power system, and ensure that reliability is held constant as wind is added to the system. An important outcome of such work could be supply curves that provide cost estimates of mitigating carbon emissions with wind that do not impose an exogenous limit on wind development. Such supply curves could serve as input into integrated assessment models to achieve a fairer treatment of wind under a carbon constraint.

2.8 References to Chapter 2

Clemmer, S., Donovan, D., Nogee, A., and J. Deyette. (2001). *Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future*. Boston, MA: Union of Concerned Scientists.

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, Coal and Electric Power Division, US Department of Energy, (2004). *Model Documentation: Renewable Fuels Module of the National Energy Modeling System*. DOE/EIA-M069(2004). Washington, DC: US Government Printing Office.

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, US Department of Energy, (2003). *Annual Energy Outlook 2003*. DOE/EIA-0383(2003). Washington, DC: US Government Printing Office.

Ernst, B. (1999). “Analysis of Wind Power Ancillary Services Characteristics with German 250 MW Wind Data.” Golden, Colorado: NREL, NREL/TP-500-26969.

EWEA (European Wind Energy Association). (2003). “Wind Force 12.” Accessed 1 July 2003 from http://www.ewea.org.

Factor, T and Wind, T. (2002). "Delivering 2,000 MW of Wind Energy to the Metropolitan Centers in the Midwest." Iowa Department of Natural Resources.

Grubb, M.J. (1988). “The Economic Value of Wind Energy at High Power System Penetrations: An Analysis of Models, Sensitivities and Assumptions.” *Wind Engineering* 12(1), 1-26.

Grubb, M.J. and Meyer, N.I. (1993). “Wind Energy: Resources, Systems, and Regional Strategies.” *Renewable energy: sources for fuels and electricity*, T. B. Johansson and L. Burnham (Eds.). Washington, DC: Island Press.

Hirst, E. (2001). “Interactions of Wind Farms with Bulk-Power Operations and Markets” Website: www.ehirst.com/publications.html. Accessed on 21 August 2003.

Hirst, E. (2002). "Integrating Wind Energy with the BPA Power System: Preliminary Study." Website: www.ehirst.com/publications.html. Accessed on September 2004.

Hirst, E. and Hild, J. (2004). "The Value of Wind Energy as a Function of Wind Capacity." *The Electricity Journal*, July 2004.

Hudson, R. and Kirby, B. (2001). "The Impact of Wind Generation on System Regulation Requirements." Paper presented at *Windpower 2001*, 3-7 June 2001, Washington, DC.

Ilex and Strbac, G. (2002). "Quantifying the System Costs of Additional Renewables in 2020." Oxford, UK: Ilex Energy Consulting.

Kirby, B. and Hirst, E. (2000). "Customer-Specific Metrics for the Regulation and Load-Following Ancillary Services." Oak Ridge, Tennessee: Oak Ridge National Laboratory, ORNL/CON-474.

Liik, O., Oidram, R. Keel, M. and Landsberg, M. (2004). "Co-operation of Wind Generators with Fossil Power Plants: Problems and Gains." Presented at the *Nordic Wind Power Conference*, 1-2 March 2004, Chalmers University of Technology.

Milborrow, D. (2004). "The Real Cost of Integrating Wind." *Windpower Monthly*, February, 2004.

Milligan, M. (2003). "Wind Power Plants and System Operation in the Hourly Time Domain." Paper presented at *Windpower 2003*, 18-21 May 2003,Austin, TX.

Pacificorp. (2003). "Integrated Resource Plan 2003." Portland, Oregon: Pacificorp. See Appendix L, pp. 365-372.

Richardson, D. and McNerney, G.M. (1993). "Wind Energy Systems." *Proceedings of the IEEE*, 81(3): 378-390.

Smith, S. (2004). *Personal communication*. Richland, Washington: Pacific Northwest National Laboratory (PNNL).

UWIG (Utility Wind Interest Group). (2003). "Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning." *Xcel Energy – North Case Study, Final Report.*

van Kuik, G.A.M. and J.G. Slootweg. (2001). "Wind Energy Harvest and Storage Strategies." Paper presented at the *VGB Conference*, December 2001, Brussels.

Chapter 3: Assessing the Cost of Large-Scale Wind

3.1 Chapter Overview

While the wind integration studies described in Section 2.4 provide useful economic estimates of integrating small-scale wind into current electric power systems, they are limited in scope. On the other hand, integrated assessment models are often used to evaluate climate change policy over a century-long timescale, but do not simulate the supply and demand dynamics of an electric power system. The model described in this chapter builds on the conceptual work in Chapter 2 by simulating supply and demand, but in a simplified greenfield system that has sufficient flexibility to represent the potential contribution of large-scale wind several decades in the future[11]. The modeling work is meant to bridge the intellectual gap between near-term wind integration studies and long-range integrated assessment models.

Section 3.2 reviews previous analyses that estimate the cost of large-scale wind. Section 3.3 discusses the rationale for embedding a simulation inside an optimization model and the associated computational tradeoffs. Section 3.4 describes the modeling framework: structure, assumptions, and objectives. Section 3.5 describes the technologies employed in the model that can mitigate the problems posed by the remote location and intermittency of wind. A description of the wind data and wind site geometry used in the model are provided in Section 3.6. Section 3.7 describes the model results, and Section 3.8 explores why storage does not perform well under a carbon tax. Section 3.9 presents the conclusions drawn from the modeling effort.

---

[11] Much of the work described in this chapter was originally written as a journal article, and has been accepted for publication in *Energy Policy*.

3.2 Previous Modeling Work

The emergence of wind as a dominant generating technology under a strong constraint on carbon emissions will depend critically on whether the challenges posed by the spatial distribution and intermittency of wind can be met cost-effectively. Several technologies such as HVDC transmission, storage, and gas turbines can be utilized to make distant, intermittent wind resources into a cost-effective method for making deep cuts in electric sector carbon emissions.

The modeling work described in this chapter was built upon several previous analyses. Cavallo (1995) addresses the issue by estimating the cost of "baseload" wind (a wind-storage system with 90% capacity factor) at 6¢/kWh. Because Cavallo's analysis focuses on a specific case study of a Kansas windfarm connected to southern California via a 2000 km HVDC line, it is difficult to extrapolate the results to scenarios that include multiple wind sites, where the utilization of weakly correlated wind sites might improve the economics by reducing periods of intermittency. In a similar analysis, Factor and Wind (2002) estimate the cost of delivering 2 GW of wind energy to Midwest demand centers to be 4-6 ¢/kWh, of which 1.5-2¢/kWh represents the cost for new HVDC lines. Although Factor and Wind examine several wind sites connected to different demand centers, they also neglect to test benefit of increasing the spatial spread of wind farms in order to reduce intermittency.

Recent analysis by Ilex Energy Consulting (2002), examined the balance of system costs incurred by renewables serving 20 and 30 percent of electricity demand in Great Britain. In the North Wind scenario with high demand, the additional system cost due to wind energy serving 30 percent of electricity demand is ~1.8 ¢/kWh (Ilex and Strbac, 2002). However, the analysis does not include the cost of the wind turbines or the cost of new transmission to tie the wind farms to the grid – only the system costs incurred for grid reinforcement, managing transmission losses, balancing, and security.

The National Renewable Energy Laboratory is developing a model called the Wind Deployment Systems Model (WinDS), a multi-regional, multi-time-period, GIS and linear programming model. Preliminary results indicate that in the base case (with infinite extension of existing regulatory incentives) wind capacity may reach several hundred GW in the next 50 years (Short, Blair et al., 2003).

In contrast to these studies, the modeling work presented in this chapter focuses on the cost-effectiveness of large-scale wind in meeting a CO_2 constraint. In order to do this, the interaction of several large wind farms and a time-varying demand is simulated in a greenfield scenario, where wind, storage, transmission lines, and gas turbines are optimized to meet load on an hourly basis. This analysis builds on work by both Cavallo (1995) and Factor and Wind (2002) by including multiple wind sites in order to quantify the benefit of geographically dispersed wind farms, which exhibit greater aggregate reliability by exploiting less correlated wind patterns. At the same time, this analysis is meant to be transparent and generalizable, in contrast to the Ilex analysis (2002) and NREL's WinDS model which are detailed policy analyses with a strong national focus.

3.3 Model Numerics, Implementation, and Challenges

To estimate the cost of large-scale wind under a carbon tax, the model performs a simulation of time-varying wind and load, and optimizes wind, transmission, storage, and gas turbine capacities in order to minimize the delivered cost of electricity under a carbon tax. The purpose of this optimization model is twofold: (i) to provide an economic characterization of large-scale wind, which accounts for the spatial distribution and intermittency of wind resources, and (ii) to determine the cost of carbon mitigation using wind at different levels of penetration, and use the results to construct supply curves.

Although the incorporation of a simulation inside an optimization model is computationally intensive, such an approach is more accurate than using sophisticated statistical models to represent wind power and load. In principle, wind power can be represented by capacity factors, minimum values, as well as statistical properties on different timescales and used to meet demand represented by a load duration curve – with a fair degree of accuracy and at significantly less computational cost. However, a time-resolved simulation is required to test the effectiveness of different storage algorithms. Because the use of storage is a potentially critical technology for mitigating wind's intermittency, direct simulation was chosen over a statistical model that would likely prove cumbersome for testing storage algorithms.

The model was implemented in MatLab as a nonlinear, constrained optimization. The MatLab function `fmincon` used a line search method without user-defined gradients to find the cost minimum by adjusting capacity values. Using 6 years of hourly simulated wind power from 5 wind sites at a single carbon tax, the model requires roughly 50 seconds to perform the optimization on a Pentium4 PC running at 2.4 GHz.

The execution of a simulation inside the optimization routine led to convergence problems. When the optimization varies the wind or transmission capacity by a small amount, the wind power vector must be truncated to always remain below the capacity limit of the transmission line. See Figure 3.1

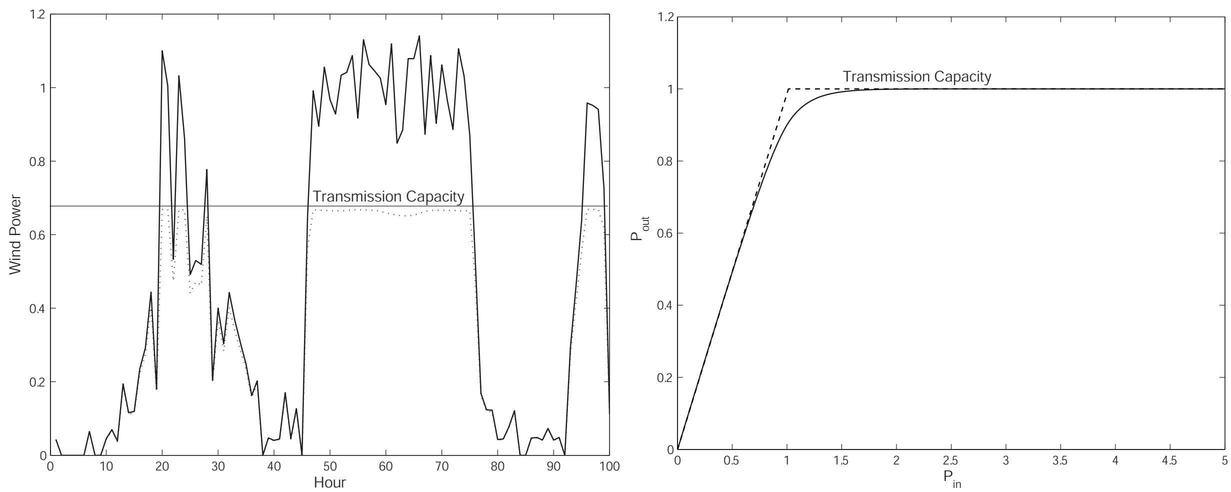


Figure 3.1 − Illustration of how hourly values of wind power exceeding the transmission capacity are truncated. (A) Hourly wind power (solid line) is truncated at the transmission line capacity, which creates uneven steps in the cost derivative with respect to wind or transmission capacity. The cost derivative was smoothed out by mapping the truncated wind power vector to the piecewise linear function on the right. (B) The piecewise linear function used to smooth out the truncated wind power vector. When wind power is small, $P_{\text{in}} = P_{\text{out}}$, and P_{in} close to the transmission capacity is transformed smoothly into P_{out}, which eliminates the sharp cutoff in the wind power vector. The transformed wind power vector is shown in the left panel (dotted line).

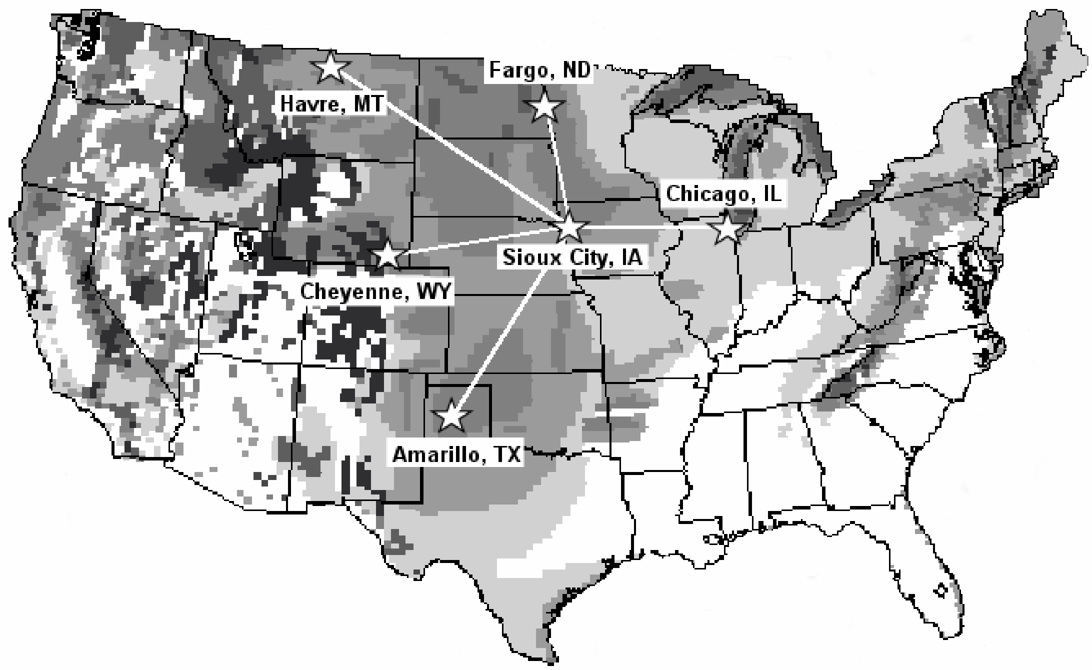
Since hourly wind power is randomly distributed, changing either the wind or transmission capacity will result in a differing number of hourly wind power values being truncated to the transmission capacity, which results in uneven steps in the cost derivative with respect to wind capacity or transmission capacity, i.e. the second derivative of cost with respect to wind or transmission capacity is not monotonic. In many cases, the non-smooth derivative caused the model to fail to find a global minimum. In the limit where the wind power time series was infinitely long, the cost derivative would vary smoothly with wind and transmission capacity. In order to create a smooth cost derivative while attempting to minimize the computation time, the truncated wind power time series was mapped to a piecewise continuous function that smoothly varied hourly wind power values near the thermal line limit, which eliminated the abrupt cutoff.

3.4 Model Description

The model includes 5 wind sites (Figure 3.2). The simulated wind power time series from the 5 sites serve as the cornerstone of the optimization, determining how much, where and at what carbon tax wind capacity is installed. The other capacities are optimized along with wind to meet the model constraint that total hourly energy supplied equals total hourly energy demanded, such that the cost of electricity over the course of the simulation is minimized.

The baseline model contains 13 decision variables, as indicated by the number in parenthesis in the following list.

- Wind capacity at each of the five sites (5).
- Transmission line capacities between wind sites Fargo, Helena, Amarillo, Cheyenne and Sioux City (4).
- Transmission line capacity between Sioux City and the demand center, Chicago (1).
- Capacity of the compressor/turboexpander associated with the storage system located at Sioux City (1).
- Simple- and combined-cycle gas turbine capacities located at the Chicago demand center (2).



	Power Class	Wind Power (W/m^2 at 50m)	Speed (m/s)	Capacity Factor (%)	Average Cost (¢/kWh)
	1	<200	<5.6	10	8.35
	2	200-300	5.6-6.4	18	4.78
	3	300-400	6.4-7.0	24	3.66
	4	400-500	7.0-7.5	28	3.19
	5	500-600	7.5-8.0	32	2.83
	6	600-800	8.0-8.8	38	2.43
	7	>800	>8.8	45	2.10

Map adapted from Elliot et al (1986).

Figure 3.2 – Model geometry and map of US wind potential. The table relates wind class to average cost using the optimistic cost parameters for future wind in Table 1. The capacity factors were estimated from McGowan and Connors (2000). The map also shows the geometric configuration of wind sites used in the optimization model. Sites were selected for sufficient geographic diversity to span synoptic scale weather patterns across the Great Plains. Chicago, IL is the demand center being served.

The parameter values used for capital costs, natural gas turbine efficiencies, and natural gas costs in the model are presented in Table 3.1. Sensitivity analysis of natural gas cost as well as wind and storage capital costs were performed.

Table 3.1 – Cost and efficiency parameters used in the optimization model.

	GT	GTCC	Wind	HVDC	CAES
Efficiency (%)	35	55		85[a]	86
Capital Cost ($/kW)	350	450	600	530,000[b] / 100	400[c] / 0.33
Fuel Cost ($/GJ)	4	4			4
Fixed O&M ($/kW-yr)	7	15	10		10
Variable O&M ($/kWh)	0.0005	0.0005	0.002		0.004

Gas turbine costs are based on Johnson and Keith (2004). Wind costs are based on McGowan and Connors (2000), with a lower capital cost of 600 $/kW, likely achievable in the next two decades. The CAES cost and efficiency estimates are based on Cavallo (1995), EPRI-DOE (2003), as well as conversations with members of industry, then projected a couple decades out. All capital costs are evaluated at a 10% discount rate and 20 year lifetime, giving a capital charge rate of 11.7%.

[a] The transmission line losses were calculated each hour according to the formula: $P_{out} = P_{in}(1 - T_{eff} \times (P_{in}/T_{cap}))$. The transmission line efficiency, T_{eff}, is 85% at the thermal limit.

[b] 530,000 $/mile for a 408 kV DC-bipole transmission line with a thermal line rating of 1934 MW; 100 $/thru kW represents the substation cost for the HVDC line (Hauth et al., 1997). The capital cost ($/kW) for each line is given by:

$$\text{capital cost}\left(\frac{\$}{\text{kW}}\right) = \text{capital cost}\left(\frac{\$}{\text{mile}}\right) \times \frac{1}{\text{thermal line rating}}\left(\frac{1}{\text{kW}}\right) \times \text{line length}(\text{miles}) + \text{substation cost}\left(\frac{\$}{\text{kW}}\right)$$

Because each transmission line in the model had a different length, this calculation resulted in 5 different transmission line capital costs.

[c] The cost of the turbomachinery components is 300 $/kW of expander capacity, with an estimated balance of plant cost of 100 $/kW. In cases where the ratio of compressor/expander capacity is not 1, the cost of compressor capacity is 150 $/kW and the cost of expander capacity is 150 $/kW. 0.33 $/kWh$_e$ represents the cost to develop an underground storage reservoir. The reservoir cost is a rough composite between the cost of using an aquifer, 0.10 $/kWh$_e$ (our estimate) and a solution mined salt cavern, 1 $/kWh$_e$ (Holdren et al., 1999, 5-7).

All costs are evaluated at an annual capital charge rate (CCR) of 11.7 percent. The choice of CCR has an important impact on model results and deserves justification. If the objective is to predict how firms will respond to regulations or incentives in a market economy, then it is appropriate to use the CCR employed by investment firms. The firm CCR is based on their opportunity cost of capital, which is often ~15 percent. In performing public benefit-cost analysis, changes in the cost of production are calculated with a lower CCR, usually based on the long-run growth rate of the economy, roughly 8 percent. From a public perspective, the opportunity cost of capital is determined by the rate of economic growth, without regard to shifts in wealth between different firms. The optimization model can be viewed from either the perspective of an investment firm or the perspective of public benefit-cost analysis. Therefore, a CCR of ~12 percent – directly between the firm and public rates – was chosen. An alternative approach would be to use the firm-level CCR to determine the investment decisions under a carbon tax in the model, but use a lower CCR to estimate the cost to society.

3.5 Technologies in the Model

3.5.1 Wind Turbines

A conservative benchmark for the current capital cost of wind turbines is 1000 $/kW, although it depends on the wind farm size. The cost of a single 1 MW wind turbine is over 1600 $/kW, declines to 1200-1400 $/kW for a 10 MW wind plant, and levels off to 1000-1100 $/kW for wind plants beyond 50 MW (McGowan et al., 2001, 3-19) due to economies of scale in production. The same study projects that in 20 years, the capital cost of wind plants larger than ~60 MW will have a significantly lower capital cost of ~700 $/kW, mainly as a result of increased volume of production, simplified design based on direct drive generators, and incremental design improvements (*ibid.*). McGowan and Connors (2000) find that under the best/optimistic scenario, the greenfield overnight capital cost is currently 750 $/kW. Although only a single point estimate, the Danish turbine manufacturer Vestas is rumored to have sold turbines without towers for 400 $/kW to Florida Power and Light, resulting in a greenfield cost of roughly 600 $/kW (Parsons, 2001). The capital cost for wind turbines used in the model is 600 $/kW, which is aggressive by current estimates but achievable in two or three decades.

The fixed and variable O&M costs used in the model are drawn from the best/optimistic scenario from McGowan and Connors (2000): 10 $/kW-yr for fixed O&M and 0.002 $/kWh for variable O&M. This is only slightly lower than the McGowan et al. (2001) estimate, which neglects variable O&M and estimates fixed O&M at ~20 $/kW-yr for wind projects larger than 50 MW.

The average cost of wind-generated electricity depends not only on capital costs, but also on the capacity factor: the ratio of annual average power generated to rated power. McGowan and Connors (2000) estimate that wind turbine capacity factors range from 25 – 40 percent as the average wind speed at hub height varies from 7 – 9 m/s, corresponding to Wind Classes 4, 5, and 6. Increasing wind turbine hub heights will allow access to stronger and more constant winds, which will improve capacity factor (McGowan and Connors, 2000; Grubb and Meyer, 1993; Cavallo et al., 1993). NEMS includes learning-induced improvement in wind turbine capacity factor, which asymptotically approach maximum capacity factor limits, which are set at 36% for Class 4, 41% for Class 5, and 45% for Class 6 wind resources (EIA, 2004, 47;52). Given these estimates, the wind speed time series were scaled to produce capacity factors at all the wind sites near 35%. More detail on the wind speed time series are provided below in Section 3.6.

3.5.2 Gas Turbines

The model includes both simple-cycle gas turbines (GT) and combined-cycle gas turbines (GTCC), and assumes a baseline cost of 4 $/GJ for natural gas, consistent with the 20-year projection in the Reference Scenario of the US Energy Information Administration's

(EIA) *Annual Energy Outlook* (EIA, 2003). See Table 1. Because natural gas is the only source of carbon emissions in the system, the cost of natural gas and the carbon tax are commensurate: a natural gas cost of 6 \$/GJ instead of 4 \$/GJ would reduce the carbon taxes in the model by ~150 \$/tC. The model simplifies the scheduling problem by utilizing only gas turbines and wind to meet load. Because the simulated wind power is an hourly time series, the model meets demand hour-to-hour but lacks sufficient time resolution to quantify the cost of AGC or load-following. But gas turbines have fast ramp rates suitable for AGC and load-following, so the model assumes that the installed gas turbines are technically capable of resolving the minute-to-minute and intrahour balancing problem, but these balancing costs are not calculated. Hirst and Hild (2004) demonstrate that the operating costs for intrahour balancing are low (0.001-0.002 \$/MWh). While they find the cost of regulation is more significant (1-2 \$/MWh), Chapter 2 argues that the regulation requirement for wind grows more slowly than wind capacity because energy output from wind turbines on the regulation timescale is weakly correlated. Therefore, the ramping costs for regulation and intra-hour load-following to balance variable wind are unlikely to pose a serious economic constraint on the growth of wind.

Early versions of the model included coal, but it is driven out of the generating mix at a carbon tax of ~50\$/tC while wind doesn't enter until carbon taxes exceed 100\$/tC. As a result, there is no direct tradeoff between wind and coal capacity under a carbon tax in this greenfield system. In a similar non-greenfield scenario; however, there will likely be a direct economic tradeoff between wind and coal. In many systems, where the capital investment in coal plants has long been paid off, the average cost of electricity from new wind capacity will be competing against the marginal cost of electricity from coal. In such a scenario, wind and coal will be used simultaneously to meet demand until sufficiently high carbon taxes drive coal out of the system.

Although coal with carbon capture and sequestration and nuclear are both capable of supplying baseload power with near-zero carbon emissions, these technologies were not included in this analysis both for simplicity, and because their slow response to supply and demand variability (slow ramp rates) make dispatch in a wind-dominated system more difficult and expensive. The absence of these technologies in the model highlights an important assumption: coal and other technologies that can not ramp quickly to compensate changes in supply or demand will be less valuable in a wind-dominated system.

As argued in Chapter 2, the economics of large-scale wind must be considered in the context of a non-static system. Several decades of gradual expansion will be required for wind to serve more than a third of demand in a given electric power system. Over this same period, the composition of the rest of the generating fleet can be expected to change as well. If wind is employed as a strategy to achieve deep reductions in electric sector emissions, then it will be competing with gas turbines and other technologies capable of fast ramping and low emissions. The rapid growth in gas turbine capacity is likely to continue as a cost-effective near-term measure to curb carbon emissions, thereby supplanting older coal capacity and making the economics increasingly attractive for wind. For this reason, the model is based on the simplifying assumption that wind's main competition will be from gas turbines, which avoids the unnecessary complexity of simulating several generating technologies. In places where this assumption is wrong because nuclear and coal experience significant growth over gas turbines, wind will not likely have a significant role to play because such generators have limited ability to ramp output in order to compensate variable wind.

3.5.3 Compressed Air Energy Storage (CAES)

The capital costs of storage can roughly be divided between power-specific and storage-specific capital costs. The former is the cost to generate electricity with a storage technology, and the latter is cost to develop a storage reservoir. Compressed air energy storage (CAES) and pumped hydro are the only storage technologies that offer sufficiently low storage-specific capital costs suitable for use in conjunction with large wind farms. Because pumped hydro requires two bodies of water at different elevations located in close proximity to each other, its application is limited. By contrast CAES is broadly applicable since roughly 80 percent of the land in the US has suitable geology, including solution-mined salt caverns, depleted gas reservoirs, hard rock caverns, aquifers, or abandoned mines (Cavallo, 1995). While several storage technologies such as batteries, capacitors, flywheels, and superconducting magnetic energy storage exist, either their cost per kWh makes them prohibitively expensive in large-scale applications or they are specifically designed for intra-hour load following.

To first order, a CAES system is simply a gas turbine in which the compressor and expander are disconnected, and high-pressure air produced by the compressor is stored in an underground reservoir at roughly 80 times atmospheric pressure. When connected to a wind farm, excess wind-generated electricity that exceeds the transmission line capacity or demand can be used to run the compressor and store air at high pressure.

When lulls in the wind require electricity from the CAES system, compressed air is released from the storage reservoir, heated through a recuperator, mixed with natural gas, and then the air-gas mixture is burned in the turboexpander. In a simple-cycle gas turbine, approximately 1/2 - 2/3 of the power produced by the turbine is diverted to run the compressor. As such, the heat rate for a simple-cycle gas turbine is roughly 9750 Btu/kWh. For comparison, the specific CAES system design reported by Desai et al. (2003) has a heat rate of 4300 Btu/kWh. The advantage of CAES is that it burns natural gas more efficiently by precompressing air with excess wind-generated electricity. However, the functionality of CAES systems is limited by the size of the reservoir, and the installed compressor and expander capacities.

Only two compressed air energy storage (CAES) facilities are in operation today. The first was constructed in Huntorf, Germany in 1978 with a capacity of 290 MW and 4 hours of storage, and the second was built in McIntosh, Alabama in 1991 with a capacity of 110 MW and a storage time of 26 hours (Schoenung, 1996). A third is slated for construction in Norton, OH with an ultimate capacity of 2,700 MW to be achieved by adding 300 MW units incrementally (Borroughs and Bauer, 2001). When completed the Norton CAES facility will be able to run at full capacity for 16 hours (Baxter and Makansi, 2003).

The model is allowed to construct a single CAES facility at the Sioux City, IA site. The CAES system was placed at the central wind site rather than the demand center because it makes more efficient use of the transmission infrastructure.

The economic performance of CAES depends strongly on the configuration of the storage system. For the model, a partially optimized system was developed that focused on displacing gas turbine capacity. If the compressor capacity or the storage reservoir are too small, or if the expander capacity is too large, then the storage unit will dispatch energy at a faster rate than it receives excess wind energy and reserves will quickly be depleted. If this occurs, CAES will not be able to displace GTCC capacity, and the carbon tax at which CAES enters the model will be very high because the total cost of CAES will have to be lower than the marginal cost of GTCC. To ensure that CAES operates optimally in the model by displacing gas capacity, a parametric analysis of two important features of a CAES system was performed: (i) the storage lifetime, which represents the amount of time the CAES facility can run continuously at full output if the storage reservoir is full, and (ii) the ratio of compressor/expander capacity in the CAES system, which allows the compressor and expander capacities to optimize to different values. This latter parameter is important because it allows the storage system to absorb more energy than it can release at a given time, which means that CAES will not deplete the storage reservoir faster than it can be filled. Optimal parameter values were determined by using the method described in Section 3.8.

3.5.4 High Voltage Direct Current (HVDC) Transmission

Long-distance electricity transmission will be a critical component in the development of large-scale wind, particularly for the geographic dispersal of wind farms to work as a means of mitigating intermittency. To span the several hundred miles separating Great Plains wind energy from distant demand centers, High Voltage Direct Current (HVDC) lines are more cost-effective than the equivalent three-phase HVAC lines. Assuming the same transmitted power, DC bipole line losses including skin effects and core losses are typically 65-73% of the equivalent 3-phase AC line (Hauth, Tatro et al., 1997). Smaller DC line losses must be balanced by the higher capital cost and cost of losses associated with the DC to AC substations. There is a break-even distance beyond which DC becomes more cost effective than AC, on the order of 100-400 miles depending on the specific configuration (*ibid.*). It should be noted that HVDC technology is not just theory – there are roughly 35,000 MW of HVDC transmission line capacity installed worldwide (Rudervall, Charpentier et al.).

Although not considered in this model, further advances in DC converter technology have led to the development of the Voltage Source Converter (VSC), which allows independent control of both reactive and active power in the system (Chamia, 2000). Reactive power is not carried by DC transmission, but the conversion stations at both the sending and receiving terminals require a significant amount of reactive power support for their respective AC systems (Casazza and LeKang, 1995). VSC technology allows the regulation of reactive power without the need for additional capacitors, and could provide voltage support to wind turbines with induction generators.

Another interesting possibility not explored in the modeling work is to allow variable speed wind turbines to feed DC power directly to the HVDC line. Such a scenario could provide significant cost savings because the variable speed wind turbine would not require an inverter and the HVDC line would not require an AC/DC substation on the end of the line fed by wind power.

3.5.5 Assumptions about Scale

Finally, it is assumed that the problems of remoteness and intermittency matter on a relative scale rather than an absolute. For example, constructing a remotely located 5 GW windfarm connected to a 10 GW grid poses the same basic problem as constructing a remotely located 50 GW windfarm connected to a 100 GW grid. Addressing the intermittency problem from wind on a small-scale poses the same basic challenges as wind on a large-scale, provided that wind constitutes a significant fraction of supply in either case. However, the choice of transmission line limits the scale independence assumption. The optimization model utilizes HVDC lines to tie the wind farms to the demand center. These lines typically have large capacities in the range of 1-5 GW, and would only be constructed to transmit power of this magnitude. In addition, certain storage technologies are not considered, such as flow batteries and capacitors, because they are only cost-effective at small scale due to their high storage-specific capital costs. As such, the economic results generated by the model are roughly scale-independent for windfarms of a few GW capacity or more.

3.6 Wind Data and Site Geometry

Hourly wind data for each wind site in Figure 3.2 was obtained from the National Climatic Data Center (NCDC, 2003). NCDC makes available hourly wind recordings since July 1, 1996 from WBAN (Weather Bureau Army-Navy) stations. Because the WBAN station data is recorded at ground level, the wind speed time series had to be scaled to represent wind speeds at higher altitudes. Although power law and logarithmic extrapolation are often used to estimate wind speeds at higher altitudes, these techniques ignore stability corrections, whereby winds are more constant with fewer periods of calm at standard turbine hub heights of 50-80 meters (Grubb and Meyer, 1993). Although the work by Archer and Jacobson (2003) provides a noteworthy methodological improvement to the standard extrapolation techniques, it is quite data intensive. For simplicity, the wind speeds were scaled such that the resultant wind turbine capacity factors were close to 35 percent: a realistic value for wind turbines with a hub height of 80 meters. Scaling the wind speed time series such that the mean in each case was 8 m/s resulted in capacity factors ranging from 32–35 percent. The simplified scaling used here does not aim to provide the most accurate extrapolation of wind speeds, but rather to accurately estimate the capacity factors and correlations between wind sites, since they are the key factors that determine average cost.

The wind sites in the model were chosen for strong wind resources with a wide spatial distribution spanning the Great Plains in order to test the benefit of geographic site diversity. The specific towns chosen are not meant to represent the exact location of wind farms, rather, wind sites were chosen based on the location of WBAN stations that are near significant tracts of Wind Class 4 or 5 land. The model utilizes 6 years of simulated wind power, 1997 through 2002, to account for potential inter-annual variability in wind speed and correlation. Wind turbine power output was simulated by running the scaled wind speed time series through a parameterized wind power output curve for a Vestas 1.75 MW turbine, similar to the one displayed in Figure 1.1.

To represent a time-varying load, recorded hourly PJM loads from 1997 – 2002 were used to represent Chicago demand. The PJM data is readily available, and serves as a reasonable proxy for Chicago demand since most load centers exhibit the same basic diurnal and seasonal fluctuations.

3.7 Model Results

At each carbon tax the optimization model calculates three quantities: (i) the optimal wind, transmission, storage, and gas turbine capacities, (ii) the fractional carbon emissions reductions, and (iii) the average cost per kWh. The baseline case represents the model results at zero carbon tax.

Figure 3.3A represents the optimal wind, transmission, GTCC, GT, and CAES capacities as a function of carbon tax when the model is restricted to one wind site. Wind appears at a carbon tax of 140 $/tC, a value that can be verified analytically. Because supply must meet demand each hour, there must be enough gas capacity (GT or GTCC) installed to meet demand when the wind farms are not producing electricity. As such, wind enters the system when the combined cost of the wind farm and transmission line is less than the marginal cost of the gas turbines (cost of gas, carbon tax, and variable O&M). At a carbon tax of 500 $/tC, CAES enters the model. The CAES curve in Figure 3.3A denotes turboexpander capacity, which represents the maximum power the CAES system can generate each hour.

Figure 3.3B represents the optimal capacities when the model can optimize wind capacity across all 5 wind sites. At the highest carbon taxes, wind energy is serving roughly 70 percent of the electricity demand. At a carbon tax of 140 $/tC, the model begins installing wind capacity at the Sioux City, IA site, as in the 1-site case. This is expected since the Sioux City site is closest to Chicago, and minimizes the investment in transmission. At a carbon tax of 280 $/tC, the model installs wind capacity at the

Cheyenne, WY and Fargo, ND sites. At a carbon tax of 300 $/tC, wind capacity is also constructed at the Havre, MT and Amarillo, TX sites. This result suggests that at sufficiently high carbon taxes, the economic benefit of utilizing distributed wind sites with less correlated winds outweighs the cost of the longer HVDC transmission lines. As the carbon tax increases, wind is serving a larger fraction of demand and backup capacity is needed less often. As a result, GT capacity, with lower capital costs but higher variable costs, exceeds GTCC capacity at carbon taxes greater than 600 $/tC.

In contrast to Figure 3.3A, note that no CAES capacity is installed in Figure 3.3B. This represents a key result of the analysis: there is a tradeoff between wind site diversity and storage. The use of geographically distributed wind sites limits the periods of intermittency, thereby limiting the economic benefit of storage.

In Figures 3.3A and 3.3B, the combined GTCC, GT, and CAES capacities are equal to the maximum load across all carbon taxes, suggesting the coincidence of peak demand with little or no wind power output. In fact, there are 43 hours in 6 years in which the power output across all five wind sites is zero. If all 5 wind power time series are averaged together with equal weighting, the correlation, *r*, between wind power and load over all 6 years is 14%.

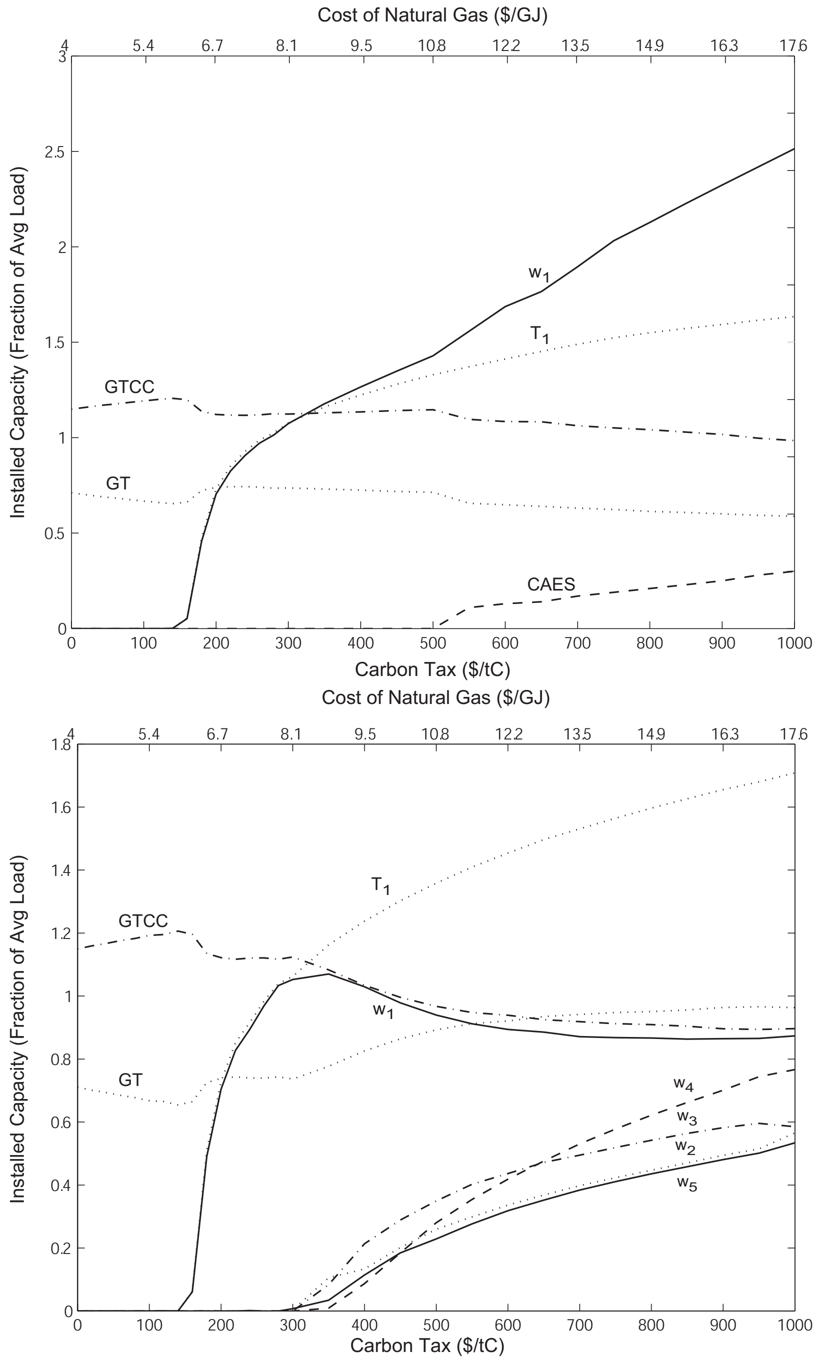


Figure 3.3 – Optimal capacities as a function of carbon tax. The effective cost of natural gas (fuel cost + carbon tax) is given along the top horizontal axis. As such, this plot can also be interpreted as a sensitivity analysis of natural gas cost, where adding 2 $/GJ to the baseline natural gas cost would reduce the carbon taxes in the model by ~150 $/tC. The tuned parameters for CAES determined in Section 3.8 were used. (A) 1 wind site in the model run, where w_1 is the wind capacity near Sioux City, IA and T_1 is the transmission line from Sioux City to Chicago. (B) 5 wind sites in the model. The wind sites are w_1=Sioux City, IA; w_2 = Fargo, ND; w_3 = Havre, MT; w_4 = Amarillo, TX; and w_5 = Cheyenne, WY.

To test the benefit of geographic site diversity, the model was run under 5 different scenarios, where each scenario provided a different number of wind sites available to the optimization. For each scenario, $n \in \{1...5\}$, all combinations of *n* wind sites were simulated, and, for each *n*, the combination that yielded the lowest cost at a 25% reduction in carbon emissions was used in plotting the five curves in Figures 3.4 and 3.5. In Figure 3.4, the fraction of carbon emissions reduction is higher at a given carbon tax with more wind sites, for example, a carbon tax of 500 $/tC produces a 37% reduction when *n*=1, compared to a 52% reduction for *n*=5. The benefits of wind site diversity are also demonstrated in Figure 3.5, where the average cost at each level of carbon emissions abatement is inversely proportional to the number of wind sites used by the model; for example, to achieve a 50% reduction in carbon emissions with wind, the average cost is 5.6¢/kWh for *n*=1, and 5.1¢/kWh for *n*=5.

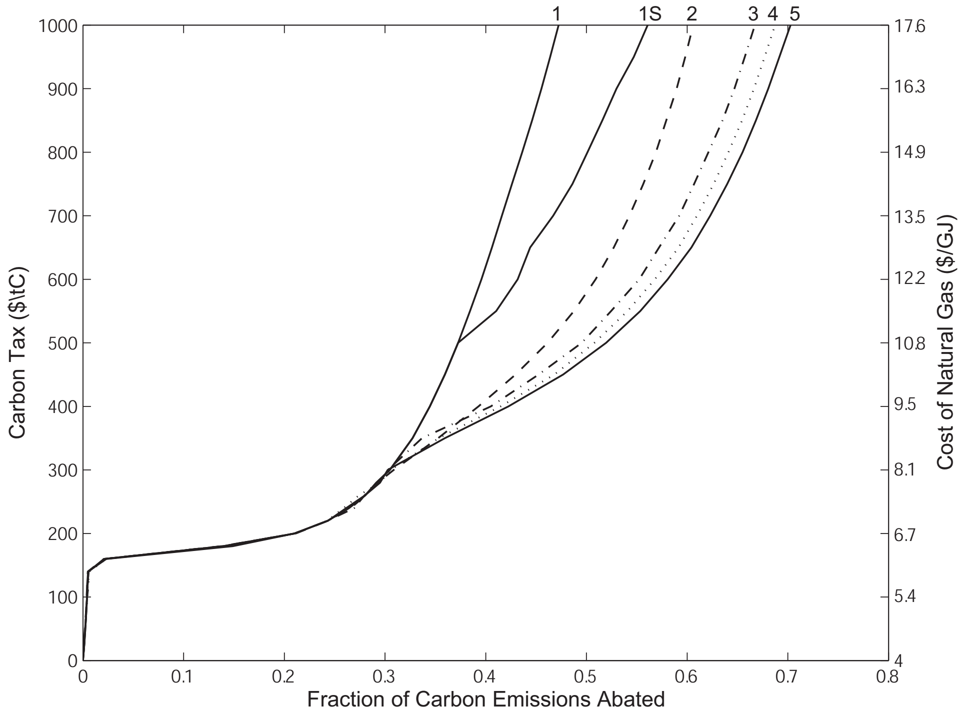


Figure 3.4 – Marginal cost of carbon mitigation as a function of the fractional reduction in emissions from the baseline scenario at zero carbon tax. The number above each curve represents the number of wind sites used in the model run. Because storage becomes cost-effective in the model run with 1 wind site, the curves representing wind with storage ('1S') and without storage ('1') are both shown for comparative purposes. Adding wind sites to the model increases the achievable carbon reductions. Because gas turbine utilization is directly traded for wind utilization as the carbon tax increases, the level of carbon abatement can also be interpreted as the fraction of wind energy serving demand. All five scenarios demonstrate declining marginal reductions in carbon emissions as the carbon tax increases above 500$/tC, which is due to the inherent intermittency of the wind, which always requires some amount of backup gas turbine capacity to ensure that supply meets demand each hour.

Figure 3.4 demonstrates the fractional emissions reductions as a function of carbon tax. In all five scenarios, the results exhibit declining marginal reductions in carbon emissions as the carbon tax is increased beyond 500$/tC. The decline occurs because as wind capacity increases with the carbon tax, a significant amount of wind is wasted as the supply of wind energy exceeds demand. While adding additional wind sites reduces the number of hours with low or zero wind power output and expands the carbon reductions frontier, there is still an effective limit imposed by intermittency. Regardless of how much wind capacity is built, there are still periods when the wind doesn't blow and the backup gas turbine capacity must be utilized to meet the load.

Rather than imposing a carbon tax, the model can be run by imposing a constraint on the allowable carbon emissions. In this case, the model computes the minimum cost of supplying electricity to meet the carbon constraint. Figure 3.5 represents a key model result: average cost (without the carbon tax) as a function of fractional carbon emissions reductions. The average cost of electricity supplied by GTCC and GT is 3.95¢/kWh in the base case. The average cost rises as the level of wind capacity increases with the carbon constraint.

The increasing costs of wind can be understood a follows. Neglecting intermittency, the *average cost* of wind power delivered to the load center at Chicago from the Sioux City site is 4.1¢/kWh including transmission line capacity and transmission losses, just a few percent larger than the average cost of electricity in the all-gas baseline. The 'CoW1' line in Figure 3.5 is constructed to intersect the right hand axis, which corresponds to the hypothetical emission-free system at this average cost. The line therefore indicates the costs that would arise if intermittency could be neglected.

The line labeled 'CoW2' is tangent to the cost curve at zero carbon tax; it therefore includes the cost to have gas turbines serve as reserve capacity to mitigate wind intermittency. The difference 'CoW2-CoW1' represents the cost of intermittency if these costs were independent of the amount of wind capacity. The costs above 'CoW2' arise because the addition of wind capacity produces marginally declining reductions in emissions because more of the wind power must be wasted as supply exceeds demand.

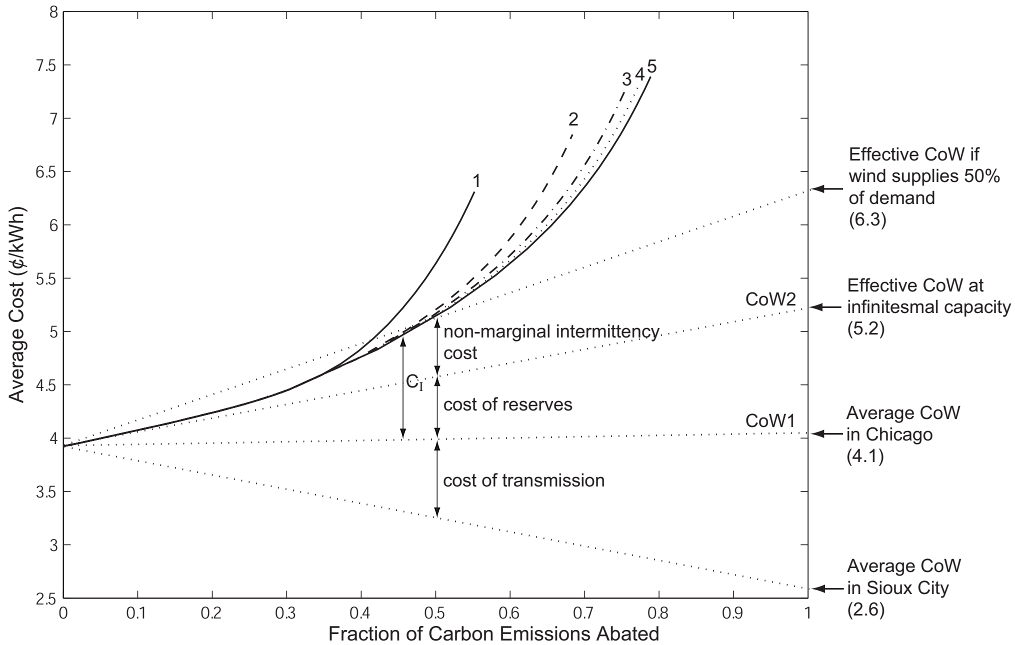


Figure 3.5 – The average cost of electricity as a function of the fractional reduction in emissions from zero carbon tax. The number above each curve represents the number of wind sites used in the model run. The labels on the right-hand side refer to the average cost of dispatchable wind (CoW) under various assumptions. The line labeled ‘CoW1’ is the cost of using wind to mitigate carbon emissions, accounting for the cost of the transmission line and transmission losses, but assuming wind is perfectly dispatchable. The line labeled ‘CoW2’ is tangent to the cost curve at zero carbon tax and includes the cost to have gas turbines serve as reserve capacity to mitigate wind intermittency. Therefore, ‘CoW2-CoW1’ represents the cost of using gas turbines as reserve capacity to mitigate intermittency. The costs above ‘CoW2’ are also due to intermittency: each marginal addition of wind capacity produces a lower marginal reduction in emissions.

Because there is a direct tradeoff between wind and gas turbine capacity, the fractional reduction in carbon emissions can also be read roughly as the fraction of wind serving demand. Therefore, Figure 3.5 provides estimates of the cost of wind’s intermittency, C_I, defined by (2.1). When use of all wind sites is allowed (n=5), the additional cost of using wind to reduce carbon emissions by 50% is 1.2¢/kWh, with 0.6¢/kWh attributable to the cost of managing intermittency with reserve capacity and an additional 0.6¢/kWh attributable to the declining cost effectiveness of wind when wind capacity is large compared to demand. With n=1, the added cost due to declining cost-effectiveness rises to 1.1 ¢/kWh. Finally, extrapolating the cost of wind at a 50% emissions reduction (in the 5-site case) to the right-hand axis indicates that the effective cost of dispatchable wind energy serving 50% of demand is 6.3¢/kWh. Compared with a 2.6 ¢/kWh generation cost of wind, the premium imposed on the cost of wind by the spatial distribution and intermittency of wind resources is 3.7 ¢/kWh for wind serving 50 percent of demand.

3.8 Exploring the benefits of Compressed Air Energy Storage (CAES)

3.8.1 Description of a Reduced-Form Model

The absence of CAES capacity in Figure 3.3B and the utilization of CAES only at high carbon taxes in Figure 3.3A is an intuitively surprising result. Residual emissions generated by the CAES system handicap its performance under a carbon tax, such that CAES does not compete effectively with GT and GTCC capacity. To scrutinize CAES performance under a variety of assumptions, a reduced-form optimization model was constructed. Rather than embedding a simulation of wind power within the optimization, the reduced-form model depends on four functions: (1) the fraction of load served by wind as a function of installed wind capacity, FLS, (2) the minimum power supplied by wind, MPS, (3) the derivative of FLS with respect to storage expander capacity, FLS′, and (4) the derivative of MPS with respect to storage capacity, MPS′. See Figure 3.6. All four are functions of installed wind capacity and are evaluated at zero storage capacity since the objective is to study the value of storage at the margin.

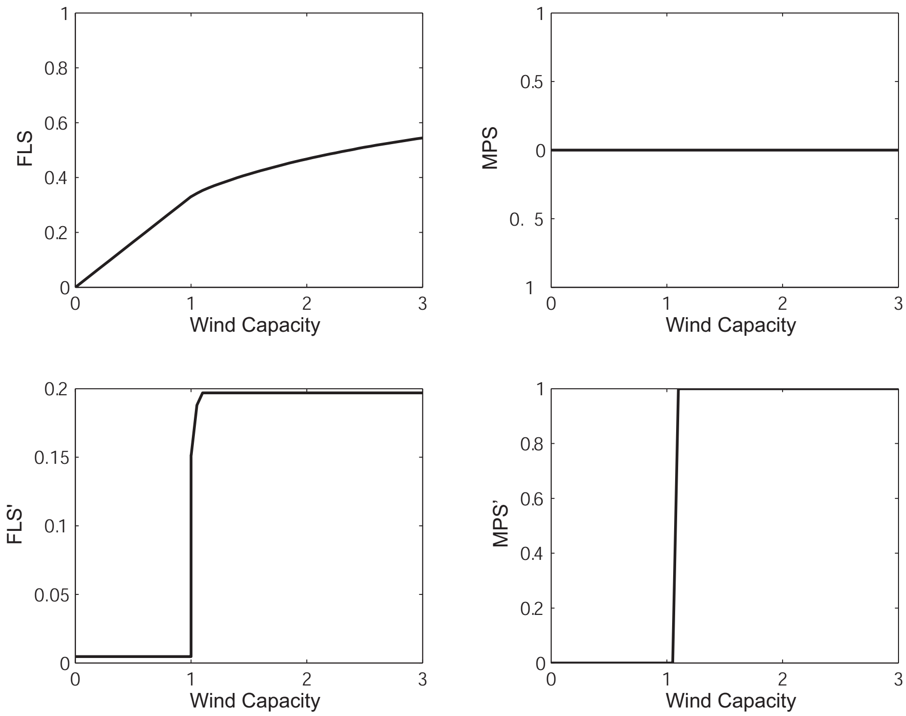


Figure 3.6 – The four functions used in the reduced-form model. The functions were obtained by stepping the wind capacity at the Sioux City, IA site and running the wind power vector through the storage algorithm. The storage parameters are optimally tuned such that CAES becomes cheaper than GTCC at the lowest possible carbon tax. In this case, the storage lifetime is 550 hours and the ratio of compressor/expander capacity is 1.2, and CAES becomes cost-effective at a carbon tax of 335\$/tC.

In this model, one wind site competes directly with GTCC as a function of carbon tax, assuming constant load and 5 years of wind power simulation from the Sioux City, IA wind site. Neglecting storage, the cost is given by

$$wW_{\mathrm{C}} + G_{\mathrm{C}}\,(1-\mathrm{MPS}(w)) + W_{\mathrm{V}}\mathrm{FLS}(w) + G_{\mathrm{V}}\big(1-\mathrm{FLS}(w)\big),$$

where *W* represents wind costs, *G* represents GTCC costs, the subscript ‘C’ denotes capital costs and ‘V’ denotes variable costs. In addition, *w* represents wind capacity. The costs are given in Table 3.1.

Adding storage at the margin will change the value of the FLS and MPS functions. The marginal cost of storage is estimated by adding a small amount of storage (expander) capacity, recalculating the values of FLS and MPS as a function of wind capacity in the reduced-form model, and calculating the numerical derivatives FLS′ and MPS′. Adding storage will tend to increase FLS at a given level of wind capacity, and push MPS to a nonzero value if energy from storage can always be dispatched to fill in hours with no wind power output. The marginal cost of storage can be expressed as:

$$C' = -G_{\mathrm{C}}\mathrm{MPS}' + \mathrm{FLS}'\left(S_{\mathrm{V}} - G_{\mathrm{V}}\right) + SP_{\mathrm{C}} + SS_{\mathrm{C}}S_{\mathrm{T}}, \tag{3.1}$$

where S_{V} is the variable cost to run the CAES plant, SP_{C} represents the power-specific capital cost for the CAES turbomachinery components, SS_{C} represents the storage-specific capital cost to develop the underground reservoir, and S_{T} is the length of time that the CAES system can run at full capacity. CAES becomes cost-effective when C' is less than zero; that is when the total cost of CAES is less than the displaced GTCC costs at a given carbon tax.

Because the economic performance of CAES is sensitive to its configuration, a parametric analysis of the storage lifetime and ratio of compressor/expander capacity using equation (3.1) was performed. The pair of parameters that make CAES more cost-effective than GTCC at the lowest possible carbon tax are considered optimal. With the costs given in Table 3.1, CAES becomes cost-effective at 335 \$/tC, when the storage lifetime is 550 hours and the ratio of compressor/expander capacity is 1.2. This result indicates that CAES operates more efficiently in this simple system when there is more compressor capacity than expander capacity, because a larger compressor can more effectively capture the excess wind energy. Table 3.2 demonstrates how the carbon tax at which CAES becomes cost-effective changes as the storage lifetime and storage-specific capital cost are varied, while holding the ratio of compressor/expander capacity constant at 1.2.

Table 3.2 – Carbon tax at which CAES and H_2 storage systems become cost-effective over GTCC, as a function of the storage lifetime and storage-specific capital cost.

Storage Lifetime	Storage- Specific Capital Cost ($/kWh$_e$)			
(hours)	0.1	0.33	1	0.01 (H_2)
100	1000	1140	1170	910
500	410	410	730	770
1000	330	380	1780	730
1500	340	720	>2000	410
2000	280	1070	>2000	340
2500	280	1410	>2000	340

The storage-specific capital cost represents the cost to develop an underground storage reservoir. The low estimate (0.10 $/kWh$_e$) represents the cost to use an aquifer as the storage medium (my estimate), and the high estimate (1 $/kWh$_e$) represents the cost to develop a solution-mined salt cavern (Holdren et al., 1999). In the H_2 scenario, SS_C = 0.01$/kWh$_e$ is based on Ogden (1999). The ratio of compressor/expander capacity was set to the tuned values for CAES and H_2, 1.2 and 2.5 respectively.

3.8.2 Cost Comparison with an H_2 system

Because CAES is penalized by its residual carbon dioxide emissions, the performance of an H_2 storage system was tested because it does not produce carbon emissions. Excess wind can be used to run an electrolyzer to generate hydrogen, which can then be stored under pressure in a storage reservoir. When electricity is needed, the hydrogen is released from storage and burned in a combustion turbine. The cost to generate hydrogen from large-scale alkaline electrolysis is projected to be as low as 300 $/kW at efficiencies of 70%-85% (HHV), and the levelized cost to store H_2 underground (in the same formations as compressed air) is 2-6 $/GJ (Ogden, 1999). It is also plausible to assume that combined-cycle H_2 turbines could operate at the costs and efficiency given for GTCC in Table 3.1 (Audus, 2001). As such, an H_2 storage system could likely operate with a round-trip efficiency of roughly 40%.

As with CAES, a parametric analysis was performed to determine the optimal storage lifetime and ratio of electrolyzer/turbine capacity that allows the H_2 system to become cost-effective at the lowest carbon tax. An optimal H_2 storage system becomes cost-effective over GTCC at 343$/tC with a storage lifetime of 2,500 hours and an optimal ratio of electrolyzer/turbine capacity of 2.7. The tuned H_2 system requires significantly more storage reservoir capacity and more electrolyzer capacity than in the analogous CAES system for two reasons: (i) the H_2 system has an electricity output/input ratio of 0.4 compared with 1.5 for CAES, which means much more energy will be lost in the H_2 system, and (ii) the H_2 system does not incur fuel costs or a carbon tax penalty so more capital can be devoted to building additional storage capacity in order to make up for the energy lost through inefficiency.

The comparative economic performance of CAES and H_2 is given in Figure 3.7, which plots the value of the cost derivative in equation (3.1) as a function of carbon tax. An unoptimized CAES system, in which the storage lifetime is 100 hours and the compressor/ expander ratio is 1, does not become cost-effective until a carbon tax of more than 1000$/tC. Varying the storage lifetime and compressor/expander ratio demonstrates that CAES performance can be dramatically improved when the parameters are tuned, making CAES cost-effective at 335$/tC.

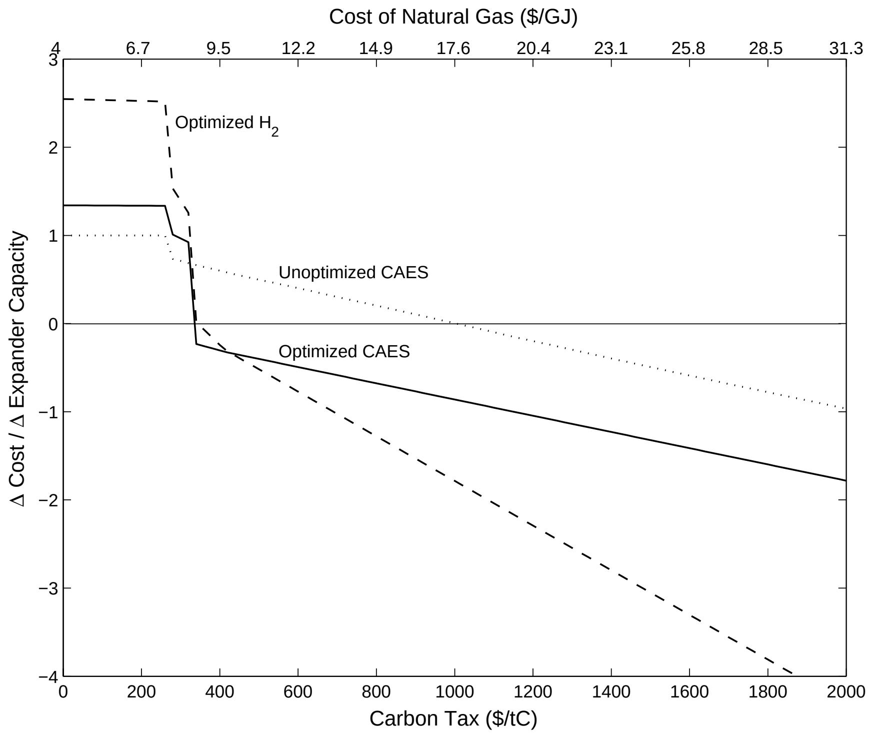


Figure 3.7 – Plot of C′, equation (1), as a function of carbon tax. The curves were normalized by the C′ of unoptimized CAES evaluated at zero carbon tax. Storage is more cost-effective than GTCC when the derivative crosses zero. CAES and H_2 become cost-effective at 335$/tC and 343$/tC, respectively, when the parameters are tuned. In the model run with optimized CAES, the storage lifetime is 550 hours and the ratio of compressor/expander capacity is 1.2. In the model run with optimized H_2, the storage lifetime is 2500 hours and the ratio of compressor/expander capacity is 2.7. Both CAES and H_2 with tuned parameters perform significantly better than the non-optimal CAES with a compressor/expander ratio of 1 and a lifetime of 100 hours.

The first steep drop in the cost derivative near 260$/tC corresponds to the jump in FLS′ when wind capacity exceeds 1 (because excess wind fills the storage reservoir), and the second steep drop at 320$/tC corresponds to the jump in MPS′ when CAES displaces GTCC capacity. In the unoptimized curve, there is no second steep drop because CAES does not displace GTCC capacity, so CAES only becomes cost-effective when its total costs are lower than the marginal costs GTCC. The H_2 system is the most expensive at zero carbon tax, but exhibits a dramatic decline in cost relative to GTCC because it is unaffected by the carbon tax, and becomes cost effective at 343$/tC.

3.9 Conclusions Drawn from the Model

The model presented in this chapter estimates the cost of using large-scale wind to achieve deep cuts in CO_2 emissions by optimizing distributed wind sites, transmission lines, storage, and gas turbines to mitigate the problems posed by the remoteness and intermittency of wind resources. While the model is idealized, several interesting conclusions about the use of large-scale wind can nevertheless be drawn.

First, assuming comparatively low costs for wind turbines and a discount rate of 10%, the average cost of electricity in a gas/wind system in which wind supplies half of demand is of order 5¢/kWh including the cost of transmission and backup. While the capital cost for wind is arguably too low for the near future, the relative cost to deal with the remote location and intermittency of wind is insensitive to a change in wind's capital cost because higher capital costs have roughly additive effects on average cost. The cost of wind's intermittency, as defined by (2.1), is 1.2 ¢/kWh if wind is used to serve half of demand. Further, if wind must supply half of demand, the costs arising to both manage intermittency and build long-distance transmission lines increase the system-level cost of electricity by 1.9 ¢/kWh.

Under aggressive cost assumptions for wind, the average cost of wind-generated electricity at the remote site is 2.6¢/kWh, about 30% less than the cost of electricity in the all-gas system. Because the effective cost of wind serving 50% of demand is 6.3 ¢/kWh, the cost premium imposed by the remote location and intermittency of wind is 3.7 ¢/kWh. Although this cost premium is based on a simple greenfield system, it represents the cost imposed beyond the average cost of generation from a single wind turbine and helps explain the lack of large-scale wind development in the windiest US states.

Second, even when the costs of intermittency and location are included, wind power is roughly competitive with costs of using other technologies, such as nuclear or coal with carbon capture and sequestration, to achieve deep reductions in CO_2 emissions. For example, using similar economic assumptions to those employed here, Johnson and Keith (2004) found that the cost to reduce carbon emissions by 50% using a combination of coal to gas fuel switching and carbon capture and sequestration was 1-2 ¢/kWh, with the latter entering at carbon taxes of 100 $/tC or less. The results in this chapter suggest that, even when it is required to supply more than half of demand, large-scale wind can be a competitive means of mitigating CO_2 emissions.

Third, the costs imposed by wind's intermittency scale to very low levels of penetration, contradicting the studies reviewed in Section 2.5 that suggest a threshold. Such studies do not account for the cost resulting from a decrease in available system reserve and so neglect the decreased level of grid reliability, however small, stemming from intermittent wind. In the model, even small amounts of wind must be matched by additional gas capacity serving as system reserve or reliability would be compromised.

Fourth, the economic benefit of expanding the spatial distribution of wind farms to reduce intermittency can exceed the costs of additional transmission infrastructure. Figure 3.4 demonstrates that at carbon taxes greater than 280 $/tC, increasing the number of wind sites in the model increases the achievable level of carbon emissions abatement. Figure 3.5 demonstrates that at a given level of carbon emissions abatement (without a carbon tax), increasing the number of wind sites in the model decreases the average cost of the system.

Fifth, there is a direct tradeoff between wind site diversity and storage. Spreading out wind farms reduces wind speed correlations, which mitigates the intermittency problem by smoothing out the aggregate wind power time series. Figure 3.3B demonstrates that sufficient wind site diversity renders CAES economically uncompetitive, even at carbon taxes approaching 1000 \$/tC, whereas with only a single wind site CAES is cost-effective at 500 \$/tC.

Sixth, compressed air energy storage (CAES) is less competitive than expected under a carbon tax: its residual carbon dioxide emissions do not allow it to compete effectively against gas turbines. This insight represents a key model result that has important implications for the development of large-scale wind to mitigate climate change. In addition, Figure 3.7 demonstrates that the economic performance of storage is sensitive to how well the storage parameters are tuned. Interestingly, both the CAES and the H_2 system described in Section 3.8 exhibit similar economic performance, both becoming cheaper than GTCC near a carbon tax of 340 \$/tC. CAES has lower capital costs and higher roundtrip efficiency, but burns gas and incurs an economic penalty from the carbon tax. On the other hand, the H_2 system has significantly higher capital costs and lower roundtrip efficiency, but does not require a natural gas and is not subject to the carbon tax. While CAES is often described as an inexpensive way to make wind dispatchable (e.g., Cavallo, 1995; Desai et al., 2003), the model results indicate that CAES is not the most cost-effective option for mitigating wind’s intermittency under a carbon tax. More generally, the storage analysis also indicates that a large-scale storage system that does not require the use of a fossil fuel (and has reasonable capital costs) could make a significant contribution in a wind-dominated system.

Finally, the use of simple-cycle (GT) and combined-cycle gas turbines (GTCC) as backup are a crucial part of the large-scale wind system, particularly in the scenario with 5 wind sites. As the level of wind increases in the 5-site system, the sum of GTCC and GT capacities remains constant and equal to the maximum load, which suggests the coincidence in the data set between peak demand and no wind power output. At high levels of wind penetration, the gas turbines effectively act as capacity reserve that ramp to complement the time-varying wind. When wind serves upwards of 60 percent of demand, the model chooses to install more GT than GTCC capacity because the lower rates of gas utilization dictate the use of lower efficiency, lower capital cost gas turbines.

Coal was not included in the greenfield model because it exists in a different carbon tax regime than wind, and is eliminated at carbon taxes exceeding 50$/tC. Even if existing coal capacity were included in the model, it would very expensive to run at high carbon taxes, and furthermore, at high levels of wind penetration coal ramps too slowly to be a useful complement to intermittent wind. Nevertheless, it would be an interesting extension to the work presented here to explore the tradeoff between wind and coal in a non-greenfield scenario under a carbon tax where the average cost of new wind capacity competes against the marginal cost of existing coal plants.

In summary, the cost of wind serving more than a third of demand, accounting for the remoteness and intermittency of wind resources, is similar to the cost of other carbon mitigating technologies in the electricity sector. While other technologies may compete effectively with wind, the model results suggest that wind is a serious option for electricity generation in a carbon constrained world.

3.10 References to Chapter 3

Archer, C.L. and Jacobson, M.Z. (2003). "Spatial and temporal distributions of U.S. winds and wind power at 80 m derived from measurements." *J. Geophys. Res.* **108** (D9), 4289, doi:10.1029/2002JD002076

Audus, H. and Jackson A.B.J. (2001). "CO_2 Abatement by the Combustion of H_2-Rich Fuels in Gas Turbines." *Greenhouse Gas Control Technologies: Proceedings of the 5th International Conference*. D. Williams, B. Durie, P. McMullan, C. Paulson and A. Smith (Eds.), Collingwood, Australia: CSIRO Publishing, 759-764

Baxter, R. and Makansi, J. (2003). "Energy Storage: An Innovative Answer to a Few of Today's Challenges." *EnergyPulse*. Website: www.energypulse.net/centers/article/article_display.cfm?a_id=436. Accessed on 19 December 2003.

Borroughs, S. and Bauer, S. (2001). "Solution to some of country's energy woes might be little more than hot air." Livermore, CA: Sandia National Laboratories. Website: www.sandia.gov/media/NewsRel/NR2001/norton.htm. Accessed on 23 November 2003.

Casazza, J.A. and LeKang, D.J. (1995). "Electric Power Systems and Transmission." In: Bisio, A. and Boots, S. (Eds.), *Encyclopedia of Energy Technology and the Environment*. New York, New York: John Wiley & Sons, Inc., 1047-1059.

Cavallo, A. (1995). "High-Capacity Factor Wind Energy Systems." *Journal of Solar Energy Engineering* 117**:** 137-143.

Cavallo, A.J., Hock, S.M., and Smith, D.R. (1993). "Wind Energy: Technology and Economics." *Renewable energy: sources for fuels and electricity* T. B. Johansson and L. Burnham (Eds.) Washington, D.C: Island Press.

Chamia, M. (2000). "HVDC: A Major Option for Electricity Networks." *IEEE Power Engineering Review*, February 2000, 14-18.

DeCarolis, J.F. and Keith, D.W. (2001). "The real cost of wind energy." *Science*, 294(5544): 1000-1001.

Desai, N., Garza, S., et al (2003). "Study of Electric Transmission in Conjunction With Energy Storage Technology." Houston, TX : Lower Colorado River Authority.

EIA (Energy Information Administration), Office of Integrated Analysis and Forecasting, US Department of Energy (2003). "Annual Energy Outlook 2003 With Projections to 2025" DOE/EIA-0383(2003) US Government Printing Office, Washington, DC.

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, Coal and Electric Power Division, US Department of Energy, (2004). *Model Documentation: Renewable Fuels Module of the National Energy Modeling System*. DOE/EIA-M069(2004). Washington, DC: US Government Printing Office.

Elliott, D.L., Holladay, C.G., Barchet, W.R., Foote, H.P., and Sandusky, W.F. (1986). "Wind Energy Resource Atlas of the United States." Richland, WA: Pacific Northwest Laboratory, DOE/CH 10093-4.

EPRI-DOE (2003). "EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications." Washington, DC: Report 1001834.

Factor, T and Wind, T. (2002). "Delivering 2,000 MW of Wind Energy to the Metropolitan Centers in the Midwest." Iowa Department of Natural Resources.

Grubb, M.J. and Meyer, N.I. (1993). "Wind Energy: Resources, Systems, and Regional Strategies." *Renewable energy: sources for fuels and electricity* T. B. Johansson and L. Burnham (Eds.) Washington, D.C: Island Press.

Hauth, R.L., Tatro, P.J., et al. (1997). "HVDC Power Transmission Technology Assessment." Report ORNL/Sub/95-SR93/1. Oak Ridge, TN: Oak Ridge National Laboratory.

Hirst, E. and Hild, J. (2004). "The Value of Wind Energy as a Function of Wind Capacity." *The Electricity Journal*, July 2004.

Holdren, J.P. et al (President's Committee of Advisors on Science and Technology, Panel of Energy Research and Development) (1999). "Powerful Partnerships: The Federal Role in International Cooperation on Energy Innovation." Washington, D.C.: Office of Science and Technology Policy, Executive Office of the President of the United States.

Ilex and Strbac, G. (2002). "Quantifying the System Costs of Additional Renewables in 2020." Oxford, UK: Ilex Energy Consulting.

Johnson, T.L. and Keith, D.W. (2004). "Fossil electricity and CO_2 sequestration: how natural gas prices, initial conditions and retrofits determine the cost of controlling CO_2 emissions." *Energy Policy* 32: 367-382.

McGowan, C., Finney, K., Peterson, T. and Hughes, E. (2001). "Renewable Energy Technical Assessment Guide – TAG RE: 2000." Palo Alto, California: Electric Power Research Institute (EPRI). Report no. 1000575.

McGowan, J.G. and Connors, S.R. (2000). "Windpower: A Turn of the Century Review." *Ann. Rev. of Energy Environ.* 25: 147-197.

National Climatic Data Center. (2003). Data downloaded from: http://lwf.ncdc.noaa.gov/oa/ncdc.html. Accessed on 13 March 2003.

Ogden, J. (1999). "Prospects For Building A Hydrogen Energy Infrastructure." *Annu. Rev. Energy Environ.* 24: 227-279.

Parsons, B. *Personal Correspondence with David Keith*. November, 2001

Rudervall, R., Charpentier, J.P., et al. "High Voltage Direct Current (HVDC) Systems Technology Review Paper." World Bank.

Schoenung, S. (1996). "Energy Storage for a Competitive Power Market." *Annu. Rev. Energy Environ.* 21: 347-370.

Short, W, Blair, N., et al. (2003). "Modeling the Long-Term Market Penetration of Wind in the United States." Golden, CO : National Renewable Energy Laboratory, NREL/CP-620-34469.

Chapter 4: Environmental Impacts of Wind Power

4.1 Chapter Overview

While the thesis has thus far established that large-scale wind – based on economic considerations – has the potential to play a leading role in a carbon constrained world, wind power also creates unique environmental impacts that must be evaluated. Wind power's fundamental limitation is its low energy density. At 100 m hub heights typical of large modern wind turbines, the horizontal flux of kinetic energy can be as much as 1 kW/m^2. However, turbines on the perimeter of large arrays slow down the wind. The air passing through the swept area of the rotors regains kinetic energy from the boundary layer at a rate of roughly 1.5 W/m^2 over the global land surface (Peixoto and Oort, 1992). It is this downward energy flux resulting mainly from shear-driven turbulence that determines the available energy density inside large wind turbine arrays. Wind turbines are typically spaced 5 to 9 rotor diameters apart in the prevailing wind direction to avoid significant shading effects (McGowan et al., 2001, 3-12).

In 2001, US electricity demand was 3,414 TWh (EIA, 2003). With an energy density of 1.5 W/m^2, roughly 2.6×10^5 km^2 would be required to meet half of the current US electricity demand with wind, which represents roughly 3 percent of US land area. However, only 3-5 percent of the land required would be physically occupied by the turbines (McGowan and Connors, 2000), leaving the rest of the land area for agricultural use or other limited purposes that do not obstruct the flow of wind. While large-scale wind presents a serious land use constraint, biomass has an energy density of ~3 W/m^2

and all of the land required for biomass must be utilized for fuel crop production[12]. For comparison, the power density of bituminous coal removed from a large open-cast mine can easily exceed 1×10^4 W/m^2 (Smil, 1999).

Low wind energy density results in environmental impacts related to avian mortality, noise, and aesthetics. Section 4.2 details the early problems related to bird kills in the Altamont Pass, what has been learned since, and what measures can be taken to mitigate avian deaths. Section 4.3 investigates the types and level of noise generated by wind turbines. Section 4.4 describes the aesthetic issues related to wind farm layout, and discusses the key factors – that if addressed by developers – improve the aesthetics. Section 4.5 summarizes the findings.

4.2 Avian Mortality

Avian interaction with wind turbines became a prominent environmental issue in the US in the late 1980s when it was discovered that significant numbers of birds, particularly golden eagles and red-tailed hawks protected by federal law, were being killed in collisions with wind turbines in the Altamont Pass (McGowan, 2000). A 1989 report by the California Energy Commission (CEC) on bird fatalities in the Altamont Pass and Tehachapi wind farms recorded 72 raptor fatalities between 1984 and 1988 as a result of collisions with wind turbines or the transmission lines serving the wind farms, including 26 golden eagles (CEC, 1989). The death of golden eagles was particularly contentious because it violated the Bald and Golden Eagle Protection Act, under which the death of a single golden eagle – even if by accident – constitutes a federal crime (Asmus, 2001,

[12] The average global mean solar radiation reaching the Earth's land surface is ~180 W/m^2 (Smil, 1999). The maximum theoretical efficiency of photosynthesis is roughly 11 percent, but a more realistic estimate for crop lands is 2-3 percent (*ibid.*). A crude estimate of biomass energy density is therefore 3-4 W/m^2.

138). Subsequent studies confirmed the results of the CEC study, which led the Altamont wind turbines to be labeled "Cuisinarts of the air" and created a significant public relations problem for the wind industry (Gipe, 1995, 345). A recent study estimates that there are 1.5 to 2.2 raptor fatalities/MW/year, and 3.0 to 8.1 bird fatalities/MW/year (Smallwood and Thelander, 2004, 3). Several mitigation options have been identified to reduce raptor kills in the Altamont Pass, including the relocation or removal of high risk wind turbines, removal of broken turbines, repowering with larger turbines, installation of bird flight diverters (poles located at the end of a turbine row that would divert the flight path of birds), and compensatory mitigation by obtaining off-site conservation easements (*ibid.*).

Another wind farm producing significant bird kills, particularly raptors, is located in Tarifa, Spain along a major migratory route that traverses the Strait of Gibraltar (Luke and Hosmer, 1994). Because the Altamont and Tarifa wind farms lacked adequate avian interaction studies, their impact is anomalous compared with the balance of wind farms around the globe. For a sense of perspective, Table 4.1 compares bird kill estimates resulting from collisions with wind turbines to other common avian hazards. Although the estimates of bird kills range widely due to the inherent uncertainty involved in such estimation, wind turbines do not appear to pose an extraordinary risk to birds in general. However, careful estimates of avian interaction should still be performed before new wind installations are constructed to ensure that undue stress is not placed on sensitive raptor populations, which are more susceptible to wind turbine collisions as a result of their tendency to perch on turbines and use the vantage point to hunt prey on the ground. After the controversy surrounding Altamont, wind developers are much more receptive to the issue of avian mortality. The National Wind Coordinating Committee (NWCC) has published a definitive guide to designing and conducting avian field studies, which if widely implemented, will produce credible and comparable results on avian interaction (Anderson et al., 1999).

Table 4.1 – Comparative avian risk in the US. Normalized risk is obtained by dividing the estimated annual bird kills in Column 2 by the amount of infrastructure in Column 3. Estimates are from Erickson et al. (2001).

Hazard	**Estimated Bird Kills (10^6/year)**	**Size of Infrastructure**	**Annualized Risk (Normalized Bird Kills)**
Vehicles	60-80	4×10^6 miles of road	15-20 / mile
Buildings and Windows	98-980	9.8×10^7 buildings[a]	1-10 / building
Power Lines	0.01-174	5×10^5 miles of transmission	0.02-348 / mile
Communication Towers	4-50	8×10^4 towers	50-625 / tower
Wind Generation Facilities	0.01-0.04	1.5×10^4 wind turbines	0.67-2.67 / turbine

[a]The estimate of buildings includes both commercial and residential structures.

It is unclear how the bird kill problem might scale with the level of installed wind capacity. The wind turbines posing the greatest risk to birds are located at the ends or around the perimeter of wind farms. For example, only 16 of Kenetech's 3,400 wind turbines in the Altamont Pass have been implicated in at least one eagle death over a nine-year period – and most are located near the end of a string of turbines (Asmus, 2001, 241). The concentration of dangerous turbines near the edges of wind farms suggest that, all else equal, as wind farms are scaled to larger sizes, the increase in avian mortality is less than linear. If there are *n* turbines located in a single row along a ridgeline, and assuming that most bird kills are caused by turbines on the end of the line, then very roughly the number of bird kills scales as 2/n. Likewise, the number of bird kills in a square array of *n* wind turbines, assuming most bird kills happen along the perimeter of the wind farm, roughly scales as the ratio of perimeter to area ($4n/n^2 = 4/n$). This observation is countered by the consideration of habitat loss as the land occupied by wind farms continues to expand. If wind were used to meet half of US electricity demand as discussed in Section 4.1, then significant impacts to bird habitat would result. In some cases, habitat for particular species may be lost entirely within the wind farm. Land encroachment on avian habitats will have disproportionate impacts on particular species, depending on geographic distribution of new wind farms and species sensitivity to changes in habitat.

4.3 Noise

Although early 1980s-vintage wind turbines with faster tip speeds were noisy and led to justifiable complaints, the noise generated by wind turbines has declined markedly as the technology has improved (Burton et al., 2001, 528). The sounds generated by wind turbines can be categorized into several different types.

Broadband noise is a continuous distribution of sound pressure with frequencies greater than 100 Hz, which often causes a swishing noise as the blades interact with atmospheric turbulence (Anderson et al., 2002). There are two main sources of broadband noise in wind turbines: inflow turbulence and airfoil self-noise. The former is the noise caused by the interaction of the blades with eddies caused by atmospheric turbulence. The latter is generated by the airfoil itself, and can be attributed to several causes: trailing edge noise (interaction of the trailing edge blade with the turbulent boundary layer), tip noise (the majority of the power as well as noise is created on the outer 25 percent of the blade), and stall effects (blade stall causes unsteady flow around the airfoil) (Burton et al., 2001, 532). Tonal noise occurs at discrete frequencies and can be caused by turbine mechanical components and unstable flows over holes and slits (Anderson et al., 2002). Discrete tones are more perceptible to the ear and are more likely than broadband noise to lead to complaints by nearby residents, and therefore incur a 5 dB penalty in many noise standards (Burton et al., 2001, 531). Low frequency noise ranges from 20 to 100 Hz and is experienced by the blades due to the presence of the tower or wind shear, but the effect is much more significant and pronounced in downwind turbines, which are uncommon today (*ibid.*, 532).

Modern turbines are sufficiently quiet that the ambient noise generated by the wind is often enough to mask the sound of the turbine (Anderson et al., 2002). Because a 3 dB change in sound is considered barely discernable outside the laboratory (*ibid*), the turbine noise heard a few hundred meters from the edge of a modern wind farm will not be much noisier than the ambient background. See Table 4.2 for a comparison of wind turbine noise to other sources. Note in particular the significant overlap in sound level between wind turbine noise and nighttime background noise in rural areas. Turbine noise has also been reduced by the increased use of tubular towers and streamlined nacelles as well as more efficient airfoils that convert more wind energy into rotational torque and less into acoustical noise (McGowan, 2000). A sufficient noise assessment before new wind farms are built should include three components: (i) a survey of ambient background noise levels, (ii) a prediction of noise levels from turbines at and near the site, and (iii) an assessment of acceptable noise levels in the area (McGowan, 2000).

Table 4.2 – Comparison of different sounds with wind turbines. Note that sound levels are denoted by decibels and measured on a logarithmic scale. A doubling in sound intensity (W/m^2) represents a 3dB change. Examples adapted from Anderson et al. (2002) and Burton et al. (2001).

Source	Distance From Source (m)	Type of Noise	Sound Level (dBA)
Jet Takeoff	60	Broadband, tonal	120
Ambulance Siren	30	Tonal	90
Light Traffic	30	Broadband	60
Wind farm	350	Broadband, tonal	35-45
Rural nighttime background	0	Broadband	20-40
Threshold of Hearing	1		0

The obvious way to further reduce aerodynamic noise – low frequency, inflow turbulence, and airfoil self noise –is to reduce the tip speed of the rotor, but such a measure could result in decreased efficiency of energy capture (Burton et al., 2001, 532). A major benefit to variable speed turbines is the ability to reduce noise at low wind speeds (*ibid.*). The blade angle of attack could also be reduced, but that would result in efficiency losses.

4.4 Aesthetic Impacts of Wind Farm Development

4.4.1 A Renewed Debate: Conservation versus Preservation

Even if costs for wind energy were negligible, people's perception of altered landscape aesthetics would remain a significant challenge to the expansion of wind power. Wind's low energy density means that for wind to serve a large fraction of electricity demand and make deep cuts in CO_2 emissions, a noticeable impact on the landscape will be unavoidable.

The conflicting environmental priorities of clean energy and land preservation have created a deep fissure in the environmental community, reminiscent of the debate between Gifford Pinchot and John Muir around the turn of the century (Gipe, 1995, 256). Gifford Pinchot served under President Theodore Roosevelt, organized the US Forest Service, and developed a conservation ethic that focused on the sustainable management of land for utilitarian purposes. Pinchot summarized his view by defining conservation as "the development and use of the earth and all its resources for the enduring good of man" (Worster, 1994, 266). Muir disagreed vehemently with Pinchot, believing that nature should remain pristine and wild, declaring that "none of Nature's landscapes are ugly so long as they are wild" (Muir, 1901). The debate over the merits of wind energy has resurrected the century-old tension between the ethos of conservation and preservation. One can imagine Pinchot and Muir debating the environmental merits of the large California wind farms today. This conflict has polarized environmentalists by forcing them "to choose between the promise of clean, endlessly renewable energy and the perils of imposing giant man-made structures on nature" (Seelye, 2003). In a study of opinions regarding the Altamont Pass wind farms, Thayer and Freeman (1987) found that those who held strongly positive views toward Altamont did so because they valued the clean energy connotation of wind over the visual impact, whereas the opposite was true for those with negative attitudes. The survey results suggest that education regarding the positive attributes of wind energy could make the purely aesthetic impacts less salient (Thayer and Freeman, 1987). How wind turbines are perceived to alter the landscape – which will vary by geography and culture – will be a key determinant of what role wind will have in mitigating climate change.

A recent example of the debate regarding the merits of wind energy is taking place in Cape Cod, where plans for a 420 MW off-shore wind farm have pitted clean energy advocates against fishing interests, boaters, tourism representatives, and residents who do want to see the coastal horizon marred by spinning turbines (Ziner, 2002; Polachek, 2002). The same conflict arises for proposed wind farms along ridgelines, which are also popular recreation areas (Seelye, 2003). While some of the proposed projects near popular recreation areas may succeed in the short term, they may ultimately be limited by public opposition. For example, few people in Pennsylvania seem to be overly concerned with the visual impacts of the state's six wind farms. However, if the state approves a renewable portfolio standard, which appears likely at the time of this writing, then the prospect of wind farms covering many of the ridgelines in the Allegheny Mountains may cause considerable public consternation and outcry. Significant public resistance will be likely when wind farms are sited close to popular recreation areas and/or ecologically sensitive lands.

4.4.2 NIMBYism and Wind Power

NIMBY is a pejorative term used to describe those who respond to the possibility of nearby construction with "Not In My Backyard!" Some writers go so far as to discredit opposition to wind development as "technophobia" (Righter, 2002), but such an approach is more likely to alienate than convince. In many cases, people support wind energy as an abstract concept, but oppose a particular project that may impose on their local environment. The siting of a wind farm imposes a negative externality on nearby residents because it disrupts the landscape. As Chapter 1 suggests, if climate change mitigation is the primary reason for the development of wind energy, than the benefit is spread across the global population while the negative visual externality is limited to nearby residents. Thus rational individuals can easily arrive at the conclusion that wind is a superb idea in the abstract, but an unpleasant prospect when applied to their local context. If significant benefits could be garnered by the local community, it could change the personal calculus that determines whether a community member supports a wind project.

Local control and ownership – one of the keys to success in Denmark – is closely tied to aesthetic apprehension (Brittan, 2002). As mentioned in Chapter 1, there is a residency requirement for participation as well as a limit on the investment each individual can make in a Danish wind farm cooperative. The public involvement and investment in wind energy has been a critical factor in its expansion, making many Danes both socially and economically committed to the successful operation of wind power (Nielsen, 2002). When community members are involved in planning and/or collective ownership of the wind farm, their outlook on the aesthetic impact of the wind farm tends to improve. Psychologically, when individuals have a personal stake in an outcome of a wind project, they are likely to forgive or even become enthusiastic about the aesthetics as well. Local involvement and control has the potential to expand the economic and aesthetic benefits garnered by the local community, which in many cases will decrease the prevalence of NIMBYism and tip the balance in favor of wind development.

4.4.3 Addressing Aesthetic Concerns

Whether an individual of community approves of a local wind farm does not depend simply on whether they value clean energy more or less than landscape preservation in the abstract. Measures can be taken to improve the aesthetic quality of individual wind turbines as well as wind farms, which can build community support for a wind project. While cost and efficiency are critical components of wind turbine design, aesthetically pleasing wind turbines will increase public acceptance (Gipe, 1995, 292). In particular, integrated design of tower, nacelle, and blades promotes elegant design and avoids awkward combinations of components (*ibid*). The nacelle and tower should appear simple and aerodynamic, with tubular towers offering the simplest design and "most sculptural" image (Stanton, 1996). Stanton (1996) even suggests that the difference in blade position is more obvious in two-bladed turbines than three-bladed ones, the latter offering "more continuous and harmonious" movement. In contrast, Righter (2002) suggests the need to depart from the established design paradigm – three-bladed, upwind turbines mounted on a tubular tower – and encourage more radical designs that are judged on both efficiency and aesthetic compatibility with the landscape.

Equally important is how the wind turbines are integrated into the land as wind farms. Artists and landscape architects can have a significant role to play by acting as facilitator and mediator in developing a communal consensus on a specific wind project (Short, 2002). After all, the expression of landscape through art often sets the aesthetic standards by which people judge real-world scenery. German landscape managers, who work for the government, approve wind projects, and determine compensatory levies based on aesthetics, are still influenced by the landscape paintings of the Romantics who argued that their work expressed “the beauty of nature” (Hoppe-Kilpper and Steinhäuser, 2002). Nielsen (2002) suggests that wind turbine clusters introduce a massive sculptural element into the landscape – a “land-art project” – that must be adapted to the particulars of the site. In Denmark, it is now common practice to employ a landscape architect at an early stage on large projects (Nielsen, 2002).

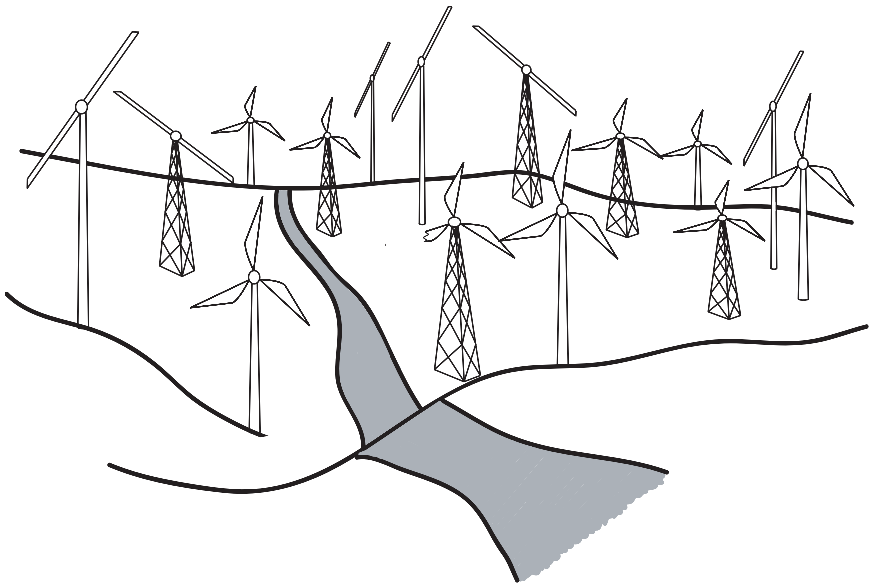
There are also several pragmatic considerations that improve aesthetic perceptions of wind farms[13]. Perhaps the simplest measure is to keep the wind turbines spinning (Gipe, 2002; Righter, 2002). Thayer (1987) reports that two-thirds of all subjects surveyed cited the apparent unreliability of the Altamont wind farm as a major disadvantage to wind development. Eyes are drawn to motionless turbines in a wind farm, and it can reinforce the notion that wind turbines do not produce significant amounts of energy, and is not worth the visual degradation of the landscape. For the same reason and to prevent visual clutter, it is important to remove broken, unfixable turbines.

Wind developers should also provide visual order and uniformity by ensuring that all the turbines spin in the same direction, clusters of turbines are separated into distinct visual units (to prevent the cluttering effect evident in the Tehachapi Pass and San Gorgonio Pass wind farms), and the same or similar wind turbines (tower, nacelle, and rotor) are used across the wind farm. Limiting the number of turbines per cluster and using open spacing minimizes visual clutter, which prevents the appearance of a mechanical forest of wind turbines. Siting experience in Europe suggests that limiting clusters to 1 - 10 wind turbines improves the aesthetic perception of nearby residents. Aesthetics are also improved by burying intra-project power lines and by using local

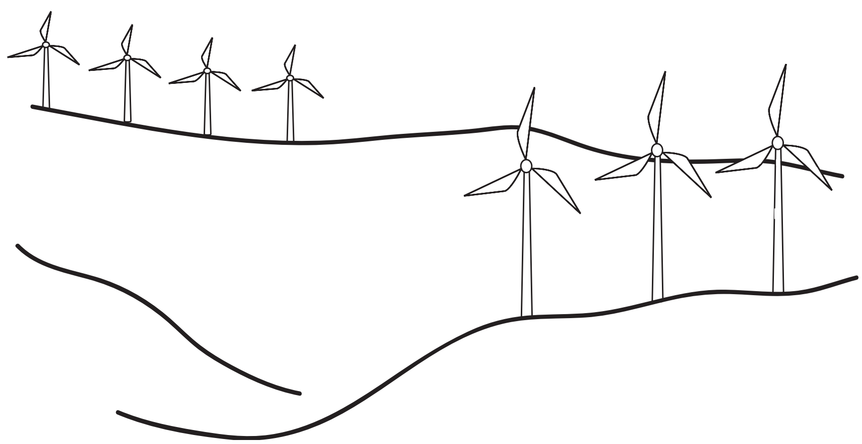
[13] Except where noted, the practical aesthetic recommendations are drawn from Gipe (2002) and Stanton (1996).

building materials to harmonize ancillary structures (such as transformers and substations) with the landscape. See Figure 4.1 for examples that emphasize both good and bad aesthetic design.

And finally, in addition to improving aesthetics, the following measures also minimize the impact on the local environment: avoid steep slopes to minimize earth moving and control erosion, minimize or eliminate roads, use existing roads where possible, minimize the grading width where roads are necessary, minimize staging areas and crane pads used only during the construction phase, and finally, restore the original contour of the land and revegetate.



Poor Aesthetic Design



Good Aesthetic Design

Figure 4.1 – Comparison of good and bad aesthetic designs for wind farms, drawn from observations by Gipe (2002) and Stanton (1996). The top panel emphasizes several of the aesthetic attributes that contribute to a negative image of wind power. Multiple turbine designs mixed in the same cluster, haphazard placement, a broken turbine (foreground), and an access road all lead to the assessment of this wind farm as a cluttered, industrial-looking mess. The bottom panel, on the other hand, emphasizes positive aesthetic characteristics: a single turbine design throughout the wind farm and small, openly spaced rows to minimize the visual clutter.

Since many of the California wind farms were quickly erected to benefit from the temporary tax credit, most of these aesthetic guidelines were ignored. At a 1987 wind energy conference, Birger Madsen of BTM Consult flashed photos of San Gorgonio Pass in California, and told the audience "never again" should such rapid and chaotic development take place (Gipe, 1995, 289). Since then, small wind farms in northern Europe have indeed paid much closer attention to wind farm aesthetics – in large part due to local cooperative ownership and control.

4.4.4 Aesthetic Considerations versus Land Requirements

There is little question that the logical and prudent design considerations detailed in the previous section will certainly help improve the visual quality of future wind farms. However, it is worth considering whether the aesthetic desire for small clusters of wind turbines, artfully adapted to particular landscapes, implicitly limits the ultimate scale of wind development. Assume for a moment that a strong constraint on carbon emissions is enacted in the US, and wind is called upon to cut electric sector emissions in half. With a wind power density of 1.5 W/m^2 as discussed in Section 4.1, the required land area for wind development is roughly 2.6×10^5 km^2. Assume, however, that the spacing of wind turbine clusters is much less dense in order to avoid the mechanical forest effect of the early California wind farms. With small, distributed clusters of wind turbines, it is easy to imagine a density of installed wind capacity an order of magnitude smaller (0.15 W/m^2) which would require 2.6×10^6 km^2 of land, i.e. roughly equivalent to 28 percent of the US land area. While the calculation is very rough, it nonetheless presents us with a crucial decision if wind is to make a deep cut in CO_2 emissions: spread wind turbines out in small clusters that are more aesthetically pleasing but require more overall land, or centralize large wind farms to reduce the overall land required but perhaps create an unsightly landscape that covers thousands of square kilometers. To be sure, even massive arrays of future wind turbines would be aesthetically cleaner than the early California farms, which utilized an array of different designs of smaller turbines that often broke and were left unfixed. Even though wind projects in Northern Europe, particularly Denmark, have been mindful of landscape aesthetics, the sheer number of distributed wind turbine clusters there is creating public opposition and a shifted focus to off-shore development.

Some authors advocate the further decentralization of wind energy. For example, Lovins (1982) argues for small, distributed wind turbines in the following excerpt from *Brittle Power:*

> …small machines can be produced faster than the big ones, since they can be made in any vocational school shop, not only in elaborate aerospace facilities, and are also probably cheaper by the kilowatt. What may be more important and is hardly ever captured in this type of comparison is that there are thousands of times more farms than electric utilities on the Great Plains, subject to fewer institutional constraints and inertias (pp. 231-232).

Lovins ignores the significant economies of scale with respect to wind turbine construction. The cost for multi-MW turbines is currently in the range of 700-1000 \$/kW (McGowan, 2000), while the price of small-scale (1-100 kW) wind turbines for household use are considerably more expensive at 1000-3000 \$/kW (NREL, 2004). In addition, farms in no way match the generating capability of the nation’s electric utilities. While Lovins desire for distributed wind may have a different motivation, it is difficult to imagine how wind can be used to make deep cuts in electric sector CO_2 emissions without large-scale centralization of wind power projects that will require the cooperation of electric utilities.

4.5 Summary of Environmental Impacts and the Path Forward

Most of the environmental concerns related to wind power can be ameliorated with careful design procedures. Thorough avian field studies before project construction can rule out major migration corridors or habitats, so that the anomalous problems at Altamont Pass will never take place again. Concerns related to wind turbine noise have faded somewhat with better design; in particular, more efficient blade designs convert a greater fraction of wind energy into rotational torque and less into acoustical noise.

The same conditions that ensure cost-effective wind power – open grassland, treeless ridges, mountain passes, and open water – also ensure high visibility. The simplest solution is to move large-scale wind facilities to more remote locations where their visual impact will be experienced by fewer people. For this reason, it is likely that the development of large-scale wind in the US will take place in the central part of the country, particularly the Great Plains, where the land is flat, there are low population densities, the land has already been altered for agricultural purposes, and farmers can collect revenue from land leases. And farmers are unlikely to be overtly concerned with the aesthetic impacts of wind turbines, since they make their living by applying landscape change to nature (Hoppe-Kilpper and Steinhäuser, 2002). Given the high population densities and spatial constraints onshore, much of the new wind development in Western European is taking place offshore (BTM Consult, 2003).

The greatest hurdle to the large-scale development of wind energy, aside from economics, is the issue of aesthetics. Sleek industrial design can reduce the awkward, mechanical look and improve the aesthetic quality of wind turbines. When wind farms are built close to major population centers, smaller clusters of 10-20 turbines with a simple geometrical layout that stresses visual uniformity and minimizes clutter can improve the public's aesthetic judgment of wind farms. Success in northern Europe can be traced to the involvement of landscape architects early in the design process to ensure the proper aesthetic integration of wind farms into the local landscape, as well as local control and ownership of small wind farms.

If nations – particularly the US – impose strong constraints on CO_2 emissions from the electric power sector, wind may be called upon to deliver deep cuts in emissions. Under such a scenario, the development of massive wind farms many times the size of Tehachapi, Altamont, or San Gorgonio may be a viable option because it conveys an important advantage: the aesthetic impact of wind farms is limited to a more confined area. While the aesthetic guidelines discussed in this chapter can be applied to wind farms of any size, a key issue will be whether wind turbines are centralized in large arrays that limit the aesthetic impact to large tracts of land or distributed in smaller, more aesthetically pleasing clusters that span a much greater land area.

4.6 References to Chapter 4

Anderson, R. et al. (1999). "Studying Wind Energy/Bird Interactions: A Guidance Document." Washington, DC: National Wind Coordinating Committee.

Anderson, R. et al. (2002). "Permitting of Wind Energy Facilities: A Handbook." Washington, DC: National Wind Coordinating Committee.

Asmus, P. (2001). *Reaping the Wind*: *How Mechanical Wizards, Visionaries, and Profiteers Helped Shape Our Energy Future*. Island Press, Washington, DC.

Brittan Jr., G.G. (2002). "The Wind In One's Sails: A Philosophy." *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

BTM Consult (2003). “International Wind Energy Development: World Market Update 2002” Ringkøbing, Denmark.

Burton, T, *et al*. (2001). *Wind Energy Handbook*. West Sussex, England: John Wiley & Sons, Ltd.

California Energy Commission (CEC). (1989) “Avian mortality at large wind energy facilities in California: identification of a problem.” California Energy Commission staff report P700-89-001.

EIA (US Energy Information Administration), Office of Energy Markets and End Use, US Department of Energy, (2003). *Annual Energy Review 2002*. DOE/EIA-0384(2002). Washington, DC: US Government Printing Office.

McGowan, C., Finney, K., Peterson, T. and Hughes, E. (2001). "Renewable Energy Technical Assessment Guide – TAG RE: 2000." Palo Alto, California: Electric Power Research Institute (EPRI). Report no. 1000575.

Erickson, W.P. (2001). “Avian Collisions with Wind Turbines: A Summary of Existing Studies and Comparisons to Other Sources of Avian Collision Mortality in the United States.” Washington, DC: National Wind Coordinating Committee.

Gipe, P. (1995). *Wind Energy Comes of Age*. Wiley, New York, NY.

Gipe, P. (2002). “Aesthetic Guidelines for a Wind Power Future.” *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

Hardin, G. “The Tragedy of the Commons.” *Science.* 162(1968): 1243-1248.

Hoppe-Kilpper, M. and Steinhäuser, U. (2002). “Wind Landscapes in the German Milieu.” *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

Lovins, A. (1982). *Brittle power : energy strategy for national security*. Andover, Massachusetts: Brick House Publishing Company.

Luke, A. and Hosmer, A.W. (1994). “Bird deaths prompt rethink on wind farming in Spain.” *WindPower Monthly* 10(2):14-16.

McGowan, J. (2000). “Windpower: A Turn of the Century Review” *Ann. Rev. of Energy Environ.* 25: 147-197.

Muir, J. (1901). *Our National Parks*. Houghton, Mifflin and Company, Boston and New York, pp. 4.

Nielsen, F.B. (2002). “A Formula for Success in Denmark.” *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

NREL (National Renewable Energy Laboratory). (2004) “Small Wind Electric Systems: A U.S. Consumer’s Guide.” Department of Energy, DOE/GO-102004-1902.

Peixoto, J.P. and Oort, A.H. (1992). *Physics of climate*. New York, New York: American Institute of Physics.

Polacheck, J.S. (2002). “Cape Cod: Twisting in the Wind?” *Public Utilities Fortnightly*. 140(10): 30-37.

Righter, R.W. (2002). “Exoskeletal Outer-Space Creations.” *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

Seelye, K.Q. (2003). “Windmills Sow Dissent for Environmentalists.” *The New York Times*. New York, New York. June 5, 2003.

Short, L. (2002). “Wind Power and English Landscape Identity.” *Wind Power in View*. M.J. Pasqualetti, P. Gipe, and R.W. Righter (eds.). San Diego, CA: Academic Press.

Smallwood, K.S. and Thelander, C.G. (2004). “Developing Methods to Reduce Bird Mortality in the Altamont Pass Wind Resource Area.” BioResource Consultants, prepared for the California Energy Commission, Report No. P500-04-052.

Smil, V. (1999). *Energies*. Cambridge, Massachusetts: MIT Press.

Stanton, C. (1996). The Landscape Impact and Visual Design of Windfarms. Edinburgh, Scotland: Edinburgh College of Art, Landsape Publication No LP/9603.

Thayer, R.L. and Freeman C.M. (1987). “Altamont: Public Perceptions of a Wind Energy Landscape.” *Landscape and Urban Planning*. 14(1987): 379-398.

Worster, D. (1994). *Nature’s Economy*. Cambridge University Press, Cambridge, UK, pp. 226.

Ziner, K.L. (2002). “Offshore Harvest of Wind Is Proposed for Cape Cod” *The New York Times*. New York, New York. April 16, 2002.

Chapter 5: Climatic Impact of Wind Turbines

5.1 Chapter Overview

Although the environmental impacts described in the previous chapter raise important concerns, steady advances in design as well as increasingly rigorous siting procedures have led to marked improvement over the hastily built California wind farms of the 1980s. This chapter raises a new environmental concern that could be of significant consequence to the future of the wind industry. Wind turbines dissipate additional kinetic energy within the wind farm field, which could result in important climatic impacts. This chapter presents collaborative modeling work using two general circulation models (GCMs) to assess the impact of wind turbines on climate[14].

Section 5.2 discusses how wind turbines can affect climate. Section 5.3 describes how wind turbines were parameterized in the GCMs by adjusting the drag formulation, and the following section translates the drag added by the wind turbines into the amount of electricity generated. Section 5.5 presents analysis of the model results. While wind turbines may directly impact the climate by changing the flow of atmospheric kinetic energy, wind also mitigates climate change indirectly by displacing fossil fuels. The ratio of direct to indirect impacts for important climatic variables provides a metric for valuing wind's role in mitigating climate change. Section 5.6 utilizes a simple model that includes trajectories of future wind capacity and carbon emissions to estimate the ratio of

[14] Because this chapter presents collaborative work, it is important to outline my contribution to the effort. The core intellectual contribution was made by David Keith. I interfaced with the supercomputer at NCAR to download model output, which I imported into MatLab and analyzed. I built the visualization tools used to generate the surface plots shown in Figures 5.2, 5.4 and 5.7. The ratio calculation of direct to indirect climate impacts from wind was based on a memo written by David Keith titled "Comparing the impacts of wind power and CO_2: Some notes on the economics" and dated 12/13/2003. Much of the work presented in this chapter, excluding the derivation of atmospheric efficiency and ratio calculations, has been submitted for publication in *Proceedings of the National Academy of Sciences*.

impacts. The chapter concludes with Section 5.7, which discusses the implications for large-scale wind and future research priorities.

5.2 Wind in the Atmospheric Boundary Layer

Most of the kinetic energy that drives wind turbines originates with the generation of available potential energy at planetary scales, which fuels winds throughout the atmosphere. As a heat engine, the atmosphere is only ~0.5% efficient at converting solar radiation into kinetic energy. This global heat engine results in ~200 terawatts (TW) of wind power being dissipated in the atmospheric boundary layer, which is the layer of air directly above the Earth's surface where wind is directly influenced by surface friction, and significant fluxes of momentum, heat, or matter are carried by turbulent motions (Garrett, 1992). Wind turbines, even with blade heights exceeding 200 m, operate within the atmospheric boundary layer.

Wind power is a renewable resource, but the renewal rate is finite. The yearly average horizontal flux of atmospheric kinetic energy can exceed 1 kWm^{-2} for large wind turbines at ~100 m hub heights. Turbines located on the leading edge of large arrays intercept the strongest winds, but slow local winds inside the wind farm. Turbulent mixing with the free flow above the turbine's wake creates shear-driven turbulence that transports momentum downward to the surface, eventually converting kinetic energy to heat via frictional dissipation. The downward flux of kinetic energy depends on the ambient turbulence level, but averages ~1.5 W/m^2 (Peixoto and Oort, 1992). It is this downward flux of kinetic energy that ultimately determines the amount power that can be extracted by arrays of wind turbines (Best, 1979).

The climatic effect, if there is one, has nothing to do with the direct effect of wind turbines on the thermal energy field caused by frictional heating, since all of the atmospheric kinetic energy is dissipated as heat in any case. Even though the generation and dissipation of kinetic energy is a small part of the global atmospheric energy budget, wind mediates much larger energy fluxes by transporting heat and moisture. Thus the perturbation of kinetic energy fluxes can have much greater climatic effects than would perturbation of radiative fluxes by an equal magnitude (Peixoto and Oort, 1992; Keith, 1996).

5.3 Model Parameterization

The climatic impact of wind turbines was explored by altering surface drag coefficients in a suite of numerical experiments using two different GCMs, one developed at the National Center for Atmospheric Research (NCAR) and the other at the Geophysical Fluid Dynamics Laboratory (GFDL). In each experiment, the drag coefficients were perturbed uniformly over an area defined by one of three wind farm arrays, denoted 'A', 'B', and 'C' and shown in black outlines on Figures 5.2, 5.7A, and 5.7B respectively.

Two different parameterizations were used to represent the additional drag due to wind turbines in the GCMs. The first was a modification of the roughness length, z_0. Roughness length is a length-scale parameter that describes the logarithmic dependence of mean wind speed on height, according to the relation $\bar{v}(z) \propto \ln(z/z_0)$ (Burton et al., 2001). The rougher the surface – forests and cities compared to oceans and fields – the larger the roughness length. In the boundary layer parameterizations (Holstlag and Boville, 2003; Collins et al., 2003), the drag coefficient is determined by

$$C_D = f(Ri)\frac{k^2}{\ln(z_1/z_0)^2} \tag{5.1}$$

where z_1 is the height of the first layer midpoint, $k = 0.4$ is the von Karman constant, and f is a function that modifies C_D due to the influence of buoyancy on shear-driven turbulent mixing, which is parameterized by the Richardson number, Ri. To simulate the effect of a uniform increase in drag, a modified roughness length, z_0', is found by adding a constant drag term to (5.1):

$$\frac{1}{\ln(z_1/z_0')^2} = C_{DW} + \frac{1}{\ln(z_1/z_0)^2}$$

where C_{DW} is the constant drag term representing wind turbines[15]. Solving for the modified roughness length gives

$$z_0' = z_1\left(\frac{z_1}{z_0}\right)^{\left(1+C_{DW}\ln\left(\frac{z_1}{z_0}\right)^2\right)^{-\frac{1}{2}}}$$

C_{DW} is chosen to produce a particular change in drag, δC_{D}, such that $C_D(z_0')-C_D(z_0) = \delta C_{\mathrm{D}}$.

The second parameterization was an explicit drag scheme. Though the specifics differed, in both models a new drag component

$$\frac{\partial\vec{v}}{\partial t} = -\frac{C_{DW}}{\Delta z}|v|\vec{v} + \ldots \tag{5.2}$$

was added to the model physics in the lowest two layers, where C_{DW} is the explicit drag coefficient representing the wind farms and Δz is the model layer thickness. The term in (5.2) creates a uniform deceleration of the wind speed through the wind farm mask. In the

[15] Treating f as a constant in this calculation is a reasonable approximation, since f departs only slightly from unity, and is closest to unity when winds (and drag forces) are closest to unity.

NCAR model, the drag was applied to the lowest two model layers with midpoints at 65 m and 250 m, resulting in $C_{DW} / \Delta z$ equal to 17×10^{-5} and 0.8×10^{-5} m^{-1} respectively. These values were chosen to represent to represent an array of wind turbines, 2.8 turbines per km^2, each with 100-m diameter rotors and 100-m hub heights that remove 40 percent of kinetic energy of the resolved flow.

Experiments at NCAR used the Community Atmospheric Model (CAM), version 2.0.1, run at its standard resolution: 26 hybrid vertical layers with T42 dynamics mapped to a 2.8×2.8° horizontal grid (Collins, 2003). Experiments at GFDL used the new "AM2"Atmospheric Model, version p10 of AM2 run at its standard resolution: 18 hybrid vertical layers with grid-point dynamics at 2.0×2.5° (lat×lon) horizontal grid (GFDL, 2004).

For the NCAR model, the perturbed model runs were compared with 108 years of control integration composed of 5 control runs of various lengths each initiated with a random perturbation of the initial temperature field to assure independence. For the GFDL model a single 20 year control run was used. All model runs used climatological sea surface temperatures (SSTs).

5.4 The Relationship between Added Drag and Wind Farms

5.4.1 Power Dissipation in the Model

GCMs are not designed to simulate the effect of wind farms. Increasing the model drag results in higher surface stress, which is additive, and when surface stress is multiplied by the local wind speed, the product represents the power dissipated by the wind turbines. The challenge lies in relating the drag perturbation and resulting climatic response to the amount of power generated by wind turbines. The increase in drag coefficient δC_D is related to the power dissipated by

$$\delta P = \rho v^3 \delta C_D \tag{5.3}$$

where ρ is the density of air at hub height. The global integral of δP is the additional power dissipated by surface friction as a result of the additional drag. In both models, δP was calculated by running the model's surface physics twice at each time step, once with the original z_0 and once with the perturbed z_0' in order to compute the change in surface stress, $\vec{\tau}$, which is the frictional force per unit surface area. δP can then be computed as $\left(\vec{\tau}(z_0') - \vec{\tau}(z_0)\right) \cdot \vec{v}$ at the lowest model layer, a direct measure of the additional kinetic energy dissipation at the surface.

5.4.2 Relating Power Dissipated to Electricity Produced

Only a fraction of the power dissipated by the wind turbines is turned into electricity. The fraction of electricity produced can be approximated using the actuator disk concept shown in Figure 5.1.

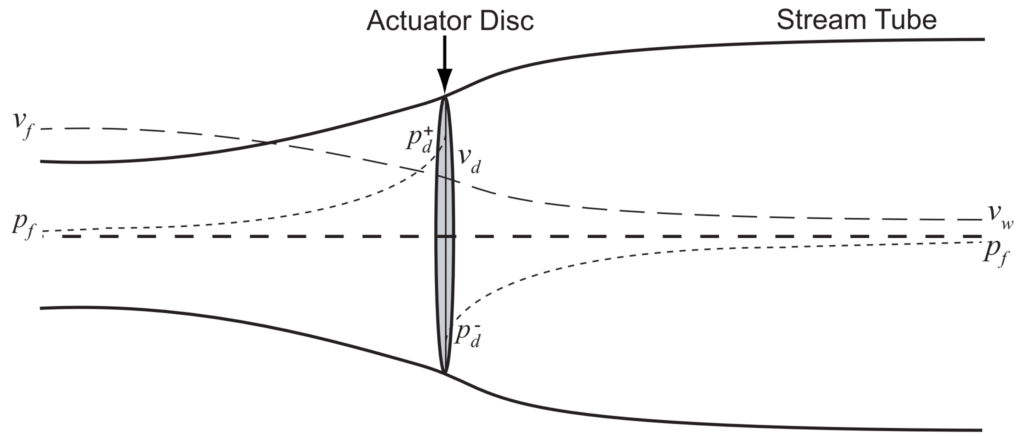


Figure 5.1 – An energy extracting actuator disc, which is used as a simplified representation of a wind turbine. Velocity is '*v*' and pressure is '*p*', while the subscript '*f*' denotes freestream, '*d*' denotes disc, and '*w*' denotes wake. The pressure difference across the actuator disc allows energy removal from the free stream. Picture adapted from Burton et al. (2001).

Wind turbines work by converting the kinetic energy in the wind to the rotational energy of the turbine blades. The loss of kinetic energy means that the downstream velocity will be lower than upstream. The net velocity at the actuator disk is given by:

$$v_d = v_f(1-a)\,, \tag{5.4}$$

where a is the axial flow induction factor, which represents the fractional reduction in wind speed at the actuator disk compared to the free-stream air flow. Since the flow rate of air must remain constant on either side of the disk due to conservation of mass, the cross-sectional area of the stream tube is smaller upstream than downstream. The change in velocity ($v_f - v_w$) can be expressed as a force, which is the product of the change in velocity and the mass flow rate:

$$F = (v_f - v_w)\rho A_d v_d\,, \tag{5.5}$$

where ρ is the density of air and A_d is the cross-sectional area of the actuator disk. The force causing the momentum change comes entirely from the pressure difference across the disk – the air around the stream tube is at atmospheric pressure, which produces zero net force. So the force given in (5.5) can also be expressed as:

$$\left(p_d^+ - p_d^-\right)A_d = (v_f - v_w)\rho A_d v_f (1-a)\,. \tag{5.6}$$

Bernoulli's equation can be applied separately to the upstream and downstream sections of the stream tube to find a new expression for the pressure difference[16]:

$$(p_d^+ - p_d^-) = \frac{1}{2}\rho(v_f^2 - v_w^2) \tag{5.7}$$

Substituting (5.7) into (5.6) yields the following relation:

$$v_w = (1-2a)v_f \tag{5.8}$$

Therefore, half of the axial speed loss takes places upstream and half downstream. Substituting (5.8) into (5.6) produces a new expression for the force on the actuator disk:

$$F = \left(p_d^+ - p_d^-\right)A_d = 2\rho A_d v_f^2 a(1-a) \tag{5.9}$$

The power extraction from the air is the product of the force and the velocity at the actuator disk:

$$P = Fv_d = 2\rho A_d v_f^3 a(1-a)^2 \tag{5.10}$$

Dividing the power extracted in (5.10) by the total available power flowing through the actuator disk yields the power coefficient C_P:

$$C_P = \frac{2\rho A_d v_f^3 a(1-a)^2}{\frac{1}{2}\rho v_f^3 A_d} = 4a(1-a)^2 \tag{5.11}$$

---

[16] Bernoulli's equation states that the sum of the pressure (p), kinetic energy per unit volume ($\frac{1}{2}\rho v^2$), and gravitational potential energy per unit volume (ρgh) has the same value at all points along the stream flow: $p + \frac{1}{2}\rho v^2 + \rho gh = constant.$ In this case, Bernoulli's equation must be applied separately to upstream and downstream sides because energy is removed from the free stream at the actuator disk.

The maximum C_P – known as the Betz limit – occurs when $dC_P/da = 0$, corresponding to $a = ⅓$ and $C_P = 16/27$. Normalizing the force given in (5.9) by the total force capable of acting on the actuator disk yields the drag coefficient, C_D:

$$C_D = \frac{2\rho A_d v_f^2 a(1-a)}{\frac{1}{2}\rho v_f^2 A_d} = 4a(1-a) \tag{5.12}$$

Finally, the amount of power dissipated can be related to the electrical power generated through the atmospheric efficiency, given by:

$$Atmospheric\ efficiency = \frac{P_{generated}}{P_{dissipated}} = \frac{\frac{1}{2}C_P \rho A v_f^3}{\frac{1}{2}C_D \rho A v_f^3} = \frac{C_P}{C_D} = \frac{4a(1-a)^2}{4a(1-a)} = 1-a\ .$$

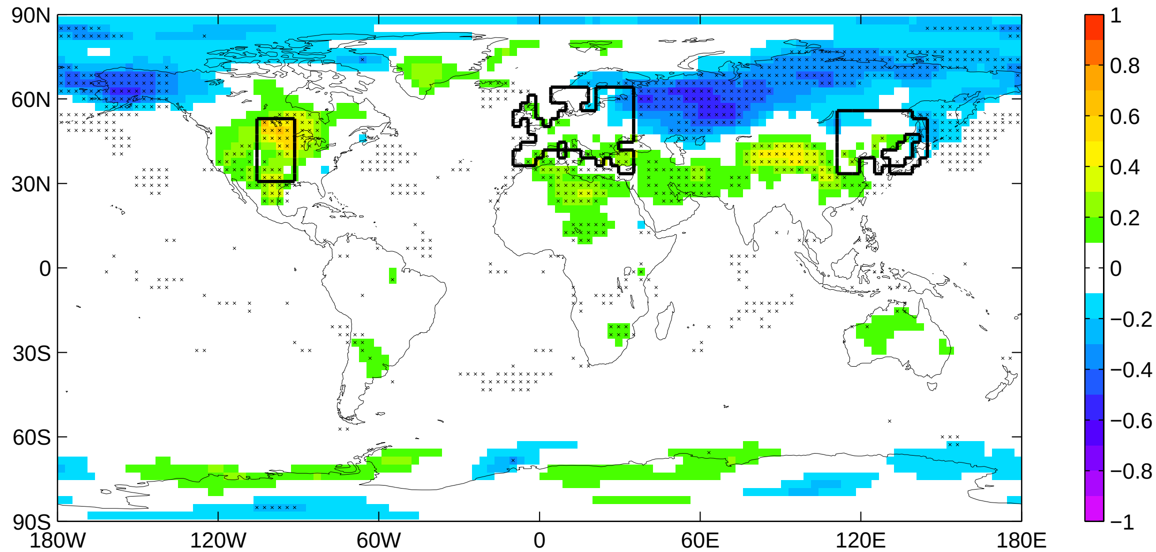
The theoretical limit corresponds to a=⅓, or a maximum atmospheric efficiency of ⅔. In practice, C_P is lower and C_D is higher: at typical velocities, C_P ranges from 0.35 to 0.4 (Gipe, 1995; Bossanyo, et al, 1980) and C_D from 0.7 to 0.75, yielding an atmospheric efficiency of 47 to 57 percent. Note that the actuator disk analysis does not include gearbox or generator inefficiencies nor does it account for the effect of increased wake turbulence produced by the turbine blades. A wind turbine converts a portion of the kinetic energy in the free stream flow to turbulence, which is expected to increase the transport of turbulent momentum downstream, thereby increasing the effective drag. Neglecting turbulence in the drag parameterizations may lead to an underestimate of climatic impact.

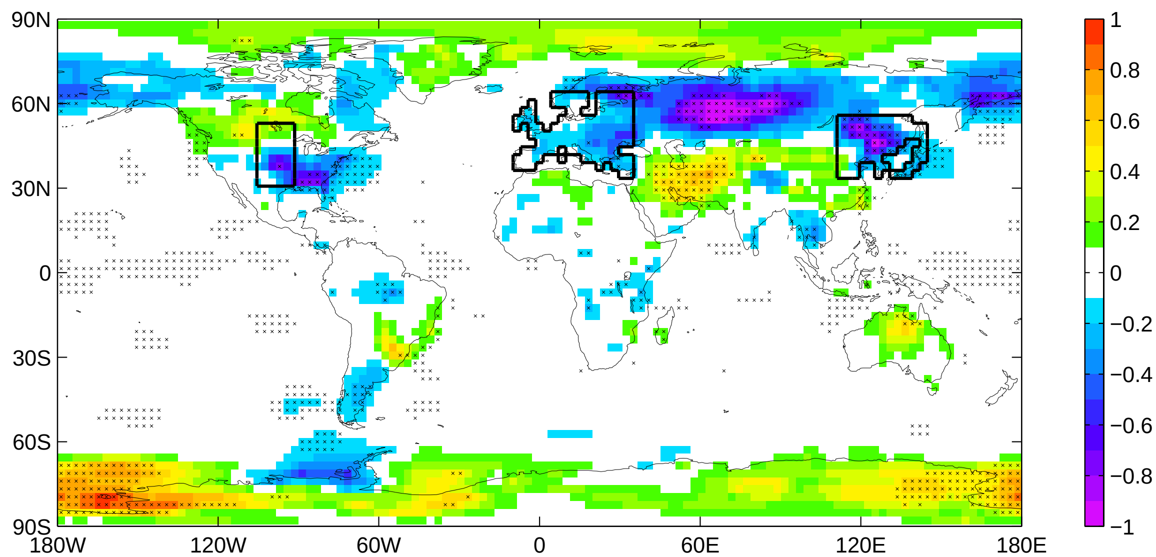
Measurements at the San Gorgonio Pass windfarm in California show average $\delta C_D = 0.007$ at hub height (Kelley, 2004). These measurements are for a wind farm with ~20 m turbine hub heights, and may underestimate the drag that would be produced by large wind farms build over the next few decades in which mean hub heights will likely exceed 100 m. A recent analytic model of the interaction of wind turbines arrays with the boundary layer flow predicts a δC_{D} (at 80 m) of 0.013 to 0.005 for average turbine spacings of 5 to 8 rotor diameters respectively assuming 100 m turbine hub height (Frandsen and Thøgersen, 1999).

Drag perturbations between 0.0006 and 0.016 were used at the model's 80 m reference height. Wind farm with δC_{D} greater than roughly 0.003 are likely unrealistic when averaged over the scale of a GCM grid cell; larger δC_{D}'s were used here only to test the model's climate response and to improve signal-to-noise-ratio (SNR). The smallest δC_{D}'s used here were about an order of magnitude smaller than the δC_{D} expected from typical wind farms, equivalent to filling roughly 1/10 of a grid cell with wind farms.

5.5 GCM Results

Figure 5.2 shows the response of near-surface (2 m) temperature to an increase in the drag coefficient (δC_{D} = 0.005) produced by a uniform increase in z_0 within the wind farm arrays outlined in black. This array was chosen to (i) be simple, (ii) be near areas of high energy demand; (iii) have strong wind resources; (iv) avoid high topography, (v) cover the northern extra-tropics in order to simplify analysis of changes to general circulation; and, (vi) have wind farms cover enough area to produce sufficient signal-to-noise (SNR) over a range of δC_{D}. The array covers 10% of global land area. The increase in dissipated power by the wind farms due to added drag, δP, is 21 and 13 TW for the NCAR and GFDL models respectively.


90N
60N
30N
0
30S
60S
90S
180W
120W
60W
0
60E
120E
180E
1
0.8
0.6
0.4
0.2
0
−0.2
−0.4
−0.6
−0.8
−1


90N
60N
30N
0
30S
60S
90S
180W
120W
60W
0
60E
120E
180E
1
0.8
0.6
0.4
0.2
0
−0.2
−0.4
−0.6
−0.8
−1

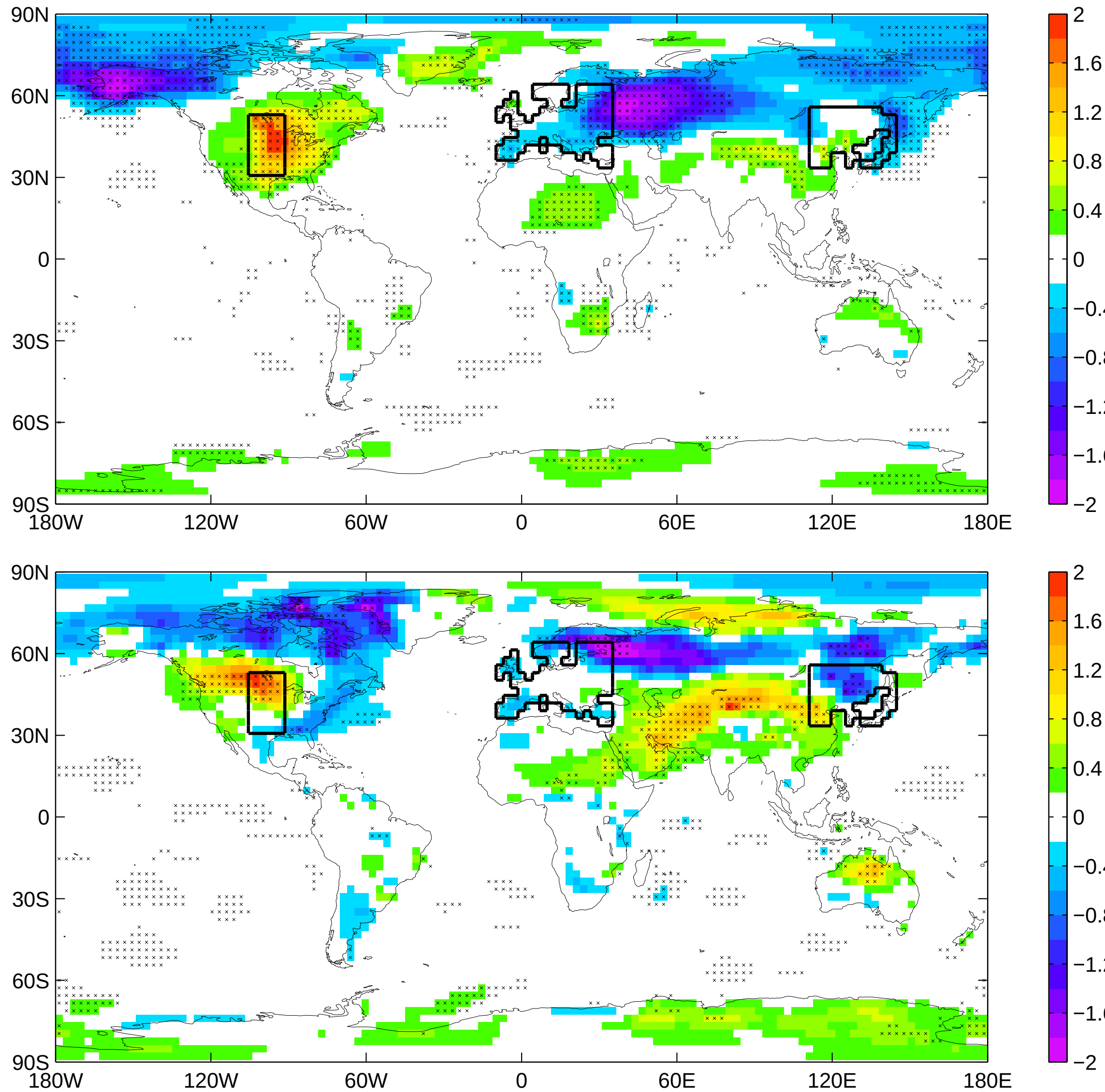


Figure 5.2 – Wind farm array and temperature response. Data are surface (2 m) air temperature (degrees K), experiment (with perturbed drag) minus control. The drag perturbation, δC_D, was 0.005 over the 'A' wind farm array outlined in black. Points that are significant at $p > 0.9$ using a binary *t*-test on annual/seasonal means are marked with an '×'. NCAR data are 37 years of perturbed run composed of 2 runs with differing initial conditions and 108 years of control composed of 5 independent runs. GFDL perturbed and control runs are both 20 years long. (A) NCAR and (B) GFDL annual mean. (C) NCAR and (D) GFDL winter (DJF) means.

Although the change in global mean surface air temperature is negligible, regional peak seasonal responses exceed ±2 °C. Note the similarities between the two models over most of the globe, particularly the strong cooling effect over northern Europe and Russia.

The strongest contrast between the models is in North America, where the NCAR model predicts warming across the US and the GFDL model predicts warming to the north and west of the wind farm, and cooling to the south and east.

Within the northern extra-tropics, note that (i) the magnitude of the response is roughly as large outside the areas with drag perturbation as within them, (ii) the sign of the response is not the same in each of the three wind masks, and (iii) the zonal pattern of response is similar across both models and all drag perturbations (Figure 5.8B). These observations indicate that the primary climate-altering mechanisms are non-local. There effects are likely driven by the perturbation of global processes, such as poleward heat transport, rather than local changes in surface energy budget resulting from increased surface drag. The long range impacts indicate that GCMs are an appropriate tool for studying the interaction of wind turbines and climate.

Note that the climatic response is constrained by the use of prescribed climatological sea surface temperatures. The climatic changes induced by wind power will be different, and possibly larger, when the models are run with an interactive ocean.

In Figures 5.2 and 5.7, the '×' markers represent grid cells where the perturbed and control runs were different at a 90 percent level of significance in a *t*-test computed for annual or seasonal means. The *t*-test results must be interpreted with caution because the test assumes a white noise spectrum, assuming there are no temporal correlations. Because there are often spatio-temporal correlations in atmospheric models, statistical significance can be difficult to establish (Livezey, 1983). Rather than rely on a statistical measure of significance, a suite of numerical experiments was developed to demonstrate that the climatic impact of increased drag produced non-random effects. In Figures 5.3-

5.5, the monotonicity of relationships between the size of the drag perturbation and the corresponding climatic response demonstrates that the effects are clearly non-random.

To provide a reference response for comparison with alternative models and parametrizations, and to explore how the magnitude of climatic response scales with the amount of wind power extracted, δC_D was varied in an ensemble of seven model runs. Each model run was roughly 20 years long and used wind farm layout 'A' shown in Figure 5.2. Figure 5.3 demonstrates how δP and the global surface dissipation change with an increasing drag coefficient.

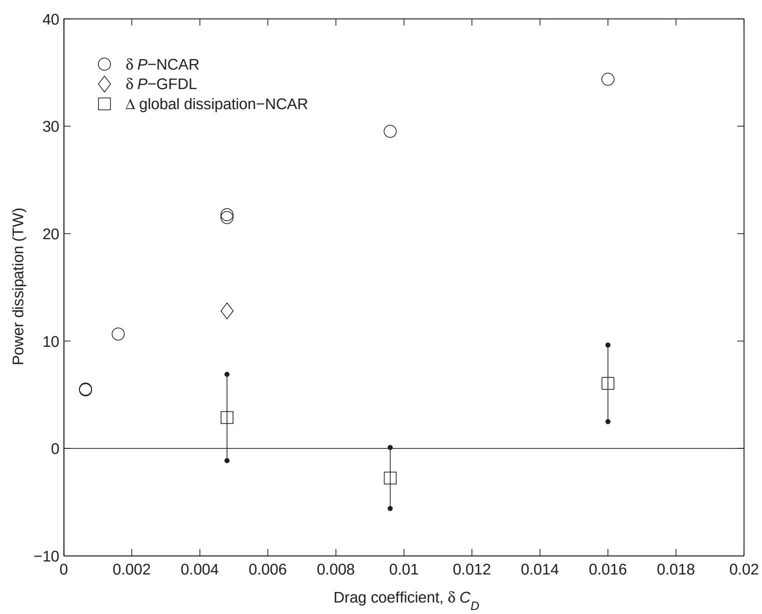
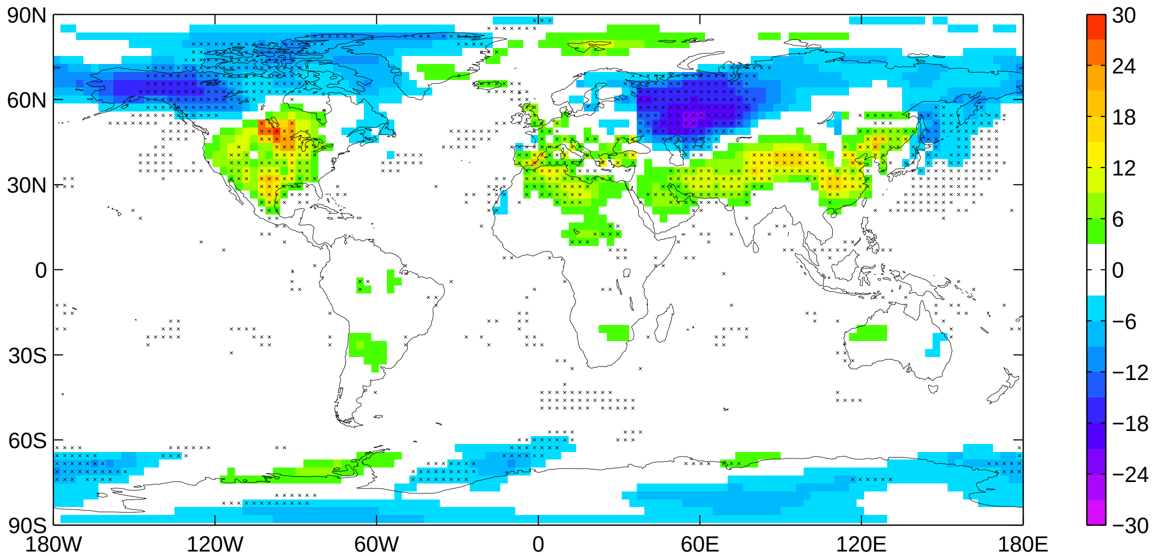
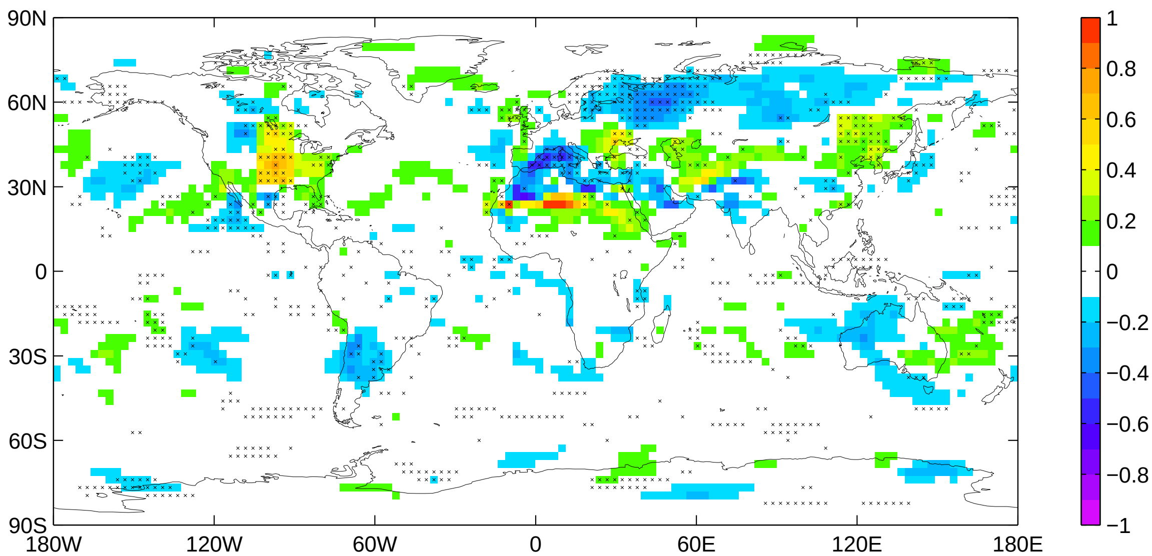


Figure 5.3 – Energy dissipation versus drag. Statistical uncertainty in δP is negligible. The ensemble of seven NCAR model runs with different drag coefficients are shown (there are two points at both δC_D = 0.0006 and 0.005). The change in global mean surface dissipation (as a result of increased drag) is <1 percent of the control mean of 1.7 Wm^{-2} or 850 TW summed globally. The uncertainty bars associated with the global mean surface dissipation represent the standard error of the mean.

Two interesting results can be drawn from Figure 5.3. First, the relative proportion of dissipated power decreases with increasing δC_D because the surface winds inside the wind farm arrays slow down with increasing drag. Second, slower winds outside the arrays result in reduced dissipation that compensates for the increased dissipation inside the arrays. Because the atmospheric heat engine is ultimately driven by a constant input of solar energy, dissipation must remain constant for the atmosphere to remain in steady-state. These conclusions suggest that studies assuming that regional or global wind capacity can be estimated by simply summing local wind resources (e.g. Metz et al., 2003; Grubb and Meyer, 1993) are flawed. Large-scale atmospheric dynamics provide a rough upper bound on the power that can be extracted by wind farms just as wind-shadowing effects limit the amount of power that can extracted by individual wind turbines within an array (Frandsen, 1992).

The climatic response to δP was estimated by regressing observed climatic change against δP over the ensemble. For each spatial location, a least squares linear fit of a particular climatic variable versus δP was performed, where the fit was constrained to have a *y* intercept of zero. This method provides a clean measure of climatic response across the ensemble and also provides a test of significance that is independent of the temporal characteristics of the noise spectrum, unlike the *t*-test results in Figures 5.2 and 5.7. The regressions in Figure 5.4 provide an estimate of the magnitude and direction of change in a particular climatic variable per TW of wind power at specific grid locations.


90N
60N
30N
0
30S
60S
90S
180W
120W
60W
0
60E
120E
180E
30
24
18
12
6
0
−6
−12
−18
−24
−30


90N
60N
30N
0
30S
60S
90S
180W
120W
60W
0
60E
120E
180E
1
0.8
0.6
0.4
0.2
0
−0.2
−0.4
−0.6
−0.8
−1

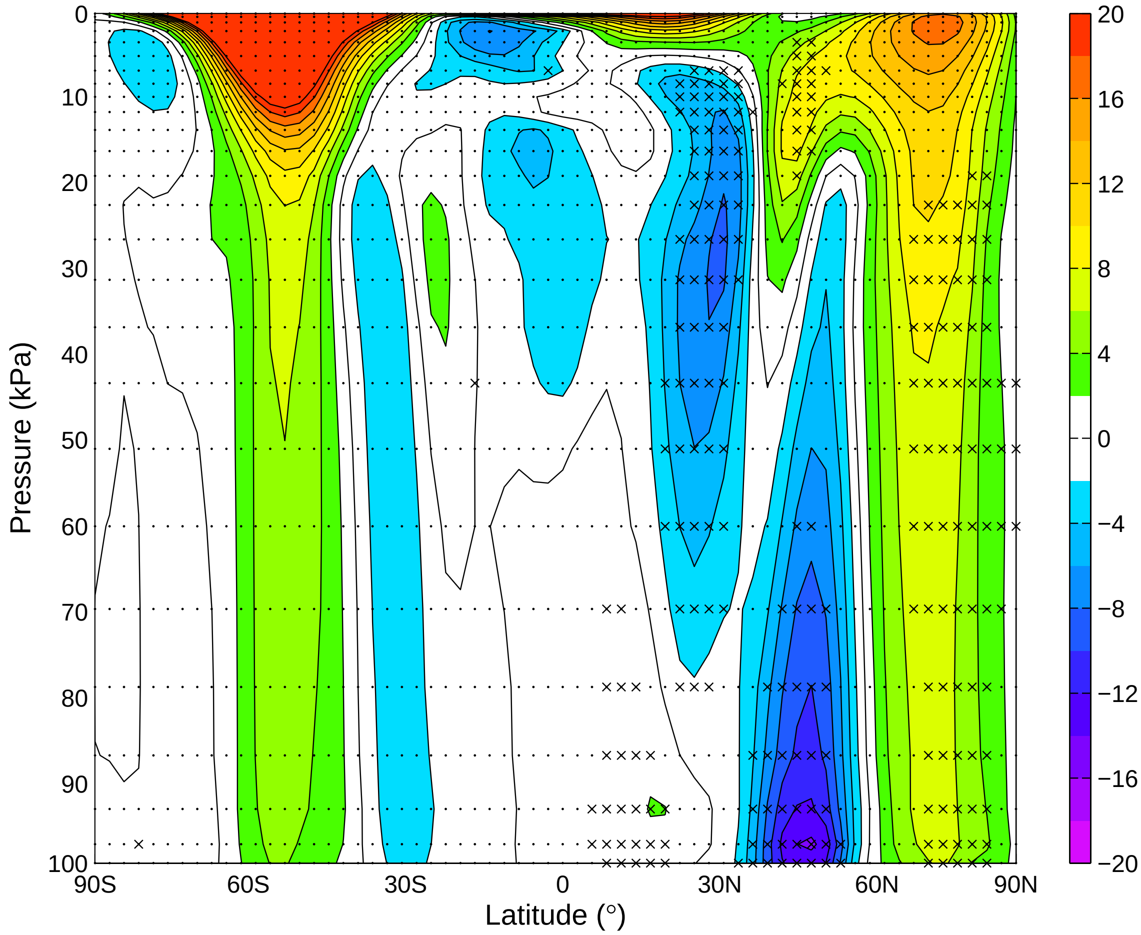
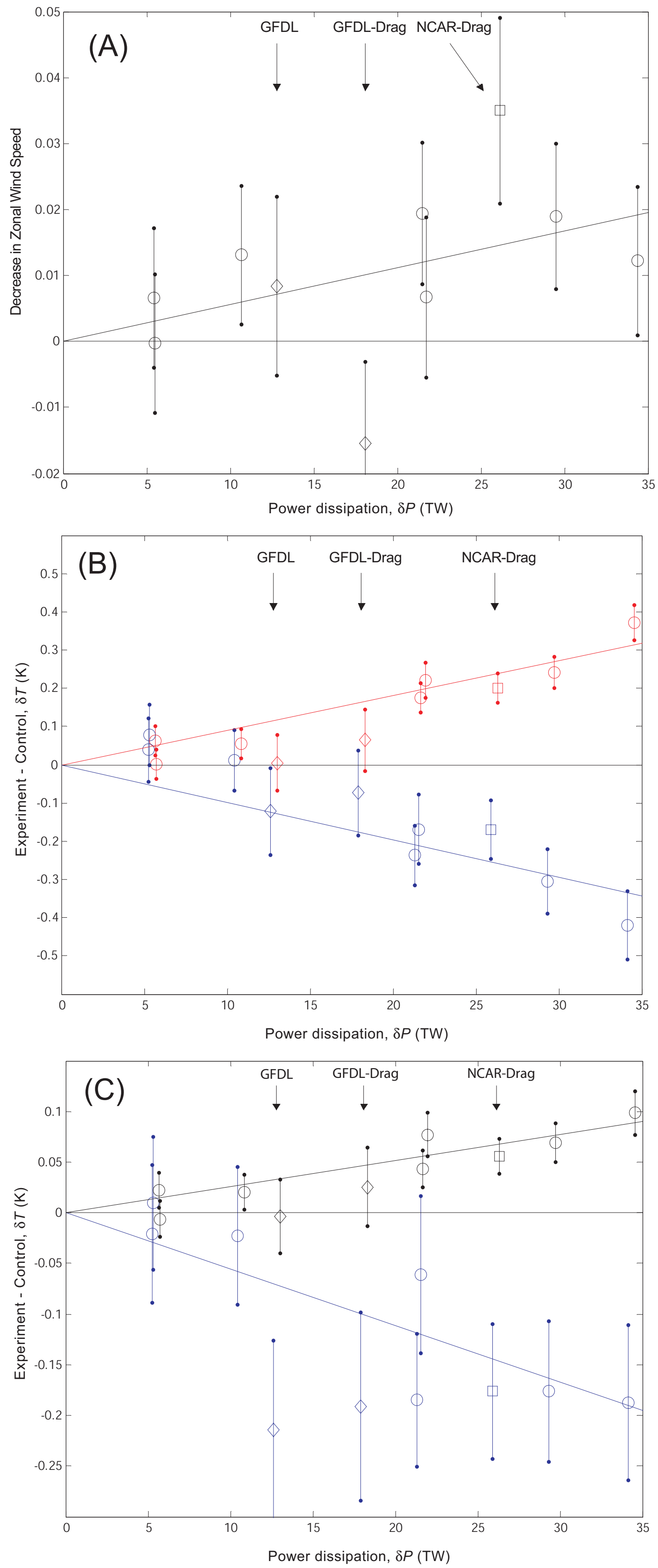


Figure 5.4 – Linear coefficient (slope) of climatic response in the NCAR linearity ensemble. In each plot, the magnitude at each point is the slope of a least-squares linear regression of the deviation in the climatic variable with respect to the global δP's using one datum from each of the 7 linearity runs shown in Figure 5.3. The 'y-intercepts' are constrained to zero. Points where the correlation between the variable and δP was significant at $p > 0.9$ are marked with an '×'. (A) Annual mean (2 m) air temperature, mK TW^{-1}. (B) Percent change in annual mean precipitation, % TW^{-1}. (C) Annual mean change in zonal wind, mm sec^{-1} TW^{-1}, note that the dipole corresponds to a poleward shift of the northern hemisphere jet.

Figure 5.5 compares response across the two models and two parameterizations by plotting various integrated measures of response versus δP. Responses are generally similar across models and parameterizations. An obvious exception is the difference between the two GFDL parameterizations in Figure 5.5A, which predict changes in jet intensity that are opposite in sign. The explicit drag scheme did not produce climatic responses that were systematically higher or lower than the runs with modified roughness length.


(A)
GFDL
GFDL-Drag
NCAR-Drag
Decrease in Zonal Wind Speed
Power dissipation, δP (TW)
(B)
GFDL
GFDL-Drag
NCAR-Drag
Experiment - Control, δT (K)
Power dissipation, δP (TW)
(C)
GFDL
GFDL-Drag
NCAR-Drag
Experiment - Control, δT (K)
Power dissipation, δP (TW)

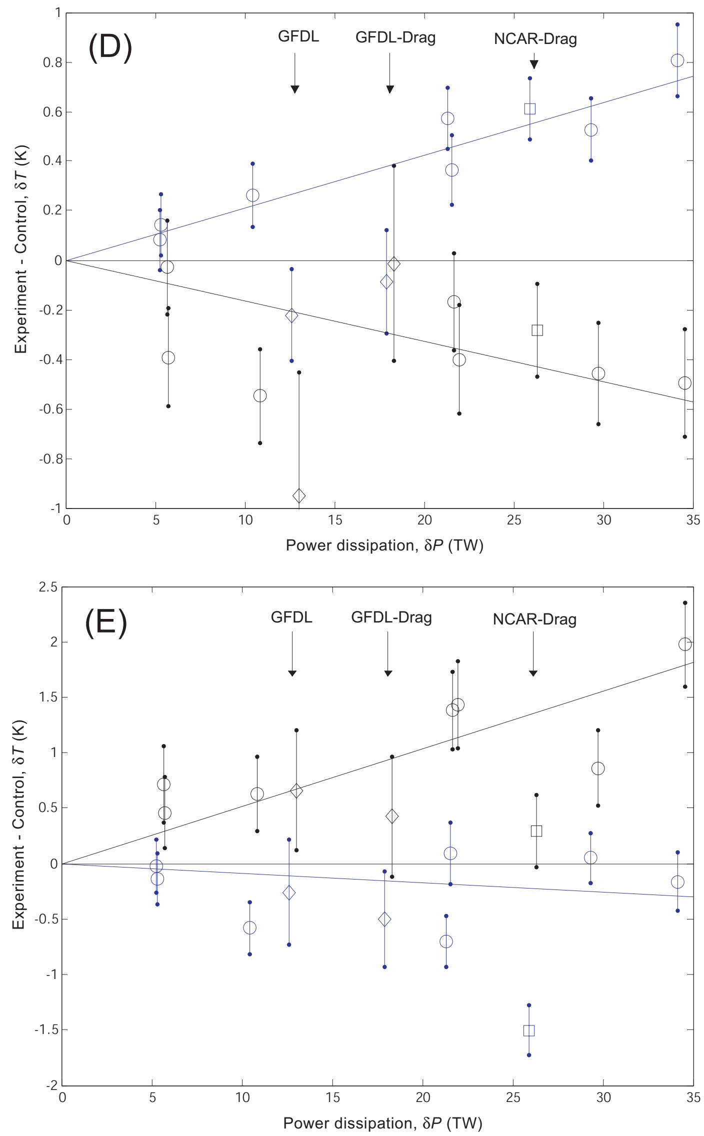


Figure 5.5 – Mean climatic response over various masks versus δP. For each point, the seasonal or annual means of a given model run are first averaged across a mask, with differences and standard errors of the mask averages computed for each model year in both the experiment and control runs. Results from 10 model runs are shown all using the 'A' array shown in Fig 5.2: '○' marks data from the 7 elements of the NCAR ensemble, '□' marks the NCAR drag physics run, and '◊' marks data from the two GFDL runs where the 13 and 18 TW points mark, respectively, the roughness length and drag physics runs. (A) Fractional decrease in the zonal wind speed over a mask that extends from 40-60°N and 100 to 30 kPa. (B) Annual mean $\delta T_{2-\mathrm{m\,air}}$ averaged over two separate masks. The red (blue) points use a mask defined by the points that are positive (negative) and significant in Fig 5.4A. (C) Annual mean $\delta T_{2-\mathrm{m\,air}}$ over zonal land-surface masks at 25-45°N (black) and 55-65°N (blue). (D) Summer (JJA) $\delta T_{2-\mathrm{m\,air}}$ for the North American (black) and European (blue) areas of the 'A' wind farm array shown in Fig 5.2. (E) Same, but for winter (DJF).

Both the roughness length and explicit drag parameterizations have strengths and weaknesses. The roughness length modification leaves the self-consistency of the model physics unaltered since only a single parameter was modified, but it is unclear how accurately wind turbines are represented by an increase in surface roughness. Wind farms will be more dissipative, which may result in understated impacts. On the other hand, the explicit drag formulation is more physically realistic, but the results must be treated with caution because the effect of the added drag on the model physics was not fully explored. In addition, neither method accounts for the wake turbulence created by the wind turbines. Baida Roy et al. (2004) model wind turbines as a net sink of resolved kinetic energy and source of turbulent kinetic energy in a mesoscale model, and find that the generation of wake turbulence by wind turbines greatly increases their climatic influence.

Over the northern mid-latitudes, the wind farms increase the mean drag coefficient (C_D) over land by ~20 percent for $\delta C_D = 0.005$. The added drag slows mid-latitude winds by a few percent (Fig 5.5A), shifts the jet polewards (Fig 5.4C), and increases surface stress by ~5 percent (Fig 5.8A). Collectively, these results demonstrate that increased drag in areas comprising only 10 percent of global land surface can produce statistically significant changes in the general circulation. Given that $\tau \propto C_D v^2$, these changes are consistent with the assumption that winds slow sufficiently to roughly conserve surface dissipation in response to increasing drag.

The ensemble results allow a rough assessment of the functional form of the climatic response for δP up to 25 TW (see the points marked with '○' in Fig 5.5). The 25 TW perturbation amounts to a ~4% alteration of global surface energy dissipation, or a ~20% change in drag over northern hemisphere land. Within the limits of the experimental error, the results suggest that the climatic response is often roughly linear for δP up to 25 TW (Figs 5.5A, 5.5C black, 5.5D blue), but might be saturating (5.5D black, 5.5C blue).

Simulations below 5 TW were not performed because the smaller perturbation would require significantly longer model runs to differentiate the signal from the noise and produce a statistically useful estimate. Nonetheless, how the climatic response scales as $\delta P \rightarrow 0$ carries critical implications for the future of wind power. If there is no discernable climatic impact below a particular level of added drag, then the climatic impact of wind turbines may not be important. If, on the other hand, the climatic impacts scale down to zero added drag, then the value of wind power lies in the ratio of beneficial climatic impact (displacing fossil fuels) to detrimental climatic impact (changing the distribution of wind energy dissipation). The ratio of climatic impacts from wind power will be discussed further in the next section.

The regression in Figure 5.4 provides an estimate of the derivative of climatic response with respect to wind-induced dissipation by assuming a linear relationship. As $\delta P \rightarrow 0$, climatic response will be increasingly linear (Mitchell, 2003, Sexton et al., 2003). While δC_{D} is interpreted as a variation in wind power from zero, the climate model is responding to small changes in drag from an arbitrary initial C_D that is nonzero. A strong nonlinear effect to small changes in drag might be expected if there is no drag in the baseline models, and drag is varied from zero to represent wind farms. A nonlinear effect from a small drag perturbation could only be expected in the actual models if the drag in the baseline model is somehow optimized to produce a minimum or maximum effect: a possibility that is highly unlikely. See Figure 5.6.

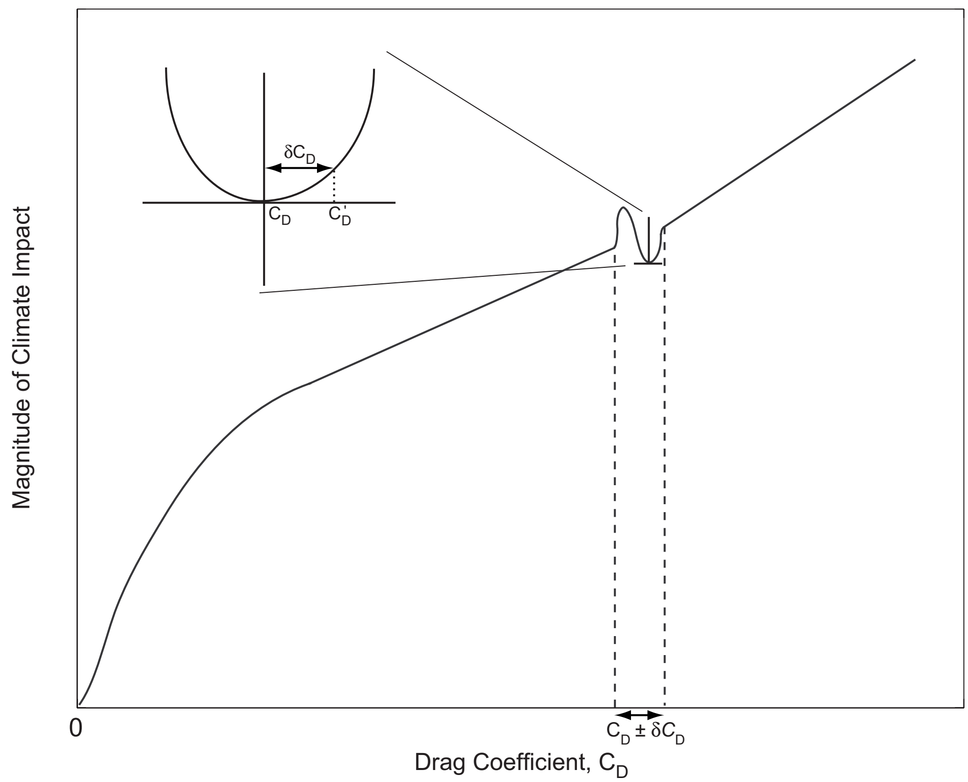


Figure 5.6 – Schematic illustration of the linear scaling assumption. In order for small perturbations (δC_D) to the drag coefficient to produce non-linear climate impacts, a kink must be present close to the default drag, C_D. Such an assertion would imply an optimal distribution of drag in the base case (C_D); a possibility that is considerably weakened by the observation that both the NCAR and GFDL have different drag coefficients in their respective base models. The possibility of a nonlinear response to a small drag perturbation is therefore highly unlikely. Note that δC_D can be negative, and the linearity assumption would still apply.

The particular 'A' configuration of wind-farm arrays shown in Figure 5.2 produced the patterns of climatic response shown in Figures 5.2-5.5. To test how the climatic impacts vary with different wind farm arrays, alternative 'B' and 'C' configurations shown in Figure 5.7 were also tested.

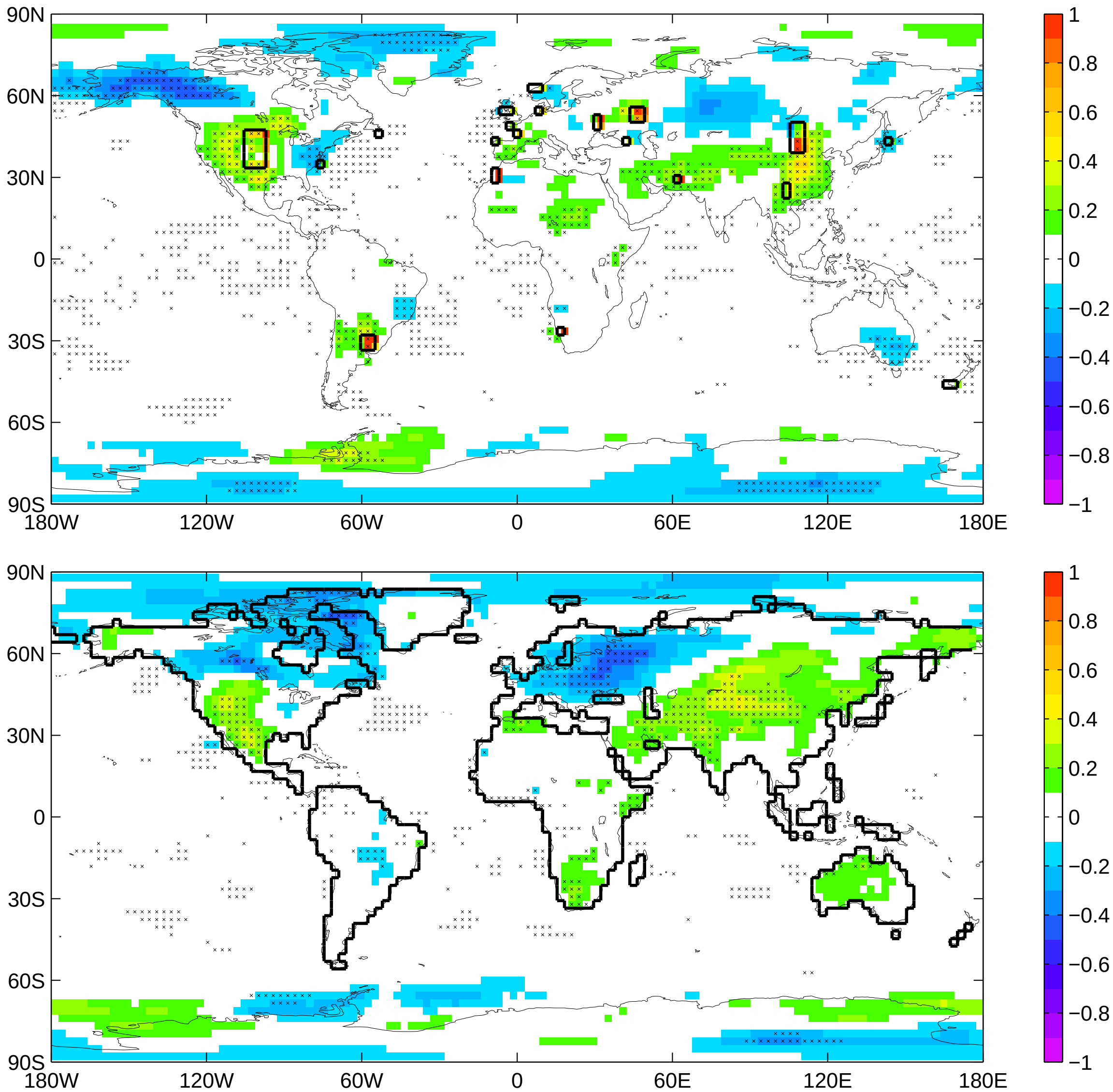
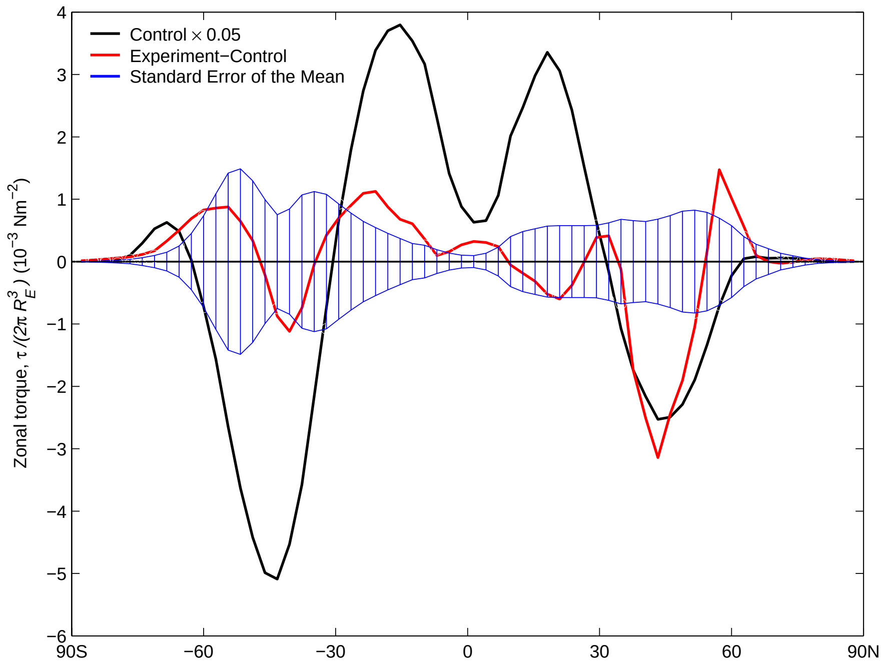
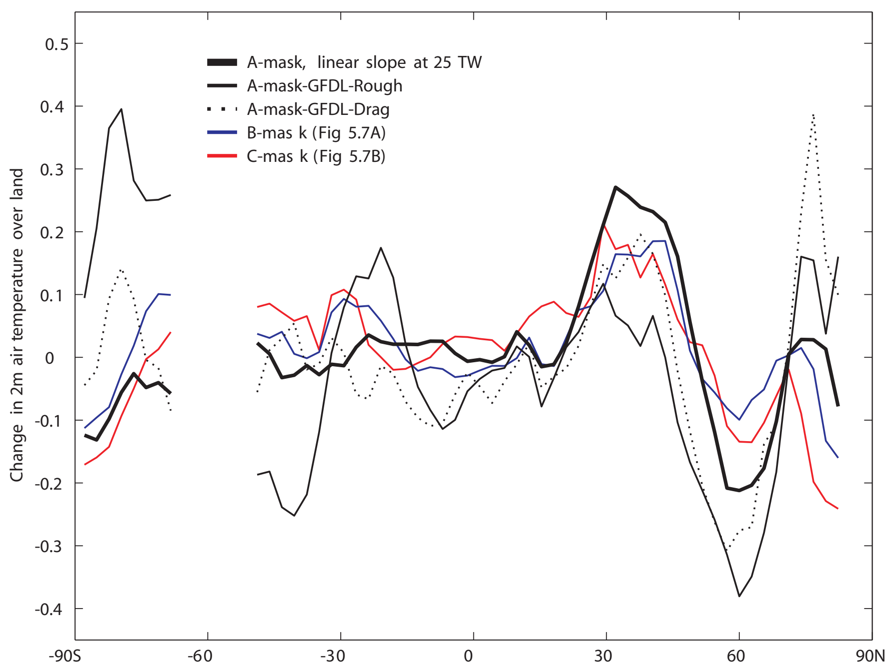


Figure 5.7 – Surface temperature response ($\delta T_{2\text{-m air}}$) to two different spatial configurations of wind-farms and δC_{D} . (**A**) The 'B' array, which covered 2.5% of global land surface. The roughness length, z_0, was (aggressively) set to 5 m everywhere within the array, in contrast to the array's original 0.12 m areal-mean roughness length. The resultant $\delta C_{\mathrm{D}} \cong 0.016$ corresponds to $\delta P = 15\text{TW}$. Data shown are for 50 years of integration. (**B**) The 'C' array with $\delta C_{\mathrm{D}} = 0.0006$ globally (excepting Antarctica) corresponding to $\delta P = 30$ TW with 30 years of integration.

One might suppose that the effects were strongly dependent on the high density of turbines in the wind farms, and that a uniform global distribution of δC_{D} that generated similar δP would produce a much smaller climatic response. This hypothesis was tested in the NCAR model by setting δC_{D} = 0.0006 over all land except Antarctica (the ‘C’ configuration). The resulting δP was 30 TW, about 5 times larger than the 6 TW dissipation produced using the same δC_{D} in the ‘A’ configuration that covers 10% of the land surface (see the δP = 6 TW points in Figure 5.5). The surface temperature response to distributed δC_{D} (Figure 5.7B) was of roughly similar peak magnitude to that resulting from a δP of 21 TW generated in the ‘A’ configuration (Figure 5.2). This result suggests that a uniform distribution of δC_{D} does not drastically reduce the magnitude of climate impacts for a given δP. In addition, visual comparison of Figures 5.2 and 5.7 indicate similar patterns of response across all three wind-farm configurations, which suggests that the changes in general circulation are not strongly dependent on the particular configuration of wind array. The similarities are confirmed by the surprising consistency in the zonal pattern of temperature response (Figures 5.8B and 5.8C).



Control × 0.05
Experiment−Control
Standard Error of the Mean
Zonal torque, $\tau/(2\pi R_E^3)$ (10^{-3} Nm^{-2})
4
3
2
1
0
−1
−2
−3
−4
−5
−6
90S
−60
−30
0
30
60
90N



A-mask, linear slope at 25 TW
A-mask-GFDL-Rough
A-mask-GFDL-Drag
B-mas k (Fig 5.7A)
C-mas k (Fig 5.7B)
Change in 2m air temperature over land
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-90S
-60
-30
0
30
60
90N

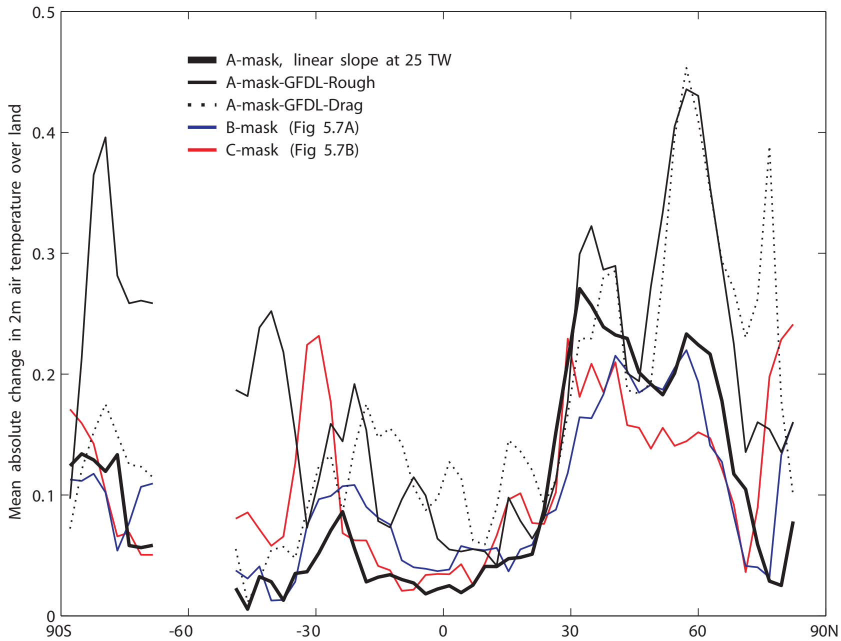


Figure 5.8 – Zonal measures of climatic response. (A) Torque. Data is from the NCAR model as described in Figure 5.2A. (The plotted quantity is F(θ)cos^2(θ) which is torque per-radian-of-latitude divided by $2\pi R_E^3$, where R_E is the earth's radius and F(θ) is the zonal stress.) Note how the torque added by the wind farm drag at ~30-60°N is redistributed so that total torque remains at zero. (B) Zonal and annual mean $\delta T_{2\text{-m air}}$ over land. The black lines show response to the 'A' array shown in Figure 5.2. Red and blue lines show data from the experiments using the 'B' and 'C' wind farm masks shown in Figure 5.7. All lines correspond to single model run except the heavy black line which is derived from the linear response data of Figure 5.4A scaled with an arbitrary δP = 25 TW. (C) Same, but for zonal means of the absolute magnitudes.

5.6 Comparison of Direct and Indirect Climatic Effects

5.6.1 Defining a Metric

Wind turbines directly affect the climate by extracting kinetic energy from the atmospheric boundary layer, but also mitigate climate change indirectly by displacing fossil fuels. The ratio of direct to indirect climatic impacts provides a useful metric for judging the efficacy of using wind to mitigate climate change. Because the previous section argued that the climatic impacts scale linearly as $\delta P \rightarrow 0$, the ratio is relevant at any scale. The ratio, α, can be defined as:

$$\alpha = \frac{\delta \overline{I_W}}{\delta \overline{I_R}}, \tag{5.13}$$

where I_W is the direct climatic impact due to wind energy and I_R is the indirect climatic impact due to the displacement of the fossil fuels. The bar indicates the discounted mean computed with an exponential discount rate, φ.

The ratio of climatic impacts from wind power must be computed over a sufficiently long time horizon because the direct impact of wind power occurs immediately whereas the indirect climatic benefit grows over time as electricity from wind reduces CO_2 emissions and slows the growth of atmospheric CO_2 concentrations. A comparison of the effects depends, among other things, on (i) how impacts at different times are aggregated, (ii) the effectiveness of electricity from wind in reducing CO_2 emissions, and, (iii) the baseline CO_2 emissions profile. The section below describes a series of calculations to determine the ratio of direct to indirect climate impacts from wind. While the estimation is based on the use of wind power to produce a measurable reduction in global CO_2 emissions, the ratio calculation does not depend on the amount of projected wind power. If the climate response to both the extraction of wind power and CO_2 concentrations is assumed linear, then the ratio calculation applies at any scale. In the analysis below, the ratio of direct to indirect climate impacts from wind should be considered applicable to a single wind turbine.

5.6.2 Estimating the Ratio of Direct to Indirect Climate Impacts

The objective is to translate a plausible trajectory of global carbon emissions to concentrations of atmospheric CO_2 and radiative forcing. The baseline global carbon emissions without wind can be expressed as the product of two logistic functions:

$$E(t) = 15\left(\frac{1}{1+e^{-t/50}}\right)\left(\frac{1}{1+e^{(t-t_0)/50}}\right), \tag{5.14}$$

where t_0 is the time constant that determines when the emissions peak occurs. Though (5.14) is not a standard formulation for an emissions trajectory, it has the advantage of being simple while still producing a trajectory similar to Wigley (1996) and Metz et al. (2001). With $t_0 = 150$ years, the emissions curve approximates a standard 550 PPM stabilization scenario, where atmospheric concentrations of CO_2 peak at ~630 PPM before stabilizing at twice the pre-industrial level of 280 PPM.

Two wind power trajectories were tested. In the first case, wind is proportional to the second logistic function in (5.14), representing the case where wind power declines with declining CO_2 emissions as wind and fossil fuels are gradually replaced by a future CO_2-neutral energy source. In the second case, wind power remains constant with time. Wind power reduces emissions by $\beta w(t)$, where β is the efficiency with which wind-generated electricity reduces CO_2 emissions and depends on the carbon intensity of the generators being displaced. In an extreme high efficiency case, wind displaces coal plants ($\beta \cong 3$ GtC/TW-yr), and in an extreme low efficiency case wind displaces combined-cycle gas turbines ($\beta \cong 0.8$ GtC/TW-yr). See Figure 5.9.

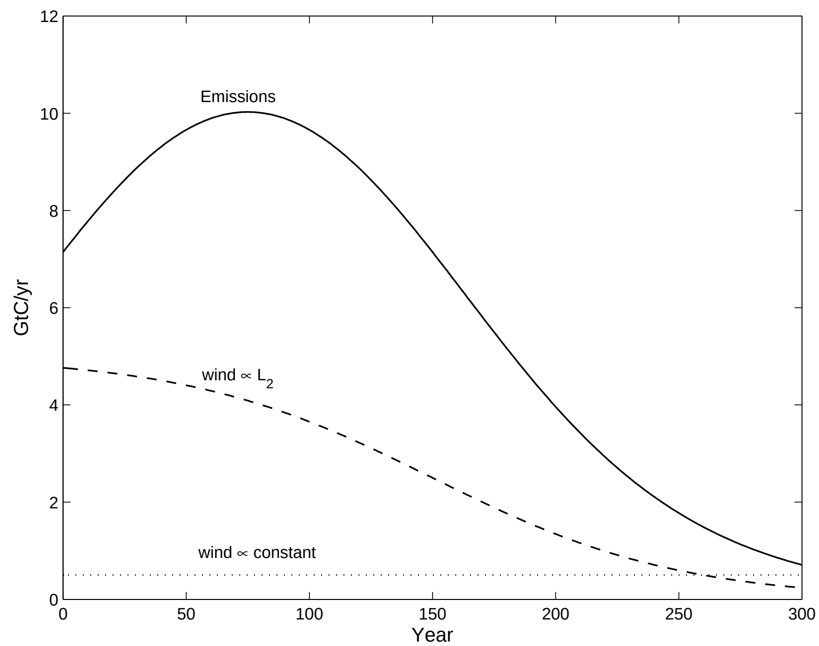


Figure 5.9 – Hypothetical trajectories for carbon emissions and wind power for the next three centuries. In one case, wind is proportional to the second logistic function (L_2) in (5.14), and scaled to displace ~5 GtC/yr in the year 2300. In the second case, wind power remains constant. Changing the trajectory of *w(t)* affects the ratio calculation, but scaling the amount wind power given a particular trajectory to achieve a different level of carbon abatement does not change the ratio estimate. The wind capacity depends on the average assumed carbon intensity of the existing system, β. A reasonable unbiased estimate of β = 1.6 GtC/TW-yr would imply a wind capacity of 3.8 TW in 2300.

The annual emissions specified in (5.14) can be converted into atmospheric concentrations by using an impulse-response carbon cycle model. Impulse response functions (IRFs) are highly simplified mathematical representations that reproduce the characteristics of the climate response to an external forcing computed with GCMs (Hooss, 2001). The carbon-cycle IRF is composed of a sum of exponentially decaying functions, one for each fraction of the additional concentrations, which reflects the time scales of different sinks. An impulse-response function developed by Hooss (2001) was used to convert the emissions given in Figure 5.9 into CO_2 concentrations:

$$I(t) = 0.132 + 0.311e^{-t/237} + 0.253e^{-t/60} + 0.209e^{-t/12} + 0.095e^{-t/1.3} \qquad (5.15)$$

where $I(t)$ is the response to a 1 percent perturbation (2.8 PPM) of pre-industrial concentrations of atmospheric CO_2 (280 ppm).

The IRF in (5.15) represents the response to a single perturbation. The change in concentration of atmospheric CO_2 as a result of emissions over time can be expressed as:

$$C(t) = \int_{t_0}^{t} E(t')I(t-t')dt' \,. \tag{5.16}$$

In the integral above, the product of the emissions and impulse-response function each year is summed from the initial year t_0 to the current year t to ensure that CO_2 remains in the atmosphere with the correct residence times. The concentrations calculated in (5.16) are added to the equilibrium level of pre-industrial CO_2 emissions, 280 PPM. The lower bound of the integral t_0 is set such that the concentration in year zero corresponds to the present CO_2 concentration of 370 PPM. See Figure 5.10.

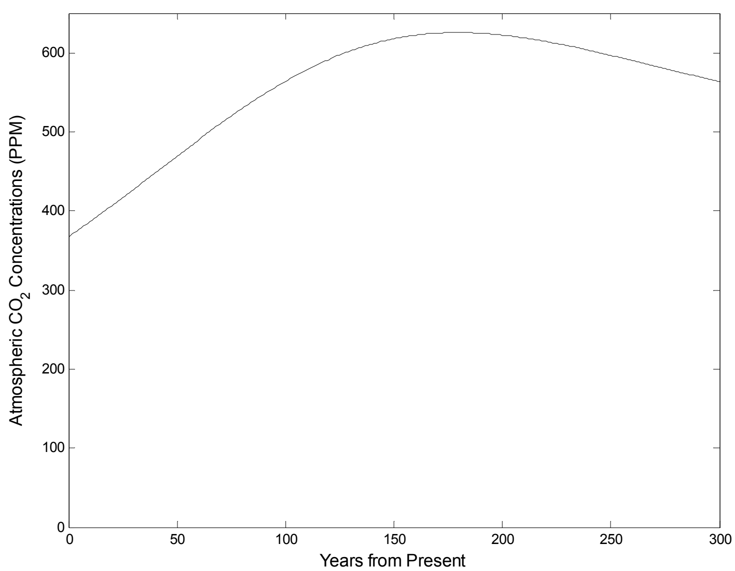


Figure 5.10 – Hypothetical atmospheric concentration of CO_2 – given by (5.16) – over the next three centuries. The current concentration of ~370 PPM peaks in 2175 at ~630 PPM, and eventually stabilizes around 550 PPM, roughly twice pre-industrial levels.

Concentrations of CO_2 can then be converted into a radiative forcing, using a standard formula (Metz et al., 2001):

$$r = 4.841 \ln\left(\frac{C}{C_0}\right) + 0.0906\left(\sqrt{C} - \sqrt{C_0}\right), \tag{5.17}$$

where C_0 is the pre-industrial CO_2 concentration, and r has units of Wm^{-2}. The mean radiative forcing due to wind power displacing fossil fuels, computed with an exponential discount rate φ, is expressed as:

$$\delta\bar{r} = \int_0^\infty \left(e^{-\varphi t} \left.\frac{dr}{dC}\right|_{C(t)} \int_0^{t_{\max}} \beta w(t') I(t_{\max} - t') dt' \right) dt \tag{5.18}$$

where $dr/dC = 4.841/C + 0.453/\sqrt{C}$. Because the impulse-response carbon cycle is used, $C(t)$ enters (5.18) only through dr/dC. The constant β determines the efficiency with which wind reduces carbon emissions, and represents the carbon intensity of the electric power system, in GtC/TW. Larger βs improve the indirect climatic benefit by displacing larger amounts of CO_2 emissions. If wind replaced only combined-cycle gas turbines running at 55 percent efficiency , $\beta \cong 0.8$ GtC/TW-yr, and if wind replaced only coal capacity running at 35 percent efficiency instead, $\beta \cong 3$ GtC/TW-yr. A reasonable unbiased estimate of global average carbon intensity is $\beta \cong 1.6$ GtC/TW-yr[17]. While β would be expected to change over time, it is assumed a constant in this analysis for simplicity.

---

[17] Data to produce average global carbon intensity estimate are drawn from EIA (2004). Net global electricity generation in 2002 was 1.7 TW-yr. Assuming an average power plant efficiency of 30%, 5.8 TW of primary energy are used to meet the world's electricity needs. The fraction of primary that goes toward electricity supply is then ~40%, obtained by dividing 5.8 TW-yr by the total amount of primary energy consumption globally, 13.75 TW. Assuming that global carbon intensity is relatively constant across different energy sectors, then ~40% of global CO_2 emissions are produced by electric power production. With 6.7 GtC produced globally in 2002, the estimate of average global carbon intensity in the electric power sector is β = (0.4)(6.7 GtC)/(1.7 TW) = 1.6 GtC/TW-yr.

In order to calculate the direct climate impact from wind power, the peak linear coefficient from Figure 5.4A is multiplied by the mean discounted wind power, given by:

$$\delta \overline{w} = \int_0^\infty w(t) e^{-\varphi t}\, dt. \tag{5.19}$$

The ratio of direct to indirect climate impacts from wind power given by (5.13) now can be calculated using (5.18) and (5.19) as follows:

$$\alpha = \frac{\text{direct climate impact}}{\text{indirect climate impact}} = \frac{\delta \overline{w} \times (60\text{ mK/TW})}{\delta \overline{r} \times \lambda}, \tag{5.20}$$

where 60mK/TW is the peak temperature change drawn from Figure 5.4A divided by an assumed atmospheric efficiency of 50%, and λ is a (relatively) scale-invariant proportionality constant equal to 500mK/Wm^{-2} (Metz et al., 2001, 354). Estimates of α are provided in Table 5.1 below.

Table 5.1 – Estimates of α: the ratio of direct to indirect climatic impacts produced by wind power, as a function of the carbon intensity of the baseline electric power system (β), the trajectory of wind power production over time $w(t)$, and discount rate (φ).

Carbon Intensity (GtC/TW)	w(t)[a] (GtC/TW)	Ratio of Direct to Indirect Impacts (α)			
		φ=0%	φ=1%	φ=2.5%	φ=5%
β = 0.8 (natural gas)	$w(t) \propto L_2$	0.021	0.22	0.37	0.57
	$w(t) \propto c$	0.033	0.22	0.37	0.57
β = 1.6 (global average)	$w(t) \propto L_2$	0.010	0.11	0.18	0.28
	$w(t) \propto c$	0.017	0.11	0.18	0.28
β = 3 (coal)	$w(t) \propto L_2$	0.0055	0.057	0.097	0.15
	$w(t) \propto c$	0.0088	0.058	0.098	0.15

[a] Two wind power trajectories were tested. In one case, $w(t)$ is proportional to the second logistic function (L_2) in (5.14). In the other case, $w(t)$ is proportional to a constant.

Table 5.1 demonstrates that under a variety of assumptions, the largest α estimates are still less than unity. The estimate of 60 mK/TW drawn from Figure 5.4A represents the peak temperature change, which means that the α estimates in Table 5.1 represent an upper bound on the peak temperature change due to the direct impact of wind turbines on climate. Although the assessment provided in this section is highly simplified, it provides evidence that the direct climatic impact caused by the dissipation of atmospheric kinetic energy by wind turbines is less than the indirect climate benefit provided when wind displaces fossil fuels. In the case where wind displaces combined-cycle gas and is evaluated at higher discount rates, the direct impact is within a factor of two of the indirect impact.

5.7 Conclusions

Wind power's climatic impact is currently negligible in comparison to other sources of anthropogenic climate change. Suppose that wind power use grew a hundredfold to 2

TW, somewhat beyond the largest quantity envisaged for the next half century by recent studies (EWEA, 2003; Edmonds et al., *forthcoming*), but only about a tenth of the global electricity demand in 2100 under fossil intensive emissions scenarios (Nakiâcenoviâc and Swart, 2000). At an atmospheric efficiency of 50% this corresponds to a δP of 4 TW, just under the smallest δP used here. The results here suggest that the resulting peak changes in seasonal-mean temperature might be ~0.5 K, with RMS changes about an order of magnitude smaller and near-zero change in global mean temperature. The climatic changes from wind power are detectable above background climatic variability in model runs of a few decades duration, but they might remain too small to detect in the presence of other anthropogenic change and natural climate variability.

Preliminary estimates of the ratio of direct to indirect climate impacts from wind (α) using a simple model suggest that the beneficial, indirect impacts of wind power outweigh the direct impacts caused by the dissipation of kinetic energy by wind turbines. A more systematic analysis would need to use the tools developed in more sophisticated integrated assessment models of climate change and account for the spatial distribution of climate changes and the sensitivity to climate impacts. It is critical to refine the α calculation, because if $\alpha \cong 1$ for any important climatic variables, it may indicate a problem with using wind power – at any scale – to mitigate climate change. On the other hand, $\alpha << 1$ would suggest that fossil fuel displacement by wind power offers strong climatic benefits, reinforcing the conclusion from Chapter 3 that wind can play a key role in a carbon constrained world.

The long range climatic impacts – particularly evident in Figures 5.2, 5.4, and 5.7 – indicate that GCMs are an appropriate tool for studying the interaction of wind turbines and climate. If the climatic impacts had been predominantly local, then the importance of higher resolution and better orography might have dictated the use of a mesoscale model. Improved parameterizations of wind turbines in general circulation models will be critical to making more accurate assessments of the climatic impact of wind turbines. In particular, new parameterizations should account for the wake turbulence created by wind turbines, which will increase drag and reduce atmospheric efficiency.

In addition, further research is warranted on the local effects of current wind-farms on surface climate and boundary layer meteorology. Additional mitigation of impact might be achieved by siting wind farms so that their effects partially cancel and by tailoring the interaction of turbines with the local topography in order to minimize the added drag.

5.8 References to Chapter 5

Baidya Roy, S., Pacala, S.W., and Walko, R.L. (2004). "Impact of Large Windfarms on Local Meteorology." *J. of Geophys. Res*. 109(D19), D19101 10.1029/2004JD004763

Best, R.W.B. (1979). "Limits to Wind-Power." *Energy Conversion*, 19: 71-72.

Bossanyi, E.A., Maclean, C., Whittle, G.E., Dunn, P.D., Lipman, N.H., and Musgrove, P.J. (1980). "". In *Proceedings of the Third International; Symposium on Wind Energy Systems*, Lyngby, Denmark.

Burton, T, *et al*. (2001). *Wind Energy Handbook.* West Sussex, England: John Wiley & Sons, Ltd.

Collins, W. D., et al. (2003). "Description of the NCAR Community Atmospheric Model (CAM2)." Boulder, CO: National Center for Atmospheric Research.

Edmonds, J, Clarke, J, Dooley, J, Kim, S H & Smith, S J (Forthcoming). "Stabilization of CO2 in a B2 World: Insights on The Roles of Carbon Capture and Disposal, Hydrogen, and Transportation Technologies" *Energy Economics.*

EIA (Energy Information Administration), Office of Energy Markets and End Use, US Department of Energy (2004). "Annual Energy Review 2003" DOE/EIA-0384(2003) US Government Printing Office, Washington, DC.

EWEA (European Wind Energy Association). (2003). "Wind Force 12." Website: www.ewea.org. Accessed on 1 July 2003.

Frandsen, S. (1992). "On the Wind-Speed Reduction in the Center of Large Clusters of Wind Turbines." *Journal of Wind Engineering & Industrial Aerodynamics*. 39(4), 251-265.

Frandsen, S. and Thøgersen, M.L. (1999). *Wind Engineering* 23: 327-339.

Garratt, J.R. (1992). *The atmospheric boundary layer*. Cambridge, England: Cambridge University Press.

Gipe, P. (1995). *Wind Energy Comes of Age*. Wiley, New York, NY.

Grubb, M.J. & Meyer, N.I. (1993). "Wind Energy: Resources, Systems, and Regional Strategies." in *Renewable energy: sources for fuels and electricity*, Johansson, T. B. & Burnham, L. (eds.) Washington, DC: Island Press, pp. 157-212.

Holstag, A.A.M. and Boville, B.A. (1993). "Local versus nonlocal boundary-layer diffusion in a global climate model." *Journal of Climate* 6: 1825-1842.

Hooss, G., Voss, R., Hasselmann, K., Maier-Reimer, E., and Joos, F. (2001). "A nonlinear impulse response model of the coupled carbon cycle – climate system (NICCS)." *Climate Dynamics* 18: 189-202.

Keith, D.W. (1996). "Energetics." In *Encyclopedia of Climate and Weather*, Schneider, S.H. (ed.). New York, New York: Oxford University Press, pp. 278-283.

Kelley, N. (2004). *Personal Communication*. Golden, Colorado: National Wind Technology Center.

Livezey, R.E. and Chen, W.Y. (1983). *Monthly Weather Review*. 111, 46-59.

Metz, B., Davidson, O., Swart, R. & Pan, J. (eds.). (2001). *Climate Change 2001: Mitigation: Contribution of Working Group III to the Third Assessment Report of the IPCC*. Cambridge, UK: Cambridge University Press.

Mitchell, T.D. (2003). "Pattern scaling - An examination of the accuracy of the technique for describing future climates." *Climatic Change* 60: 217-242.

Nakiâcenoviâc, N. and Swart, R. (eds.) (2000). *Special report on emissions scenarios: a special report of Working Group III of the Intergovernmental Panel on Climate Change*. Cambridge, England: Cambridge University Press.

Peixoto, J.P. and Oort, A.H. (1992). *Physics of climate*. New York, New York: American Institute of Physics.

Sexton, D.M.H., Grubb, H., Shine, K.P. and Folland, C.K. (2003). "Design and analysis of climate model experiments for the efficient estimation of anthropogenic signals." *Journal of Climate* 16: 1320-1336.

The GFDL Global Atmospheric Model Development Team. (in press). *Journal of Climate*.

Wigley, T.M.L., Richel, R. (1996). "Economic and environmental choices in the stabilization of atmospheric CO_2 concentrations." *Nature* 379: 240-243.

Chapter 6: Thesis Conclusions and Future Work

6.1 Chapter Overview

The environmental impacts of fossil-fueled electricity drive interest in a cleaner electricity supply. The prospect of anthropogenic climate change presents a serious threat to future generations and a considerable technological challenge. At best, unchecked climate change will result in changes that disproportionately affect the world's poor with less adaptive capacity; and at worst, anthropogenic climate change could trigger abrupt changes that could lead to unforeseeable and possibly catastrophic impacts. Analyses of global carbon emissions trajectories indicate the need for a major transition to carbon-neutral energy sources, e.g. an average of 20 TW of carbon-free power over the next century to stabilize atmospheric concentrations of CO_2 at twice pre-industrial levels (Hoffert et al., 1998).

The electricity sector will likely bear the brunt of future greenhouse gas reductions to mitigate climate change since electric power plants are among the largest and most manageable point sources of CO_2. Yet no single electric generation technology currently available provides a comprehensive solution to the carbon challenge. Fossil technology with carbon capture and sequestration, nuclear, wind, biomass, and photovoltaics are potentially viable, but each technology possesses a unique set of limitations and costs.

Because wind power is currently one of the cheapest ways to generate electricity without carbon emissions, the purpose of this thesis is address the role that wind might play under a strong constraint on carbon emissions. In doing so, this thesis answers two basic questions. First, can wind be used to reduce carbon emissions at a cost comparable to other generating technologies? Second, does wind power produce unique environmental impacts serious enough to preclude its use on a large-scale? This chapter summarizes the findings of this thesis and ends with a proposal for future work.

6.2 The Costs of Wind's Variability: Is There a Threshold?

The supply of electricity must meet (inelastic) demand on an instantaneous basis. System operators managing electricity supply require sufficient operational flexibility to respond to time-varying demand, forecast inaccuracies, and forced outages of dispatched units. To manage system variability, operators dispatch units that can ramp output quickly – known as operating reserve – to correct supply or demand imbalances. The level of operating reserves for each control area is set by deterministic criteria in order to maintain a consistent reliability standard.

The need to manage system variability with operating reserves leads several papers to assert that the variability of small-scale wind will have a negligible impact on grid operations because existing reserves can be utilized to correct wind-induced imbalance. Some analyses go further by asserting that a threshold exists – expressed as the fraction of demand served by wind energy – below which wind imposes negligible costs on grid operation and above which wind imposes significant costs.

To the contrary, even infinitesimal amounts of wind power installed to meet growing demand impose intermittency costs, because variable wind adds to existing system variability. If new reserve is not added to compensate wind, then the increased system variance results in lower reliability. Chapter 2 asserts that wind's intermittency imposes non-negligible costs even when wind is infinitesimal, and these costs grow monotonically from zero but need not be prohibitive even when wind serves more than half of demand.

The manner in which the cost of intermittency scales with the fraction of wind serving demand has important implications, particularly for long-range modeling of energy futures. Several integrated assessment models, important tools for the formulation of climate change policy, assume an exogenous threshold that wind can not exceed. If no threshold exists, as Chapter 2 contends, then integrated assessment models are unfairly penalizing wind and possibly understating the role it could play in a carbon constrained world.

6.3 The Cost of Large-Scale Wind

Chapter 2 presents a conceptual argument about how the intermittency cost of wind scales as wind grows from current levels to serving a large fraction of demand. Chapter 3 skips ahead to a future carbon constrained world, presenting modeling work that estimates the cost of large-scale wind under a carbon tax, and accounts for the costs imposed by the spatial distribution and intermittency of wind. The optimization model provides an economic characterization of a wind system in which long-distance electricity transmission, storage, and gas turbines are used to supplement variable wind power output to meet a time-varying load in a greenfield system. With somewhat optimistic assumptions about the cost of wind turbines, the use of wind to serve 50% of demand adds ~1-2¢/kWh to the cost of electricity, a cost comparable to that of other large-scale low carbon technologies. More importantly, the model estimates that the cost premium to deal with the remote location and intermittency of wind resources adds ~3.7

¢/kWh to the effective cost of wind and adds roughly 1.2 ¢/kWh to the system-level cost of electricity when wind serves 50% of demand. The quantification of these costs, even in a simple greenfield system, provides an explanation for the lack of wind development in absolute terms, despite generation costs for wind approaching 4 ¢/kWh.

The modeling results confirm the conceptual argument advanced in Chapter 2: even when wind serves an infinitesimal fraction of demand, its intermittency imposes costs beyond the average cost of delivered wind power. Interestingly, the optimization model determines that at sufficiently high carbon taxes, it becomes cost-effective to use distributed wind farms interconnected with long-distance transmission lines as a means of mitigating wind's intermittency. The use of geographically distributed wind sites mitigates intermittency by increasing the aggregate level of wind power output, thereby limiting the economic benefit of storage. Although CAES is often touted as an inexpensive, large-scale storage technology capable of making wind dispatchable, the modeling work suggests that CAES is less competitive than expected under a carbon tax: its residual carbon dioxide emissions do not allow it to compete effectively against gas turbines or distributed wind farms. In addition, analysis of a hydrogen-based storage system indicates that a large-scale storage system that does not require the use of a fossil fuel (and has reasonable capital costs) could make a significant contribution in a wind-dominated, carbon constrained system.

The cost estimates of abating carbon emissions with large-scale wind produced by the optimization model could be used as input into integrated assessment models. Rather than imposing exogenous limits on the growth of intermittent renewables, integrated assessment models should incorporate supply curves that factor in the cost of building and utilizing ancillary technologies that make wind capable of serving a large fraction of demand. The assumption that wind can make deep cuts in electric sector emissions – even when the cost of long-distance transmission and backup is considered – may result in wind playing a much larger role in climate change mitigation than currently suggested by long-range energy models.

6.4 Environmental Impacts from Wind

Although wind can be utilized to make deep cuts in CO_2 emissions at reasonable cost, wind also presents unique environmental impacts that must also be assessed before wind is deployed on a large scale. The common objections to wind power on environmental grounds generally stem from noise, avian mortality, and aesthetics. While noise was a valid concern two decades ago, improved aerodynamic design of turbine blades and slower rotor tip speeds have significantly reduced wind turbine noise. Significant bird kills – particularly of endangered raptors – have been reported in Atlamont, California and Tarifa, Spain. However, poor siting procedures that failed to recognize the existence of avian migratory corridors make these wind sites the exception rather than the rule. The rigorous siting procedures performed on newer wind projects have significantly reduced the threat to bird populations.

One of the toughest issues to resolve is wind farm aesthetics. Developers have learned from the mistakes made in the early 1980s in California where wind farms were hastily built without regard to appearance. While aesthetic principles emphasizing small clusters of turbines thoughtfully integrated into the local landscape can significantly improve the public's aesthetic perception of wind farms, such design principles may need to be compromised if massive turbine arrays are necessary to make deep cuts in CO_2 emissions.

Chapter 5 of this thesis presents collaborative work that raises a new environmental impact from wind turbines that may be of considerable importance: wind turbines may directly alter the climate by removing kinetic energy from the atmosphere. The drag coefficient in two different general circulation models (GCMs) was modified to represent the dissipative effect of wind turbines. The results suggest that wind power can produce non-negligible climatic impacts. Given the underlying model dynamics, there is strong reason to suspect that the climatic impact from wind turbines scales linearly with the power dissipated by the turbines. Because the main motivation for using wind is to indirectly mitigate anthropogenic climate change by displacing fossil fuels, the direct climatic impact calls into question the use of wind. As such, the ratio of direct to indirect climatic impacts provides a useful metric for determining whether wind – at any scale – should play a role in climate change mitigation. Preliminary estimates of the ratio using a highly simplified model indicate that the indirect impact dominates. The results presented in Section 5.6 are not definitive; however, and more work is required to improve the parameterization of wind turbines in GCMs and to improve ratio estimates using more sophisticated integrated assessment models under a variety of assumptions.

6.5 Future Work

6.5.1 Decarbonizing the Electric Power Sector

Given the likelihood of climate change regulation and rising natural gas prices, there is broad agreement among energy planners that renewable energy will have an expanding role to play in the US electric power system. The Energy Information Agency (EIA) predicts that by 2025, renewables will serve roughly 3 percent of US electricity demand in the reference case, and 6 percent in the "high renewables" case (EIA, 2003). The timing of regulatory constraints on CO_2 emissions remains profoundly uncertain, but when they arrive, renewables may have a much larger role to play than that projected by the EIA under business as usual. If serious efforts are made to slow climate change, then the US electric sector will likely need to cut CO_2 emissions in half within the next quarter century, and renewables will likely play a central role.

However, renewables are not the only way to decarbonize the electric power system. Coal-based generators that employ carbon capture and sequestration are also expected to play a role in providing electricity with lower specific carbon emissions than the current generating system. Coal can be partially oxidized to create a synthesis gas. The synthesis gas can either be burned in a combustion turbine or chemically transformed into CO_2 and H_2, with the former being captured and sequestered underground in geologic formations, and the latter being burned as a carbon-free fuel in a combustion turbine. As an alternative, the synthesis gas can be converted into methanol for use in combustion turbines. This clean coal technology is possible today, and the levelized cost of electricity from decarbonized coal is similar to the cost of other electric generation technologies with low carbon emissions (Johnson and Keith, 2004). Finally, the use of coal as a central generating technology in a low-carbon world bolsters US energy security, as the reserve/production ratio for coal is over 200 years in the US (BP, 2003).

In general, previous studies of decarbonized electric power systems fall into one of three categories: (i) particular technologies are analyzed in isolation (e.g., MIT, 2003;

EWEA, 2003), (ii) hypothetical scenarios are analyzed in which new technologies are added to an existing system (e.g. Ilex and Strbac, 2002; Grubb, 1988), and (iii) hypothetical greenfield scenarios that assume an entirely new system (DeCarolis and Keith, 2004).

Choosing between different generation technologies always involves tradeoffs because each technology has unique costs and benefits. As such, studies that fall into category (i) are often of limited value because they do not make detailed comparisons with other technologies. In particular, many studies look at either renewables or decarbonized fossil plants in isolation, without exploring how these technologies might interact on the same system. Studies that fall into category (ii) are more realistic, but are limited to a near-term focus that assumes much of the existing infrastructure remains in place. Studies that fall into category (iii), although potentially unrealistic in the near term, are vitally important because they suggest how the electric power system could operate if all of the most promising generating technologies are fully leveraged for maximum benefit. Future work should include expanding the optimization model described in Chapter 3 to examine the interaction of wind and coal with carbon capture and sequestration under a carbon constraint, taking into account the limitations of the respective technologies and the physical constraints imposed on grid operations.

6.5.2 Wind

Among renewable technologies, wind is currently one of the least expensive. At good sites, the average cost of wind is currently 4-6 ¢/kWh without credits or subsidies, and advances in turbine design may plausibly reduce the cost to 2-3 ¢/kWh in the next two decades. Despite such a promising economic outlook, wind is currently more expensive than conventional fossil capacity. As such, the growth of wind capacity in the US currently depends on two regulatory incentives: (i) a federal production tax credit (PTC), which provides a 1.8 ¢/kWh tax credit for wind generators and (ii) state renewable portfolio standards (RPS), which specify that a certain fraction of electricity must be generated with renewable sources of energy. With an intermittent PTC, the average growth rate of wind capacity in the U.S. has been 15% over the last decade, and 36% in 2003. There is currently ~6.3 GW of wind in the U.S. serving 0.2% of electricity demand nationally.

Fifteen states currently have an RPS, and there is also talk of a federal RPS, which was included in the Senate version of the recent omnibus energy bill. Under an RPS (state or federal), the relatively low cost of wind will allow it to capture a large share of the required renewables in areas with strong wind resources. The confluence of the PTC, RPS, and strong wind resources in Texas led to the development of 935 MW of wind capacity in 2001 when only 400 MW of statewide RPS obligations were required. If a federal RPS were developed, then states with strong wind resources, such as the Dakotas, could overdevelop wind and sell green certificates to utilities in other states with poorer renewable resources. In addition to the PTC and RPS, there is a strong likelihood over the next couple decades that a regulatory constraint will be placed on carbon emissions, such as a carbon tax or cap-and-trade program that would further catalyze wind development.

All three regulatory mechanisms that promote wind (PTC, RPS, and a carbon constraint) encourage the development of wind in areas with strong resources where the average generation cost of wind is lowest. Because wind power is proportional to the cube of wind speed, the economics of wind are very sensitive to location. The best location in the US to construct large-scale wind farms is in the central part of the country, where flat land, low population densities, and strong wind resources make wind development easy and economical. There is no shortage of wind: under moderate land use constraints on wind farm siting, 12 Midwestern states could supply 4 times the current U.S. electricity demand (Grubb and Meyer, 1993).

The declining costs, favorable regulatory environment, and exploitable resource base suggest enormous potential for growth that can ultimately lead to wind serving a significant fraction of US electricity demand. However, two factors – the spatial distribution and intermittency of wind resources – raise the cost of wind above the average cost of electricity from a single turbine. Additional costs arise from long distance electricity transmission (to compensate for mismatch between the spatial distribution of wind capacity and demand) and backup capacity and/or storage systems (to compensate for the mismatch in temporal distribution of supply and demand). While these costs arise at any scale, their influence on the economics of wind-power grow rapidly as wind serves a larger fraction of demand.

Recent analysis by Ilex Energy Consulting (2002) examined the balance of system costs incurred by renewables serving a large fraction of electricity demand in Great Britain. In the North Wind Scenario with high demand, the additional system cost (for grid reinforcement, managing transmission losses, balancing, and security) due to wind energy serving 30% of electricity demand is ~1.8¢/kWh (Ilex and Strbac). The Ilex analysis noted that the U.K. lacks significant transmission interconnections with the rest of Europe, which limits the amount of capacity sharing that can take place. Denmark, by contrast, participates in the relatively large Nordpool market, which consists mainly of hydro that effectively serves as capacity reserve for intermittent Danish wind energy. Unless high capacity power cables are laid to mainland Europe, the UK must design their grid system with sufficient reserve capacity to ensure proper grid operation with high penetrations of intermittent renewables. A similar situation will prevail in the US if it deploys renewable generators on a large scale.

6.5.3 Clean Coal

Typically coal is directly combusted, with pollutants removed from the flue gases using an array of pollution-control technology. However, coal can be partially oxidized to form a synthesis gas, composed mainly of CO and H_2, which can be cleaned of impurities and burned in a combustion turbine. Or, the synthesis gas can be used in a water-gas shift reaction to produce CO_2 and H_2 – the CO_2 can be captured and sequestered underground and the H_2 burned in a combustion turbine without carbon emissions. If the syngas or H_2 is burned in a combined-cycle plant – known as integrated gasification combined-cycle (IGCC) – then efficiencies between 45-60% can be achieved, which is an improvement over the 33-38% efficiencies possible with a conventional coal-based boiler plant. President Bush recently pledged $1 billion for “FutureGen”, an IGCC system that sequesters the carbon and produces electricity and H_2.

Gasification provides three advantages over direct combustion: (i) impurities and pollutants can be removed from the coal feedstock prior to combustion, resulting in cleaner power, and (ii) the coal-derived fuel can be burned in combustion turbines that operate at high efficiencies, and (iii) combustion turbines operating on coal-derived fuel can ramp output quickly to changing demand, unlike conventional coal, which provides mostly baseload power.

Because IGCC has high capital costs, it has to run as much as possible at full capacity in order to result in a reasonable levelized cost. One possibility is to run IGCC plants as baseload with potential curtailment of other generators, which may be required at low demand levels. As an alternative, IGCC plants can produce electricity when needed, and during periods of low demand, produce fuel that can be stored for use by peaking combustion turbines when required by high demand. Syngas cannot be stored in large quantities for safety reasons, so it must either be stored as gaseous H_2 or converted to liquid methanol. When electricity demand is high, the stored fuel can be used in peaking combustion turbines to increase electricity production. Already, a demonstration plant in Kingsport, TN, utilizes an IGCC plant to produce electricity and methanol (DOE, 1997).

6.5.4 Integration Issues

System operators typically treat wind as negative load, whereby instantaneous wind power is subtracted from instantaneous load. The dispatchable fossil generators are required to make up the difference between wind and load. When wind is uncorrelated or anti-correlated with load, variable wind adds to the load variability, which increases the ramping requirements of the dispatchable generators. The cost of cycling the fossil generators as a result of wind variability scales with the amount of wind on the system. So even at the margin, intermittent wind imposes additional costs by requiring fossil generators to cycle more frequently. This creates a fundamental problem for the use of wind and IGCC together: wind would force IGCC plants to cycle – which to the degree IGCC ramping is technically possible – makes the economics of IGCC look worse by adding ramping costs and lowering the IGCC capacity factor. However, the ability of IGCC plants to switch from electricity to fuel production means that the gasification plants can run continuously, regardless of the current level of wind or load. The H_2 or methanol can be stored during periods of low demand, high wind output, or both and used to power the combustion turbines during periods of high demand, low wind output, or both. The combustion turbines can participate in AGC as well as effectively follow changes in intra- and inter-hour load or wind.

6.5.5 Proposed Modeling Work

The cost of using wind and IGCC together will be based on modeling work described in Chapter 3. The optimization model includes a time-resolved simulation of wind power and load that was performed inside an optimization routine. Wind, transmission, combined-cycle natural gas, simple cycle natural gas, and storage capacities were optimized under a carbon tax to minimize the cost of electricity. Most electric dispatch models (e.g. Johnson and Keith, 2004) represent demand as a load duration curve, which sorts hourly loads according to their magnitude. While use of load duration curves in electric dispatch models is a reasonable simplifying assumption, information about the hour-to-hour changes in load is lost. While such information is not important when modeling dispatchable generators, it is critically important to preserve information about how wind and load change on an hour-by-hour basis, since wind can not be reliably dispatched. Significant effort was put into building the nonlinear, constrained optimization model to investigate the economics of large-scale wind. In the modeling work to date, wind competed against combined-cycle and simple-cycle natural gas turbines as a function of carbon tax. The optimization model can be expanded to include IGCC plants producing both electricity and coal-derived fuel for use in combustion turbines. The model would estimate, as a function of carbon tax: the total system cost ($), average cost of electricity ($/kWh), carbon intensity (tC/MWh), and the optimal capacities of wind, transmission, IGCC, and simple- and combine-cycle turbines running on coal-derived fuel.

The following questions would be addressed:

- In a greenfield system, how do wind, IGCC, and combustion turbines running on coal-derived fuel compete as a function of carbon tax? How do the economics of IGCC compare to the economics of simple- and combined cycle turbines running on natural gas (as a function of natural gas price)?
- Under a carbon tax, is it more cost-effective to generate and store H_2 or methanol for use by the combustion turbines?
- Rather than using IGCC to generate and store coal-derived fuel during low demand periods, is it economical to use IGCC-generated electricity to drive a compressed air energy system (CAES)?
- The cost of long-distance transmission for wind is high because the low capacity factor for wind (typically 25-35%) results in a high levelized cost for

transmission. If the IGCC plants and wind farms are co-located near the source of both large coal reserves and strong wind resources in the central and western US, to what degree are the levelized transmission costs improved?

- How sensitive are the model results to cost assumptions? A parametric analysis of key capital costs used in the model can be performed.
- If there is interest, it would be easy to model a different renewable technology. For example, photovoltaics can be modeled by obtaining a time-series of solar insolation, simulating the output from a solar cell, and changing the capital costs to reflect solar rather than wind.

6.5.6 Summary

The cost estimates of using IGCC and wind in conjunction would be of significant importance: few studies have looked at the cost of utilizing the most promising carbon-mitigating technologies in the electric power sector, taking into account the physical limitations imposed on grid operations. It would draw attention to the need for dispatchable fossil generation in systems that employ intermittent renewable energy, while being supportive of planning for increased deployment of wind power. Such an analysis would also provide quantitative guidance regarding the costs and the environmental benefits of using wind and coal with carbon capture and sequestration to achieve deep cuts in carbon emissions under a strong regulatory constraint on greenhouse gas emissions, which will be required given the radical transformation of the global energy system necessary to mitigate anthropogenic climate change.

6.6 References to Chapter 6

Ansolabehere, S. et al. (2003). *The Future of Nuclear Power*. Cambridge, MA: Massachusetts Institute of Technology.

British Petroleum (2003). *BP Statistical Review of World Energy*. Egham, UK: British Petroleum.

DOE (US Department of Energy) (1997). "Clean Coal Technology Project Produces First Methanol from Coal." *DOE Fossil Energy Techline*, May 20, 1997

EIA (US Energy Information Administration), Office of Integrated Analysis and Forecasting, US Department of Energy, (2003). *Annual Energy Outlook 2003*. DOE/EIA-0383(2003). Washington, DC: US Government Printing Office.

EWEA (2003) 'Wind Force 12: A Blueprint to Achieve 12% of the World's Electricity From Wind Power by 2020' European Wind Energy Association, Brussels, Belgium

Grubb, M.J. and Meyer, N.I. (1993). "Wind Energy: Resources, Systems, and Regional Strategies." *Renewable energy: sources for fuels and electricity* T. B. Johansson and L. Burnham (Eds.) Washington, D.C: Island Press.

Hoffert, M.I. et al. (1998). "Energy implications of future stabilization of atmospheric CO_2 content." *Nature* 35: 881-884.

Ilex and Strbac, G. (2002). "Quantifying the System Costs of Additional Renewables in 2020." Ilex Energy Consulting, Oxford, UK

Johnson, T.L. and Keith, D.W. (2004). "Fossil electricity and CO_2 sequestration: how natural gas prices, initial conditions, and retrofits determine the cost of controlling CO_2 emissions." *Energy Policy* 32: 367-382.