



Community Wind Information Packet



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More information on Community Wind

1. **Farmers Legal Action Group (FLAG)**
Community Wind: A Review of Select State and Federal Policy Incentives by Jessica A. Shoemaker and Christy Anderson
<http://www.flaginc.org/topics/pubs/arts/CommWindAug06.pdf>
2. **Windustry**
<http://www.windustry.com>
3. **Wind-Works**
<http://www.wind-works.org/articles/community.html>
4. **Community Wind: An Oregon Guidebook**
Energy Trust, in collaboration with Northwest SEED, has developed a Community Wind guidebook specifically for Oregon. This 106-page book introduces the basic concepts behind community wind development.
http://www.energytrust.org/RR/wind/community/forms_request.html
5. **Community Wind Financing Handbook**
This handbook from the Environmental Law & Policy Center explains the options for structuring and financing community-based wind power projects.
<http://www.farmenergy.org/publications.php>
6. **A Survey of State Support for Community Wind Power Development**
Mark Bolinger of the Lawrence Berkeley National Laboratory analyzed state policies for community wind in this March 2004 report.
http://eetd.lbl.gov/ea/EMS/cases/community_wind.pdf

Community Wind Energy

WHAT IS COMMUNITY WIND ENERGY?

Locally owned, commercial-scale wind projects that optimize local benefits. Locally owned means that one or more members of the local community has a significant direct financial stake in the project other than through land lease payments, tax revenue, or other payments in lieu of taxes. Commercial-scale, for this purpose, means all projects that are too large to qualify for net metering.

COMMUNITY WIND STORIES

Moorhead Public Service

This municipal utility used its own funds to purchase and install two 750 kW wind turbines, one in 1999 and the other in 2001, in Moorhead, MN. This project is among the most successful in the nation with one of the highest percentages of customers opting to pay a little extra to support the *Capture the Wind* program.

Public Schools

Lac qui Parle Valley School was the first public school district in Minnesota to install a wind turbine with a 225 kW machine in 1997 in Madison, MN. Pipestone-Jasper School District, Pipestone, MN, followed with a 900 kW turbine in 2001. Wind turbines can provide schools with clean energy, a new source of revenue, and great hands-on learning opportunities.

Minwind Energy

An innovative business model that allows local investors (at least 85% farmers) to own their own commercial scale wind turbines. The group installed four 950 kW turbines (Minwind I and II) in 2002 near Luverne, MN and seven 1,650 kW turbines (Minwind III-IX) in December 2004 near Beaver Creek, MN.

Kas Brothers

The first farmers in the nation to own their own commercial scale wind turbines when they installed two 750 kW machines in 2001 in Woodstock, MN. The Kas brothers host a larger wind farm on their land, which allowed them to learn about wind turbines before teaming with a community wind project developer to put together their own project.



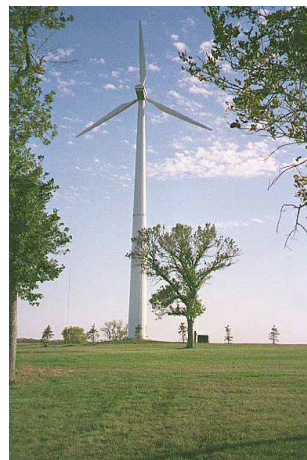
Woodstock Wind Farm

An early community wind project owned and operated by a local wind developer. Constructed in 1999 near Woodstock, MN, it consists of 17 600 kW turbines, totalling 10.2 MW.



Carleton College

Became the first college or university in the U.S. to own a commercial scale wind turbine with the installation of a 1,650 kW machine in 2004 near Northfield, MN.



Community Wind Energy *continued*

WHAT ARE THE BENEFITS OF COMMUNITY WIND ENERGY?

- **Stimulates the local economy** by creating new jobs, new business opportunities, and bringing new investment to the community.
- **Ushers in more renewable energy** and support for wind by getting local people involved.
- **Strengthens rural communities** by broadening the tax base and generating new income for farmers.
- **Produces clean energy**, and reduces pollution, pollution-related illnesses, and emissions of greenhouse gases.
- **Keeps energy investment dollars local.**
- **Builds a new industry** in rural communities that is compatible with agriculture.
- **Addresses climate change** with local solutions.

WHAT MAKES MINNESOTA #1 IN THE U.S. FOR COMMUNITY WIND DEVELOPMENT?

Public Policy

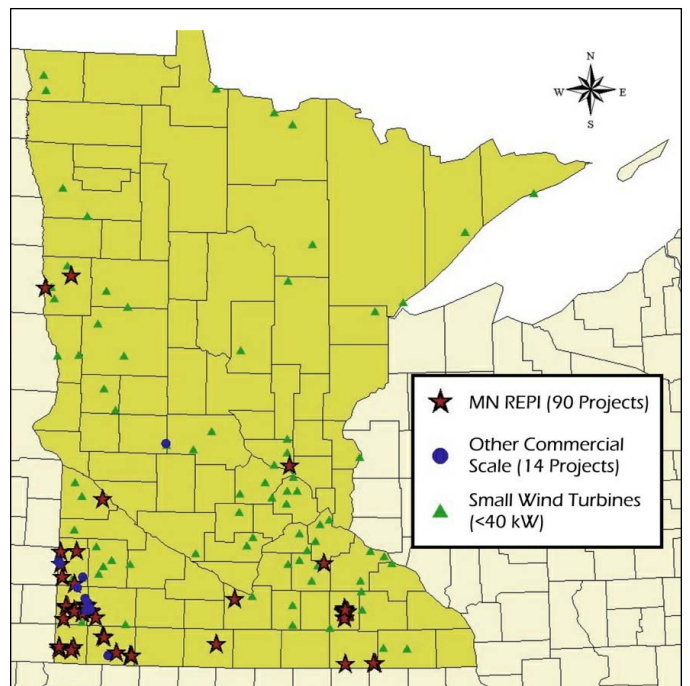
Minnesota has a long-standing commitment to supporting renewable energy and especially community wind development through public policy and regulatory action. A variety of programs, including Minnesota's Renewable Energy Objective and Xcel Energy's wind energy mandates, have created a steady market wind in Minnesota. Community wind has grown to fill an important role in this market through the support of the MN Renewable Energy Production Incentive for projects under 2 MW, Xcel Energy's small wind tariff and standardized power purchase agreement for projects under 2 MW, and the Renewable Development Fund. Some Minnesota community wind projects have also taken advantage of federal programs such as USDA grants, the federal Renewable Energy Production Incentive, and the Production Tax Credit.

Minnesota Entrepreneurs

Minnesota farmers and entrepreneurs have used public policy support combined with their own resources and ingenuity to create a variety of profitable business models for locally owned wind projects. Schools, colleges, and local utilities have followed, seeing the opportunity to bring new investment and clean energy to their communities, while creating a source of community pride.

Leadership Today

Minnesota has demonstrated the immense possibilities for revitalizing rural communities and keeping the benefits of a growing rural industry local. Continued leadership and policy support is essential to creating and growing community wind opportunities for the future.



Most Minnesota Community Wind Projects owe part of their success to the MN Renewable Energy Production Incentive, which is now fully subscribed.

What Is C-BED, and How Does It Help Community Wind?

Minnesota's recently-passed Community-Based Energy Development (C-BED) legislation offers some important benefits to community wind projects, but understanding how it works can be a little challenging. This article will try to explain the major aspects of the C-BED program and illustrate how community projects are helped with a simple example.

Summary

First, the legislation sets out ownership rules in its definition of C-BED projects, defining "qualified owners" as Minnesota residents, nonprofits, LLCs, non-electric co-ops, local governments and school systems, and tribal councils. No single qualified owner may control more than 15% of the project (except for one- and two-turbine projects), and the project must obtain the support of the county board where it will be installed. If new transmission lines must be built for the project, landowners whose property will be crossed by the lines must be given an opportunity to invest. The upshot of these rules is that more individuals are given a stake in the project, and its benefits will flow broadly to the community. (Projects can be joint ventures between qualified and non-qualified owners, but qualified owners must have the majority share, and the C-BED tariff benefits will not be received by the non-qualified owners.)

Second, public utilities are required to set out a C-BED tariff. This tariff has two important differences from other tariffs. First, it has to allow for rates with a net present value of up to 2.7 cents per kilowatt hour over the 20-year life of the power purchase agreement (more on this shortly). Second, the tariff must provide for a higher rate in the first ten years of the contract than in the second ten years. The higher early rates will make it easier for project to obtain financing, while the use of net present value calculations makes sure that the utility's bottom line is not jeopardized. While utilities are required to file a C-BED tariff and are directed to give consideration to C-BED projects when looking for new generation, they are not obligated to enter into any contracts with a C-BED project. This, too, helps make sure that C-BED contracts will be fair to all parties. Finally, C-BED projects have the option of negotiating a rate with different provisions than those specified in the legislation if they wish (for instance, choosing not to vary the rate over time). Any contracts which include the "front-loaded" rate must be approved by the Public Utilities Commission.

Nuts and Bolts – Net Present Value

The key to understanding the advantages of the C-BED tariff is the concept of net present value rates. This is a common financial tool, which basically reflects the idea that having a given amount of money today is more valuable than receiving the same amount of money in the future. That is, I'd rather have \$100 right now than know I'll receive \$100 in five years, because I can put that money to work in the meantime. Similarly, in order to understand how much a series of payments is worth, all of the amounts need to be converted to their "present value" by applying a discount factor to the future payments. The further into the future the payment is, the less it's worth today. By adding up the present values, we can determine the "net present value" of all the payments. So, would I rather have \$400 today, or \$100 a year for five years? That depends on the discount I apply

to the future payments (or, put another way, how much interest my \$400 will earn if I put it in my savings account or some other investment).

C-BED requires utilities to determine the net present value of their rate schedule using the standard discount factor that they apply to their other business decisions. That means calculating the expected payments over the life of the contract and applying the discount to find the net present value of the series of payments. The net present value is then divided by the total energy produced over the 20 years, resulting in the “net present value rate” – the present value of every kilowatt-hour the project will produce over its lifetime. C-BED requires that the utility offer a tariff that provides for a rate schedule resulting in a net present value rate of up to 2.7 cents per kilowatt-hour.

Different payment schedules can result in the same net present value. Since utilities are concerned with long-term planning, they are more concerned about protecting the net present value of a contract than about the specific amount of each payment. For community wind projects, however, the payment schedule can be very important, since they are faced with high capital costs and need to make large debt payments in the first part of the project’s life. By providing for a front-loaded payment schedule, in which the utility pays a higher rate early on and a lower rate later, the net present value of the payments can be maintained, while allowing a C-BED project to increase its income while its expenses are high. This higher income during the debt-service period can help make the project more attractive to lenders and improve access to financing.

Example

The SimpleC-BED spreadsheet contains a comparison of the front-loaded rate with a fixed rate, and may make it easier to understand how the net present value rate works. For this example, we’ve assumed a single wind turbine producing 5,200 MWh per year and annual debt payments of \$150,000 for the first ten years. We’ll use 3% as the utility’s discount rate (a fairly standard rate for businesses), 3.5 cents/kWh for the flat rate example, and 4.2 and 2.8 cents/kWh for the rates in the front-loaded example. (You can plug in your own numbers in the Assumptions tab and see how the outcome changes on the other tabs.) To keep things simple, we’ll ignore insurance, maintenance, etc. and assume that debt service is the project’s only expense and that the turbine produces the same amount of electricity every year for twenty years.

Looking at the Summary Comparison tab (copied in the table below), we can see that the total amount of cash received (the “nominal sales”) by the project is greater under the fixed rate, by about \$100,000. After debt service, the fixed rate comes up with nominal net revenue of about \$2.24 million, while the front-loaded rate results in net revenue of \$2.14 million. Why, then, would the project opt for a front-loaded rate?

	Flat Rate	Front-Loaded Rate
Total Nominal Sales	\$3,744,000.00	\$3,640,000.00
Nominal Net Revenue (after Debt Service)	\$2,244,000.00	\$2,140,000.00
Present Value of Total Sales	\$2,785,063.29	\$2,787,159.11
Present Value of Net Revenue	\$1,505,532.87	\$1,507,628.68
Net Present Value Rate (\$/kWh)	\$0.0268	\$0.0268
Sales:Debt Service ratio (years 1-10)	1.248	1.456



Despite the higher nominal value of the fixed rate, the front-loaded rate has nearly the same *present* value (actually higher by about two thousand dollars). Providing higher dollar amounts in the first half of the project means that the money paid early on can go to work for the project, rather than having its value reduced by discounting over several years. In other words, the sooner the project can get its hands on the money, the more it's worth. The increased value of the high payments early on are enough to outweigh the lower payments in the second half of the contract.

Comparing the detail pages for each structure, we notice that the annual nominal revenue *after* debt service is nearly twice as much under the front-loaded scenario. By delivering more money early on, the front-loaded rate achieves a higher income-to-debt-service ratio, a key ratio banks consider when evaluating whether to issue a loan. A strong revenue stream early in the project's life will make it easier for the project to get financing. Later, after the debt has been retired, the project can afford to accept a lower rate, since it will have fewer expenses.

That explains why a wind project might opt for a front-loaded rate even if the nominal value of the payments is lower. Why would a utility be willing to consider such a payment structure? Well, as we saw, the net present value of both cash flows is nearly the same. On a per-kilowatt-hour basis, the utility would be faced with a net present value rate of 2.68 cents per kWh in both cases (just under the C-BED maximum). From a long-term perspective, the contracts would cost the utility about the same amount, and so they're likely to be relatively indifferent between the two structures. Thus, the front-loaded rate creates a tremendous benefit for community wind projects in terms of helping them achieve financial feasibility, while not increasing the long-term cost to utilities.

All utilities are faced with slightly different financial situations, and have differing expectations for the future. Therefore, they'll each have different discount rates. Still, the general principle demonstrated here will apply to each. And again, the C-BED legislation explicitly states that while the utilities are required to develop a tariff offering a front-loaded rate, they are not required to enter into any contracts using it. So if a community wind project chooses to negotiate a front-loaded rate, the utility will have plenty of opportunity to make sure that the structure is workable for them and fits into their long-range financial planning.

Additional information about C-BED can be found at www.c-bed.org

Wikipedia has a good entry on net present value, which includes links to additional information about cash flows and discount rates: http://en.wikipedia.org/wiki/Net_present_value



Re-examining the Production Tax Credit for Wind Power: An Assessment of Policy Options

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fig. CE-02

82 METER DIAMETER ROTOR



80 METER TOWER

The views expressed in this study are the authors', not those of the University of Minnesota.



Fresh Energy

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ABSTRACT

This study considers six different aspects of incentive packages to promote locally based wind energy.

The first and most important is the federal Production Tax Credit (PTC), which was extended in July 2005 until December 31, 2007, and should be further extended and enhanced.

The second is a discussion of two major methods that might expand the PTC's usefulness, especially to those with insufficient passive income to make use of its tax shield. One is the outright sale of tax credits to other investors (which for various reasons is problematic); another is the assignment of ownership rights between investors in a wind power facility in return for rights to extract the tax benefits of the PTC.

Third is a discussion of changes in the assignment of property rights to a stream of wind revenues and tax credits, known in the industry as an ownership flip.

Fourth is a discussion of incentives over and above the PTC, including direct income tax credits, state-level small producer incentive payments, Rural Development Grants, and several state and federal accelerated depreciation opportunities, all of which help locally based investors. These are shown on a set of spreadsheet simulations, demonstrating how the aforementioned incentives affect the bottom line of four different wind facility ownership models.

Fifth, we estimate and discuss the fiscal implications of various alternatives and the

offsetting benefits of further wind power expansions.

Sixth, we consider the overarching constraints to wind power due to difficulties in gaining access to the transmission grid and suggest further study of this key problem.

The study concludes that the PTC can be extended for longer periods (6 to 10 years), ending its on-again, off-again character, and accompanied by two- to three-year fiscal impact assessments. Second, although outright sale of PTC credits is a limited option, assigning ownership rights to investors, including locally based limited liability companies (LLCs), is feasible. Third, this ownership structure can take a number of forms, depending on the arrangement of equity, debt, and ownership. Fourth, despite the salience of the PTC, other federal and state incentives are also critical to many wind projects, suggesting that states need to follow the lead of Minnesota and Iowa in creating additional incentives. Fifth, the fiscal implications of PTC extension are small relative to the benefits of expanded wind for energy security, environmental quality, rural development, and employment. Sixth, in addition to the need for expanded federal and state incentives, especially to locally based entities, regulatory and technical innovations must overcome the constraints to wind transmission.

EXECUTIVE SUMMARY

Introduction

- Wind energy has grown from a negligible energy source in the early 1990s to an increasingly important part of a national renewable energy portfolio. Up to 2,500 megawatts are scheduled to come on line in 2005, powering the equivalent of 700,000 homes. Even so, wind accounts for only about one tenth of 1 percent of total U.S. energy production. National installed capacity (megawatts) of wind power grew from 1,525 megawatts in 1990 to 2,578 megawatts in 2000, an increase of 69 percent. From 2000 to 2004, capacity increased to 6,740 megawatts, another 4,162 megawatts or 160 percent.
- The single most important federal incentive to invest in wind is the Production Tax Credit (PTC) of 1.9 cents per kilowatt-hour (adjusted for inflation), which was extended in July 2005 until December 31, 2007. The PTC is the focus of this study because of its central importance to wind power adoption. The PTC is necessary, but not sufficient, to induce investments in wind generating facilities, because the PTC is only one of various incentives, some sponsored by states and others by the federal government, which together define an investment package for wind. These packages need to be structured so developers can take full advantage of the PTC, which for a variety of reasons has proven difficult, especially for small local producers and cooperatives.
- This study focuses on six different aspects of wind incentive packages.
 - (1) First is a discussion of the need to extend the PTC (beyond 2007) and a corresponding need for benchmarks to oversee its application to improve predictability and budget discipline.
 - (2) Second is a discussion of two major methods that might expand its usefulness, especially to those with insufficient passive income to make use of its tax shield. One is the outright *sale* of tax credits to other investors (which for various reasons is problematic); another is the *assignment* of ownership rights between investors in a wind power facility in return for rights to extract the tax benefits of the PTC.

- (3) Third is a discussion of changes in the assignment of property rights to a stream of wind revenues and tax credits, known in the industry as an ownership flip.
- (4) Fourth is a discussion of incentives over and above the PTC, including direct income tax credits, the Minnesota Small Producer Incentive Payment, Rural Development Grants, and several state and federal accelerated depreciation opportunities, all of which could help locally based investors. These incentives are shown on a set of spreadsheet simulations, demonstrating effects on the bottom line of four different wind facility ownership models.
- (5) Fifth, we estimate and discuss the fiscal implications of various alternatives and the offsetting benefits of wind power further expansions.
- (6) Sixth, we consider the overarching constraints to wind power due to difficulties in gaining access to the transmission grid and suggest further study of this key problem.

The Need for PTC Extension for Longer Periods

- Nearly every analyst of the wind industry has noted that the PTC has suffered from its on-again, off-again character. The PTC, which provides a 10-year 1.5 cent/kilowatt-hour credit (adjusted for inflation, now 1.9 cents), has been reauthorized and extended for a few years at a time: too short for investors to plan, organize, and finance many projects. The PTC first expired in 1999, was extended by Congress to 2001, expired again, and was extended in 2002 to the end of 2003. It was again extended in 2004 to the end of 2005, and had its most recent extension as part of the July 2005 energy bill, which extended it to December 2007. The on-again, off-again status of the PTC has severely affected the operations of wind industry firms.
- Although the PTC has been extended to December 31, 2007, the next reauthorization and extension could be made for up to a decade if Congress and the President agree.

Such an extension, of 6 to 10 years, could be accompanied by two- to three-year benchmarks in which total use of the credit is appraised and its fiscal impacts tallied by the Congressional Budget Office. If these impacts should exceed circuit-breaker levels, PTC availability could then be rationed. This provision would assure a longer term commitment to its use, while controlling budget exposure.

Salability and Assignability of Production Tax Credits

- **B** fully exploit the PTC, a firm must have a substantial tax liability that is not subject to the Alternative Minimum Tax (AMT). This has the effect of excluding many potential investors, especially smaller local entities, and has concentrated the PTC benefits in the hands of a few large firms with passive income who have aggressively courted wind development partners. These large firms are led by Florida Power and Light, American Electric Power, PacifiCorp, and Shell. The inability to utilize the PTC and accelerated depreciation due to a lack of passive income discourages investment in wind projects by many individuals and partnerships at the local level.
- In the face of these constraints, some have called for changes allowing the sale of the PTC credits or the ability to assign them to other entities without the currently required levels of passive income. Unfortunately, outright sale of the credits is also restricted, because only *owners* of the wind project can claim the PTC for federal tax purposes, and it cannot be sold to a third party unless they, too, are project owners.
- Recently enacted federal energy legislation incorporates parts of the Wind Power Tax Incentives Act of 2005 (S.715), which assigns the PTC to ordinary and not just passive income of agricultural cooperative members. The Energy Tax Incentives Act of 2005 also includes provisions for Clean Renewable Energy Bonds for public power systems and electric cooperatives (RECs).

Property Rights and Ownership Rules: Flips and LLCs (Limited Liability Corporations)

- Because the PTC currently requires those benefiting from its provisions to be owners with

sufficient passive income against which to set it, an alternative to outright sale of the credit to non-owners is a shift in the right of ownership itself. The financial importance of the PTC has led to innovative ownership models called flips, which are a creature of the constraints discussed above. A flip occurs in a community wind project when an equity partner with passive income becomes the majority owner in the early phases of a wind project. In the first 10 years, for example, the outside initial majority owner extracts the bulk of the tax benefits of the PTC and accelerated depreciation provisions, after which it cedes ownership to the local partners (initial minority owners).

- In the case of such a flip, an LLC is probably the preferable business model. This is because LLCs are not tax-exempt, and their ability to assign the PTC to someone else does not create the precedent of conferring a federal tax credit to an exempt institution. Under new federal energy legislation, agricultural coops can now apportion and pass the PTC through to their members.

All Incentives Considered: A Simulation Model

- Although other ownership arrangements and trading schemes can be envisioned, we focus on a modeling exercise to determine the relative significance of four discrete examples of ownership structures and incentives. After describing the base assumptions, we will analyze the following scenarios:
 - (1) A Minnesota Flip LLC scenario with an outside passive investor.
 - (2) A Multiple Local Owner LLC scenario with some passive income.
 - (3) Cooperative ownership under *status quo ante* conditions, prior to passage of federal energy legislation.
 - (4) Cooperative ownership after passage of legislation allowing the PTC to be set against co-op members' ordinary income.
- The model determines how investments in physically identical wind turbines would perform financially with various ownership models under the stated assumptions. This analysis helps us understand the overall motivations of investors in wind turbines, as well as the willingness of bankers to finance the projects. We describe

individual assumptions and results for Minnesota Flips, Multiple Local Owner LLC, and cooperative wind ownership models under the *status quo ante* and under new energy legislation.

- In each scenario the differences in Net Present Value (NPV) result from the timing and magnitude of the cash flows or utilized credits in the project and the opportunity by companies and individuals to use various payments, credits, and depreciation methods due to their marginal tax rates. The Minnesota Flip and Multiple Local Owner LLCs can qualify for the Minnesota Small Wind Incentive Payment of 1.5 cents per kilowatt-hour, unlike the co-op ownership models. In addition to receiving this state incentive, the Minnesota Flip and Multiple Local Owner LLCs have a greater opportunity to use accelerated cost recovery and the PTC. A combination of these factors and a lower payment level of the Renewable Energy Payment Incentive (REPI) put the cooperatives at a disadvantage compared with the Minnesota Flips and Multiple Local Owner LLC models. Favorable economics occur when wind projects receive grants such as USDA Section 9006 grants. In some cases, the lack of such grants can ruin the financial viability of a proposed wind project.
- Co-ops are clearly at a disadvantage, even when allowed to pass through a revised PTC to members. NPVs are still lower for the coops than for the Minnesota Flip ownership models and Multiple Local Owner LLCs largely due to the lower marginal tax rates assumed for co-op members. If new-style agricultural co-ops were formed by wealthier individuals with greater opportunity to use the PTC, higher returns could result. However, such a new style of co-op might lose the advantage of retaining and later selling tradable renewable credits or Green Tags in the course of negotiating power purchase agreements.
- Overall, the modeling exercises suggest several conclusions. First, the PTC is a critical and necessary incentive, which could be made even more useful by extending it and targeting it to locally based entities. Second, despite its importance, other incentives including USDA Section 9006 Rural Development loans and grants, attractive purchase prices, state wind incentive payments and Green Tags all play a potentially important role. Third, for a variety of reasons, LLCs fare better than cooperatives in

packaging these incentives to generate favorable returns, although recently enacted provisions targeted at co-ops may help level the playing field.

Fiscal Impacts

- As noted above, U.S. wind power developments have been seriously hamstrung by the erratic availability of the PTC due to Congressional reluctance to embrace longer term extensions. This reluctance is based in large part on fears of rising fiscal burdens in the face of current deficits. If federal legislation was enacted that made the PTC available for a reasonable period of time (6 to 10 years), wind prospectors, contractors, bankers, landowners, and potential passive investors could better organize investment groups to use the PTC in conjunction with other state and federal incentives. But this extension needs to account for the fiscal implications of expanded PTC use. Accordingly, we estimate fiscal impacts based on historical growth rates in installed U.S. windpower capacity and assumed expansion at the 2005 rate of 2,500 megawatts a year. Foregone taxes rise from \$101 million in 2005 to \$428 million in 2013.
- An alternative estimate can be calculated based on the 18 percent per year annual growth in wind capacity required to meet the U.S. Department of Energy stated goal: 100,000 megawatts or 6 percent of U.S. capacity from wind by 2020. The more ambitious goal of installing 6 percent of U.S. generating capacity with wind by 2020 thus has a greater fiscal impact after 2012, reaching roughly \$720 million in 2015. In either scenario, however, total taxes foregone are substantially less than \$1 billion, quite small in relation to the trillion-dollar U.S. budget, or the hundreds of billions projected in Social Security and Medicaid costs. And the taxes foregone are not simply losses to the U.S. Treasury—they represent an investment in wind energy with manifold public benefits. These include both enhanced energy security and environmental quality, coupled with rural development and employment. When these public and private benefits are tallied, the less than \$1 billion in taxes foregone appears to be a cost-effective investment in America's energy future.

Transmission Constraints on Wind Expansion

- Even if PTC reform is undertaken in the ways discussed in this paper, additional wind energy development will be limited because of lack of transmission capacity in many areas of the United States and rules that favor conventional thermal power plants. In addition, wind power's variable nature makes it more costly per unit transmitted due to the charges needed to reserve transmission capacity for times when it fails to arrive as anticipated. A comprehensive long-term plan for investment in the transmission grid that balances the variable nature of wind power and regulations governing access and system reliability requires additional analysis and investigation. In the same way that targets have been developed by states with respect to renewable energy, tax incentives can be developed to reward investment in transmission assets that carry targeted percentages of renewable power.

INTRODUCTION

Wind energy has grown from a negligible energy source in the early 1990s to an increasingly important part of a national renewable energy portfolio. Up to 2,500 megawatts are scheduled to come on line in 2005, powering the equivalent of 700,000 homes. At the beginning of 2005, 10 states had operating community wind projects, led by Minnesota with 17, Iowa with 9, Nebraska with 4, Illinois, Michigan, Ohio, and South Dakota with 2, and Colorado, Massachusetts, and North Dakota with 1.¹ Even so, wind accounts for only about one tenth of 1 percent of total U.S. energy production. National installed capacity (megawatts) of wind power grew from 1,525 megawatts in 1990 to 2,578 megawatts in 2000, an increase of 69 percent. From 2000 to 2004, capacity increased to 6,740 megawatts, another 4,162 megawatts or 160 percent.

Although wind is regarded by many as a minor energy source, it has provided power to people for thousands of years by filling sails, and was captured for power mills and waterworks many centuries ago, essentially by combining the idea of a sail with a rotating turbine. Faced with growing costs for hydrocarbon-based fuels and legal and waste-disposal problems for nuclear fuels, wind appears increasingly attractive. With total U.S. energy consumption projected to increase faster than production through 2025, leading to increases in net energy imports from 27 percent of total consumption in 2003 to 38 percent in 2025, the importance of domestic renewables, including wind, will grow.²

Apart from a growing dependence on foreign energy, CO₂ emissions by the United States are projected to increase from 5,789 million metric tons (mmt) in 2003 to 8,062 mmt in 2025, an average annual increase of 1.5 percent.³ Wind power produces little or no CO₂ or other emissions, representing a clean alternative to fossil fuels.

Wind energy is therefore a potentially significant investment in both energy security and reduced dependence on imported fuels, as well as a response to the environmental damages and climate disruptions increasingly linked to fossil fuel consumption. In addition, wind energy can help promote rural development and employment. In states like North Dakota, for example (which ranks 1st in development potential but 13th in state-level production), each 1,000 megawatts of wind capacity is estimated to generate \$1 billion in capital investment, \$5.3 million in annual property taxes,

and nearly 400 indirect and secondary jobs.⁴

Figure 1 (page 19) shows the relative costs of generating electricity from coal, gas combined cycle facilities, wind, and nuclear power in new plants to be built by 2015. These costs are divided into transmission, fuel, operation and maintenance, and capital, based on data from the U.S. Energy Information Administration (EIA). Wind compares favorably in terms of combined costs to both coal and natural gas. A key point is that most of the costs of natural gas derive from its fuel price, which is high and rising. Natural gas is projected by the EIA to have the largest share of increase in total electricity generation to the year 2025, from 17 percent in 2003 to 20 percent in 2010 to 24 percent in 2025.⁵

These trends reflect the fact that natural-gas-derived electricity has been favored since the 1990s due to low capital costs, ease in siting generators near load centers, and potential to capture and utilize waste heat by other nearby users. But in contrast to natural gas, fuel costs for wind are essentially zero: its cost structure is dominated by heavy up-front capital expenditures, operation and maintenance, and transmission. Like the large hydroelectric projects that were built in the United States in the 1930s through the 1960s, today's wind turbines are capturing power from a renewable flow resource. And, like the hydroelectric projects of previous decades, today's wind projects require a high proportion of up-front capital and significantly higher expenditures for transmission per unit of capacity.

Natural gas derives support from a policy perspective from the current deductibility of higher natural gas costs. Natural gas producers are also regular recipients of substantial tax credits for alternative fuels, primarily coalbed methane and tight sands, receiving \$1.048 billion in FY 2000 (the largest amount received by any domestic source of energy).⁶ In considering wind versus natural gas for future power generation, any incentives lowering wind's capital, operation, or transmission costs will favor new wind facilities, which will be further enhanced if natural gas prices continue to increase.

Like natural gas, the wind power industry has been underpinned by state and federal policies. At the state level, they include public investments to assess state wind resource potential and state mandates for renewable energy purchases. Fifteen states have renewable energy funds, which are estimated to grow to \$3.8 billion by 2012.⁷ Other

incentives include state property and sales tax exemptions, grants and rebates, loans, and production incentives.⁸

The reason for these state incentives is to promote local economic development and increased energy self-reliance. In Iowa, for example, MidAmerican Energy announced in 2004 a 310-megawatt wind project, worth \$312 million, on two sites in north central and northwest Iowa. The company estimates that installing 100 of the 1.5-megawatt wind turbines will provide enough energy for 85,000 homes, create 250 construction and 20 operation jobs, and help move the state toward its 1,000-megawatt goal of renewable energy by 2010.⁹ In Pennsylvania, a Spanish wind energy firm, Gamesa Corporation, has developed power purchase agreements to sell 400 megawatts of wind power to Pennsylvania utilities, enough to power 135,000 homes. Gamesa's offices and construction effort are expected to generate 1,000 jobs over the next five years.¹⁰

In Minnesota, corporate income tax regulation allows accelerated depreciation provisions that mirror the federal Modified Accelerated Cost Recovery Schedule (MACRS), offering five-year 20 percent double-declining balance accounting. In 2005, the Iowa Legislature enacted renewable energy tax credit certificates for wind, which may be applied for refunds of sales or user taxes. A unique aspect of the Iowa program is that certificates for the credits are issued by the Iowa Department of Revenue upon application to either the producer or purchaser of renewable energy based on documented energy production data. In addition, each tax credit certificate may be transferred once to another party before being redeemed against sales or user tax liability. The amount of this credit for wind is 1.5 cents per kilowatt-hour produced in a 10-year period for facilities placed in service from July 1, 2005, to January 1, 2011. The Iowa statute limits eligibility to 90 megawatts of nameplate generating capacity.¹¹ The Iowa program makes it advantageous for purchasers of renewable energy to accept and support it because the tax credits can be sold to others. Within one week of being offered, the Iowa credits had all been claimed.

At the federal level, the Public Utility Regulatory Policies Act (PURPA) law and evolving Federal Energy Regulatory Commission (FERC) regulations compel utilities to accept wind energy and manage it as part of the portfolio of power sources in their service areas. In 1978, PURPA defined a new class of energy producer, a qualifying facility, composed of small-scale commercial energy producers who

may have surplus power. If a facility meets FERC's ownership, size and efficiency requirements, utilities must purchase this power based on avoided cost rates, including a subsidy component. This has the effect of making qualifying facilities, such as wind, more attractive as investments. In addition, the USDA offers direct Section 9006 grants to rural wind projects.

However, the single most important federal incentive to invest in wind is the Production Tax Credit (PTC) of 1.9 cents per kilowatt-hour (adjusted for inflation), which was extended in July 2005 until December 31, 2007. The PTC is the primary focus of this study because of its central importance to wind power adoption. It would be fair to say that the PTC is necessary, but not sufficient, to induce investments in wind generating facilities. The PTC is only one of various incentives, some sponsored by states and others by the federal government, which together define an investment package for wind. These packages need to be structured to take full advantage of the PTC, which for a variety of reasons has proven difficult, especially for small local producers and cooperatives. As private banks and legal experts have gained experience in financing wind projects and negotiating and executing power purchase agreements between wind producers and utilities, it is increasingly clear that the incentives provided by the PTC can be extended and structured to ensure that a diverse set of potential local wind power investors can fully capture its benefits.

This study focuses on six different aspects of incentive packages for wind.

First is a discussion of the need for a longer extension of the PTC (beyond 2007) and a corresponding need to benchmarks to oversee its application to improve predictability and budget discipline.

Second is a discussion of two major methods that might expand its usefulness, especially to those with insufficient passive income to make use of its tax shield: the outright *sale* of tax credits to other investors (which for various reasons is problematic), and the *assignment* of ownership rights between investors in a wind power facility in return for rights to extract the tax benefits of the PTC.

Third is a discussion of changes in the assignment of property rights to a stream of wind revenues and tax credits, known in the industry as an ownership flip.

Fourth is a discussion of incentives over and above the PTC, including direct income tax credits, the Minnesota Small Producer Incentive Payment, USDA Rural Development Grants, and several state

and federal accelerated depreciation opportunities. These are shown on a set of spreadsheet simulations, demonstrating how the aforementioned incentives affect the bottom line of four different wind facility ownership models.

Fifth, we estimate and discuss the fiscal implications of various alternatives and the offsetting benefits of further wind power expansions.

Sixth, we consider the overarching constraints to wind power due to difficulties in gaining access to the transmission grid and suggest further study of this key problem.

THE NEED TO EXTEND PTCs FOR LONGER PERIODS

Nearly every wind industry analyst has noted that the Production Tax Credit (PTC) suffers from its on-again, off-again character. The PTC has been reauthorized and extended for a few years at a time: too short for investors to plan, organize, and finance many projects. The PTC first expired in 1999, was extended by Congress to 2001, expired again, and was extended in 2002 to the end of 2003. It was again extended in 2004 to the end of 2005 and had its most recent extension as part of the July 2005 energy bill, which extended it through December 2007.

This on-again, off-again character has severely affected the operations of wind industry firms, ranging from manufacturers of turbines and components to wind facility construction crews and wind prospectors and developers. Higher capital costs and fees are the consequences. Lars Moller, president of DMI Industries and a wind industry leader, noted that this tax treatment has led to a loss in industry momentum and a boom/bust pattern of investment leading to increased uncertainty, shortages of key equipment, and added financial risks.¹² **Figure 2** (page 19) shows the effect of this policy on U.S. wind capacity installation, which has

proceeded in fits and starts. Terry Hudgens of PPM Energy estimates that the on-again, off-again PTC may have added as much as 20 percent to wind power costs.¹³

The Wind Energy Association and other groups such as the American Corn Growers have regularly called for longer extensions of the PTC to permit a reasonable investment horizon. Although the PTC has been extended to December 31, 2007, the next reauthorization and extension could be for up to a decade if Congress and the President agree. However, a long-term extension of the PTC may induce anxiety on the part of those worried over its budget implications, including deficit hawks in Congress and the Congressional Budget Office (CBO). Yet, there is no reason such an extension, say for 6 to 10 years, could not be accompanied by two- to three-year benchmarks in which total use of the credit is appraised and its fiscal impacts tallied by the CBO. If these impacts exceed circuit-breaker levels, PTC availability could then be rationed. This provision would assure a longer term commitment to PTC use while controlling budget exposure. The fiscal implications of long-term extension of the PTC are discussed in a later section of this paper.

SALABILITY AND ASSIGNABILITY OF PRODUCTION TAX CREDITS

The PTC is usable (like accelerated depreciation) only to project owners with tax liability. This has limited wind development projects for entities that are nontaxable, such as cooperatives, nonprofits, and publicly owned utilities, which have been disallowed from making use of the 1.9 cents per kilowatt-hour PTC credit or the accelerated depreciation provisions of federal law relating to wind projects. Co-ops and other nontaxable entities have had access to an alternative federal incentive, the Renewable Energy Production Incentive (REPI). However, REPI is subject to annual Congressional appropriations, unlike the PTC, which has no budget line item and is guaranteed for 10 years.

In order to fully exploit the PTC, a firm must have a substantial tax liability not subject to the Alternative Minimum Tax (AMT). This has the effect of excluding many potential investors, especially smaller local entities, and has concentrated PTC benefits in the hands of a few large firms with passive income who have aggressively courted wind development partners. These large firms are led by Florida Power and Light, American Electric Power, PacifiCorp, and Shell.¹⁴ The inability to use the PTC and accelerated depreciation due to a lack of passive income has discouraged investment in wind projects by many individuals and partnerships at the local level.

Bolinger, et al., (2004), estimate that a 1.5-megawatt wind project with a 33 percent wind capacity factor will allow a PTC of about \$85,000 on average for 10 years. Over the first six years, accelerated depreciation provides a comparable tax savings. To fully utilize these combined tax advantages, a minimum tax liability in the range of \$100,000 to \$200,000 in each of the first six years is required, which fits few taxpaying entities other than large firms. Even if tax liability is increased by spreading ownership across many local investors, an additional hurdle is that returns from wind turbines are treated as *passive* income only if the investor is not involved in day-to-day management.¹⁵ This regulation requires the investor to have *other* passive income (such as rental income but not interest and dividends) against which to claim the PTC. It cannot be claimed to offset active or ordinary income. Because most individuals or small firms do not have large levels of passive income, use of the PTC is further limited.

In the face of these constraints, some have called for changes allowing the sale or assignment of the PTC to other entities without the currently required levels of passive income. Unfortunately, outright sale of the credits is also restricted, because only *owners* of the wind project can claim the PTC for federal tax purposes, and it cannot be sold to a third party unless they, too, are project owners.

A recent measure, introduced in the U.S. Senate as the Wind Power Tax Incentives Act of 2005

(S.715), would assign the PTC to ordinary, and not just passive, income. The final passage of federal energy legislation in July 2005 included provisions drawn from S.715, including an amendment enabling individual members of agricultural cooperatives to receive the PTC.

Specifically, Senate amendments to the Energy Tax Incentives Act of 2005, adopted by the final conference committee, allow agricultural cooperatives (although not rural electrical cooperatives), to pass through the PTC to members, based on their eligibility for patronage dividends.¹⁶

In addition, separate provisions provide rural electric co-ops (RECs) and public power systems with Clean Renewable Energy Bonds, with advantages designed to level the playing field for entities, such as RECs, that were previously ineligible for the PTC. These bonds can be offered by qualified lenders such as the National Rural Utilities Finance Corporation and CoBank. Instead of paying interest as it does on a conventional bond, the federal government pays a tax credit to the bondholder in lieu of interest, which can then be deducted from total income tax liability. These bonds will become available for two years beginning January 1, 2006, subject to an \$800 million limit, no less than \$300 million of which is reserved for RECs.¹⁷ One expert estimates that with these bonds, RECs may capture 75 percent of the value of the PTC received by large passive investors on many wind projects.¹⁸

PROPERTY RIGHTS AND OWNERSHIP RULES: FLIPS AND LLCs

Since the PTC has required those benefiting from its provisions to be owners with sufficient passive income to offset it, an alternative to outright sale of the credit to non-owners is a shift in the right of ownership itself. The financial importance of the PTC has led to innovative ownership models called flips, which are a creature of the constraints discussed above. A flip occurs in a community wind project when an equity partner with passive income becomes the majority owner in the early phases of a wind project. In the first 10 years, for example, the outside initial majority owner extracts the bulk of the tax benefits of the PTC and accelerated depreciation provisions, after which it cedes ownership back to the local partners (initial minority owners).

This arrangement originated in Minnesota and is known as the Minnesota Flip. A local farmer-landowner (or a group of them) forms a limited liability corporation (LLC) with an outside party (normally a C-corporation) able to use the PTC and

other tax benefits due to its levels of passive income. The local partner(s) in the LLC become 1 percent equity holders, while the outside corporate partner contributes 99 percent of equity (although the LLC maintains 51 percent of voting rights). Over the first 10 years, all revenues and tax benefits accrue according to a 1 percent/99 percent split. The LLC may also pay the local partners a management fee. Once all the PTC credits have been received (at the end of 10 years), ownership flips to 99 percent/1 percent, at which time the corporate partner may sell out its remaining 1 percent share, or preserve it as evidence to the IRS that it has a long-term investment interest. After the flip, the local owners in the LLC can run the wind facility for the rest of its useful life (another 10 or more years), continuing to sell power to a utility often under a small wind tariff. Bolinger, et al., (2004, p. 78), estimate that a 1.5-megawatt wind project under this arrangement would generate returns of about 15 percent to the

corporate owner and 87 percent to the local LLC members.

An alternative arrangement is known as the Wisconsin flip, in which local partners provide debt, rather than equity, in support of the project.¹⁹ In this case (implemented in few cases to date), the local investors raise funds by selling shares in an LLC, then loan these funds to the outside corporate investor, which contributes both equity and its own debt (from a commercial lender) to finance the project. The corporate investor owns the project outright for the first 10 years and extracts the PTC, depreciation benefits, and all revenues. Meanwhile, it services the commercial debt on the project. It fully repays the commercial loans, but pays only interest, not principal, on the loan from the LLC. At the end of 10 years, the corporate entity takes the principal amount of the LLC's loan as payment for the project, which becomes the property of the LLC, free and clear. This ownership structure may be better at attracting multiple local investors, who benefit

in the first 10 years from tax deductible interest payments. In the next 10 years, the new LLC owners receive all project revenues and can use straight-line depreciation starting in year 11 with the basis determined by the principal on the original loan to the corporate investor. The internal rates of return on a 1.5-megawatt facility estimated by Bolinger, et al., for the Wisconsin flip are 15 percent for the corporate investor and 10 percent for the local LLC members.²⁰

In the case of either the Minnesota or Wisconsin flip, an LLC is probably the preferable form of organizational arrangement. This is because LLCs are not tax-exempt, and their ability to assign the PTC to someone else does not create the precedent of conferring a federal tax credit to an exempt institution. Under the provisions of the new energy legislation, agricultural co-ops can now also participate in the PTC, and rural electric co-ops (RECs) can make use of Clean Renewable Energy Bonds.

ALL INCENTIVES CONSIDERED: A SIMULATION MODEL

Although other ownership arrangements and trading schemes can be envisioned, we focus in this section on a modeling exercise to determine the relative significance of four discrete examples of ownership structures and incentives. After describing the base assumptions, we will analyze the following scenarios:

- (1) Minnesota Flip LLC scenario with an outside passive investor
- (2) multiple local-owner LLC scenario with some passive income
- (3) cooperative ownership under *status quo ante* conditions, prior to passage of the new energy legislation
- (4) cooperative ownership after passage of new federal legislation allowing the PTC to be set against co-op members' income

The simulation model that will be used to gauge the impact of different tax and investment incentives on a representative wind power facility is an investment model appropriate for decision-making with long-lived assets. The model represents the capital cost of a single large wind turbine and the associated income and expense streams that can be expected over the life of that investment, assumed to be 20 years. The model yields the following results:

- (1) net present value (NPV) of the project
- (2) average cost per kilowatt-hour of electricity produced by the wind turbine
- (3) internal rate of return (IRR) of the project

The model is based on certain assumptions, which include the following:

- (1) capital cost of wind turbine, associated easements, legal agreements, power purchase agreements, etc., of \$1.65 million in all cases for a 1.65-megawatt capacity
- (2) residual salvage value of the turbine at the end of its economic life of \$161,000
- (3) assumed economic life of 20 years
- (4) capacity factor for the wind site of 35 percent of nameplate
- (5) power purchased at 3.3 cents per kilowatt-hour
- (6) discount rate of 12 percent

In all scenarios, it is assumed that the wind power project is undertaken with 30 percent equity and 70 percent debt and that sufficient passive income is present to fully use the PTC. Again, it must be emphasized that only earnings on nonwind assets accrue PTC value to the project. The interest rate is assumed to be 7 percent per year for a 10 year loan with equal principal retirement in each of the 10 years, all typical terms offered by bankers today.

The model demonstrates the economic attractiveness of sites with higher wind capacity factors due to favorable topography and wind currents. When the capacity factor is lowered from 35 to 30 percent, for example, the IRR for each of the four cases falls from 14.56, 12.44, 5.86, and 10.90 percent to 10.92, 9.04, 3.32, and 7.86 percent, respectively. The scenarios price electricity at 3.3 cents per kilowatt-hour, which is the small distributed wind generation purchase tariff widely used by Xcel Energy in Minnesota.²¹ In other parts of the country, lower power purchase prices have been offered and have proven unattractive to investors, particularly when lacking state incentives. In the four scenarios analyzed, dropping the purchase price to 2.5 cents per kilowatt-hour and dropping the Minnesota Small Wind Incentive Payment effectively converts the NPV to negative levels in all cases. Wind site capacity factor would have to rise to a rather unrealistic 47 percent to overcome the lower power purchase prices of 2.5 cents per kilowatt-hour and maintain a 12 percent IRR in the case of the most favorable ownership model. This has important implications for states not offering incentives for wind development and suggests that in states without them, locally based projects are unlikely.

The model also allows for various assumptions concerning interest rates as well as depreciation or cost recovery methods. Hence, net cash flows from operations, use of depreciation, and the receipt and use of PTCs, USDA grants, Green Tags, and other incentive payments can all be represented. USDA Rural Development Loans under Section 9006 are often sought and received by flips, multiple-local owner LLCs, and cooperatives and may represent up to 25 percent of project cost excluding cost of land.²² When Section 9006 grants are received, the PTC for the recipient project is reduced by an amount equal to half of the grant.²³ The selected discount rate is applied in each of the scenarios to represent the time preference of the investors as opposed to the interest rate a banker might decide to charge.

The model thus determines how investments in physically identical wind turbines would perform financially with various ownership models under the stated assumptions. This analysis helps us understand the overall motivations of investors in wind turbines as well as the willingness of bankers to finance the projects. In order of presentation, we shall describe individual assumptions and results for Minnesota Flips, Multiple Local Owner LLCs, and Cooperative wind ownership models under the *status quo ante* and *status quo post* enactment of 2005 energy legislation allowing PTC use to be set

against ordinary income in the case of agricultural cooperatives.

Minnesota Flips

The following assumptions apply to a facility under the Minnesota Flip scenario shown in **Figure 3** (page 20):

- (1) The project receives and totally uses the PTC of 1.9 cents per kilowatt-hour available to majority owners.
- (2) The project receives Minnesota Wind Incentive of 1.5 cents per kilowatt-hour paid for the first 10 years.
- (3) Green Tags are assumed to be traded away in a power purchase agreement (PPA).
- (4) No USDA grants such as Section 9066 grants are received.
- (5) The value of Modified Accelerated Cost Recovery System (MACRS) over and above straight-line depreciation for 20 years is shown in the first 6 years of the project and is assumed at 35 percent, reflecting the high marginal tax rate of majority owners.

Multiple Local Owners LLC (Without USDA Grant)

The following assumptions apply to a facility under the Multiple Local Owner LLC scenario shown in **Figure 4** (page 21):

- (1) The project receives and totally uses the PTC of 1.9 cents per kilowatt-hour available *pro rata* to all owners in the LLC (same as **Figure 3**).
- (2) The project receives the Minnesota Wind Incentive of 1.5 cents per kilowatt-hour paid for the first 10 years (same as **Figure 3**).
- (3) Green Tags are assumed to be traded away in a power purchase agreement (PPA) (same as **Figure 3**).
- (4) No USDA grants, such as the Section 9066 program, are assumed to be received (same as **Figure 3**).
- (5) The value of 10-year straight-line depreciation taken above 20-year straight-line of the asset is \$23,100 in each of the first 10 years with a 28 percent marginal tax rate of the LLC owners (different from **Figure 3**) because we assume few of the local owners are at a marginal tax rate of 35 percent.

Cooperative Status Quo Ante

The following assumptions apply to a facility under the cooperative *status quo ante* scenario shown in **Figure 5** (page 22):

- (1) The project is assumed ineligible for the federal Production Tax Credit of 1.9 cents per kilowatt-hour.
- (2) The project is assumed ineligible for the Minnesota Small Producer Incentive Payment of 1.5 cents per kilowatt-hour.
- (3) Green Tags are much more likely to be flowing into the hands of the co-ops, although they are not represented in the *status quo ante* due to poor development of this market. An alternative scenario was run with the sale of Green Tags valued at 1 cent per kilowatt-hour for 20 years, shown in the summary table (**Figure 7**).
- (4) The project receives and can use the Renewable Energy Production Incentive (REPI) for the first 10 years of the project, which is assumed to be received at 80 percent of the 1.9 cents per kilowatt-hour paid on the PTC. (This is due to the erratic appropriations and necessary percentage cuts applied due to establishment of additional co-op wind capacity exceeding appropriation.)
- (5) The project is assumed to depreciate the wind turbine over 15 years with the straight line method, resulting in a \$5,500 value for each of the first 15 years based on a 20 percent marginal tax rate of the co-op members of a rural electrical co-op (REC).

Agricultural Cooperative Able to Assign PTC to Members

The following assumptions apply to a facility under a cooperative scenario in which the qualified agricultural cooperative is able to use the PTC, apportioning the PTC *pro rata* among shareholders in the cooperative, shown in **Figure 6** (page 23). Because Clean Renewable Energy Bonds are unavailable until 2006, we model only the pass through provisions of the new energy legislation for agricultural cooperatives.

- (1) At the top of the worksheet, below the assumptions for equity, debt, and interest, a new variable is presented, which is the percent of PTC utilized. In the example, a 75 percent usage level was assumed. In other words, 75 percent of the co-op members could use the PTC if the full PTC credit is returned to the co-op members. If taxpaying co-op members had low incomes, this assumption would be too high. Alternative rates of PTC use are reported in **Figure 7**.
- (2) Federal PTCs of 1.9 cents per kilowatt-hour are assumed to be available for the first 10 years.
- (3) The co-ops are assumed ineligible for the

Minnesota Small Wind Incentive payment of 1.5 cents per kilowatt-hour.

- (4) Green Tags are assumed to be received and sold for 1 cent per kilowatt-hour.
- (5) The REPI payment is not shown because it is assumed that co-ops would be asked to choose to receive either the REPI or a reformulated PTC.
- (6) The wind turbine is assumed to depreciate over 15 years with the straight line method, resulting in a \$5,500 value for each of the first 15 years based on 20 percent marginal tax rate of the co-op members.

As shown in **Figure 7** (page 24), all of the scenarios result in electricity costing the same amount from sites of equal capacity factor and investment costs. The differences in Net Present Value (NPV) result from the timing and magnitude of the project's cash flow or utilized credits and the opportunity by companies and individuals to use various payments, credits, and depreciation methods due to their marginal tax rates. The Minnesota Flip and Multiple Local Ownership LLCs have the opportunity to qualify for the Minnesota Small Wind Incentive Payment of 1.5 cents per kilowatt-hour, unlike the co-op ownership models. In addition to receiving this state incentive, the Minnesota Flip and Multiple Local Owner LLCs have a greater opportunity to use accelerated cost recovery and the PTC. A combination of these factors and a lower payment level of the REPI put the cooperatives at a disadvantage compared with the Minnesota Flips and Multiple Local Owner LLC models. Favorable economics occur when wind projects receive grants such as USDA Section 9006 grants. In some cases the lack of such grants can ruin the financial viability of a proposed wind project.

In contrast, co-ops should logically have greater opportunity to retain and later sell tradable renewable credits (Green Tags) compared to the Minnesota Flips and Multiple Local Owner LLCs, although the market for these is somewhat undeveloped at this time. Our modeling shows how Green Tags can contribute to financial viability over the assumed 20-year life of a project. The value and importance of Green Tags will be increased as more states pass renewable energy standards. If the United States were to adopt climate change targets like the Kyoto Accord, the value of Green Tags would be further enhanced based on the ability to trade these vouchers. Any of the models may be eligible for USDA 9006 grants, which would enhance the NPVs of the baseline scenarios.

Co-ops are clearly at a disadvantage with respect to the lower payments received under the REPI program than the PTC. Even if co-ops can now pass through a revised PTC to members, NPVs are still lower for the co-ops than for the Minnesota Flip ownership models and Multiple Local Owner LLCs, largely due to the lower marginal tax rates assumed for co-op members. If new-style agricultural co-ops, rather than RECs, were formed by wealthier individuals with greater opportunities to use the PTC, higher returns could result. However, such a new style of co-op might lose the advantage of retaining and later selling tradeable renewable credits or Green Tags in the course of negotiating power purchase agreements. It is possible that the Clean Renewable Energy Bonds available as of 2006 will make up some of this ground for RECs.

Overall, the modeling exercises suggest several conclusions.

First, the PTC is a critical and necessary incentive that could be made even more useful by extending it and targeting it to locally based entities.

Second, despite its importance, other incentives including USDA Section 9006 rural development loans and grants, attractive purchase prices, state wind incentive payments, and Green Tags all play a potentially important role.

Third, for a variety of reasons, LLCs fare better than cooperatives in packaging these incentives to generate favorable returns, even under new federal legislation allowing pass-through of the PTC to agricultural co-op members.

FISCAL IMPACTS

As noted above, U.S. wind power developments have been seriously hamstrung by the erratic availability of the PTC due to Congressional reluctance to embrace longer term extensions. This reluctance is based in large part on fears of rising fiscal burdens in the face of current deficits. If federal legislation is later enacted that makes the PTC available for a reasonable period of time (6 to 10 years), wind prospectors, contractors, bankers, landowners, and potential passive investors could better organize investment groups to use the PTC in conjunction with other state and federal incentives. However, such an extension would need to account for the fiscal implications of expanded use of the PTC.

Accordingly, we estimate fiscal impacts in this section based on historical growth rates in installed U.S. windpower capacity and an assumed expansion at the 2005 rate of 2,500 megawatts a year. We then estimate the amount of wind energy expansion in the United States over the 10-year duration of PTC payments. Assuming a 30 percent capacity factor for all facilities, we estimate the megawatt-hours that could potentially receive the PTC. After applying an assumed rate of inflation, we calculate the maximum taxes foregone due to the PTC. We also assume that the population of taxpayers who use the revised PTC has a marginal tax rate of 35 percent. **Figure 8** (page 24) shows estimates based on a steady growth rate in windpower of 2,500 megawatts per year, based on an inflation rate equal to the previous 10 years (2.17 percent), and heavy participation (95 percent) by individuals and businesses who can use

the PTC to reduce taxes at their 35 percent marginal tax rates. Total taxes foregone rise from \$101 million in 2005 to \$428 million in 2013.

An alternative estimate can be calculated based on the 18 percent per year annual growth in wind capacity required to meet the stated U.S. Department of Energy goal: 100,000 megawatts or 6 percent of U.S. capacity from wind by 2020. **Figure 9** (page 25) compares the first and second estimates: a steady increase of 2,500 megawatts per year versus the 18 percent compounded rate necessary to reach 100,000 megawatts of capacity by 2020. In 2012, the fiscal impact of the 18 percent growth rate exceeds that of the steady growth rate of 2,500 megawatts per year due largely to its compounded nature. The more ambitious goal of installing 6 percent of U.S. generating capacity with wind by 2020 thus has a greater fiscal impact after 2012, reaching roughly \$720 million in 2015.

In either scenario, however, total taxes foregone are substantially less than \$1 billion, quite small in relation to the \$1 trillion U.S. budget. And the taxes foregone are not simply losses to the U.S. Treasury—they represent an investment in wind energy with manifold public benefits. These include both enhanced energy security and environmental quality, coupled with rural development and employment. When these public and private benefits are tallied, the less than \$1 billion in taxes foregone appears to be a cost-effective investment in America's energy future.

TRANSMISSION CONSTRAINTS ON WIND EXPANSION

Even if reform of the PTC is undertaken in the ways discussed in this paper, additional wind energy development will be limited because many areas of the United States lack transmission capacity and rules favoring conventional thermal power plants. Kilowatt-hours generated from wind face higher transmission costs because wind power generation is widely dispersed and the best wind resources are often far from significant load centers. In addition, wind power's variable nature makes it more costly per unit transmitted due to the charges needed to reserve transmission capacity for cases when it fails to arrive as anticipated.²⁴

Technical and regulatory solutions are being investigated by others to help overcome constrained transmission capacity for wind. In the technical area, several companies are developing improved conductors that have the capacity to carry two to three times the power loads of conventional cables through constrained portions of the grid on existing towers. However, these conductors are most likely to be used to carry power short distances in densely populated urban areas, since they are currently three times more expensive than traditional cable. Another technical approach is to improve wind forecasting to anticipate the amounts that established wind turbines will generate and have available for transmission, hour by hour and a day or more in advance.

Coupled with better forecasting of wind power, revised regulations for reserving transmission line capacity for wind can cut transmission costs and relieve the penalty charges that wind generators must often pay when unable to utilize a firm request. Among the alternatives are the development of hourly firm point-to-point and curtailable, or conditional, firm transmission products. An example of a Federal Energy Regulatory Commission (FERC)-approved improvement in this regard occurred in Texas with El Paso Electric Company, which offers hourly firm point-to-point transmission service on its system. This reform frees up transmission capacity that would otherwise not be available for

wind power.²⁵ In California, FERC approved the exemption of wind from hourly imbalance penalties in exchange for monthly netting of imbalances in return for centralized wind delivery forecasting. These two examples of regulatory reforms in states with substantial wind generation would undoubtedly be helpful in other parts of the country as well.

Wind power development also requires robust and forward-looking regional transmission planning that addresses transmission constraints in high wind resource areas and integrates the delivery of wind power into regional transmission planning. Substantial new high-voltage transmission requires at least eight years to develop, while wind plant development can take less than 12 months. Projected wind development needs to be aggregated ahead of purchase agreements for use in transmission planning. In several areas of the country, including the Midwest, regional transmission organizations (RTOs) have included significant amounts of wind power in their comprehensive transmission planning process. This is particularly important given the growing number of states that have set goals and requirements for a certain percentage of electric power to be produced from renewable resources.

In conclusion, the United States has vast wind resources waiting to be developed. The architecture of the North American transmission grid and the rules that have governed it were not created for a variable, renewable energy source like wind. As a result, transmission constraints can be deal-breakers for wind projects on numerous sites with otherwise excellent resources, even with a reformed PTC. A comprehensive long-term plan for investment in the transmission grid that balances the variable nature of wind power and regulations governing access and system reliability requires additional analysis and investigation. In the same way that targets have been developed by states with respect to renewable energy, tax incentives can be developed to reward investment in transmission assets that carry targeted percentages of renewable power.

FOOTNOTES

- ¹ Kubert, Charles, Howard Learner and Jill Geiger. "Community Wind Financing: A Handbook by the Environmental Law and Policy Center." Chicago, IL, February 2005. Appendix 1.
- ² Estimates are from the Energy Information Administration. *Annual Energy Outlook*, 2005, p. 7.
- ³ Ibid, p. 8.
- ⁴ Johnson, Roger. "Current States of Renewable Energy in the Region: North Dakota." Presentation to the Renewable Energy Conference, Grand Forks, ND, February 23-24, 2005. Economic impacts attributed to Larry Leistriz, North Dakota State University.
- ⁵ EIA. *Annual Energy Outlook*. Washington, D.C., 2005, p. 3.
- ⁶ Office of Management and Budget. *Budget of the United States Government, Fiscal Year 2000* (Washington, DC)
- ⁷ Lehr, Ron. American Wind Energy Association. Presentation to the Renewable Energy Conference. Grand Forks, ND, February 23-24, 2005.
- ⁸ See *Directory of State Incentives for Renewable Energy*, Table 5 in Kubert, et al., 2005, op. cit., note 1.
- ⁹ Press Release. MidAmerican Energy. September 24, 2004.
- ¹⁰ State of Pennsylvania. *PA Power Port*. September 2004.
- ¹¹ Iowa Senate File 390, URL: http://coolice.legis.state.ia.us/Cool-ICE/default.asp?category=billinfo&Service=Bil_lbook&hbill=sf... (viewed July 18, 2005).
- ¹² Moller, Lars. Presentation to the Renewable Energy Conference. Grand Forks, ND, February 23-24, 2005.
- ¹³ Bailey, Diane. "Booming Market but Tougher than Ever." *Windpower Monthly*, July 2005, p. 54.
- ¹⁴ Bolinger, M., R. Wiser, T. Wind, D. Juhl and R. Grace. "A Comparative Analysis of Community Wind Power Development Options in Oregon." Energy Trust of Oregon. July 2004, pp. 19-20.
- ¹⁵ Bolinger, et al., *ibid*. See Internal Revenue Service Publication 925, listing seven tests determining material participation in a project, any one of which may disqualify an investor from a passive activity.
- ¹⁶ Joint Committee on Taxation. "Description and Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, the Energy Tax Incentives Act of 2005. January 28, 2005, JCX-60-05, pp. 22-24.
- ¹⁷ Ibid, pp. 26-28.
- ¹⁸ Niezwaag, Dale. Basin Electric, personal correspondence, September 21, 2005.
- ¹⁹ Cooperative Development Services. "Wisconsin Community Based Windpower Project Business Plan." Madison, Wisconsin, 2003.
- ²⁰ Bolinger, et al., 2004, op cit., note 14, p. 82.
- ²¹ Bolinger, et al., 2004.
- ²² USDA, Rural Development Section. URL: http://www.rurdev.usda.gov/rbs/farmbill/what_is.html.
- ²³ Kubert, Charles. "Community Wind Financing," Environmental Law and Policy Center, Chicago, Illinois, p. 19.
- ²⁴ FERC, "Assessing the State of Wind Energy in Wholesale Electricity Markets," staff briefing paper, November 2004, p. 19.
- ²⁵ Ibid. p. 22.

Figure 1. Levelized electricity costs for new plants 2015

Source: Energy Information Agency, Annual Energy Outlook 2005, Market Trends - Electricity Demand and Supply

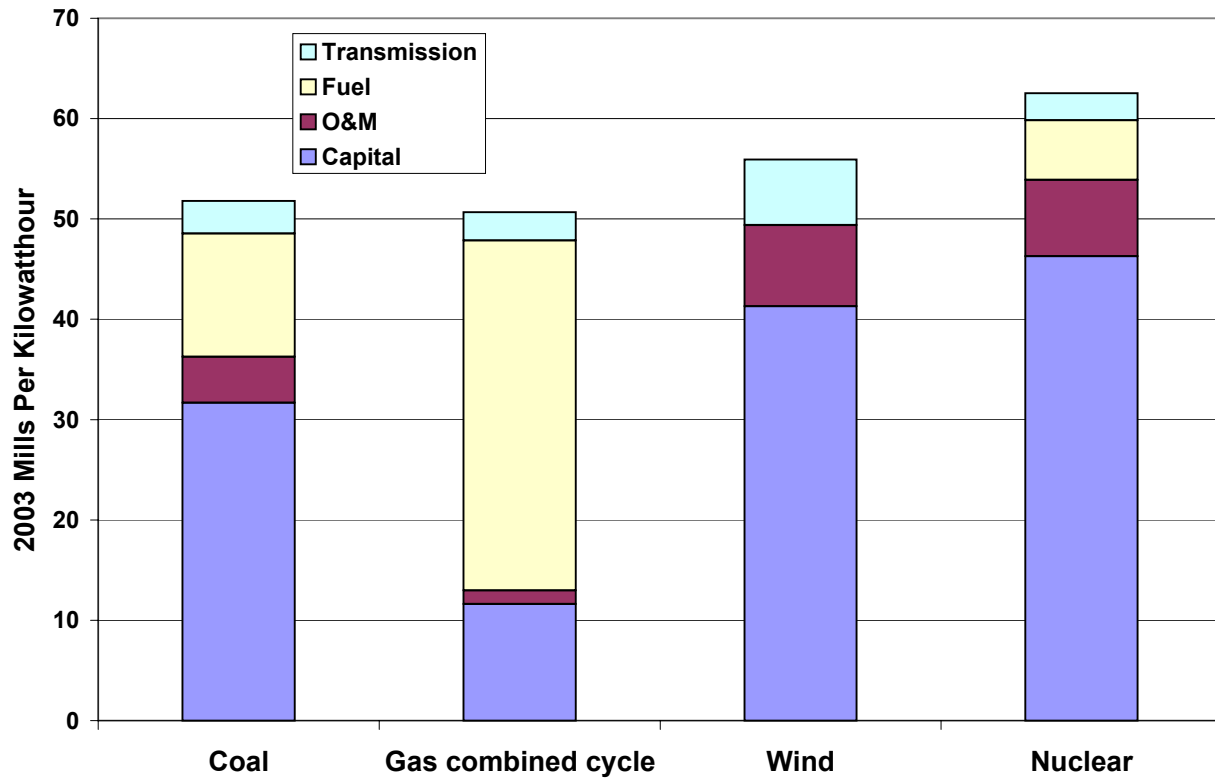


Figure 2. Annual installations of U.S. wind capacity 1995-2005

Source: American Wind Energy Association

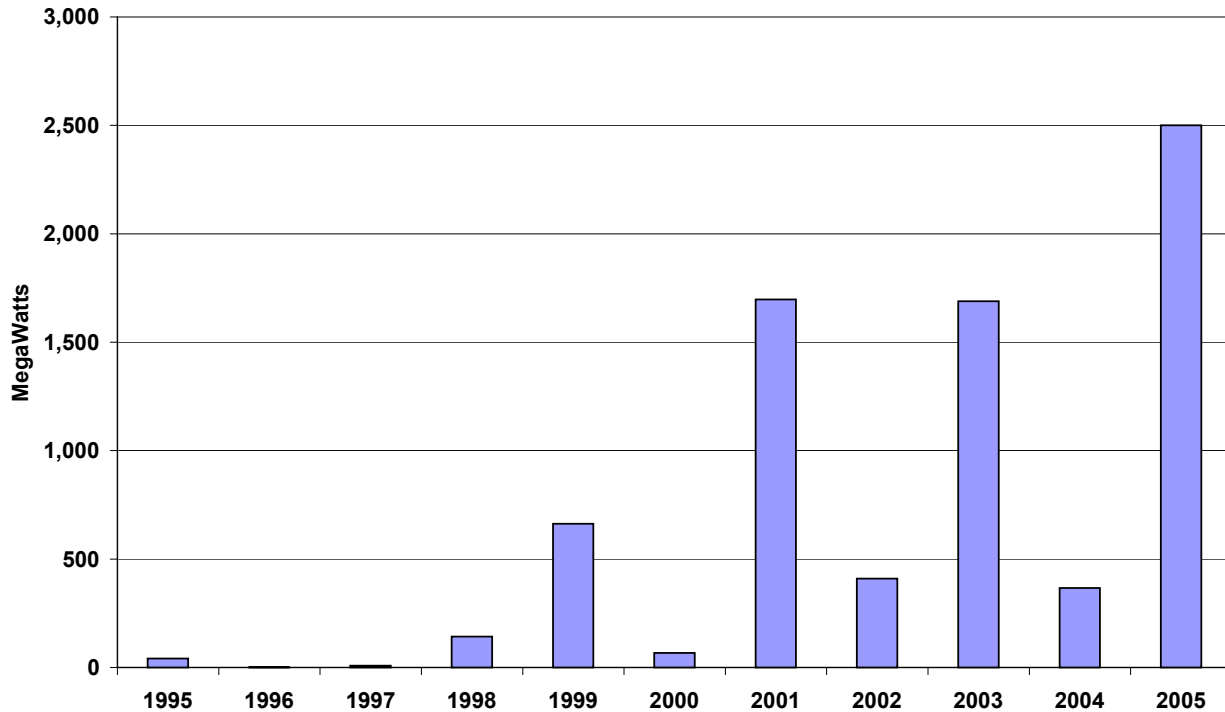


Figure 3. Wind turbine production economics
by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
MN Flip Status Quo																				
Assumptions:	1,650,000	35%	30.00%	7.00%																
Wind Turbine Capacity	1,650,000																			
Capacity Factor of Wind Site	35%																			
Annual Production	5,058,900																			
Price for Purchased Power	\$0.0330																			
Discount Factor	0.12																			
Salvage Value(+)/Removal Cost (-)	\$181,000																			
Conclusions:																				
NPV of 20 Yr. Project										213,855										
Average Cost per KWH										0.029533										
IRR for Project										14.56%										
Assumptions:																				
Wind Turbine Capacity	1,650,000																			
Capacity Factor of Wind Site	35%																			
Annual Production	5,058,900																			
Price for Purchased Power	\$0.0330																			
Discount Factor	0.12																			
Salvage Value(+)/Removal Cost (-)	\$181,000																			
Capital Expenditures																				
Resource Investigation																				
Legal--for Site	20,000																			
Legal--Power Purchase	2,000																			
Interconnection Fees	5,000																			
Tower, Turbine & Installation	3,000																			
Transmission Feeder Lines	1,605,000																			
Working Capital Debt Reserve	2,000																			
Storage Materials	8,000																			
Total Capital Expenditures	1,650,000																			
Revenue or Credits																				
Power Purchased	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
Power Tax Credit (Federal)	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419	9,419
MN State Production Payment @ \$0.015	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884
Sale of Green Tags @ \$ 0.1 / KWh																				
Renew. Energy Prod. Incent. (REPI)																				
USDA Rural Develop. Grant	85,759	154,366	81,185	37,276	37,276	4,345														
Val of Dep. Taken Above SL Asset Life	0	424,705	493,312	420,131	376,223	376,223	343,291	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946	338,946
Total Revenue or Credits	0	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355
Operating Expenses																				
Operations & Maintenance	0	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
Insurance (Hazards + Bus. Interrupt.)	0	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500
Service & Warranty	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
Electrical Usage	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607
Property Taxes	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
Land Lease	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
Accounting/Auditing	80,650	72,765	64,680	56,595	48,510	40,425	32,340	24,255	16,170	8,085										
Interest Paid	0	123,313	115,228	116,543	110,458	102,373	94,288	86,203	78,118	70,033	61,948	53,863	53,863	53,863	53,863	53,863	53,863	53,863	53,863	53,863
Total Operating Exp. Pre-Deprec.	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500
Depreciation Alternatives																				
Straight-Line Depreciation 20 Yr.	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
Straight-Line Depreciation 15 Yr.	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000
Straight-Line Depreciation 10 Yr.	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000
MACRS Depreciation Taken	330,000	528,000	316,800	190,080	190,080	95,040														
Net Cash Flow																				
Disc. Cash Flow of Year	-1,650,000	301,392	378,084	301,589	265,765	273,850	249,004	262,744	260,829	268,914	276,999	113,081	113,081	113,081	113,081	113,081	113,081	113,081	113,081	113,081
Cumulative Disc. Cash Flows	-1,650,000	269,100	301,407	214,685	168,899	155,300	128,153	114,328	105,344	96,873	89,186	32,508	29,025	25,915	23,139	20,680	18,446	16,470	14,705	13,129
Total Operating Exp. Pre-Deprec.	269,100	570,507	785,172	954,071	1,109,460	1,235,614	1,349,942	1,455,286	1,552,259	1,641,446	1,673,954	1,702,979	1,728,894	1,752,033	1,772,692	1,791,138	1,807,698	1,822,313	1,835,442	1,863,855
Net Present Value of Project																				
Initial Principal	213,855																			
Debt Retired at End of Period																				
Initial Principal	1,155,000	1,039,500	924,000	808,500	693,000	577,500	462,000	346,500	231,000	115,500										
Debt Retired at End of Period	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000	1,155,000

Figure 4. Wind turbine production economics
by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Multiple Local Owners Without Grant																				
Assumptions:																				
Wind Turbine Capacity	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650
Capacity Factor of Wind Site	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Annual Production	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000	5,665,000
Price for Purchased Power	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330	\$0.0330
Discount Factor	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Salvage Value(+)/Removal Cost (-)	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000	\$16,000
Capital Expenditures																				
Resource Investigation	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Legal—for Site	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Legal—Power Purchase	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Interconnection Fees	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Tower, Turbine & Installation	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Transmission Feeder Lines	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Working Capital, Debt Reserve																				
Salvage Value/Removal Expense																				
Total Capital Expenditures	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000	1,650,000
Revenue or Credits																				
Power Purchased	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944	186,944
Production Tax Credit (Federal)	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
MN Sm Producer Paymt @ \$0.015	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884	75,884
Sale of Green Tags @ \$0.017/KWh																				
Renew. Energy Prod. Incent. (REFI)																				
USDA Rural Develop. Grant	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100	23,100
Val of Dep't. Taken Above SL Asset Life	0	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046
Total Revenue or Credits	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046	362,046
Operating Expenses																				
Operations & Maintenance	0	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355	13,355
Insurance (Fire + Bus. Interrupt)	0	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
Service & Warranty	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500
Electrical Usage	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
Property Taxes	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607	607
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
Accounting/Auditing	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
Interest Paid	80,850	72,765	64,680	56,595	48,510	40,425	32,340	24,255	16,170	8,085										
Total Operating Exp. Pre-Deprec.	0	123,313	115,228	107,143	99,058	90,973	82,888	74,803	66,718	58,633	50,548	42,463	34,378	26,293	18,208	10,123	2,038	395	110	25
Depreciation Alternatives																				
Straight-Line Depreciation 20 yr.	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500	82,500
Straight-Line Depreciation 15 yr.	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000
Straight-Line Depreciation 10 yr.	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000	165,000
MACRS Depreciation Taken	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000
Net Cash Flow																				
Disc. Cash Flow of Year	-1,650,000	238,734	246,819	254,904	262,989	271,074	279,159	287,244	295,329	303,414	311,499	319,584	327,669	335,754	343,839	351,924	360,009	368,094	376,179	384,264
Cumulative Disc. Cash Flows	213,155	409,918	604,681	799,444	994,207	1,188,970	1,383,733	1,578,496	1,773,259	1,968,022	2,162,785	2,357,548	2,552,311	2,747,074	2,941,837	3,136,600	3,331,363	3,526,126	3,720,889	3,915,652
Net Present Value of Project																				
Initial Principal	1,650,000	1,039,500	924,000	808,500	693,000	577,500	462,000	346,500	231,000	115,500										
Debt Retired at End of Period	-1,650,000	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500	\$115,500
Conclusions:																				
NPV of 20 Yr. Project	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917	39,917
Average Cost per KWh	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533	0.029533
IRR for Project	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%	12.44%

Figure 5. Wind turbine production economics
by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cooperative Status Quo Ante																				
Assumptions:																				
Wind Turbine Capacity	1,650																			
Capacity Factor of Wind Site	0.30																			
Annual Production	500,000																			
Price for Purchased Power	\$0.03																			
Discount Factor	0.03																			
Salvage Value(+)/Removal Cost (-)	\$16,000																			
Conclusions:																				
NPV of 20 Yr. Project	160,521																			
Average Cost per KWh	0.02853																			
IRR for Project	3.62%																			
Operating Status Quo Ante																				
Assumptions:																				
Wind Turbine Capacity	1,650																			
Capacity Factor of Wind Site	0.30																			
Annual Production	500,000																			
Price for Purchased Power	\$0.03																			
Discount Factor	0.03																			
Salvage Value(+)/Removal Cost (-)	\$16,000																			
Capital Expenditures																				
Resource Investigation	2,000																			
Legal--for Site	5,000																			
Legal--Power Purchase	5,000																			
Interconnection Fees	1,600,000																			
Tower, Turbine & Installation	2,000																			
Transmission Feeder Lines	8,000																			
Working Capital, Debt Reserve	1,650,000																			
Salvage Value/Removal Expense																				
Total Capital Expenditures																				
Revenue or Credits																				
Power Purchased	0																			
Production Tax Credit (Federal)	0																			
Production Tax Credit (Federal)	0																			
Small Producer Payment (MN)	0																			
Renew. Energy Prod. Incent. (REPI)	0																			
USDA Rural Develop. Grant	0																			
Val of Depr. Taken Above SL Asset Life	0																			
Total Revenue or Credits																				
Operating Expenses																				
Operations & Maintenance	0																			
Insurance (Hazards + Bus. Interrupt.)	0																			
Salvage Value/Removal Expense	0																			
Special Warranty	0																			
Electrical Usage	0																			
Property Taxes	0																			
Land Lease	0																			
Accounting/Auditing	0																			
Interest Paid	0																			
Total Operating Exp. Pre-Deprec.																				
Depreciation Alternatives																				
Straight-Line Depreciation 20 Yr.	82,500																			
Straight-Line Depreciation 15 Yr.	110,000																			
Straight-Line Depreciation 10 Yr.	165,000																			
MACRS Depreciation Taken	330,000																			
Net Cash Flow																				
Disc. Cash Flow of Year	126,026																			
Cumulative Disc. Cash Flows	112,524																			
Net Present Value of Project	-590,521																			
Initial Principal																				
Initial Principal	1,155,000																			
Debt Retired at End of Period	\$115,500																			

Figure 7. Scenarios of ownership options of wind production assets
 Reflecting utilization of production tax credits, depreciation, wind incentive payments, Green Tags

		<u>Net Present Value</u>	<u>Avg. Cost per KWH</u>	<u>Internal Rate of Return</u>
Minnesota Flip LLC, No Grant	(Figure 3)	\$213,855	0.029533	14.56%
Minnesota Flip LLC, With Grant		\$462,571	0.029533	17.83%
Multiple Local Owner LLC, No Grant	(Figure 4)	\$39,917	0.029533	12.44%
Multiple Local Owner LLC, With Grant		\$211,143	0.029533	14.61%
Coop; Status Quo Ante, No Green Tags	(Figure 5)	-\$590,521	0.029533	5.86%
Coop; Status Quo Ante, With Green Tags		-\$212,649	0.029533	9.91%
Coop; Status Quo Ante, With Grant, No Green Tags		-\$417,456	0.029533	7.18%
Coop; Status Quo Ante, With Grant, With Green Tags		-\$39,585	0.029533	11.57%
Ag. Coop; W/ PTC Pass Thru, Gr. Tags, 50% Utilized		-\$375,578	0.029533	8.38%
Ag. Coop; W/ PTC Pass Thru, Gr. Tags, 75% Utilized (Figure 6)		-\$239,804	0.029533	9.65%
Ag. Coop; W/ PTC Pass Thru, Gr. Tags, 100% Utilized		-\$104,030	0.029533	10.97%

Figure 8. Estimation of U.S. fiscal impact of Production Tax Credit in future years
 by Douglas G. Tiffany, Dept. of Applied Economics, University of Minnesota

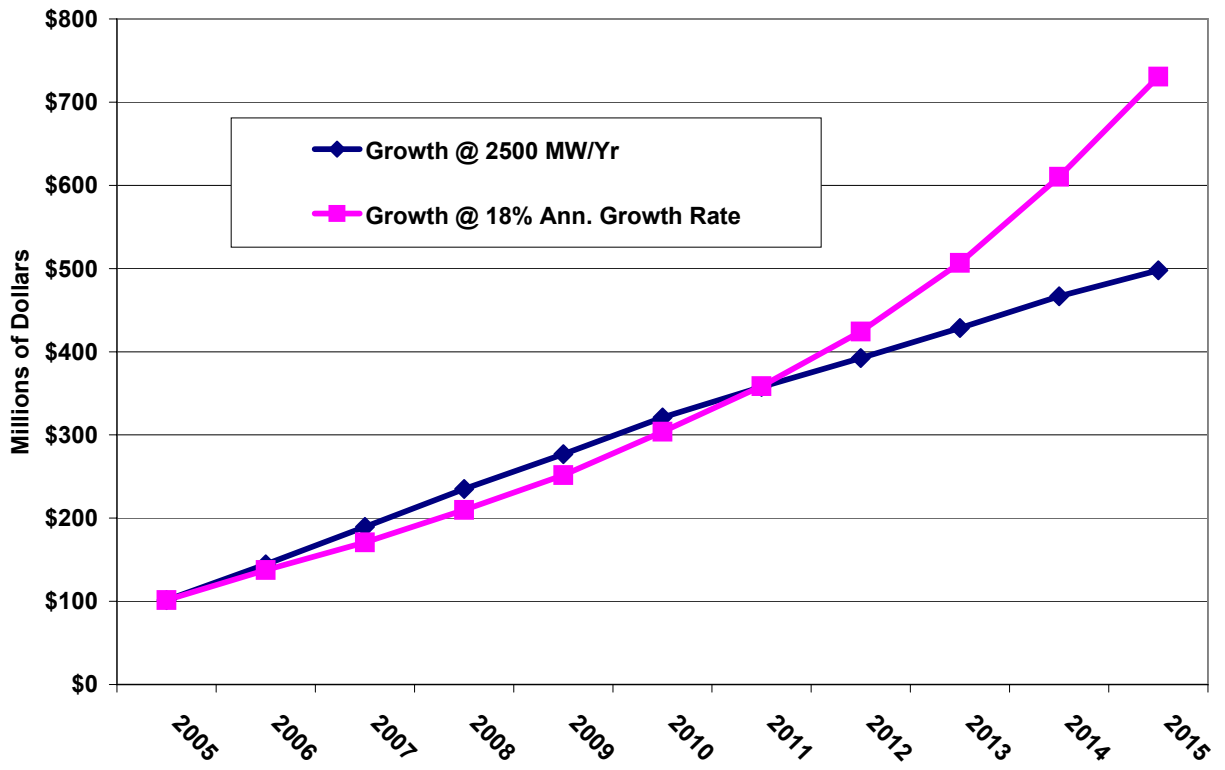
Assumptions:

Annual Growth in Wind Capacity	2500 MW
Capacity Factor U.S. Wind Sites	30.00%
Margin Tax Rate of PTC Recipients	35.00%
Percentage of Credits Used	95.00%
Inflation Rate Applied to PTC	2.17%

	2005	2006	2007	2008	2009	2010
Taxes Relieved by Usable PTC	\$101,457,252	\$144,360,600	\$189,354,965	\$235,025,814	\$276,854,819	\$321,059,437
Max. Tax Burden Relieved by PTC	\$106,797,107	\$151,958,527	\$199,321,016	\$247,395,593	\$291,426,125	\$337,957,302
MegaWattHours Receiving PTC (MWH)	1,894.05	2,637.75	3,386.40	4,113.90	4,743.15	5,383.65
Capacity Eligible for PTC (MW)	6,313.50	8,792.50	11,288.00	13,713.00	15,810.50	17,945.50
Annual Growth in Capacity (MW)	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00
Total Installed Capacity (MW)	9,240.00	11,740.00	14,240.00	16,740.00	19,240.00	21,740.00

	2011	2012	2013	2014	2015
Taxes Relieved by Usable PTC	\$357,601,905	\$392,376,253	\$428,567,739	\$466,574,061	\$497,951,278
Max. Tax Burden Relieved by PTC	\$376,423,058	\$413,027,634	\$451,123,936	\$491,130,590	\$524,159,240
MegaWattHours Receiving PTC (MWH)	5,869.05	6,303.00	6,738.15	7,179.90	7,500.00
Capacity Eligible for PTC (MW)	19,563.50	21,010.00	22,460.50	23,933.00	25,000.00
Annual Growth in Capacity (MW)	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00
Total Installed Capacity (MW)	24,240.00	26,740.00	29,240.00	31,740.00	34,240.00

Figure 9. Fiscal impacts of extended wind Production Tax Credit and alternative growth patterns in U.S. wind capacity



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