Energy Studies Review Vol.11, No. 1, 2002 pp 1-22

Analytic Assessments of the Economics, Reliability, and Operating Impacts of Wind Power Plants

Michael R. Milligan

ABSTRACT

This paper summarizes a number of projects undertaken at the National Renewable Energy Laboratory (NREL) that focus on the analysis and modeling of large-scale wind generation. The findings indicate that wind power plants can provide significant economic benefits to the generating system. Potential problems caused by the intermittency of a wind plant can be significantly reduced by accurate wind forecasting, geographic dispersion of turbines within a plant, as well as disperse wind-generating facilities. Wind plants do not require significant backup facilities because risk-analysis techniques assess the risk of system failure on a system-wide basis.

Michael R. Milligan is currently with the National Wind Technology Center at the National Renewable Energy Laboratory, 1617 Cole Blvd. Golden CO 80401, USA. Tel(303)384-6927 Fax(303) 384-6901 Email: milligan@nrel.gov

An earlier version of this paper was presented at the 24th International Conference of the International Association for Energy Economics, Houston, TX, USA. April 2001.

INTRODUCTION

In many places throughout the world, there is increasing interest in developing power plants that are fueled by the wind. Wind power plants are a clean source of electricity. Many electric generating companies are reluctant to install significant wind capacity because of the intermittent nature of the resource. Wind power plants cannot be controlled in the same way as their conventional cousins because they rely on the uncertain availability of the wind itself. It is likely that the yield from a wind power plant will vary from one year to the next. Both of these issues are aspects of risk, which is becoming an important topic as the electricity industry moves toward a greater degree of competition under restructuring.

To reduce the risk of depending too heavily on one specific type of generation or fuel, resource-planning techniques have incorporated methods of portfolio diversification theory. Financial-option theory is also used to evaluate the relative costs of building a power plant now or in the future. Another strategy is hedging, which can consist of forward trading or contracts for differences. Applying these theories and practices to resource planning helps companies assess and reduce risks in the emerging competitive environment.

In the regulatory environment, both consumers and power companies share risk. Some would argue that most risk is borne by the consumer, whereas the power company enjoys a virtual monopoly with a guaranteed rate of return set by the regulator. But as electricity markets become more open, power companies must recognize and quantify various risks that they had previously been able to ignore. Some of these include the possibility that a new unit will not be completed when it is needed, the risk of fuel cost escalation, and future regulations on emission levels. In the case of wind power plants, there is the obvious risk that such plants may not produce power when it is needed. That risk is balanced, however, against the risk undertaken by building power plants for which lifetime fuel costs cannot be accurately determined at the time of plant construction. Although the fuel for a wind plant is free and in plentiful supply, the timing of its availability is not always known in advance and is subject to variation. Other risks faced by power producers include the risk of future emissions requirements and the resulting effect on the cost of conventional power generation. Power companies facing restructuring are familiarizing themselves with the principles needed to analyze the risks and benefits associated with wind power plants. Indeed, risk-based performance measures of power systems, markets, and generators will come into increasing use.

In this paper, we examine some of the factors related to the operation of, and planning for, wind power plants. In spite of the move towards restructuring and new ways of doing business, utilities that are evaluating wind power plants are asking questions about the intermittency of wind and the implications of this intermittency on power system operation. Accurate wind forecasts can prove helpful in dealing effectively with intermittency, both in regulated and in unregulated markets. Another important consideration is the measurement of available capacity (determining whether or not electric capacity is sufficient to cover demand), which leads us to reliability assessment and to reliability-based measures of capacity credit.

We assume that the power generation industry includes many types of companies, ranging from small firms that own one or two generating resources, to large companies that can generate as much as 30,000 megawatts (MW) or more. We use *utility* here to mean the power generator (or GENCO), as we straddle environments that are still regulated and those that have restructured. We also assume that at least some of these companies will hold both wind-generating and conventional power capabilities, and that restructuring is a work in progress. The electricity industry has not been down this road before; therefore, predictions about how a specific market will perform can only be answered with experience. In one of the first examples of restructuring, some significant changes were recently made in electricity supply operating procedures in the United Kingdom's power system. In California's recently deregulated electricity market, generating-supply adequacy, reliability, and capacity measurements are still very important issues. Indeed, as the "restructuring dust" worldwide continues to settle, many underlying technical issues remain to be addressed by the market. The first, and perhaps subsequent, versions of the market rules may not address all of these issues.

The results presented in this paper are from various projects undertaken at the National Renewable Energy Laboratory (NREL), involving electricity production simulations using actual wind-speed, generator, and electric load data. Data were also used from several different utilities or regions and many wind sites, with wind penetration rates that range from less than one percent of system peak to more than 20% of system peak. The hourly data used for wind power are based on actual wind data and are applied to various wind-turbine power curves, all of which represent actual wind turbines, to calculate the hourly power output of several hypothetical wind power plants. The electricity production simulation and reliability programs used for this work are Elfin (a load duration curve model produced by Environmental Defense) and P+ (an hourly chronological model produced by the P Plus Corporation). After restructuring, both of these models were enhanced for the new electricity markets; however, the primary least-cost dispatch algorithms are still at the heart of the models. Results from an experimental chronological reliability model developed at NREL are also included in this work.

At NREL, we think that the generating company of the future will have some of the characteristics of the many generation and transmission cooperatives that are operating today in the United States - without the transmission system, but with a profit motive. Although the focus and emphasis may shift, competitive pressure will induce firms to use the most cost-effective method to produce electricity, subject to profit maximization. To maintain the reliability of the electricity supply, some form of reliability-based pricing or regulation may become necessary. One of the most important issues facing wind plant operators in restructured markets is the extent to which wind power output can be forecast. We discuss this in more detail in a later section of the paper.

Following are some questions relevant to adding wind plants into the generation mix. These questions are addressed in subsequent sections of this paper: Does a wind power plant offer any value to a generation company that owns a variety of generating resources? Can wind energy systems reduce the need for conventional generation in the industry supply portfolio? If so, how much generation can be displaced, and how can it be measured? Does the intermittency of wind power plants present any significant problems for the operation of electric power systems? Can any of these problems, or problems of lesser significance, be mitigated, and if so, how? Will it be possible for wind plant owners/operators to participate in the newly emerging electricity markets, such as day-ahead markets, in the new, restructured environment?

2. THE VALUE OF WIND POWER PLANTS

The energy value that wind power plants can provide to the grid is largely a result of the reduction in electricity generated by conventional power plants, made possible by the wind plant. We can calculate the value of offset fuel consumption and emissions using an electricity production simulation model. In many cases, wind power plants can offset the need for conventional power plants. The variable and marginal costs of wind generation are typically less than most, if not all, other power plants because there is no fuel cost, and operation and maintenance costs are very low. In regulated electricity markets, this means that each wind-generated kilowatt-hour (kWh) would be used whenever available, making it possible for the utility to ramp back on other load-following power plants. As we move toward a restructured industry, generating companies with diverse generating portfolios will still attempt to produce electricity, subject to various bidding strategies, at lowest possible cost and highest possible profit. Therefore, a generating company with a portfolio that includes wind power plants will attempt to maximize the efficient use of these plants to reduce fuel costs associated with conventional power generation.

The value of wind plants to generating companies depends heavily on the GENCO's specific combination of generators, and the influences of changing wind patterns and their relationship to the expected load. A wind site that is attractive to one utility may not be as attractive to another. Milligan and Miller (1993) experimented with various combinations of wind sites and utility data and found significant variations in the benefit of otherwise identical wind power plants to different utilities. In a study by Milligan (1999), two large utilities were modeled. The model paired each utility with each wind site, one at a time. The benefit provided by the wind power plant includes three aspects: (1) energy, which represents the reduction in conventional fuel cost resulting from adding a wind power plant; (2) capacity, defined in this case by the shortage method adopted by the California Energy Commission (CEC) before restructuring in California; and (3) emissions value, which was also valued on a per/ton basis by the CEC before restructuring. The value of reduced emission levels may not find its way into the market, but is a well-known market externality. The energy, capacity, and emission values were calculated by initially running the model without any wind generation. After the results for this no-wind case were collected, the values were recalculated to include a 125-MW wind power plant. The difference between these two cases gives us the value provided by the wind power plant.

Figure 1

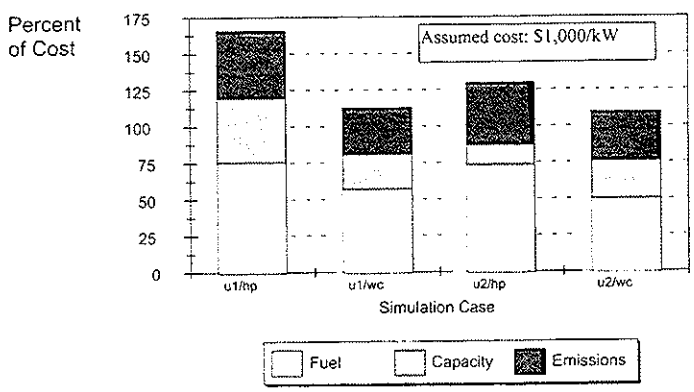


Figure 1 illustrates the results for the two utilities, U1 and U2. (As agreed, the utilities were not identified.) We used two wind sites for this study, a West Coast mountain pass and a site from the High Plains. The vertical axis of the graph represents the benefit as a percent of cost, which is $1,000/kW. The diagram shows that (a) a given wind site will contribute a different level of value, depending on the utility, and (b) the value of wind power to a utility will vary as a function of the chronological variation of the wind resource at the plant.

Milligan also shows the results of several electricity production simulations using a chronological model. Using various combinations of utilities and wind regimes, he calculates the reduction in generation from those units on the margin during periods of significant wind generation when the chronological unit-commitment and economic dispatch are optimized to include the wind plant. For one of the large utilities studied, the total number of start-stop cycles from conventional power plants was reduced by about 700 cycles/year.

A recent ruling by the Colorado Public Utility Commission (see Lehr, et al. [2001]) found that a wind power plant would be cost-effective on economic grounds alone, without considering any other benefits of the wind plant.

3. FORECASTING, CAPACITY, AND RISK

There are several ways to look at the effective capacity of wind power plants. In regulated markets, the term *capacity credit* is often used to describe the level of conventional capacity that a wind plant could replace. In this section, we assume that capacity credit may be more general in the newly restructured markets. We begin by discussing some general characteristics of various pool-bidding processes that appear to be emerging in some restructured markets, and the unique issues raised by wind power plants in these arrangements. Next, we discuss short-term markets, and the role wind forecasting can play in those markets; followed by an examination of measures of capacity credit based on reliability estimates. These estimates have been used in some regulated environments. Whether or not these estimates will be appropriate in the new electricity markets is uncertain.

3.1 Bidding Wind Power into the Supply Pool in Restructured Markets

Because electricity has a higher value during periods of system peak demand, generating companies in restructured markets will have a greater economic incentive to secure a bid into the pool during these times, as compared to periods of relatively low system demand. As restructuring continues, differences in many aspects of the wholesale electricity market will surface as they did in California and in the United Kingdom. In one emerging trend, buyers and sellers strike agreements on price and quantity before the actual transaction. The elapsed time between the agreement and the actual exchange of power may range from hours to days in these short-term markets. We only describe short-term operational transactions, and ignore any longer-term transactions, so that we can focus on the operational market.

Wind power plant owners must participate in such bidding arrangements to sell power. Although the short-term markets may include some provision to account for spinning reserves to cover unforeseen generator malfunction or higher-than-anticipated customer load, it is advantageous to the wind plant owner to ensure that the capacity or energy bid into the market can be supplied at the specified time of delivery. However, there are various mechanisms that can be used when contracted power is not delivered as specified. An example of one mechanism is the Balancing and Settlement Code (BSC) in the United Kingdom, in which market participants must pay for any imbalances during a settlement period that occurs after the time of the specified transaction. Therefore, the wind plant operator, like all power plant operators, has an economic incentive to bid quantities into the market that can be reasonably supplied.

There is an additional complication for the wind plant operator. The intermittent nature of the wind makes it impossible to control the power plant the same way a conventional unit is controlled. Significant social costs are imposed during outages, which is why all electrical systems maintain a spinning reserve. However, scheduling more generation than is needed also results in unnecessary costs. The incidence of these costs can vary widely and can include any combination of the power generators, distribution companies, or ultimate consumers. The total generation supplied should equal total demand (allowing for reserves and ancillary services) to minimize costs that are induced by either an oversupply or undersupply of electricity. Therefore, the stochastic nature of the fuel source makes it vital for the wind plant operator to obtain an accurate forecast of the wind speed for the power delivery period.

The value of an accurate wind forecast depends on many factors, including the generation portfolio controlled by the GENCO. If a quick-response unit is part of that portfolio, that unit can be brought on-line quickly during unexpected lulls in the wind. Conversely, if there is an unexpected period of wind, it is possible that a combustion turbine or other similar unit can be ramped down to avoid the use of a relatively expensive fuel.

Milligan, Miller, and Chapman (1995) modeled two large utilities in two regulated markets and showed significant economic benefits of accurate wind forecasts. Their approach was to calculate the optimal unit-commitment schedule under various assumptions about wind timing and availability. To introduce forecast error into the model, they modified the wind power availability after fixing the commitment schedule to a specific wind forecast. This allowed them to calculate the difference in power production cost that would result from wind forecasts varying in accuracy from 0% to 100%. They found an asymmetrical relationship in benefits, depending on whether the wind power forecast was too high or too low. The scale of benefits depends on a variety of factors. The capacity of the wind power plant used for this study is 1,250 MW, less mechanical and electrical losses and wake effects that total about 25%. The results show that there is significant benefit to an accurate wind forecast.

NREL is currently working with the Electric Power Research Institute on a wind energy forecasting development and testing program, and is conducting independent research on wind-forecasting techniques. Accurate wind forecasting may be one of the most important issues facing wind power plant operators in restructured electricity markets. As market-based electricity supply pools continue to develop around the world, wind plant operators must be able to participate in the various bidding arrangements. In the very short-term power markets, it remains to be seen if separate capacity payments will be made, or if energy will simply be more highly valued during peak periods than in nonpeak periods. However, the penalty for over- or under-scheduling resources during the system peak is higher than during other periods. The most effective tool for the wind plant operator, therefore, may be an accurate wind forecast for the period that is covered by the bidding process.

3.2 Reliability-based Measures of Capacity Credit

As utilities develop more risk-evaluation strategies, overall system reliability will remain critical. In this paper, we ignore the reliability aspects of the transmission and distribution grids, as the number and complexity of transactions on these grids continues to increase. An international panel of electric-system reliability experts recently found the following: (1) electric reliability, particularly generation reliability, in the United States is very high today; (2) transactions in the wholesale market arising from the restructuring of the industry will be far more complex than they were in the past; and (3) system reliability will likely worsen, but will in any case continue to be an important issue in a restructured market (Session 1997).

According to recent indications, concerns over the adequacy of the generation supply in the United States appear to be warranted. Given the stochastic component of electricity demand and a corresponding stochastic component of the generation supply, the grid operator is still faced with the problem of balancing loads and resources. As regional coordinating councils or power pools evaluate supply in future peak periods, risk assessment will continue to be important. Large GENCOs still perform reliability studies, and measures such as loss of load probability (LOLP) are still used to assess system adequacy. Until the recent BSC went into effect in the United Kingdom, LOLP was used to determine capacity prices, although that caused significant volatility in capacity prices.

There are several ways to evaluate the reliability contribution of a single power plant to the generating system. One way is to calculate the reliability measure of choice (LOLP or expected energy not served, for example) and compare the results with and without the generator of interest. Another approach involves converting to a megawatt quantity by increasing the peak load until the reliability matches the base case (excluding the generator of interest). This quantity, called the *effective load-carrying capability* (ELCC), is well known and has been widely used for many years. ELCC has traditionally been called a measure of capacity credit. To evaluate competing power plant options, one can calculate the ELCC of each plant to determine its ELCC.

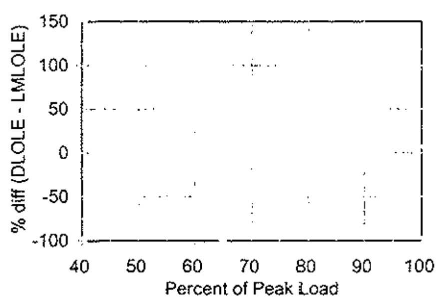
Another related approach is to compare an intermittent power plant, such as wind, to its closest competitor (a gas plant, for example). The evaluation strategy works like this. For a given size gas plant, calculate the system reliability for the generating system, including the gas plant. Record the system reliability attained by the calculations. Then remove the gas plant, substituting increasing penetrations of wind capacity until the reliability measure equals the system reliability in the gas plant case. Once this equality has been achieved, the rated capacity in megawatts of the wind plant is reliability-equivalent to the gas plant.

One might ask: Will ELCC still be relevant in the new markets? There will continue to be a need to measure capacity contributions and risk. If ELCC is not the right measure, another may take its place for large-scale evaluations of generation adequacy (pools and control areas, for example). Investors and GENCOs also need information to help them compare different power generation options, risks, and estimated rates of return for alternative power plants. These rates of return may be based, at least in part, on capacity payments, depending on the structure of contracting in the electricity market. ELCC provides important information about how the plant operates in the context of the market or GENCO assets and has a built-in risk component, so it may continue to be useful as risk analysis becomes more important in the new markets. ELCC or variations on ELCC could also play a role in determining capacity payments or risk-based assessments of whether or not a wind plant operator is likely to meet a bid into a day-ahead or hours-ahead market. Because of the evolutionary nature of restructuring, the notion of capacity credit may be somewhat transitional in nature. Whether or not ELCC continues its useful life in the long term, therefore, may be problematic.

ELCC can be calculated for a wind power plant, using the same basic technique as for conventional power generators. Because wind power plants can only operate when the wind blows, the ELCC must be calculated so periods of lull are taken into account. The most accurate way to do this is to use actual hourly chronological wind power output and hourly chronological load data.

There is an additional issue involving the calculation of ELCC and other related reliability measures involving wind power plants. Conventional production simulation and reliability models do not typically capture the probability that a wind plant may not deliver its statistically expected output and also model the time-variability of a wind plant. Figure 2 shows a comparison of the conventional reliability of LOLE as calculated by a commercial model, and then, as calculated by an experimental chronological-reliability model developed at NREL. The graph shows the difference as a function of the load level for the electrical supply in Minnesota, along with a large composite wind site. The graph shows that there is a significant difference between what is normally calculated when wind power is treated as a load-modifier (LMLOLE) in the modeling process, as compared to a direct assessment based on the chronology of the wind power output (DLOLE). As the need for wind power plant reliability assessment increases, the basic reliability algorithm must be adjusted so that more accuracy can be achieved.

Figure 2. Comparison of reliability measures of a wind power plant



3.3 Year-To-Year Variability and Extensions to Generalized Risk Assessment

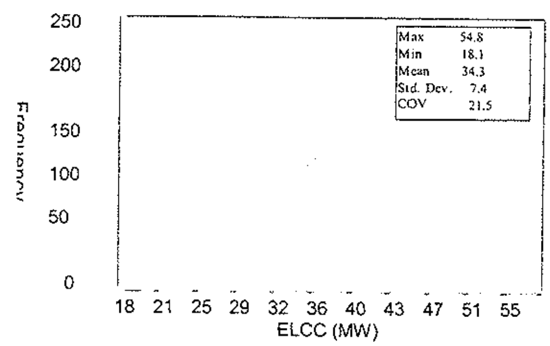
Because wind speed can vary significantly from year to year and from hour to hour, capacity credit estimates based on a single year (or less) of data and modeled without taking this variation into account may not be credible. In this section, we examine modeling techniques that can help assess this variation; we further suggest how these methods can be extended for generalized risk assessment.

Many production-cost and reliability models have a Monte Carlo option that allows sampling from the probability distributions of generator availability. This approach is used to obtain a better estimate of the range of possible outcomes than can be provided by the usual convolution approach. Another advantage of the Monte Carlo method is that it provides estimates of various probability distributions, such as system reliability and system costs. The P+ model also has a branching option that combines the more efficient convolution approach with the more precise Monte Carlo method. The branching technique performs the usual convolution on all but one generator. This generator's state will be sampled repeatedly via Monte Carlo, holding all other generator values to the expected values from the convolution. This allows the analyst to focus on the effects of a particular generator, without paying the full price of heavy execution time that can be exacted by full Monte Carlo simulations. An excellent discussion of this technique in the context of chronological production cost models can be found in Marnay and Strauss (1990).

This approach appears to be ideal for modeling wind power plants. Unfortunately, the Monte Carlo simulation procedures typically sample from a very simple probability distribution that is not appropriate for wind power plants. This leads us to consider separating the probabilistic sampling from the production-cost model. The method involves repeated creation of synthetic wind-speed data that can easily be used to calculate hourly wind power output. One can obtain a sequence of such data sets, and then run a series of production model simulations, capturing the results of these runs and summarizing in a convenient form. The Monte Carlo process is used to create the synthetic wind series, and the production-cost or reliability model can be applied to each. This is sometimes called *Sequential Monte Carlo* to differentiate it from the Monte Carlo logic that is often found in the models themselves. Milligan (1996) illustrates such a Monte Carlo method, which is similar to a technique proposed by Billinton, Chen, and Ghajar (1996). Milligan (1997) applies this approach to a 13-year data set, and compares the capacity credit results obtained with the external Monte Carlo method with results using the actual wind-speed data. The findings indicate that this modeling procedure did a very good job of estimating the variability in capacity credit, but somewhat underestimated the variation in energy production. Milligan and Graham (1997) extend the basic framework, using the Elfin and P+ models, and introduce a reduction technique to help minimize the significant model run-time that is required for the full simulation set.

The Milligan and Graham study examined the influence of interannual variations in wind on ELCC, production cost, and the scheduling of various conventional generators. Their approach was to generate 1,000 synthetic hourly time-series of wind speed with properties similar to actual hourly wind speed. For each of the synthetic series, they ran a production simulation model and calculated ELCC. Although this approach is very time-consuming, it helps answer basic questions about the likelihood of significant variations in the timing and availability of wind power. Figure 3 shows a frequency distribution of 1,000 model runs based on a wind plant with a rated capacity of 100 MW. From the graph, we can determine that 500 times out of 1,000 we would expect the ELCC of this particular wind plant to

Figure 3. Estimated variations in effective load-carrying capability of wind power plant



fall between 32 and 40% of rated capacity.

The same technique can be applied to various other items of interest. For example, a GENCO can run such a model to determine the likelihood of committing a conventional unit given a particular bidding strategy and expected wind forecast error. Milligan and Graham successfully applied this method to examine various generating schedules and costs that would vary as a function of year-to-year changes in wind generation. One of the by-products of this type of modeling is the probability distribution of the parameter of interest. As the accurate assessment of risk plays a larger role in the analysis of restructured power markets, techniques such as this will become more widespread and useful.

4. EFFECTS OF GEOGRAPHIC DISPERSION

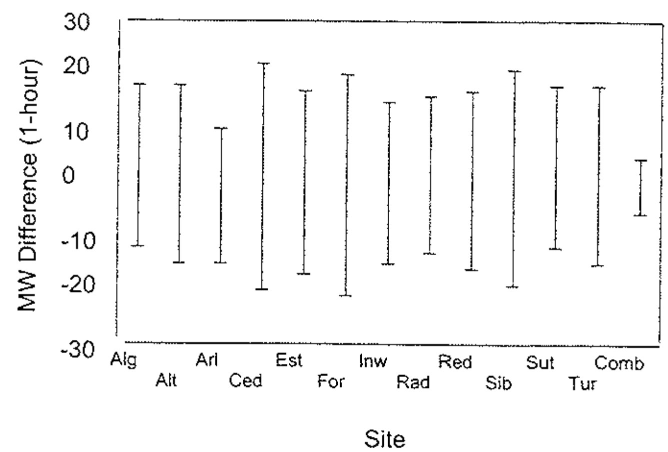
Several studies have examined the issue of geographically dispersed wind sites and the potential smoothing benefit on aggregate wind power output. The principle behind this benefit is that lulls in the wind tend to be more pronounced locally than over a wide geographic area. Building wind capacity at different locations may help reduce the problems caused by the intermittency of the wind resource. Wind developers in competitive electricity markets will likely examine these effects closely and use broader geographic areas to reduce the risks of not meeting committed capacity targets and highly varying wind output. Kahn's (1979) analysis is based on data collected in California. Grubb (1991) analyzes the effects of smoothing from wind generating units in Britain. Milligan and Artig (1998) examined a reliability optimization for the state of Minnesota but did not address economic benefits. Ernst, Wan, and Kirby (1999) provides an analysis of short-term, high-resolution wind data in Germany. Milligan and Factor (2000) examined geographical optimization using two optimization targets: reliability and economic benefit. All of these analysts found that the geographic spread of wind generators provides a smoothing benefit when wind output is aggregated. Although it is measured differently in these studies, the results appear to be robust across time scales ranging from minutes to hours.

An example of this smoothing effect can be seen in Figure 4, which is based on actual hourly wind-speed data from Iowa. For this graph, a hypothetical 25-MW wind farm was simulated at each of the 12 locations. Then, the maximum and minimum hourly changes in wind power output were calculated. These extreme values are represented in the graph. The next step was to recalculate the wind power output under the assumption that the 25 MW is evenly split among all 12 sites. The hourly power changes were calculated for this combined site ("Comb" in the figure), and appear on the far right side of the graph. This exercise shows the potential dramatic smoothing effect that can be achieved by spreading wind development over wide geographic areas. It should be noted that all of the site data is based on a single anemometer. A real wind farm at each site would be unlikely to experience the wide hourly variation that appears in the graph. Furthermore, there may be other advantages to geographic dispersion that arise from the mitigation of forecast errors over relatively broader geographic regions.

Smooth power output from a wind farm is not necessarily the objective that should be pursued. Instead, an analysis that examines either system reliability benefits or economic benefits would not necessarily find that smoother is better. From here, the analysis can get a bit complicated. In one joint project, NREL and the Minnesota Department of Public Service set out to find the combination and sizes of wind power plants that would maximize system reliability. They selected 825 MW of rated wind capacity as the total level of installed capacity, corresponding to the capacity level that was negotiated between the state of Minnesota and Northern States Power Company as part of the Prairie Island nuclear-waste storage agreement. Milligan and Artig applied a dynamic fuzzy-logic search technique to examine the most promising locations and sizes, evaluating the system reliability for the state of Minnesota. They found that a number of promising site combinations offered the most reliability for generating systems.

Milligan and Factor did a similar analysis for the state of Iowa, applying both a dynamic fuzzy-search technique and a genetic algorithm to the optimization process. However, in this case, there were 12 wind sites with a total installed capacity target of 1,600 MW. Their model was run with projected hourly load data

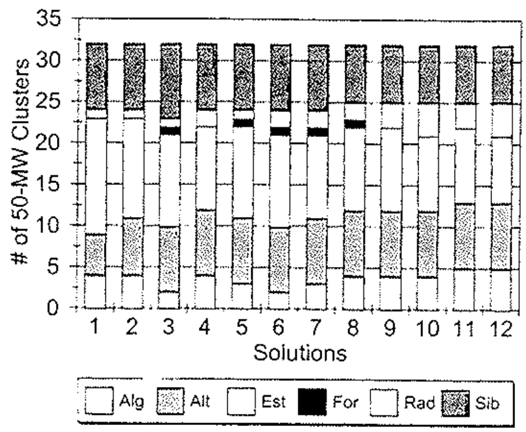
Figure 4. Smoothing effect at multiple wind sites in Iowa



for the year 2015, along with detailed information about all power generators and significant power exchanges in the wholesale power market in Iowa. To reduce computer run-time to a manageable level, they considered 50 MW as the smallest increment of wind capacity development that could be built at a single site. Even with this restriction, there are approximately 5 x 10^9 possible ways to build 1,600 MW among 12 sites. Given the extremely large number of potential solutions, their technique provides several alternative solution sets, each of which represents either the best or close-to-the-best combination of sites. In this study, they redefined "best" to be that combination of sites that would minimize the cost of running the conventional generating units. In additional model runs, they identified the combination and location of sites that would maximize reliability and described these in their paper.

Figure 5 illustrates the basic results. Each bar represents a solution that identifies a particular combination of wind plant locations and sizes. For example, the bar on the far left side shows a recommendation of four 50-MW clusters at Algona ("Alg"), 5 clusters at Alta ("Alt"), 13 clusters at Estherville ("Est"), and so forth. Bar 2 shows a slightly different combination of sites than bar 1; more wind capacity at Alta is traded against less capacity at Estherville. Even though the number of clusters at Alta and Estherville differ significantly between the two solutions, the difference in economic benefit between these two solutions is extremely small.

Figure 5. Top 12 site combinations based on economic benefit for Iowa



Not all sites were chosen for potential development. This suggests that although geographic dispersion can provide benefits, it is not a foregone conclusion that sites distant from each other will necessarily provide economic or reliability benefits to the grid.

Milligan and Factor tested alternative site combinations that they considered close to the choices recommended by their model. They found many additional site combinations that were nearly as good (by their metric) as the site combinations that appear in Figure 4. They believe that these multiple solutions provide significant latitude to take other constraints into account that are not explicitly recognized by the modeling process. Some of these constraints include transmission constraints, land-use constraints, or other operational issues such as local voltage or volt-ampere reactive support. This modeling process allows them to investigate the merit of building a small amount of capacity at one of the sites that was not chosen by the optimization process, given that they make small changes in the capacity recommendations at the remaining 11 sites. This provides decision makers with extraordinary latitude in selecting the locations and sizing of geographically dispersed wind power plants.

5. OPERATING IMPACTS

Operating a wind power plant in the electricity grid is an option receiving a great deal of attention by power generating companies. A study commissioned by the Utility Wind Interest Group in the United States has begun to examine some of these issues, and is scheduled for completion in 2002. As studies such as this one move forward, it is important to note that variations in wind power output cannot be reasonably analyzed separately from the other variations already prominent in electrical grid operations. One of the key advantages to large, interconnected systems is the principle of risk pooling. Probably the most common example of this can be seen in the various reserve requirements within grid control areas. Backup generation is not provided for each generator; rather, it is provided in the context of *system* risk.

This principle is at the heart of the simple, elegant approach developed by Strbac and Kirschen (2000) to allocate the reserve burden among all generators in the system. Their technique is based on a substantial body of reliability analysis used in the electric utility industry for many years. Milligan (2001a) adapted the Strbac and Kirschen (SK) technique to a system that includes wind generation. The basic idea is to calculate a reliability index, in this case expected unserved energy (EUE), which is related to the LOLP. Because all power plants can experience unexpected outages, the technique accounts for plants that are relatively reliable, allocating a smaller reserve burden to those plants. Conversely, a relatively unreliable plant imposes a larger reserve burden on the system because of its greater risk of outage, and therefore is charged a larger portion of the reserve cost than a reliable unit. Once the relevant reliability index is calculated for a wind plant, it can be added to the generator mix and the reserve burden can be calculated for all generators.

Applying this model to load and generator data from Minnesota, we can calculate the relative reserve burden for the wind power plant. The EUE calculations are based on a model described in Milligan (2001b), which uses a 6-hour sliding window as the basis for the LOLP and EUE calculations. For each hour, the EUE is calculated for the entire system and for the wind power plant. The relative share of the wind plant is calculated by prorating the share of the wind plant to the total and can be summarized in several ways.

Figure 6 is taken from Milligan (2001a) and illustrates the reserve calculation for the month of January. The graph shows the hourly wind power output and the calculated reserve burden for the wind plant. Although it is difficult to see in the graph, wind's reserve liability increases during time periods of more volatile wind output and decreases during periods of steady wind. The basic algorithm was

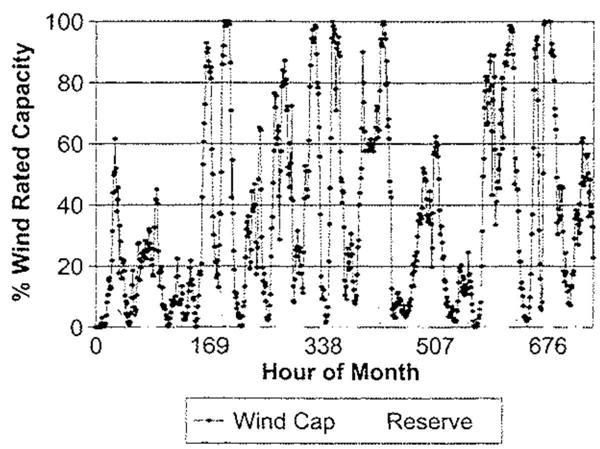


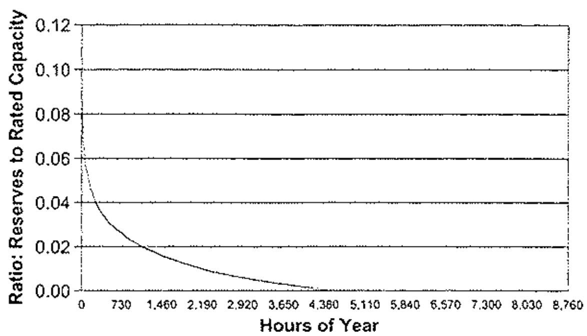
Figure 6

modified so that wind generation that exceeded the average during the sliding window was not counted towards a loss of load event.

Figure 7 illustrates the number of hours in the year that the wind reserve liability attains various percentages of the installed capacity of the wind plant. The graph indicates that the maximum reserve obligation of the wind plant is 11% of rated capacity, falling to an annual average of about 1%. These results are important because they imply that the wind plant does indeed contribute to system EUE, but is responsible for a small percentage of the total.

Similar results for system regulation burdens have been obtained using subhourly data. Hudson, Kirby, and Wan (2001) calculated the regulation burden of a wind power plant using 1-second wind power data from Lake Benton II in Minnesota. They analyzed the impact of increasing penetration of wind turbines, based on several wind turbine clusters at Lake Benton II. With about 15 MW of wind capacity, the regulation burden imposed on the wind plant was about 11% of rated capacity. When the wind penetration increased to approximately 104 MW, the regulation burden fell to just under 6% of rated capacity.

Figure 7



6. OTHER ISSUES

On the basis of day-to-day operations, various power pools and control areas have specific ways of assessing the operational capacity credit of all generators in the region. This capacity credit is assessed in part to determine if available capacity exists in the region during the specified time period. Wind power plants can provide operational capacity credit, although typically at some fraction of rated capacity. As various operating regions and pools mature under restructured electricity markets, the pool accreditation rules may be reevaluated. Under these rules, all resources should be treated in an unbiased way, recognizing the difficulties imposed by intermittent power plants.

In their analysis of Iowa, Milligan and Factor used the capacity credit procedure from the Mid-Continent Area Power Pool (MAPP), one of only two pools that specifically address wind power plants. Applying this method to the top 12 fuzzy solutions, the annual average capacity credit was 47% of the rated capacity of the composite wind plant, with significant monthly variation. The MAPP method is based on finding the median output of the power plant during a 4-hour window surrounding the monthly system peak, as contrasted with LOLP-based methods that consider a broader time period, weighting the more critical peak hours according to the potential loss of service.

In April of 2002, the United States Senate passed a renewable portfolio standard (RPS). At the time of this writing, there are differences between the House and Senate energy bills, and it is not clear whether the RPS will become part of United States energy policy. Proponents of the RPS argue that fossil fuels pollute the air, imposing various forms of environmental damage that is not factored in to the cost of the fuel. Because renewable energy does not pollute, a purely competitive market would not credit the renewable energy source for the prevented damages caused by pollution. Eight states have various RPS policies in place. Most of these require increasing levels of renewable energy over the next decade or so. A national RPS could have a significant effect on wind energy development in the United States, but this depends on the details of the legislation, if it comes to fruition. Among the various state policies, the Texas RPS is generally considered to be the most successful, with actual development exceeding the RPS targets through early 2002. Further details can be found on the web site of the American Wind Energy Association (2001).

Wind power plants must be located at sites that have a good wind resource. Unfortunately, this may be at a location far away from the load center and/or a transmission interconnection point. There can be an additional complication even if transmission is nearby, but the line is nearly fully loaded during times of peak wind plant output. Because wind power plants typically operate at annual capacity factors between 20 and 40%, the high fixed cost of transmission line construction is spread over fewer kWh than for most conventional power plants. As wind operators bid into an electricity supply pool in restructured markets, transmission capacity must also be available at the time the wind power is available. This introduces additional complications for the wind plant operator. The formation and revision of transmission access rules will play an important part in wind plant development in the new millennium. Rules should not impose implicit or explicit barriers to entry, and must fairly allocate costs, even across multiple operating regions. Penalty-based rules in ancillary service markets are less desirable than make-up rules, allowing the generator to replace capacity or standby power that may have been incorrectly supplied. Penalties resulting from operating practices different than those instructed by the system operator would be acceptable, however. The U.S. National Wind Coordinating Council has analyzed these and other transmission issues. The results are available on the Internet at http://www.nationalwind.org/pubs.

7. SUMMARY

We have begun to understand some of the issues regarding the use of large-scale wind power plants in regulated markets through a combination of growing experience with wind power plants and the application of various modeling methods and techniques. As the use of wind energy increases, this understanding will expand to a more empirical base. In addition, as the electricity system moves towards a more competitively based market structure, many of these issues will be addressed in the context of the new electricity markets. In the future, one key issue will be to adapt our knowledge base from the old to the new market structures.

Wind power plants have capacity, energy, and emissions value, depending on a variety of factors. As the utility industry enters an era of increasing risks, companies will need to be fully aware of the various risks posed by the new markets. The use of large-scale wind power plants presents some risk (for example, no wind when it is needed), but alleviates others (for example, future fuel-cost escalation or tighter constraints on future emissions levels). Some of these risks can be mitigated by good siting and by geographic dispersion. Although these smoothing effects have been documented in both high-resolution and hourly data, they are not currently well understood. However, the anecdotal evidence suggests that these smoothing benefits can be substantial. Other wind-related risks can be mitigated by accurate wind forecasts to help wind plant operators bid into the electricity supply markets.

Although additional work needs to be done to accurately assess the impact of wind systems on various ancillary services, the results so far indicate that reserve and regulation requirements for wind are not onerous. Both studies cited in this paper arrive at similar conclusions: the reserve and regulation burden appear to be on the order of 10% of the rated capacity of the wind plant. Efforts to further refine these results using subhourly data are ongoing, and will provide further insight into these issues.

Transmission will play an important role in the future development of wind energy. As regulatory and market forces evolve in the newly emerging competitive markets, there are many unresolved issues concerning reasonable and fair cost allocations, incentives for market players to provide sufficient transmission, and consistent rules governing different regions. For competition to succeed, it is critical that transmission access is afforded to all technologies in a way that does not reward those players with substantial market power.

There are several other important issues that must be addressed that will play an important role in determining the success of wind power plants in the new electricity markets. They include the specific regulatory environment of the new markets, RPS legislation, power pool rules, and bidding and settlement procedures. Significant levels of market power on the part of large generation owners will also have an important influence on the role of large-scale wind power plants in the restructured market.

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