

Wind Development in Minnesota:

Policy and Economics

Douglas G. Tiffany

Department of Applied Economics

University of Minnesota

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Abstract

The growth of wind power as an aspect of Minnesota's portfolio of electricity has been propelled to its current level by policy initiatives at both the federal and state levels. Existing statutes establish requirements for further expansion of wind energy in this state in the years to come. Locally, production economics exert their influence as wind speed and duration are translated to capacity factor, which reveals the amount of power that can be generated at a particular site. After the flow resource is thus quantified, comes the calculus of economic viability. This consists of determining the capital and operating costs and eligibility for loans and grants as well as the negotiations of wind rights, easements, and power purchase agreements.

To date, policy initiatives have been directed toward the production, or generation side of this variable flow resource. Entrepreneurs and lawyers have become more skillful at organizing business forms that can effectively bring together partners capable of utilizing the substantial tax benefits available through the federal Production Tax Credit (PTC) as well as attractive state-sponsored incentives and tariffs offered by utilities.

The variable nature of electrical power capacity from wind has been problematic for utilities, which try to meet the variable loads required by the summed demand of their customers. In Minnesota, peak power demands occur in summer months when wind power is the lowest. In addition to seasonal demands, daily and weekly patterns must be accommodated by utilities serving the markets for electricity.

By developing and using an investment model, it is possible to understand investor motivations driving the growth of wind energy in this state and the country. Net present values (NPV) and internal rates of return (IRR) are calculated over the life of power production projects conforming to various conditions such as wind capacity factor, the federal Production Tax Credit (PTC), state incentive plans for community-based energy providers, federal grant and loan programs, as well as emerging opportunities to sell "green tags" for renewable power generation.

The numerous incentives provided for windpower development on the generation side highlight the difficulties of providing sufficient transmission capacity for to carry this power from the often remote areas where generated to load centers. Equivalent incentives deployed with similar imagination are needed to enhance investment in a transmission system capable of carrying increasing volumes of wind and other renewable sources of electricity.

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Introduction

Electrical generation capacity from wind has grown rapidly in the U.S. in recent years as reflected in **Figure 1**. Despite the rapid growth and high visibility, wind remains a small portion of total electrical energy consumed in the U.S., as shown in **Figure 2**. In reviewing this data, it is important to distinguish between capacity to produce power and the actual production of power. U.S. and Minnesota wind capacity has been spurred by the federal production tax credit (PTC), which currently offers ten years of income tax credits that can be applied toward passive income. Additional state incentives such as the Community Energy Based Development (CBED), its predecessor program (Minnesota Wind Production Incentive for Small Wind), and Minnesota statutes that compel utilities to purchase targeted quantities of renewable energy have encouraged wind development in Minnesota.

Figure 1.

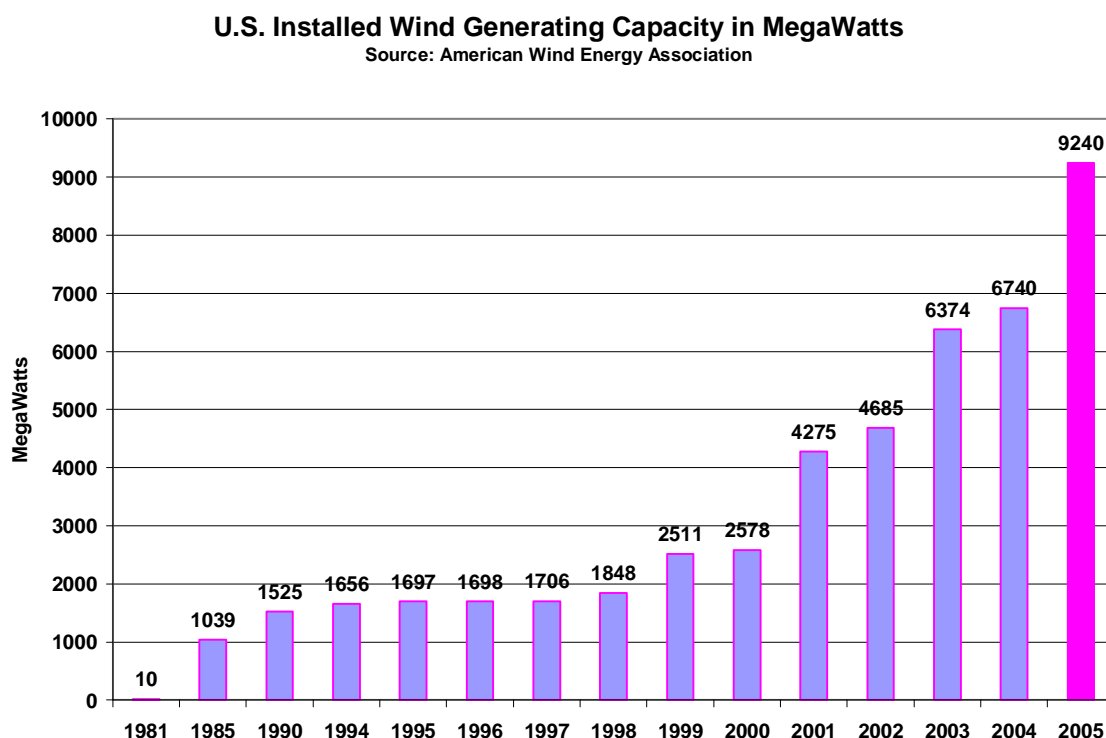
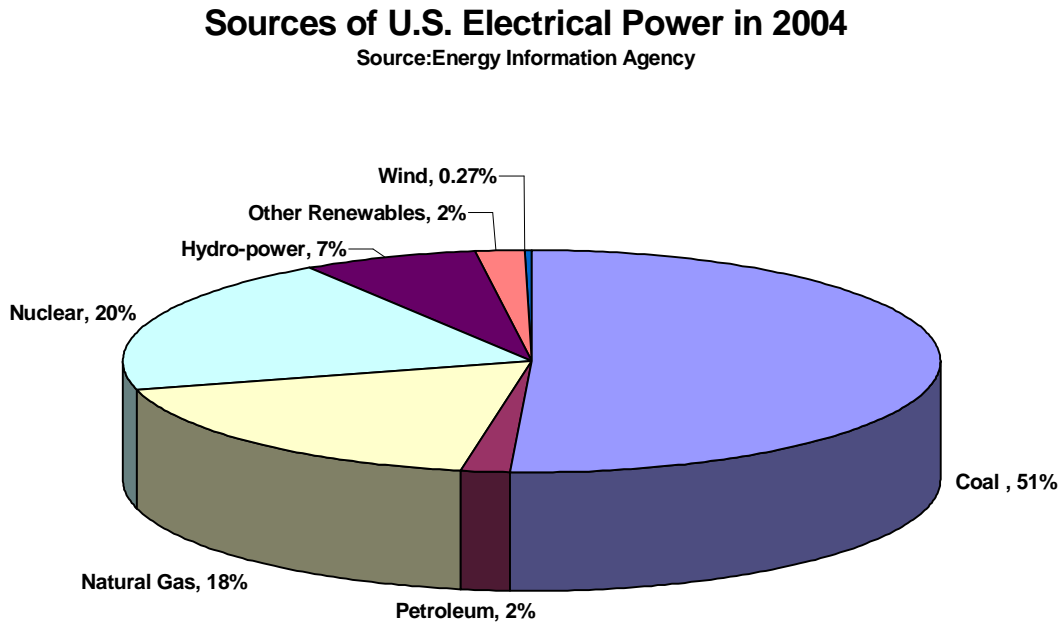


Figure 2.



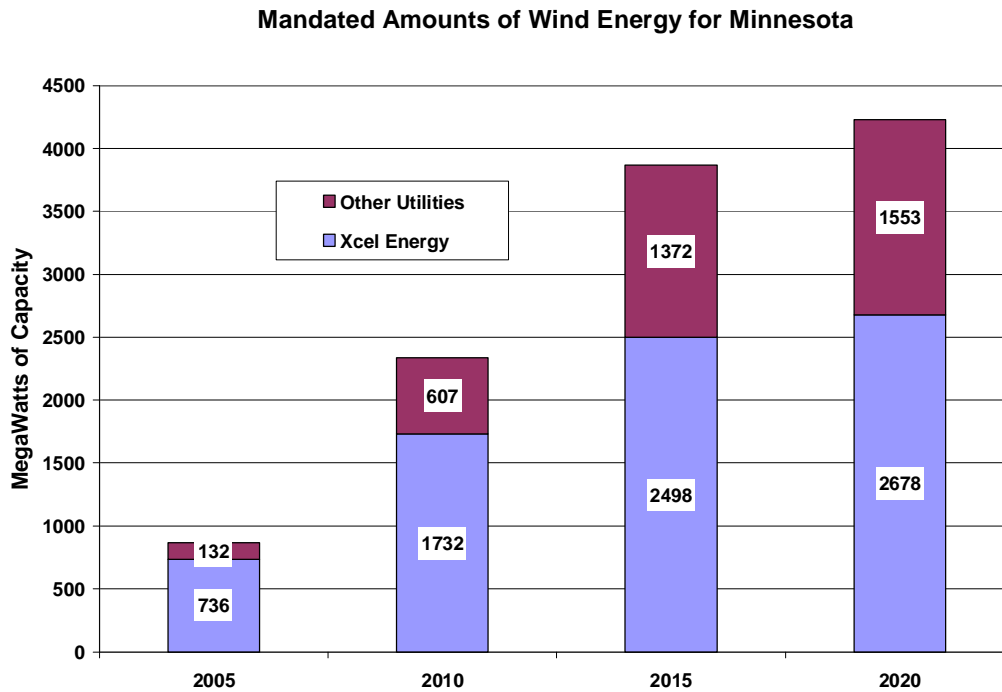
Policy, Economic, and Technical Drivers of Wind

Wind electrical generation capacity in Minnesota has been assisted by the interplay of state and national factors starting with policy drivers, which translate into economic incentives. Additional stimuli have come from enhanced knowledge of wind resources and improved wind turbines.

Figure 3 shows the amount of wind capacity that can be expected in Minnesota based on legislative mandates and renewable energy objectives enacted through 2005.¹ Dominant are the amounts of wind energy that are required by Xcel Energy, the largest investor owned utility in Minnesota. Xcel Energy has faced successively higher state requirements for mandated amounts of wind energy in exchange for permission to store spent nuclear fuel rods in the state. Also significant are the renewable energy obligations (REO) of the other utilities that operate in the state.

¹ Bailey, John and David Morris. "Renewable Electricity Mandates in Minnesota: Status and Impact," Institute for Local Self-Reliance.

Figure 3.



In addition to mandated state capacity levels, the following listing segregates and highlights the importance of some of other factors encouraging the development of wind capacity for electric power generation.

Policy Drivers

- 1) Public Utilities Regulatory Policy Act (PURPA) legislation that requires utilities to accept wind and other renewable sources of electricity at “avoided costs,”
- 2) Federal Energy Regulatory Commission (FERC) policies that foster greater access to the grid by renewable energy,
- 3) Strong interest shown by individuals and groups in support of the establishment of renewable power sources, including wind,
- 4) State goals that mandate local wind energy and other renewable energy sources versus purchases of electricity derived from fossil fuels or from other states or nations and
- 5) Investigation of regulatory barriers that reduce utilization of windpower.

Economic Drivers

- 1) U.S. policy establishing and maintaining the wind production tax credit (PTC), now extended through 2007 at 1.9 cents per kWh for ten years of production,
- 2) Minnesota’s Community-Based Energy Development (CBED) with front-loaded rates,
- 3) Experience in marketing wind-derived energy in response to corporate goals and consumer demand for “green” energy,
- 4) Growth in experience by lawyers in negotiating and executing power purchase agreements between wind producers and utilities, and
- 5) Growth in experience by bankers in financing wind energy development projects,

Technical Drivers

- 1) State of Minnesota’s public investments to assess wind resources
- 2) Increasing sophistication in design and engineering of wind turbines; especially international experience in Germany, Denmark, and Spain.

Environmental Factors Favoring Wind Energy

The various drivers cited above are strengthened by wind-derived electricity’s reputation as a clean source of electrical power. If national policy or international policies should emerge that favor the reductions in greenhouse-producing gases, windpower will certainly gain due to potential charges on emissions from fossil sources or corresponding increases in “green” energy credits. Appearing below in **Figure 4** are the amounts of carbon dioxide, sulfur dioxide, and nitrogen oxides released in the process of producing a kilowatt-hour by various methods.²

Figure 4.

Pounds of Emissions per KWH of Electricity Generated in U.S.

Source: EIA Annual Energy Review 1998

Fuel	CO2	SO2	NOx
Coal	2.13	0.013400	0.0076
Natural Gas	1.03	0.000007	0.0018
Oil	1.56	0.011200	0.0021
U.S. Average Mix	1.52	0.008000	0.0049
Wind	0	0	0

² Wind Energy Fact Sheet, American Wind Energy Association, EIA Annual Energy Review 1998. <http://www.eia.doe.gov/aer>

Economic Issues Facing Wind Energy

Despite the favorable influences and drivers that have hastened the growth in wind energy in recent years in Minnesota, there are substantial economic issues that must be surmounted before greater portions of total electrical capacity can be replaced by wind.

Key among the problems is the economic inertia that faces any alternative energy source. An operating system typically exists that functions very efficiently and supplies electricity very cheaply. Large investments have been made by utilities to supply homes, commercial enterprises, and industries with the amount of energy needed, when it is needed. Power-generating facilities, whether using coal, natural gas, or nuclear sources of energy are located at strategic locations to produce power that can be readily distributed through the continental electrical grid from the sources where produced to the places where needed. The firms generating electricity from conventional sources and transmitting that power have obvious self-interests to protect their investments in installed capacity.

Electricity is unique as a commodity because of its inherent property of flowing to sites where demanded and at the speed of light. The North American electrical grid permits utilities to automatically bid and receive power from the lowest cost supplier in real time. Few other commodities that improve the quality of life have these inherent qualities or are available in such a market. Because this market and the North American grid permit the sale of power at favorable prices, it is often difficult for renewable sources, such as wind, to compete against cheap coal and conveniently located natural gas powered generators. **Figure 5** allows one to compare the relative component costs per kilowatt-hour of electricity generated by various fuels and by wind as projected by the U.S. Energy Information Agency for the year 2015.

Figure 5.

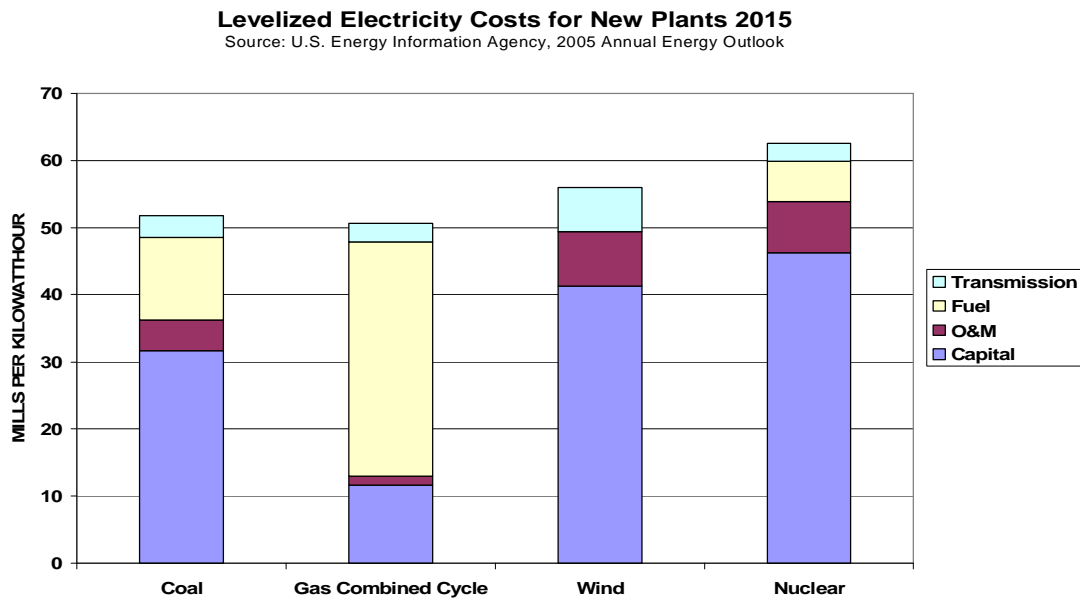


Figure 5 shows that natural gas used in a combined cycle generator has the lowest levelized cost per kilowatt-hour, and lowest capital costs, but costs for this source of power have the highest fuel cost component. Mistaken assumptions about natural gas costs over the next ten years could easily reverse these rankings. Coal-fired generators produce power with slightly higher overall costs than natural gas, but have capital costs nearly three times greater and with much lower cost for fuel than natural gas. The levelized cost of electricity derived from wind has higher capital cost per kilowatt-hour produced than both coal and natural gas with operations and maintenance expenses approximately twice as high as coal. Windpower has no fuel cost, but transmission costs are higher due to the fact that the best wind resources in the U.S. are generally quite distant from load centers. Nuclear power plants have the highest levelized cost due to higher capital costs than wind, similar O & M expenses as wind, modest fuel costs and transmission costs intermediate between natural gas and coal. A conclusion to be drawn from this generalized outlook is the competitiveness of wind in producing electricity versus coal and natural gas.

Each of the four sources of power has its particular challenges. Natural gas generation of power has recently faced fuel cost volatility. Coal requires much higher capital costs due to necessary scrubbers and uses a fuel that contributes higher emissions of greenhouse gases (GHG) than the other choices. Wind has high up-front capital costs and higher transmission costs than the major alternatives due to distance from wind sites to load centers. Nuclear power plants face high capital costs due to safety requirements as portrayed in the graph as well as the potential for expensive legal and regulatory battles in siting future plants. Coal, faces risks in the form of potential carbon permit fees, which may be implemented as part of international climate change treaties.

Electricity has a fundamental problem as a commodity in that it needs to be generated concurrently with its use. Technologies to store electricity, such as batteries, are undeveloped or too expensive to overcome the need to produce power as needed. Liquid fuels and natural gas can be cheaply transported by pipelines. Liquid fuels can be stored in tanks where needed; and natural gas can be pressurized and stored in underground caverns until needed. In contrast, electricity must be generated in the right amount at the right time to fulfill the requirements of the aggregated end users, who just flick a switch to receive more. Tremendous investments have occurred to balance the supply of electricity available in the North American electrical grid with computers and other equipment that prompt numerous generators to produce the proper amount of electricity at the right time.

A satellite view of Minnesota reveals a network of railroads that transport low-sulfur coal to some large electrical generating plants. A similar view would show a pipeline system that transports natural gas from Canada and the Gulf States to Minnesota generators using this fuel. In addition, transmission lines from mine-mouth coal plants in North Dakota and Wyoming provide significant portions of the electricity available for Minnesota users. Transmission lines are also important in transporting hydro-electric power from Ontario and Manitoba to Minnesota. Minor amounts of hydro-power and other renewable sources of electricity exist in Minnesota with the exception of wind.

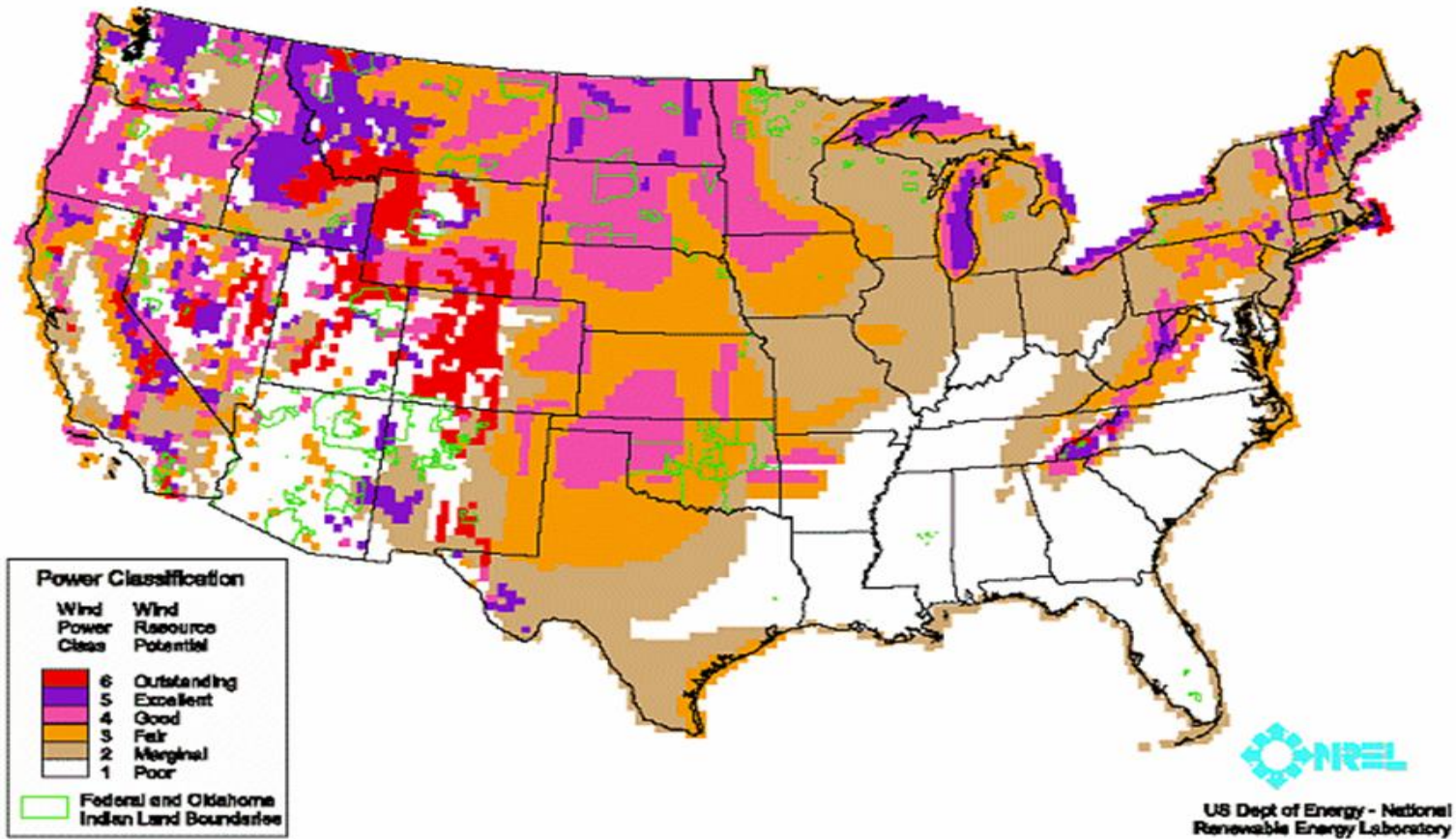
In addition to facing economic inertia in markets supplied by mature technologies that supply their customers quite cheaply, wind power has two problems that are uniquely its own.

- 1) Wind and electrical power derived from it is a variable “flow resource.”
On the other hand, power demands conform to the rhythms of modern life as meals are cooked; offices and factories are operated in daily, weekly, and seasonal patterns with some predictability.
- 2) Because such a small proportion of electrical power demand occurs in the areas of Minnesota and neighboring states with the best wind resources, constraints on transmission capacity and existing rules limit access for wind on the transmission grid. **Figure 6** shows the potential for windpower production in the U.S. It is striking that the best wind resources tend to be distant from areas of population, commerce, and power demand.

It is with this background that we can start to analyze the factors driving wind development in Minnesota and the U.S.

Figure 6.³

Figure 13. Wind Resource Potential



³ Energy Information Agency, U.S. Department of Energy. Website: <http://www.eia.doe.gov/cneaf/solar.renewables/ilands/fig13.html>

Primer on Windpower and Wind Turbines

The amount of electricity generated and the profitability of investing in a wind turbine are dependent on the wind energy available at the site selected. Investors want to select a site with wind characteristics that enable the wind turbine to provide power during a high proportion of the year. Some of the considerations in wind site selection and operation of wind turbines are mentioned here as background for the analysis which follows.

Wind Energy and Sites for Wind Turbines

Wind turbines are designed to convert the kinetic energy of wind moving its blades into direct current electrical power. The formula for the power of wind in English units appears below⁴:

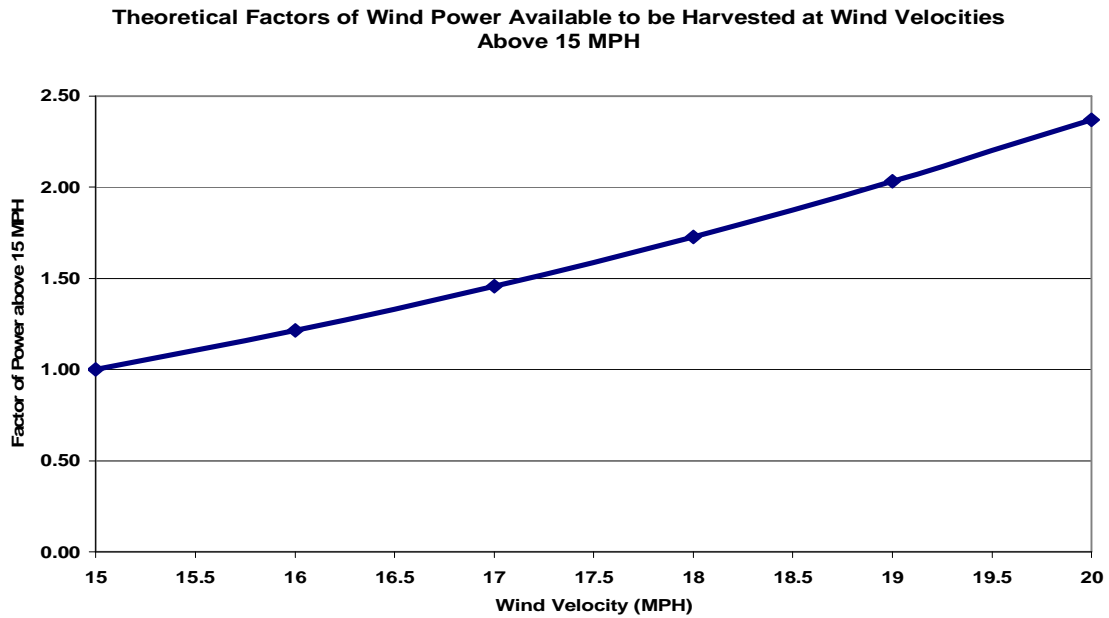
$$\text{Power} = 1/2 \rho A V^3$$

where ρ is air density
A is swept area of blades
V is wind velocity

Because the power available to generate electricity is a function of wind velocity cubed (raised to power of 3), relatively small increases in wind velocity result in substantial increases in power available to move the blades of a turbine. This factor in the formula makes selection of wind development sites with the highest possible annual wind velocity such a critical activity. **Figure 7** shows the theoretical factors of increase in power above that at 15 miles per hour in the area swept by a wind turbine for higher wind velocities. This helps explain why individuals and firms developing wind sites go to considerable expense and perform detailed analyses to select sites with the best possible wind velocities in an area. One can see from this graph that a site with a wind velocity of 17 mph is approximately 50% better than one with a wind velocity of 15 mph. Similarly a site with wind velocity of 19 mph should have twice the power of one with 15 mph. The term for air density in the formula tells us that cooler, denser air is capable of moving the blades of a wind turbine to a greater degree than warm air. One should remember that wind turbines can not be designed to capture very high portions of the theoretical power in the wind, but must always allow a certain volume of wind to pass by the turbine blades.

⁴ "Wind Energy Manual." Iowa Energy Center, 2000, p. 11. Website: http://www.energy.iastate.edu/renewable/wind/wem/wem-01_print.html, viewed 10/27/2004

Figure 7.

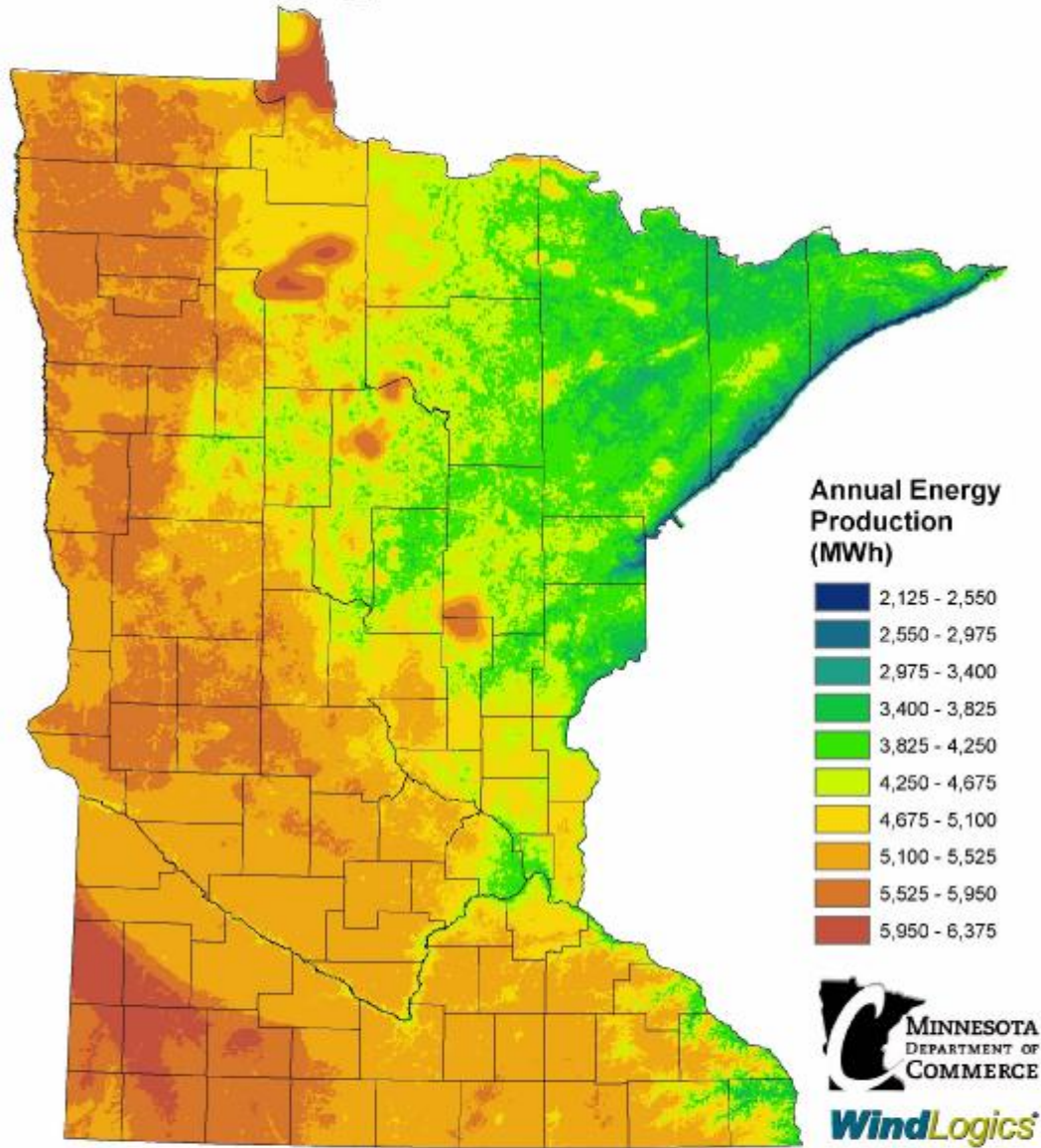


A site with favorable wind velocity also needs to be located in an area with access to the power grid. To develop a successful wind energy project, additional effort and expense must be expended to determine favorable locations with sufficient wind strength throughout a year in reasonable proximity to transmission lines.

Wind developers are like mineral prospectors to the extent that they study maps and gather data in order to find sites that have the most reliable wind resources of sufficient strength to be utilized. The map on the following page, **(Figure 8)** shows in a generalized fashion, potential wind power levels for Minnesota. The Minnesota Department of Commerce sponsored the development of this map following the collection of massive amounts of wind data by the private firm WindLogics. This map and other related public expenditures have certainly enhanced wind project development in Minnesota. The units mapped are in Watts per square meter of swept area of wind turbine blades at a hub height of 80 meters, which is a typical height for many modern, utility scale wind turbines.

Figure 8.

Minnesota's Wind Resource by Estimated Annual Energy Production at 80 Meters



This map has been prepared under contract by WindLogics for the Department of Commerce using the best available weather data sources and the latest physics-based weather modeling technology and statistical techniques. The data that were used to develop the map have been statistically adjusted to accurately represent long-term (40 year) wind speeds over the state. Energy production is based on a 1.65 MW turbine. Production has been discounted 15% to represent real world conditions. Data has been averaged over a cell area 500 meters square, and within any one cell there could be features that increase or decrease the values shown on this map. This map shows the general variation of Minnesota's wind resource and should not be used to determine the performance of specific projects.

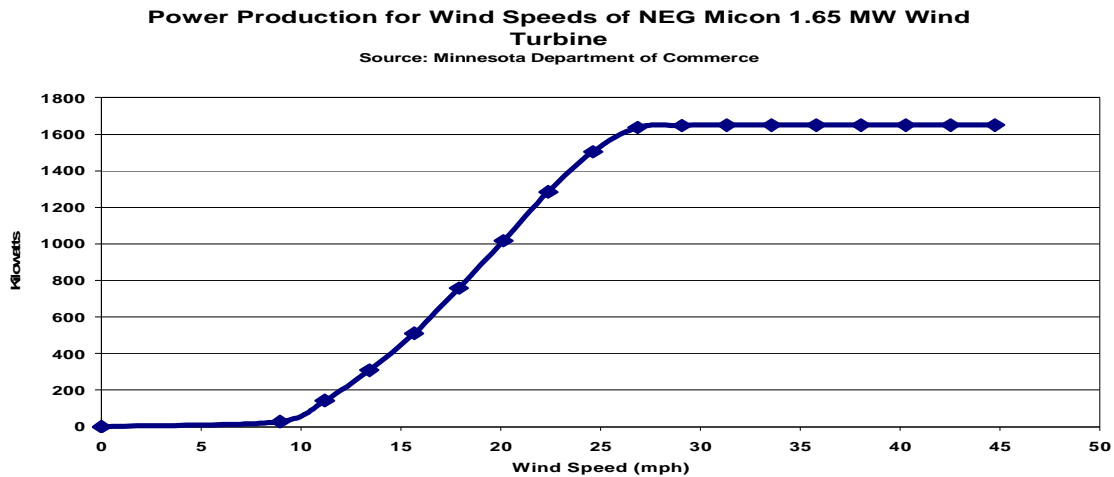
January 2006

Operation of Wind Turbines

All wind turbines that have been built have a power curve, which represents the ability of that particular design to convert the kinetic energy of wind into electrical power.

Figure 9 shows the power levels a specific wind turbine model is capable of producing at various wind speeds. Consideration of the relationship between wind speed and power generated helps one understand the importance of designing turbines capable of producing power at low wind speeds as well as the ability to keep producing energy at high wind speeds. In recent years the major wind turbine manufacturers have been able to improve (lower) the wind velocity when a wind turbine reaches maximum power.

Figure 9.



Several points about the power curve are important for our analysis. Below certain wind speeds, no electricity is produced. The minimum wind velocity that can produce electricity is called the “cut-in” velocity, which is shown as 10 miles per hour on **Figure 9**. The turbine blades turn at speeds from 14 to 29 revolutions per minute, depending upon the model. At higher wind speeds, power output increases until the nameplate output capacity of 1.65 Megawatts is reached near 27 miles per hour. As the graph shows, the output will stay at the same output level even at higher and higher wind speeds until a cut-out speed is reached. The cut-out wind speed is often around 55 to 65 mph on many models and is the point where the wind turbine sets a brake to bring the blades to a stop for protection. In addition, the blades are rotated 90 degrees out of the wind and parked. After the wind drops back below cut-out velocity as detected by the on-board anemometer for a designated period of time, the turbine’s yaw control turns the blades back into the wind and the brake is released. Soon the blades will spin back to operating speed and the turbine will again produce power.⁵

⁵ “Harvesting the Wind,” Energy and Environment Research Center.
http://www.undeerc.org/wind/literature/wind_brochure.pdf. Viewed May 2, 2005)

Discussion of Capacity Factors

Every place on the map is unique with respect to its capability to generate wind power. When the engineered capabilities of a wind turbine are combined with the wind resource of a particular site, we have the ability to determine capacity factor for annual operation of a wind turbine. The rating of the wind turbine as well as the strength and duration of the wind combine to determine capacity factor. If a 1.65 Megawatt wind turbine produces 5,058,900 kilowatt-hours during the 8760 hours in a year, we can describe this site and turbine pair as having a capacity factor of 35%. $[(5,058,900) / (1650 \times 8760) = 35\%]$ This means that the particular wind turbine produced 35% of its rated output at that site in a particular year. In the analysis to follow, project economics for wind sites ranging from 25% to 50% capacity factor will be analyzed. Each year the site and wind turbine will experience somewhat different patterns of wind strength and duration, so the capacity factor, or the opportunity to convert the wind to electrical power by that particular turbine will also vary.

Examining Wind Data

A key body of wind turbine production data that was analyzed was made available by Minnkota Electric, a power producing cooperative that is owned by and serves several rural electric service cooperatives in Minnesota, North and South Dakota. Minnkota Electric maintains and records the hourly power production of two wind turbines installed several years ago on a website.⁶ **Figure 10** shows the actual monthly production recorded for two identical 900 kW wind turbines located on two sites approximately 90 miles apart in North Dakota and operated by Minnkota Power in 2004. **Figure 11** provides further detail regarding the production of power at the two sites, including the monthly capacity factor of each turbine for each month. The availability percentage recorded for each month gives some indication of the amount of time the wind turbines are out of service or in need of repair. When considering annual production, the Valley City and Petersburg sites are remarkably close with 2784 MWh and 2824 MWh produced, respectively. Although each turbine had higher production than its twin in certain months, their annual capacity factors were 35.3% and 35.8% for Valley City and Petersburg, respectively in 2004. Evident in the graph are the lower levels of power production from wind in June, July, August, and September. This pattern can be particularly troubling for utilities because the summer months are firmly established as the times of peak power demand in most areas of the U.S. The highest monthly capacity factor of 49% was recorded in November, 2004 at Petersburg, ND. The same turbine experienced some mechanical issues in August and December when it had availability of 87%. **Figure 11** also contains evidence that wind turbines can produce power above their recorded nameplates with peaks above the 900 kilowatt nameplate recorded in the months of December-March each year.

⁶Minnkota Power, 2004 Statistics. Website: <http://www.minnkota.com/Pages/InfinityMonthly.htm>, viewed August 1, 2005

Figure 10.

Monthly Wind Power Production at Valley City and Petersburg, North Dakota in 2004

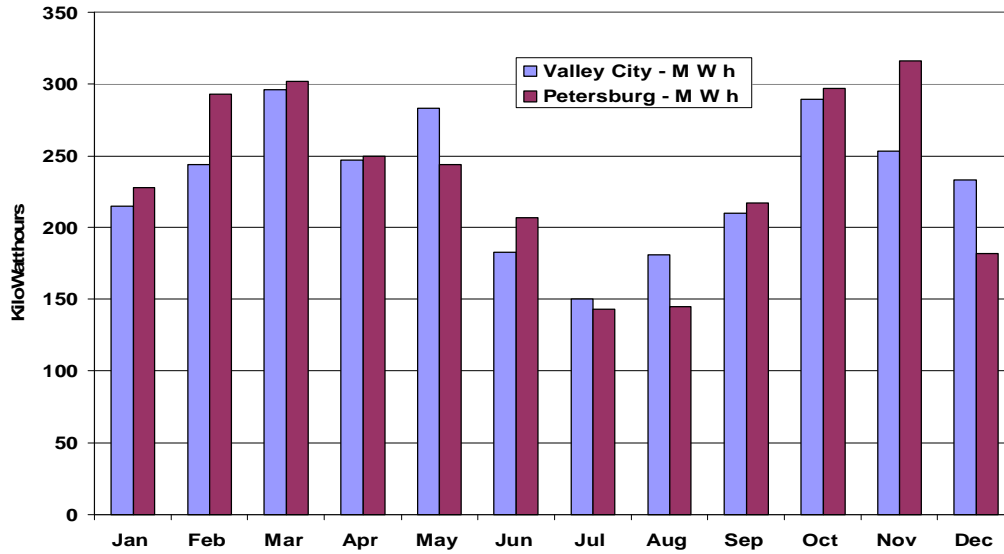


Figure 11.

2004 Monthly Statistics *Infinity* - Valley City, ND
900 kW Wind Turbine

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power production - MWh	215	244	296	247	283	183	150	181	210	289	253	233	2784
Average wind speed - mph	16	17	19	17	18	15	13	14	16	19	18	17	
Capacity factor - %	32	39	44	38	42	27	22	27	32	43	39	35	
Peak output - kW	937	939	973	866	881	757	721	785	786	900	866	929	
Availability - %	91	98	99	99	99	99	99	93	100	100	90	99	

2004 Monthly Statistics *Infinity* - Petersburg, ND
900 kW Wind Turbine

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power production - MWh	228	293	302	250	244	207	143	145	217	297	316	182	2824
Average wind speed - mph	16	19	20	17	18	16	13	14	16	19	20	18	
Capacity factor - %	34	47	45	39	36	31	21	22	33	44	49	27	
Peak output - kW	934	904	940	838	815	752	674	754	757	844	845	928	
Availability - %	95	99	99	99	99	97	97	87	100	100	100	87	

Analysis of Hourly Wind Production Data

Minnkota Electric's hourly production data for its two wind turbines is very informative concerning the availability of wind to provide power through different months of the year.⁷ In addition, availability of power generating sources during the key period of the day from 9:00 a.m. to 9:00 p.m. is typically rewarded with higher payments to firms capable of providing power at least 65 percent of the time during the key on-peak period during the summer months of June, July, August, and September, when the highest loads are typically experienced.

The graphs on the following pages reflect the hour by hour power production in the example months of July, May, and February, and are referred to as **Figures 12, 13, and 14**. Power production from wind during the month of July exhibits times of low wind velocity and times below the cut-in velocity of the wind turbine. Because many regions of the U.S. experience their peak power demands during the summer months, low production from wind can be a problem for utilities at this time. Power production from wind is better in May, as exhibited in **Figure 13**, with stronger winds of greater duration. Production of windpower is often excellent in February (as well as November) with strong winds prevailing for many hours of the month.

⁷ Minnkota Power, Hourly Historical Output. Website:
<http://www2.minnkota.com/%7Elmbbs/infinityoutput.xls>

Figure 12.

Hourly Production of Power in July 2004 at Petersburg, North Dakota

Source: Minnkota Power

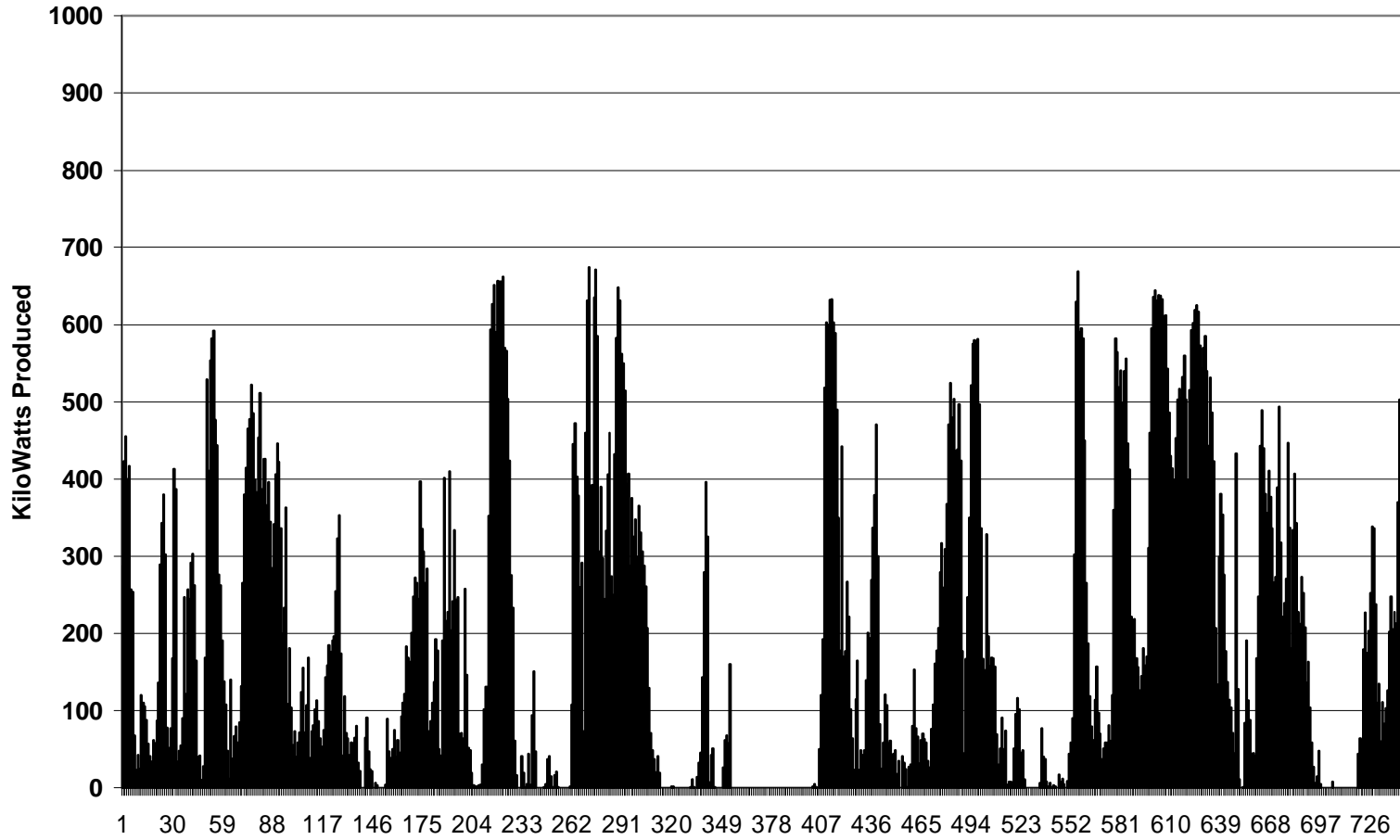


Figure 13.

Hourly Production of Power in May 2004 at Petersburg, North Dakota

Source: Minnkota Power

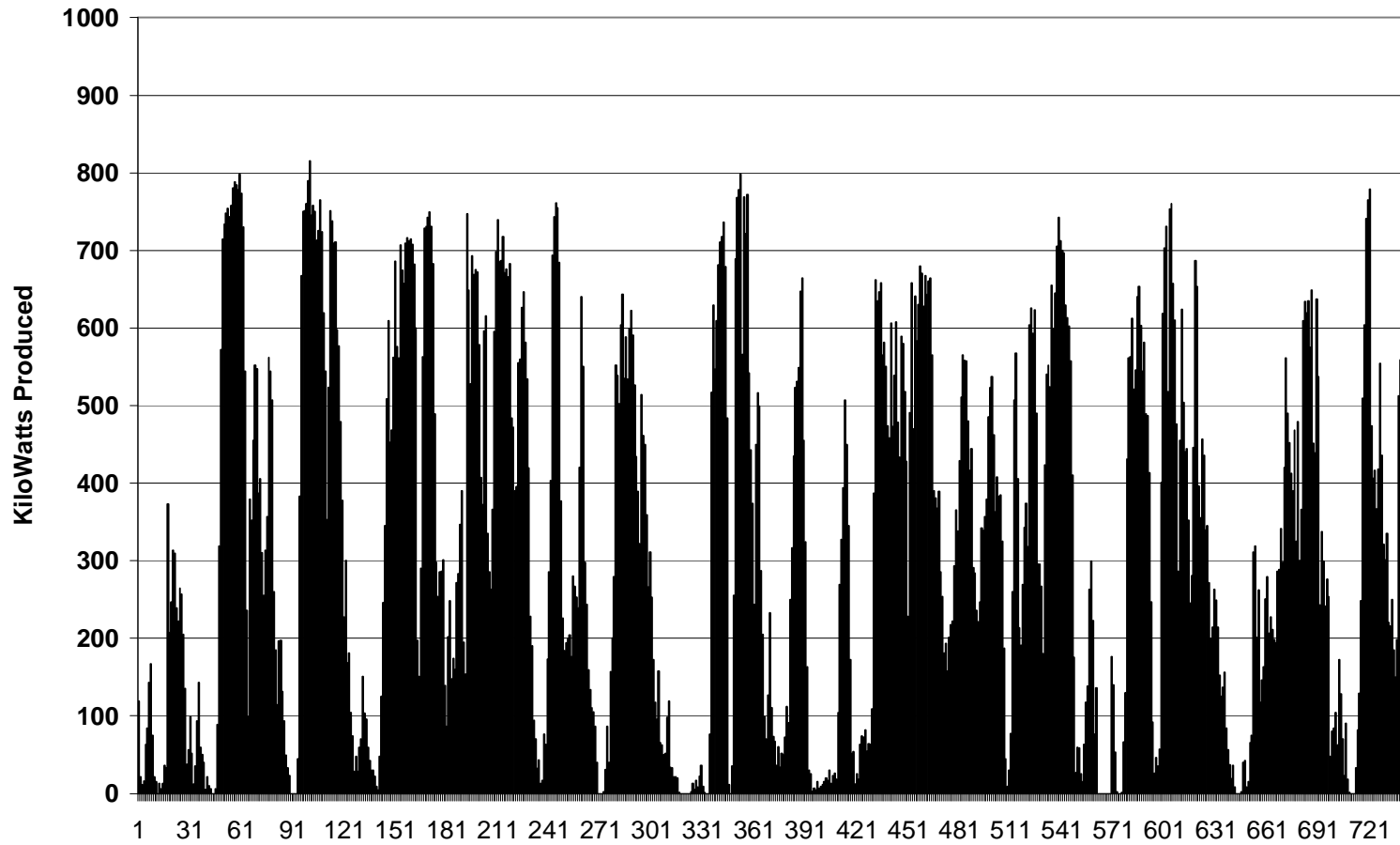
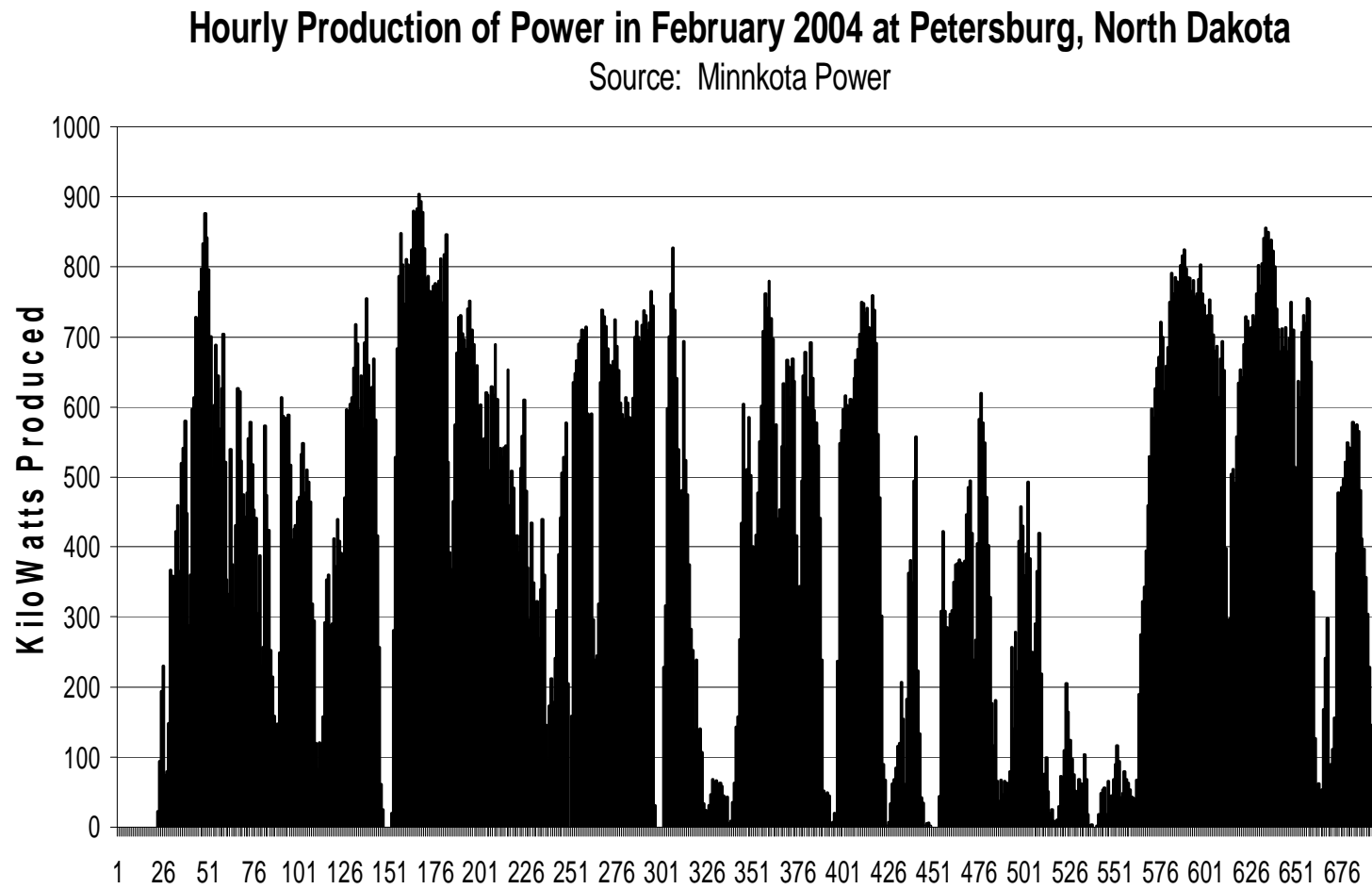


Figure 14.



Capital Costs of Wind Turbines

Establishment of a wind turbine must be preceded by the capital cost of a wind survey of a potential site. Temporary towers are set up with anemometers in order to monitor the wind over a year's time. Wind velocity readings are often taken at 70 meters because at these heights wind suffers less turbulence from trees, buildings, ground surface roughness, or local relief. When a site with suitable wind resource is identified, wind development easements are typically purchased from landowners so that the contracting party can proceed to development if other considerations are satisfied. Chief among these is the location of the possible site for interconnection with the grid. There are typically capital costs for securing and improving a service road to the tower and the area occupied by the tower supporting the turbine. Further capital costs include the installation of electrical cable to transmit the power produced by the turbine. When wind farms containing numerous wind turbines are established in an area, a control center is usually established that electronically monitors the production of power from many turbines. A shop area containing tools for turbine maintenance is generally part of the control center. The typical life of a wind turbine may vary based on the climate where established. However, increasing experience seems to indicate that 20 years of life is reasonable for many of the modern turbines being erected today. Some sources have suggested that turbine blades or the generator, itself may be replaced by superior models after twenty years of operation.

Operating Costs of Wind Turbines

As mentioned previously, wind power requires large up-front investments. Because no fuel must be purchased, operating expenses are typically quite small. However, wind turbines, like many machines have bearings and fittings that require routine greasing and inspection. In some situations, it is necessary to clean impacted insect bodies from the turbine blades to maintain high efficiency. There are instances when damage can occur from ice, high winds, or lightning that may require substantial repairs by trained mechanics. Wind turbines occasionally suffer fires and various protection components may need to be replaced. Most wind turbines have instrumentation to report levels of production. Many wind turbines are sold with maintenance packages and insurance against damage from various problems that might render the turbine inoperable, especially during the first two years of operation. Particularly important to lenders are insurance policies that protect against business interruptions. In some cases the international firms selling the wind turbines must gain experience with the unique hazards of high winds, ice, and lightning in a particular locality. Electricity to run instrumentation on a wind turbine and annual lease payments for the site of the wind turbine are additional operating expenses.

Development of the “Wind” Worksheet

To understand the financial performance of investments in wind turbines, an investment model was established in an electronic worksheet that could portray capital costs, revenues, and expenses over the life of a wind turbine of known capacity. In addition, the necessary capital costs and operating expenses are documented for this method of generating electricity. By discounting net income flows over the life of a wind turbine project, one can calculate the net present value of the investment and internal rate of return. A number of factors can be analyzed with this tool in order to understand the sensitivity of returns to investments in wind turbines due to various incentives or wind capacity factors for particular sites. As is true of many economic analyses, efforts were to gather supporting budget data from various sources.

Using the “Wind” Worksheet

Calculations using the workbook were carried out by setting assumptions specified on the “Wind” spreadsheet shown in **Figure 15**, conforming to a particular model of wind turbine established and operating on a site with a specific capacity factor. In the area labeled “Assumptions,” cells shaded yellow in the spreadsheet allow one to specify wind turbine capacity, capacity factor of the site, price for purchased power, the discount factor for the investment and the projected salvage value or even additional removal expense at the end of the assumed twenty year life. Additional assumptions can be established for the percent equity and debt as well as the rate of interest charged on debt. Amounts for up-front capital are entered under “Capital Expenditures” and include site investigation costs, legal fees covering sites, easements, and power purchase agreements. Working capital to pay interest and operational expenses are also included as well as the capital costs of the very tangible wind turbine and feeder lines.

Many wind turbines established in Minnesota are set up with a “flip” mechanism with respect to ownership. A “flip” occurs at a certain time in the life of a project when the two partners in a project exchange ownership shares at a certain pre-designated time. Typically the initial majority partner invests 99% of the capital and the initial minority partner invests 1% at the start of a project. Income, expenses, depreciation, and tax credits are usually shared in these proportions for the first ten years. Then the ownership shares “flip” with the original majority owner accepting the 1% ownership interest and the original minority owner accepting 99% of the ownership for the remainder of the life of the turbine. This arrangement is agreeable to both parties because they each typically have different propensities to utilize the federal Production Tax Credit (PTC) on passive income as well as depreciation expenses.

Under the Revenues or Credits section of the spreadsheet, Revenues for the sale of electricity are listed in each of the twenty years in Row 24. The potential credits available from the federal Production Tax Credit (PTC), which are currently 1.9 cents per kilowatt-hour produced, are listed for the first ten years in Row 25. The PTC would have no value if the owner or owners have insufficient tax liability to use the credit on passive income. Some Minnesota wind turbines have also received the Minnesota Small

Producer Wind Incentive payment for each of the first ten years of operation at the rate of 1.5 cents per kilowatt-hour produced. Eligibility for this program was limited to units in the queue and awaiting construction of 2.0 MW or less, with the incentive later reduced to 1.0 cents per kilowatt-hour in 2005. This attractive incentive payment was phased out for new facilities beyond 2006. Although no value is listed in the example, another potential source of income for the owners of a wind turbine are the sale of “green tags,” which may have value if sold to businesses or utilities that need them in particular states. In many instances green tags are transferred to the utility buying the power in the course of negotiating the power purchase agreement (PPA). In some cases rural businesses and cooperatives can receive U.S. Department of Agriculture grants up to 25% of non-land capital costs in advance of production starting, also noted with a yellow-shaded cell **D28**. This can be a substantial benefit when awarded, but only 10-15% of wind turbines built in recent years have received these grants.⁸ When awarded a U.S.D.A. grant, PTC credits are reduced in each year until the total amount of PTC reductions equal the amount of the grant. This “anti-double-dipping” provision prevents owners of wind turbines from receiving both USDA grants and the PTC in excess of the PTC in a single year.⁹

Wind operating expenses are listed for each year of the estimated twenty years of operation and include the annual amounts for land lease, service and warranty packages, electricity, insurance, accounting fees, and local real estate taxes based on production of electricity. These amounts are listed in rows 32 -37 for years 1-20. Debt service consisting of equal, amortized principal and interest payments are recorded for the first ten years in **Row 38**, although other financing approaches may be used.

After Net Operating Expenses are calculated for each of the twenty years in the projected life of the wind turbine, the Net Cash Flow for each year is calculated and recorded in **Row 41**. **Row 42** records the discounted cash flow of each year using the 9.0% rate established in cell **D9**, while **Row 43** records the accumulated discounted cash flow with each passing year of the wind turbine project. In year 20, \$161,300 is assumed to be received as a salvage value of the wind turbine. The Net Present Value of the Project is shown in cells **D45** and also **N5**. Cell **N6** contains the average cost per kilowatt-hour produced over the 20 years. Cell **N7** contains the internal rate of return that was achieved by the net cash flows actually received for the entire period of the investment and is 13.30% in the example portrayed in **Figure 15** with the wind site having a 35% capacity factor.

⁸ Noty, Lisa. U.S.D.A. Rural Development. Personal Interview April 13, 2006.

⁹ Bolinger, Mark, et al. “A Comparative Analysis of Community Wind Power Development Options in Oregon.” July, 2004.

Figure 15.

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	
		Wind Turbine Production Economics										by Douglas G. Tiffany, Dept. of Applied Econ., University of Minnesota 12/29/2006													
		Assumptions:										Conclusions:													
5	Wind Turbine Capacity		1.650	MW																					
6	Capacity Factor of Wind Site		35	%																					
7	Annual Production		5,058,900	KWH																					
8	Price for Power Sold (per KWH)		\$0.0330	1st Decade		\$0.0330	2nd Decade																		
9	Discount Factor (%)		9.00%																						
10	Salvage Value(+)/Removal Cost (-)		\$161,300																						
11		1,0	Initial																						
12	Capital Expenditures																								
13	Site Investigation		20,000																						
14	Legal-- for Site		2,000																						
15	Legal-- Power Purchase		5,000																						
16	Interconnection Fees		5,000																						
17	Tower, Turbine & Installation		1,613,000																						
18	Transmission Feeder Lines		2,000																						
19	Working Capital		8,000																						
20	Salvage Value/Removal Expense																								-161,300
21	Total Capital Expenditures		1,655,000																						-161,300
22																									
23	Revenue or Credits																								
24	Power Purchased	1	0	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944
25	Production Tax Credit (Federal)	1	0	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119	96,119
26	MN Sm Producer Paymt @1.5	0	0																						
27	Sale of Green Tags @ \$.01/kWh	0	0																						
28	USDA Rural Develop. Grant	0	0																						
29	Total Revenue or Credits	0	0	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	263,063	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944	166,944
30																									
31	Operating Expenses																								
32	Land Lease			4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
33	Service and Warranty			12,500	12,500	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900	23,900
34	Electricity			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
35	Insurance			10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
36	Accounting			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
37	Property Taxes (production)			607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607
38	Debt Service (P+ I)			141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381	141,381
39	Total Operating Expenses		0	170,488	170,488	181,888	181,888	181,888	181,888	181,888	181,888	181,888	181,888	181,888	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507
40																									
41	Net Cash Flow		-662,000	92,575	92,575	81,175	81,175	81,175	81,175	81,175	81,175	81,175	81,175	81,175	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	126,437	287,737
42	Disc. Cash Flow of Year		-662,000	84,931	77,918	62,682	57,506	52,758	48,402	44,405	40,739	37,375	34,289	31,846	48,998	44,953	41,241	37,836	34,712	31,846	29,216	26,804	24,591	22,543	51,341
43	Cumulative Disc. Cash Flows		84,931	162,849	225,531	283,038	335,796	384,198	428,603	469,342	506,717	541,006	590,005	634,957	676,198	714,034	748,746	780,591	809,807	836,611	861,202	881,202	912,543	912,543	912,543
44			Initial	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20		
45	Net Present Value of Project		250,543																						

Analysis: Using the “Wind” Worksheet

Establishing Baselines with Production Tax Credit and Standard Wind Tariff

The first stage of analysis was to use the spreadsheet model to analyze the economic performance of wind turbines under baseline conditions. Baseline conditions were established with the costs as identified on the spreadsheet in **Figure 15** with the 3.3 cents paid per kilowatt-hour (the standard wind tariff), and assuming full utilization of the PTC by a wealthy owner or primarily by the 99% partner in a “flip” ownership arrangement. Using these established baseline conditions, the effects of various capacity factors were determined on the production and project financial performance, as seen in **Figure 16**. As the capacity factors increase along with the kilowatt-hours produced per year, the costs per kilowatt-hour go down. When the capacity factor goes from 25% to 50%, the cost per kilowatt-hour is essentially cut in half. At higher capacity factors, net present values for wind turbine projects rise, as do their internal rates of return. At capacity factors of 25% and 30%, the NPV’s are negative, meaning that it would be unwise to develop such a project when considering a 9.0% discount rate along with the other assumptions established. When the site capacity factor rises to 35%, the NPV is positive by \$250,543 and the internal rate of return is 13.30% over the project’s life. As the capacity factor moves from 35% to 40%, the project’s financial performance improves substantially with IRR rising from 13.30% to 18.70%. Projects with capacity factors of 45% are rare, but improved technology may make even higher levels of performance possible in the future.

Figure 16.

**Financial Performance of 1.65 MegaWatt Wind Turbine with Capacity Factors from 25-50%,
3.3 Cents Paid per KWH, PTC of 1.9 Cents and Baseline Capital and Operating Costs**

<u>Capacity Factor</u>	<u>Production(kWh)</u>	<u>Cost per kWh</u>	<u>NPV @ 9% Rate</u>	<u>IRR</u>
25%	3,613,500	\$ 0.05108	\$ (359,535)	3.03%
30%	4,336,200	\$ 0.04258	\$ (54,496)	8.08%
35%	5,058,900	\$ 0.03652	\$ 250,543	13.30%
40%	5,781,600	\$ 0.03197	\$ 555,582	18.70%
45%	6,504,300	\$ 0.02843	\$ 860,620	24.24%
50%	7,227,000	\$ 0.02560	\$ 1,165,659	29.88%

Figure 17 graphically displays the relationship between capacity factor and internal rates of return for the wind turbines with the baseline assumptions established. The relationship is linear as one varies capacity factor. Qualification for state incentive payments can improve internal rates of returns substantially. The total costs per kilowatt-hour produced can also be calculated using the spreadsheet including the debt service fees and other operating expenses for each level of capacity factor. Because more kilowatt-hours are produced at higher capacity factor sites, the costs per unit produced are lower at the more productive sites, as is shown in **Figure 18**.

Figure 17.

Internal Rates of Return for Wind Turbines with Capacity Factors 25-50%; Assuming 3.3 cents paid per KWH, PTC of 1.9 cents and Baseline Capital and Operating Costs.

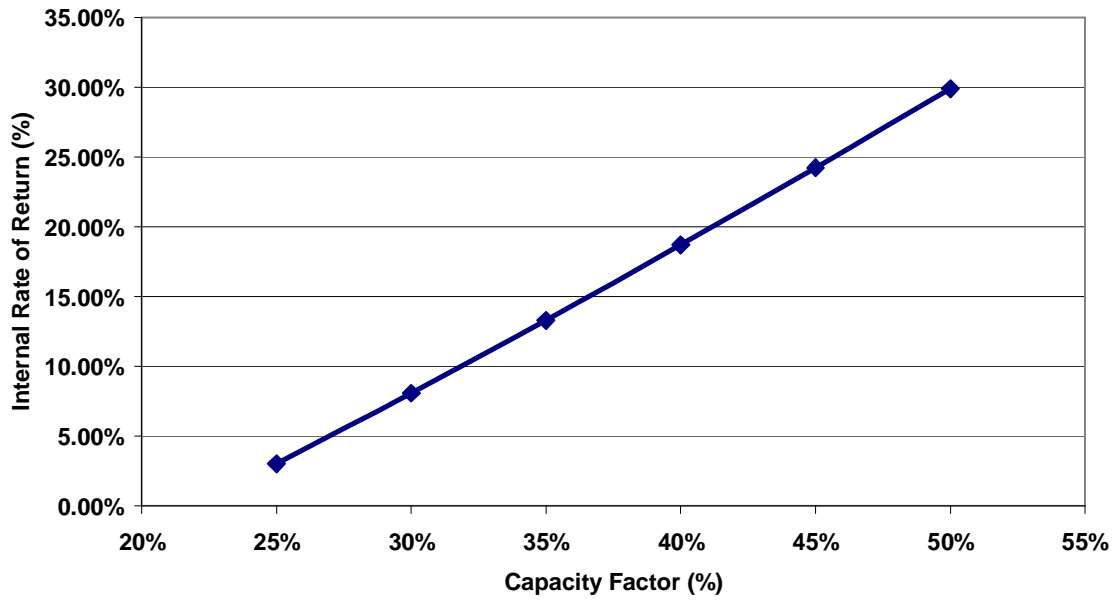
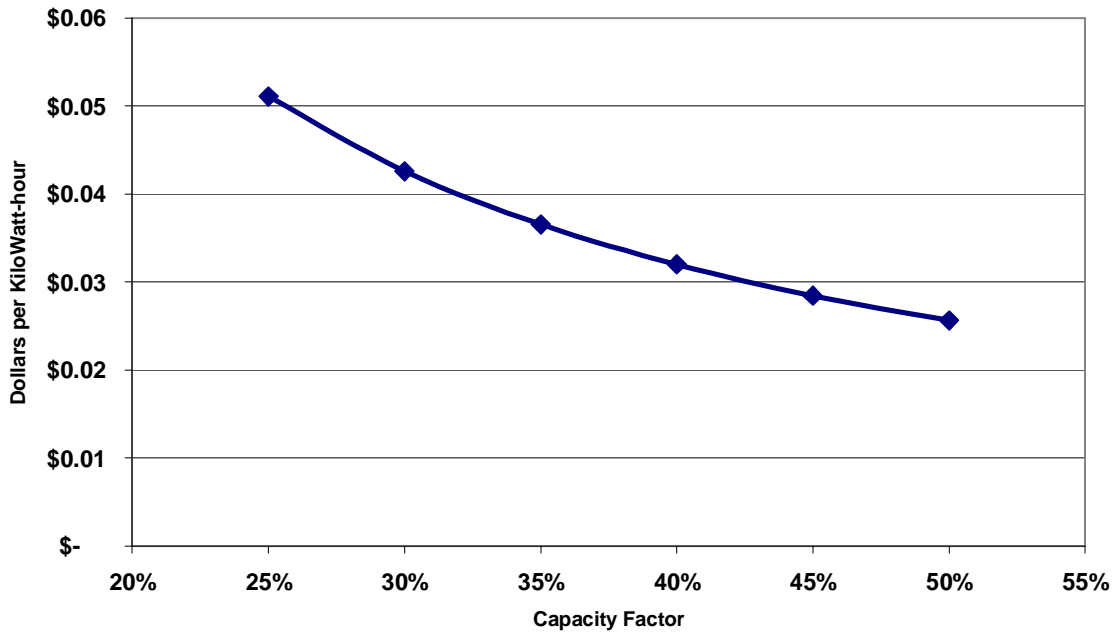


Figure 18.

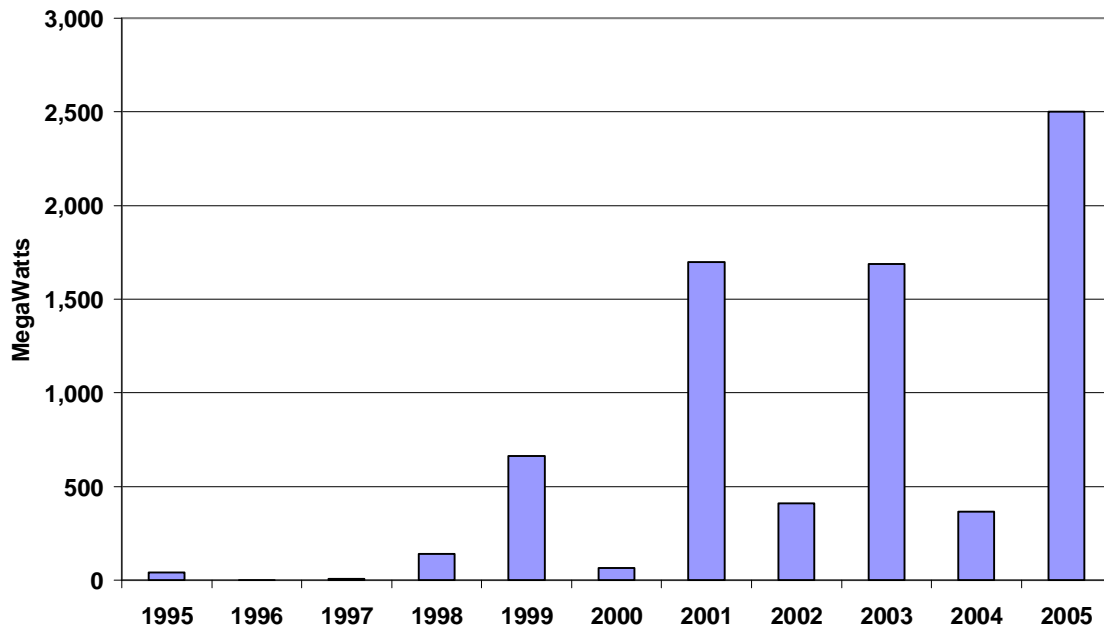
Cost per KiloWatt-Hour of Power from Wind Sites of Various Capacity Factors under Baseline Capital and Operating Costs



The importance of the federal Production Tax Credit (PTC) on the IRR's and NPV's calculated become evident when one uses the worksheet to calculate financial performance of projects that lack this favorable factor. The power of this incentive to spur investment in wind capacity is amply demonstrated on **Figure 19**, which shows the amount of U.S. wind capacity established in years with and without the PTC. Construction years 2000, 2002, and 2004 show how installations of additional wind capacity were curtailed when the PTC was not available for new investors in wind capacity.

Figure 19.

Annual Installations of U.S. Wind Capacity 1995-2005
Source: American Wind Energy Association



Effect of Community Based Energy Development on Wind Project Economics

The 2005 Minnesota Legislature passed important legislation regarding wind development in the state that provided incentives for small (2.0 MW or less) locally-owned wind projects with eligibility limited to limited liability corporations consisting of Minnesota owners with no owner having greater than 15% ownership interest. Minnesota CBED legislation provides wind facilities conforming to these criteria shall be paid \$.039 per kWh in the first ten years of operation and then \$.020 per kWh in the second ten year period. These payment rates have the effect of front-loading the payments and increasing the internal rate of return on the project. The “Wind” spreadsheet was modified to calculate the internal rates of return (IRR) and net present value for sites of various capacity factors with results shown in **Figure 20**.

Effect of Green Tags on Wind Project Economics

Prominent among other incentives that may apply to electrical power produced from wind turbines or other qualified renewable sources are “green tags.” Green tags are verified vouchers that guarantee the production of renewable energy by one party that may be sold to another party wishing to meet state or corporate goals of using renewable energy in their business. A number of clearinghouses have been developed that bring the producers of “green tags” together with parties desiring to purchase the vouchers representing production of electricity from renewable sources. However, the development of mature markets for “green tags” is still in the future---possibly after greater U.S. participation in international climate change treaties. The effect of payment for “green tags” on project economics paid in addition to the standard Minnesota Wind Tariff of \$.033 per kilowatt-hour was calculated by using the “Wind” worksheet with results shown in **Figure 20**.

Figure 20.

Comparison of Rates of Return for Wind Sites Based on MN Standard Wind Tariff, CBED Tariff, or MN Standard Wind Tariff with Green Tags of 1.0 Cent per KWH

<u>Capacity Factor</u>	<u>Standard Tariff</u>	<u>CBED</u>	<u>Std. Tariff w/ Green Tags</u>
25%	3.03%	1.38%	8.52%
30%	8.08%	8.10%	14.63%
35%	13.30%	15.04%	20.99%
40%	18.70%	22.00%	27.55%
45%	24.24%	28.86%	34.25%

Equal wind turbine investments on a 35% capacity factor site show rates of return of 13.30%, 15.04%, and 20.99% for the standard tariff, CBED, and the standard with green tags. Similar rankings among the payment plans occur for capacity factors of 30% and above, with IRR’s of 24.24%, 28.86%, and 34.25% occurring for sites of 45% capacity factor for the standard tariff, CBED, and the standard tariff with green tags. The examples in **Figure 20** show how the CBED legislation should encourage development of small, locally-owned windpower facilities, provided that the owners have sufficient passive income to utilize the federal production tax credit. In examples of “green tags” being sold for \$.01 per kilowatt-hour and the standard Minnesota wind tariff, superior rates of return would be available to investors in wind generation facilities. Further investment in windpower should occur with greater U.S. participation in global climate change treaties, resulting from greater value attributed to “green tags.”

Conclusions

This brief study of wind energy development in Minnesota reveals the interplay of policy and production economics in the growth of this clean, but sometimes challenging electrical power source. Federal tax policy in the form of the Production Tax Credit (PTC) has attracted investors with substantial passive income who are eager to invest in wind energy projects. The times when the PTC has lapsed are evident by the paucity of installed wind capacity in the years lacking this strong incentive.

State policies, particularly power production goals that must be achieved by local utilities represent strong incentives in the case of a state like Minnesota with “renewable energy objectives.” Minnesota previously provided an attractive inducement for development of wind resources in the form of a wind incentive payment that targeted small producers of less than 2.0 MegaWatts. That program was replaced by the community-based energy development (CBED) program, which established front-loaded tariffs for payment of wind energy for similarly sized local ownership entities. The Minnesota standard wind tariff of 3.3 cents per kilowatt hour provides stability and reduced transaction costs in negotiation of numerous power purchase agreements. In addition, the state of Minnesota has spent significant funds in contracting studies to map the wind resources of the state. Longer term studies of transmission capacity are underway to identify the requirements and the routes likely to provide the most additional capacity to support windpower.

Beyond the policy drivers already mentioned, are the local production economics that consider the investment costs and likely revenues from all sources associated with a wind turbine on a site with particular wind attributes. The variable nature of wind through days, weeks, and months of the year highlight the challenges that utilities must accommodate to integrate this energy source. Capital costs are higher for this method of producing electricity than most others, although the fuel cost is the cheapest. Locations that have high capacity factors are prized, as are locations with easier access to the transmission grid. The ownership models chosen for wind generation have been devised in order to utilize the PTC as well as other federal and state incentives.

This paper recounts the many ways that ownership patterns have been pushed to qualify for the PTC and other incentives that have been established to encourage investment in windpower generation capacity. The current situation lacks a corresponding level of incentives designed to encourage investments in transmission capacity that will be needed to transmit the power produced by many more wind turbines.