EnerNex CORPORATION

# Xcel Energy and the Minnesota Department of Commerce

# Wind Integration Study - Final Report

*Prepared by*

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## Project Summary

### Introduction

In 2003, the Minnesota Legislature adopted a requirement for an Independent Study of Intermittent Resources to evaluate the impacts of over 825 MW of wind power on the Xcel Energy system. The Minnesota Public Utilities Commission requested that the office of the Reliability Administrator of the Minnesota Department of Commerce take responsibility for the study and its scope and administration. Through a competitive bidding process, the study was commissioned in January of 2004. Results of that study are reported here.

Xcel Energy, formed by the merger of Denver-based New Centuries Energies and Minneapolis-based Northern States Power Company, is the fourth-largest combination electricity and natural gas energy company in the United States. Xcel Energy serves over 1.4 million electric customers in the states of Minnesota, Wisconsin, North Dakota, South Dakota and Michigan. Their peak demand in this region is approximately 9,000 MW in 2003 and projected to rise to approximately 10,000 MW by 2010.

In 2003, the Xcel Energy operating area in Minnesota, Wisconsin, and parts of the Dakotas had about 470 MW of wind power under contract, including about 300 MW operating, in Southwestern Minnesota. An additional 450 MW of wind power has been awarded through the 2001 All Source Bid process. Minnesota legislation could result in a total of 1,450 to 1,750 MW of wind power serving the NSP system by 2010 and 1,950 to 2,250 MW by 2015.

An earlier study commissioned by Xcel Energy and the Utility Wind Interest Group (UWIG, www.uwig.org) estimated that the approximately 300 MW of wind generation in Xcel Energy's control area in Minnesota at that time resulted in additional annual costs to Xcel of $1.85 for each megawatt-hour (MWH) of wind energy delivered to the system. While for some time there had been recognition and consensus that the unique characteristics of wind generation likely would have some technical and financial impacts on the utility system, this study was the first attempt at a formal quantification for an actual utility control area.

The study looked at the "operating" time frame, which consists primarily of those activities required to ensure that there will be adequate electric energy supply to meet the projected demand over the coming hours and days, that the system is operated at all times so as not to compromise security or reliability, and that the demand be met at the lowest possible cost.

The study reported on here takes a similar perspective. The scenario evaluated, however, is dramatically different. Instead of 300 MW of wind generation confined to relatively small parts of two adjacent counties, a potential future development of 1500 MW of wind generation spread out over hundreds of square miles is considered. In addition, the wind generation central to the previous study was well characterized through existing monitoring projects and measurements at all of the time scales of interest, making questions about how wind generation would appear to the Xcel system operators relatively simple to address. In this study, developing a characterization of how large, geographically-diverse wind plants would appear in the aggregate to the system operators was one early and major challenge.

To better understand the study scope, its specific challenges, and the results, some background on utility system operations and the characteristics of wind generation is helpful.

### Overview of Utility System Operations

Interconnected power systems are large and extremely complex machines, consisting of thousands of individual elements. The mechanisms responsible for their control must continually adjust the supply of electric energy to meet the combined and ever-changing electric demand of the system's users. There are a host of constraints and objectives that govern how this is done. For example, the system must operate with very high reliability and provide electric energy at the lowest possible cost. Limitations of individual network elements –generators, transmission lines, substations – must be honored at all times. The capabilities of each of these elements must be utilized in a fashion to provide the required high levels of performance and reliability at the lowest overall cost.

Operating the power system, then, involves much more than adjusting the combined output of the supply resources to meet the load. Maintaining reliability and acceptable performance, for example, requires that operators:

- Keep the voltage at each node (a point where two or more system elements – lines, transformers, loads, generators, etc. – connect) of the system within prescribed limits;
- Regulate the system frequency (the steady electrical speed at which all generators in the system are rotating) of the system to keep all generating units in synchronism;
- Maintain the system in a state where it is able to withstand and recover from unplanned failures or losses of major elements

The activities and functions necessary for maintaining system performance and reliability and minimizing costs are generally classified as "ancillary services." While there is no universal agreement on the number or specific definition of these services, the following items adequately encompass the range of technical aspects that must be considered for reliable operation of the system:

- Voltage regulation and VAR dispatch – deploying of devices capable of generating reactive power to manage voltages at all points in the network;
- Regulation – the process of maintaining system frequency by adjusting certain generating units in response to fast fluctuations in the total system load;
- Load following – moving generation up (in the morning) or down (late in the day) in response to the daily load patterns;
- Frequency-responding spinning reserve – maintaining an adequate supply of generating capacity (usually on-line, synchronized to the grid) that is able to quickly respond to the loss of a major transmission network element or another generating unit;
- Supplemental Reserve – managing an additional back-up supply of generating capacity that can be brought on line relatively quickly to serve load in case of the unplanned loss of significant operating generation or a major transmission element.

The frequency of the system and the voltages at each node are the fundamental performance indices for the system. High interconnected power system reliability is a consequence of maintaining the system in a secure state – a state where the loss of any element will not lead to cascading outages of other equipment - at all times.

The electric power system in the United States (contiguous 48 states) is comprised of three interconnected networks: the Eastern Interconnection (most of the states East of the Rocky Mountains), the Western Interconnection (Rocky Mountain States west to the Pacific Ocean), and ERCOT (most of Texas). Within the Eastern and Western interconnections, dozens of individual "control" areas coordinate their activities to maintain reliability and conduct transactions of electric energy with each other. A number of these individual control areas are members of Regional Transmission Organizations (RTOs), which oversee and coordinate activities across a number of control areas for the purposes of maintaining the security of the interconnected power system and implementing wholesale power markets.

A control area consists of generators, loads, and defined and monitored transmission ties to neighboring areas. Each control area must assist the larger interconnection with maintaining frequency at 60 Hz, and balance load, generation, out-of-area purchases and sales on a continuous basis. In addition, a prescribed amount of backup or reserve capacity (generation that is unused but available within a certain amount of time) must be maintained at all times as protection against unplanned failure or outage of equipment.

To accomplish the objectives of minimizing costs and ensuring system performance and reliability over the short term (hours to weeks), the activities that go on in each control area consist of:

- Developing plans and schedules for meeting the forecast load over the coming days, weeks, and possibly months, considering all technical constraints, contractual obligations, and financial objectives;
- Monitoring the operation of the control area in real time and making adjustments when the actual conditions - load levels, status of generating units, etc. - deviate from those that were forecast.

A number of tools and systems are employed to assist in these activities. Developing plans and schedules involves evaluating a very large number of possibilities for the deployment of the available generating resources. A major objective here is to utilize the supply resources so that all obligations are met and the total cost to serve the projected load is minimized. With a large number of individual generating units with many different operational characteristics and constraints, fuel types, efficiencies, and other supply options such as energy purchases from other control areas, software tools must be employed to develop optimal plans and schedules. These tools assist operators in making decisions to "commit" generating units for operation, since many units cannot realistically be stopped or started at will. They are also used to develop schedules for the next day or days that will result in minimum costs if adhered to and if the load forecasts are accurate.

The Energy Management System (EMS) is the technical core of modern control areas. It consists of hardware, software, communications, and telemetry to monitor the real-time performance of the control area and make adjustments to generating unit and other network components to achieve operating performance objectives. A number of these adjustments happen very quickly without the intervention of human operators. Others, however, are made in response to decisions by individuals charged with monitoring the performance of the system.

The nature of control area operations in real-time or in planning for the hours and days ahead is such that increased knowledge of what will happen correlates strongly to better strategies for managing the system. Much of this process is already based on predictions of uncertain quantities. Hour-by-hour forecasts of load for the next day or several days, for example, are critical inputs to the process of deploying electric generating units and scheduling their operation. While it is recognized that load forecasts for future periods can never be 100% accurate, they nonetheless are the foundation for all of the procedures and process for operating the power system. Increasingly sophisticated load forecasting techniques and decades of experience in applying this information have done much to lessen the effects of the inherent uncertainty

### Characteristics of Wind Generation

The nature of its "fuel" supply distinguishes wind generation from more traditional means for producing electric energy. The electric power output of a wind turbine depends on the speed of the wind passing over its blades. The effective speed (since the wind speed across the swept area of the wind turbine rotor is not necessarily uniform) of this moving air stream exhibits variability on a wide range of time scales – from seconds to hours, days, and seasons. Terrain, topography, other nearby turbines, local and regional weather patterns, and seasonal and annual climate variations are just a few of the factors that can influence the electrical output variability of a wind turbine generator.

It should be noted that variability in output is not confined only to wind generation. Hydro plants, for example, depend on water storage that can vary from year to year or even seasonally. Generators that utilize natural gas as a fuel can be subject to supply disruptions or storage limitations. Cogeneration plants may vary their electric power production in response to demands for steam rather than the wishes of the power system operators. That said, the effects of the variable fuel supply are likely more significant for wind generation, if only because the experience with these plants accumulated thus far is so limited.

An individual turbine is negligibly small with respect to the load and other supply resources in the control area, so the aggregate performance of a large number of turbines is what is of primary interest with respect to impacts on the transmission grid and system operations. Large wind generation facilities that connect directly to the transmission grid employ large numbers of individual wind turbine generators, with the total nameplate generation on par with other more conventional plants. Individual wind turbine generators that comprise a wind plant are usually spread out over a significant geographical area. This has the effect of exposing each turbine to a slightly different fuel supply. This spatial diversity has the beneficial effect of "smoothing out" some of the variations in electrical output. The benefits of spatial diversity are also apparent on larger geographical scales, as the combined output of multiple wind plants will be less variable (as a percentage of total output) than for each plant individually.

Another aspect of wind generation, which applies to conventional generation but to a much smaller degree, is the ability to predict with reasonable confidence what the output level will be at some time in the future. Conventional plants, for example, cannot be counted on with 100% confidence to produce their rated output at some coming hour since mechanical failures or other circumstances may limit their output to a lower level or even result in the plant being taken out of service. The probability that this will occur, however, is low enough that such an occurrence is often discounted or completely ignored by power system operators in short-term planning activities.

Because wind generation is driven by the same physical phenomena that control the weather, the uncertainty associated with a prediction of generation level at some future hour, even maybe the next hour, is significant. In addition, the expected accuracy of any prediction will degrade as the time horizon is extended, such that a prediction for the next hour will almost always be more accurate than a prediction for the same hour tomorrow.

The combination of production variability and relatively high uncertainty of prediction makes it difficult, at present, to "fit" wind generation into established practices and methodologies for power system operations and short-term planning and scheduling. These practices, and even emerging concepts such as hour- and day-ahead competitive markets, have a necessary bias toward "capacity" - because of system security and reliability concerns so fundamental to power system operation - with energy a secondary consideration. Wind generation is a clean, increasingly inexpensive, and stable supply of electric energy. The challenge going forward is to better understand how wind energy as a supply resource interacts with other types of electric generation and how it can be exploited to maximize benefits, in spite its unique characteristics.

### Wind Generation and Long-Term Power System Reliability

In longer term planning of electric power systems, overall reliability is often gauged in terms of the probability that the planned generation capacity will be insufficient to meet the projected system demand. This question is important from the planning perspective because it is recognized that even conventional electric generating plants and units are not completely reliable – there is some probability that in a given future hour capacity from the unit would be unavailable or limited in capability due to a forced outage – i.e. mechanical failure. This probability of not being able to meet the load demand exists even if the installed capacity in the control area exceeds the peak projected load.

In this sense, conventional generating units are similar to wind plants. For conventional units, the probability that the rated output would not be available is rather low, while for wind plants the probability could be quite high. Nevertheless, it is likely that a formal statistical computation of system reliability would reveal that the probability of not being able to meet peak load is lower with a wind plant on the system than without it.

The capacity value of wind plants for long term planning analyses is currently a topic of significant discussion in the wind and electric power industries. Characterizing the wind generation to appropriately reflect the historical statistical nature of the plant output on hourly, daily, and seasonal bases is one of the major challenges. Several techniques that capture this variability in a format appropriate for formal reliability modeling have been proposed and tested. The lack of adequate historical data for the wind plants under consideration is an obstacle for these methods.

The capacity value issue also arises in other, slightly different contexts. In the Mid-Continent Area Power Pool (MAPP), the emergence of large wind generation facilities over the past decade led to the adaptation of a procedure use for accrediting capacity of hydroelectric facilities for application to wind facilities. Capacity accreditation is a critical aspect of power pool reserve sharing agreements. The procedure uses historical performance data to identify the energy delivered by these facilities during defined peak periods important for system reliability. A similar retrospective method was used in California for computing the capacity payments to third-party generators under their Standard Offer 4 contract terms.

By any of these methods, it can be shown that wind generation does make a calculable contribution to system reliability in spite of the fact that it cannot be directly dispatched like most conventional generating resources. The magnitude of that contribution and the appropriate method for its determination remain important questions.

### Objectives of this Study

The need for various services to interoperate with the interconnected electric power system is not unique to wind. Practically all elements of the bulk power network – generators, transmission lines, delivery points (substations) – have an influence on or increase the aggregate demand for ancillary services. Within the wind industry and for those transmission system operators who now have significant experience with large wind plants, the attention has turned from debating whether wind plants require such support but rather to the type and quantity of such services necessary for successful integration.

Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research, studies, and empirical understanding gained from the installation and operation of over 6000 MW of wind generation in the United States.

The focus of these studies covers the range of technical questions related to interconnection and integration. With respect to the ancillary services listed earlier, there is a growing emphasis on better understanding how significant wind generation in a control area affects operations in the very short term – i.e. real-time and a few hours ahead – and planning activities for the next day or several days.

Recent studies, including the initial study for Xcel Energy by the UWIG, have endeavored to quantify the impact of wind generation facilities on real-time operation and short-term planning for various control areas. The methods employed and the characteristics of the power systems analyzed vary substantially. There are some common findings and themes throughout these studies, however, including:

- Despite differing methodologies and levels of detail, ancillary service costs resulting from integrating wind generation facilities are relatively modest for the growth in U.S. wind generation expected over the next three to five years.
- The cost to the operator of the control area to integrate a wind generation facility is obviously non-zero, and increases as the ratio of wind generation to conventional supply sources or the peak load in the control area increases.
- For the penetration levels (ratio of nameplate wind generation to peak system load) considered in these studies (generally less than 20%) the integration costs per MWH of wind energy were likely modest.
- Wind generation is variable and uncertain, but how this variation and uncertainty combines with other uncertainties inherent in power system operation (e.g. variations in load and load forecast uncertainty) is a critical factor in determining integration costs.
- The effect of spatial and temporal diversity with large numbers of individual wind turbines is a key factor in smoothing the output of wind plants and reducing their ancillary service requirements from a system-wide perspective.

The objective of this study is to conduct a comprehensive, quantitative assessment of integration costs and reliability impacts of 1500 MW of wind generation in the Xcel Energy control area in Minnesota in the year 2010, when the peak load is projected to be just under 10,000 MW. As discussed previously, such a large wind generation scenario poses some significant study challenges, and lies near the outer edge penetration-wise of the studies conducted to date.

Per the instructions developed by Xcel Energy and the Minnesota Department of Commerce, the study was to focus on those issues, activities, and functions related to the short-term planning and scheduling of electric generation resources and the operation of the Xcel control area in real time, and questions concerning the contributions of wind generation to power system reliability. While very important for wind generation and certainly a topic of much current discussion in the upper Midwest, ***transmission issues were not to be addressed in this study***. Some transmission issues are considered implicitly, as interactions with neighboring control areas and the emerging wholesale power markets being administered by MISO (Midwest Independent System Operator) are relevant to the questions addressed here.

### Organization of Documentation

The report for this study is provided as two volumes. This volume of the report addresses each of the four tasks of the report and provides the final conclusions. A second, stand-alone volume contains all of the detail for the first task of the study, a complete characterization of the wind resource in Minnesota. In it are dozens of color maps and charts that describe and quantify the meteorology that drives the wind resource in the upper Midwest, along with graphical depictions of the locational variation of the wind resource and potential wind generation by month and time of day. Some of the material from this companion volume is repeated as it describes the process for developing the wind generation model that used for the later tasks.

The major sections of this document address each of four tasks as defined in the work scope of the original request-for-proposal (RFP).

### Task 1: Characterizing the Nature of Wind Power Variability in the Midwest - Overview and Results

A major impediment to obtaining a better understanding of how large amounts of wind generation would affect electric utility control area operations and wholesale power markets is the relative lack of historical data and operating experience with multiple, geographically dispersed wind plants.

Measurement data and other information have been compiled over the past few years on some large wind plants across the country. The Lake Benton plants at the Buffalo Ridge substation in southwestern Minnesota have been monitored in detail for several years. The understanding of how a single large wind plant might behave is much better today than it was five years ago.

For the study, predicting how all of the wind plants in the 1500 MW scenario appear in the aggregate to the Xcel system operators and planners is a critical aspect. That total amount of wind generation will likely consist of many small and large facilities spread out over a large land area, with individual facilities separated by tens of miles up to over two hundred miles.

The approach for this study was to utilize sophisticated meteorological simulations and archived weather data to "recreate" the weather for selected past years, with "magnification" in both space and time for the sites of interest. Wind speed histories from the model output for the sites at heights for modern wind turbines were then converted to wind generation histories.

Figure 1 shows the "grid" used with the MM5 numerical model to simulate the actual meteorology occurring over the upper Midwest. The simulation featured two internal, nested grids of successively higher spatial resolution. On the innermost grid, specific points that were either co-located with existing wind plants or likely prospects for future development were identified. Wind speed data along with other key atmospheric variables from these selected grids (Figure 2) were saved at ten-minute intervals as the simulation progressed through three years of weather modeling.

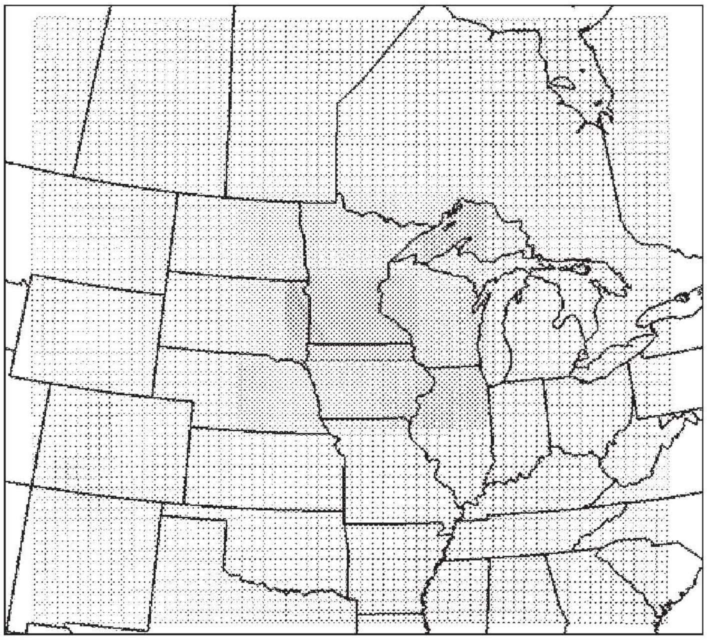

Figure 1: MM5 nested grid configuration utilized for study area. The 3 grid run includes 2 inner nested grids to optimize the simulation resolution in the area of greatest interest. The grid spacing is 45, 15 and 5 km for the outer, middle and innermost nests, respectively.

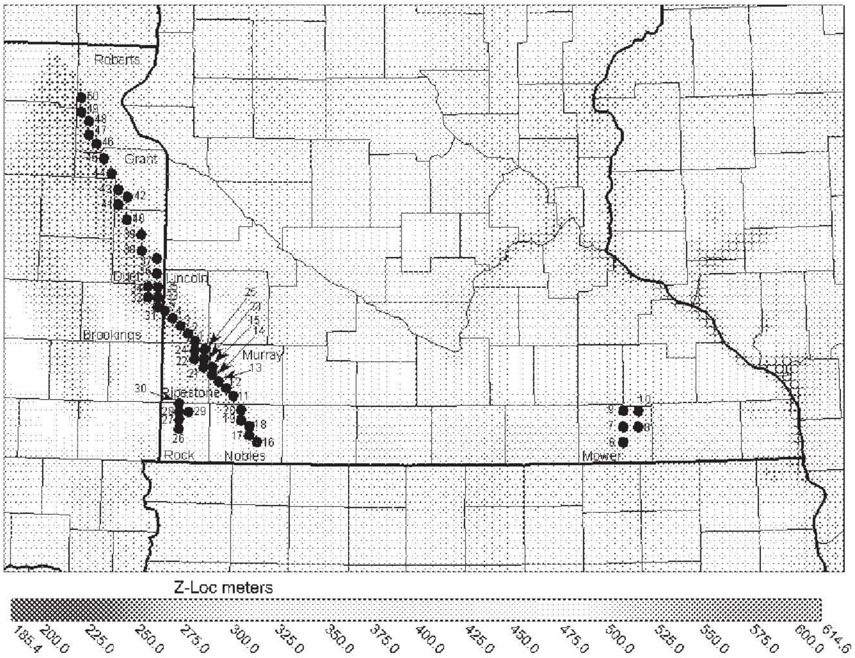


Figure 2: "Tower" locations on the innermost MM5 model grid where wind speed data and other meteorological data were captured and archived at ten-minute intervals.

The high-resolution time series of wind speed data was converted to wind generation data by applying power curves for existing and prospective commercial wind turbines at each of the grid points. As a check on the accuracy of this overall modeling approach, the calculated wind generation data was compared to actual measurements from groups of turbines in the Lake Benton, MN area for the entire year of 2003 to validate the models. A comparison for a typical month is shown in Figure 3.

| | |
|---|---|
| 5.87 | ME as % of Cap |
| 14.8 | MAE as % of Cap |
| 0.81 | Correlation |

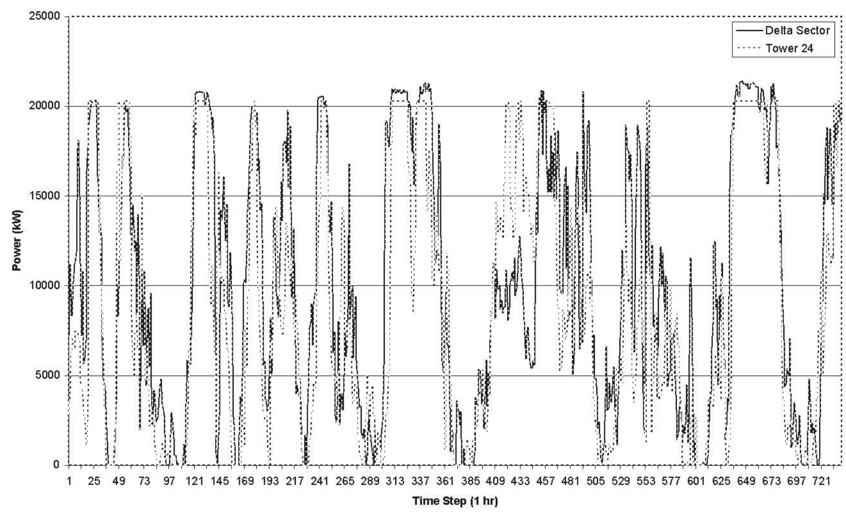


Figure 3: Comparison of simulated wind generation data to actual measurements for a group of wind turbines at Lake Benton, MN on the Buffalo Ridge

The validation exercise showed that the numerical weather modeling approach produced high quality results. In months where the wind is driven by larger-scale weather patterns, the average error as a percentage of power production over the period was about 6%. In the summer months, where smaller-scale features such as thunderstorm complexes have more influence on wind speed, the mean error was larger, but still less than 9%. Mean absolute errors as a percent of capacity were approximately 15% or less for most months.

A critical feature of the wind generation model for this study is that it captures the effects of the geographic dispersion of the wind generation facilities. For Xcel system operators, how the wind plants operate in the aggregate is of primary importance. This science-based modeling approach provides for representing the relationships between the behaviors of the individual plants over time more accurately than any other method.

Numerical weather simulations were also used in this task to develop a detailed characterization of the wind resource in Minnesota. Temporal and geographic variations in wind speed and power production over the southern half of Minnesota are characterized through a number of charts, graphs, and maps.

Task 1 concluded with a discussion of issues related to wind generation forecasting accuracy and a numerical experiment to compare various methods using the data and information compiled for developing the wind generation model. The accuracy of any weather-related forecast will decrease as the forecast horizon increases. Forecasts for the next few hours are likely to be significantly more accurate than those for the next few days. The forecast experiment did show, however, that a more sophisticated method employing artificial intelligence techniques, a computational learning system (CLS) in conjunction with a numerical weather model, holds promise for significantly improving the accuracy of forecasts spanning a range from a few hours ahead through a two day period. This forecasting technique likely will have value for control area operators. Such techniques are in the development stages now, but will be commercially available in the coming years, and relevant to the study year for which this project is being conducted.

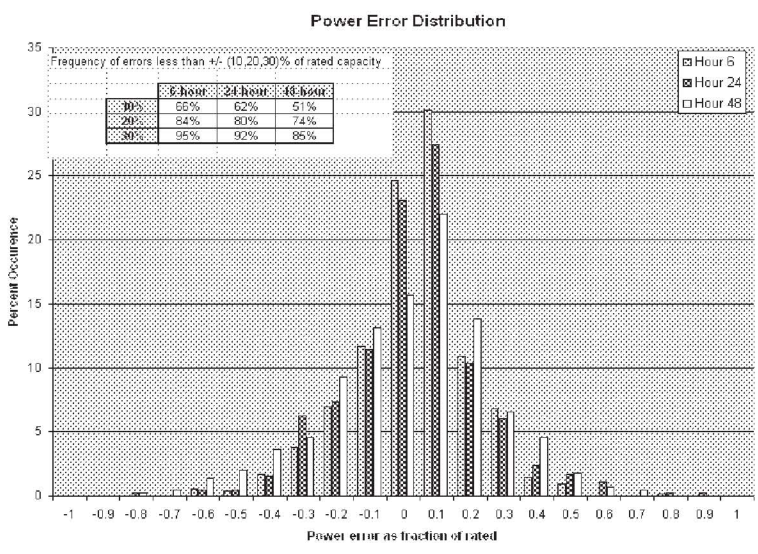


Figure 4: Frequency distribution of power error as a percent of rated capacity for 6, 24 and 48 hour forecasts. Inset table shows the frequency of power errors less than 10, 20 and 30 percent of rated capacity for the CLS 6, 24 and 48 hour forecasts.

Since transmission constraints were not considered explicitly in this project, geographic variations in wind plant output are included in the analyses only to the extent that they affect the aggregated output profile of the total wind generation in the control area. However, the spatial variations could be combined with transmission constraints for a more refined evaluation, should that be desired in a future study.

### Task 2: Develop Xcel Energy System Model for 2010 Study Year - Overview and Results

To conduct the technical analysis, models for both the wind generation development in Minnesota and the Xcel system in 2010 were developed. The wind generation scenario was derived from the numerical weather model data discussed in the previous section. In coordination with Xcel Energy and the Minnesota Department of Commerce, a county-by-county development scenario was constructed (Table 1) for the year 2010. The wind speed data created by the numerical weather model was converted to wind generation data at ten minute intervals for the three years of the simulation.

Table 1: Minnesota Wind Generation Development Scenario – CY2010

| County | Nameplate Capacity |
|---|---|
| Lincoln | 350 MW |
| Pipestone | 250 MW |
| Nobles | 250 MW |
| Murray | 150 MW |
| Rock | 50 MW |
| Mower | 150 MW |
| Brookings (SD) | 100 MW |
| Deuel (SD) | 100 MW |
| Grant (SD) | 50 MW |
| Roberts (SD) | 50 MW |
| **Total** | **1,500 MW** |

Xcel Energy predicts that the peak demand for their Minnesota control area will grow to 9933 MW in 2010. The projected resources to meet this demand are shown by type in Table 2 and graphically in Figure 5. Wind energy, which includes most of the wind generation assumed for this study, is assigned a capacity factor of 13.5% for purposes of this load and resources projection. Total capacity is projected to exceed peak demand by 15%.

Table 2: Xcel Capacity Resources for 2010

| Resource Type | Capacity (MW) |
|---|---|
| Existing NSP-owned generation | 7,529 |
| Planned NSP-owned generation | 773 |
| Long-term firm capacity purchases | 903 |
| Other purchase contracts with third-party generators (including wind) | 915 |
| Short-term purchases considered as firm resources | 1,307 |
| Total | 11,426 |

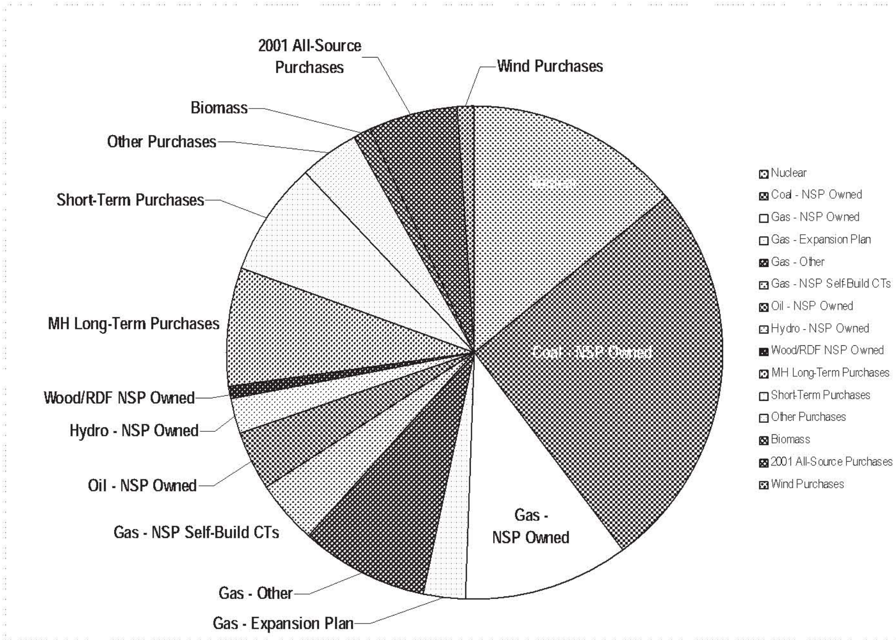


Figure 5: Xcel supply resources for 2010 by type and fuel.

Since transmission issues were not to be explicitly considered in this study, the remaining component of the Xcel system "model" for the study year is the system load. To conduct the technical analyses as specified in the RFP, it was necessary to characterize and analytically quantify the system load in great detail. A variety of measurements of the existing load were collected. To represent the system load in 2010, measurements of the current load (e.g. Figure 6) were scaled so that the peak hour for the year matched the expected peak in 2010 of 9933 MW.

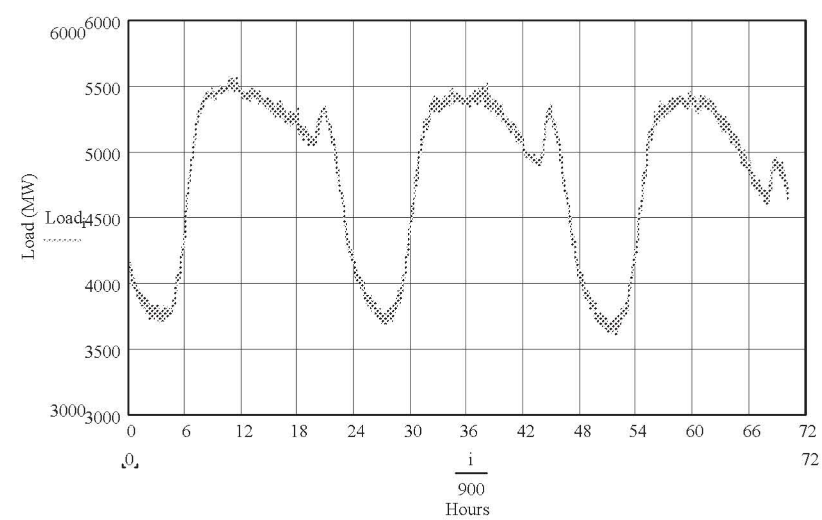


Figure 6: Measurements of existing load data used for characterizing expected load in 2010. Graph shows 72 hours of data collected at 4 second intervals by the Xcel Energy Management System (EMS)

The wind generation model derived from the numerical weather simulations was augmented with measurements from operating wind plants in Minnesota. The National Renewable Energy Laboratory (NREL) has been collecting very high resolution data from the Lake Benton I & II wind plants and the Buffalo Ridge substation in southwestern Minnesota for over three years. This data (Figure 7) was used to develop a representation of what the fastest fluctuations in wind energy delivery might look like to the Xcel system operators.

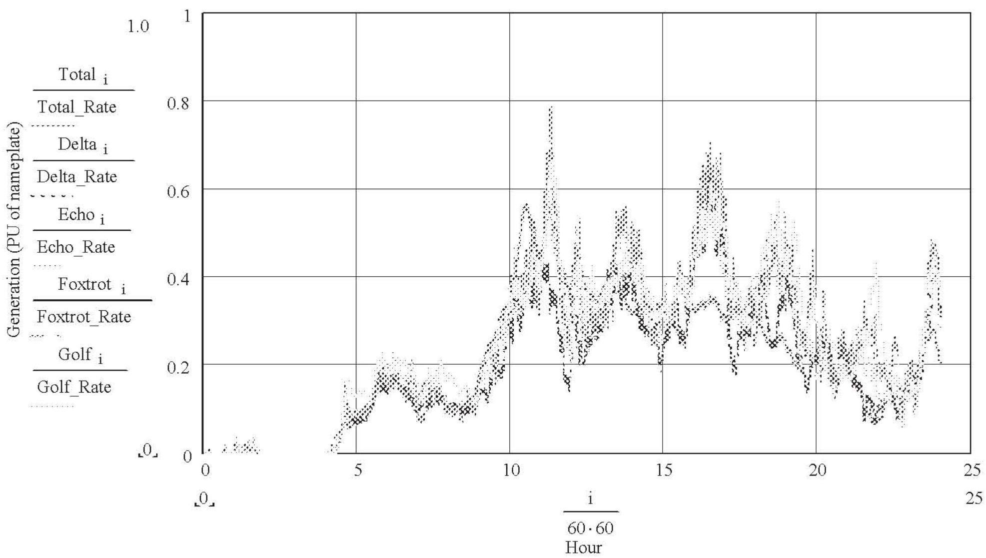


Figure 7: NREL high-resolution measurement data from Lake Benton wind plants and Buffalo Ridge substation. Data show is power production sampled at one second intervals.

### Task 3: Evaluation of Wind Generation Reliability Impacts - Overview and Results

The purpose of the reliably analysis task of this study is to determine the ELCC (Effective Load Carrying Capability) of the proposed wind generation on the Xcel system. This problem was approached by modeling the system in the GE MARS (Multi-Area Reliability Simulation) program, simulating the system with and without the additional wind generation and noting the power delivery levels for the systems at a fixed reliability level. That reliability level is LOLE (Loss of Load Expectation) of 0.1 days per year.

The MARS program uses a sequential Monte Carlo simulation to calculate the reliability indices for a multi-area system by performing an hour by hour simulation. The program calculates generation and load for each hour of the study year, calculating reliability statistics as it goes. The year is simulated with different random forced outages on generation and transmission interfaces until the simulation converges.

In this study three areas are modeled, the Xcel system including all non-wind resources, an area representing Manitoba Hydro purchases and finally an area representing the Xcel Energy wind resources. The wind resources were separated to allow monitoring of hourly generation of the wind plant during the simulations.

The MARS model was developed based upon the 2010 Load and Resources table provided by Xcel Energy. In addition, load shape information was based upon 2001 actual hourly load data provided and then scaled to the 2010 adjusted peak load of 9933 MW.

The GE MARS input data file for the MAPP Reserve Capacity Obligation Review study was provided by MAPPCOR to assist in setting up the MARS data file for this study. State transition tables representing forced outage rate information and planned outage rate information for the Xcel resources where extracted from the file where possible. In some cases it was difficult to map resources from the MAPP MARS file to the Load/Resources table provided by Xcel Energy. In those cases the resource was modeled using a generic forced outage rate for the appropriate type of generation (steam, combustion turbine, etc) obtained from the MAPP data file.

The model used multiple levels of wind output and probabilities, based on the multiple block capacities and outage rates that can be specified for thermal resources in MARS. In each Monte Carlo simulation, the MARS program randomly selects the transition states that are used for the simulation. These states can change on and hour by hour basis, making MARS suitable for the modeling of the wind resources.

To find a suitable transition rate matrix, 3 years of wind generation data supplied by WindLogics was analyzed. That data was mapped on the proposed system and an hour by hour estimate of generation was calculated for the three years. The generation was analyzed and state transitions were calculated to form the state transition matrix for input to MARS.

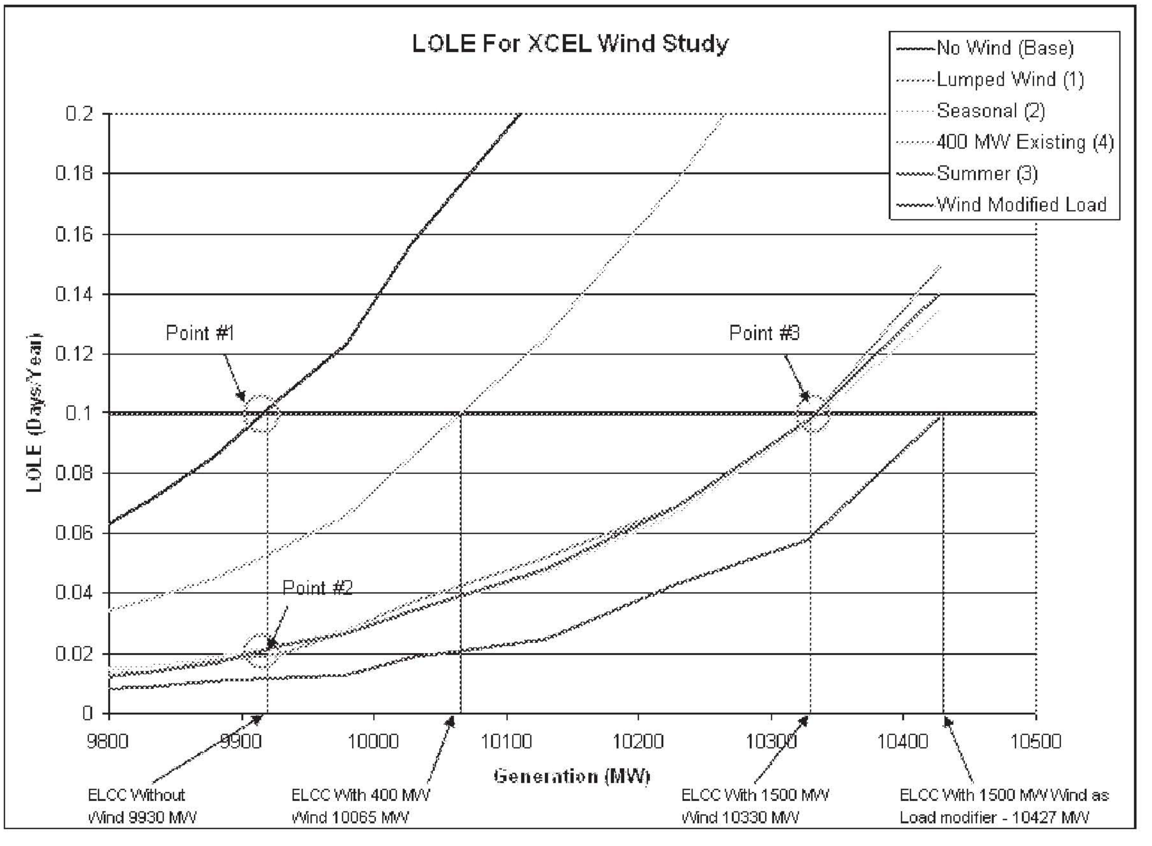


Figure 8: Results of reliability analysis for various wind generation modeling assumptions.

This result shows that the ELCC of the system improves by 400 MW or 26.67% of nameplate with the addition of 1500 MW of wind resource. The existing 400 MW improved the ELCC by 135 MW or about 33.75%. This is an estimate as the nameplate of the existing wind resource was not known precisely.

The results fall into the range of what would be "expected" by researchers and other familiar with modeling wind in utility reliability models. A remaining question, then, is one of the differences between the formal reliability calculation and the capacity accreditation procedure currently used in MAPP and being contemplated by other organizations.

The MAPP procedure takes the narrowest view of the historical production data by limiting it to only those hours around the peak hour for the entire month, which potentially excludes some hours where the load is still substantial and there would be a higher risk of outage. Applying the MAPP procedure to the aggregate wind generation model developed for this study yields a minimum capacity factor of about 17%. It is still smaller, however, than the ELCC computed using lumped or seasonal wind models (26.7%).

Even though the formal reliability calculation using GE-MARS utilizes a very large number of "trials" (replications) in determining the ELCC for wind generation, the wind model in each of those trials is still based on probabilities and state transition matrices derived from just three years of data. Some part of the difference between the MAPP method and the formal reliability calculation, therefore, can be attributed to an insufficient data set for characterizing the wind generation. When the sample of historical data is augmented to the ten year historical record prescribed in the MAPP method, the capacity value determined by the MAPP method would likely increase, reducing the magnitude of the difference between the two results.

This does not account for the entire difference between the methods, though. The MAPP procedure only considers the monthly peak hour, so the seasonal and diurnal wind generation variations as characterized in Task 1 of this project would lead to a discounting of its capacity value.

Table 3: Computed capacity values for 1500 MW wind generation scenario using MAPP accreditation procedure

| Month | Median (MW) | % |
|---|---|---|
| January | 394 | 26.3% |
| February | 498 | 33.2% |
| March | 285 | 19.0% |
| April | 370 | 24.7% |
| May | 423 | 28.2% |
| June | 334 | 22.3% |
| July | 249 | 16.6% |
| August | 293 | 19.5% |
| September | 492 | 32.8% |
| October | 376 | 25.1% |
| November | 499 | 33.3% |
| December | 444 | 29.6% |
| AVERAGE | 388 | 25.9% |

There are clear differences between the MAPP Capacity Credit method and the ELCC approach used in this study. The MAPP algorithm selects wind generation data from a 4-hour window that includes the peak, and is applied on a monthly basis. The ELCC approach is a risk-based method that quantifies the system risk of meeting peak load, and is primarily applied on an annual basis. ELCC effectively weights peak hours more than off-peak hours, so that two hypothetical wind plants with the same capacity factor during peak hours can receive different capacity ratings. In a case like this, the plant that delivers more output during high risk periods would receive a higher capacity rating than a plant that delivers less output during high risk periods.

The MAPP approach shares a fundamental weakness with the method adopted by PJM: the 4-hour window may miss load-hours that have significant risk, therefore ignoring an important potential contribution from an intermittent generator. Conversely, an intermittent generator may receive a capacity value that is unjustifiably high because its generation in a high-risk hour is lower than during the 4-hour window.

Because ELCC is a relatively complex, data-intensive calculation, simplified methods could be developed at several alternative levels of detail. Any of these approaches would fully capture the system's high-risk hours, improving the algorithm beyond what would be capable with the fixed, narrow window in the current MAPP method. Any of the methods can also be applied to several years of data, which could be made consistent with current MAPP practice of using up to 10 years of data, if available.

### Task 4: Evaluation of Wind Generation Integration Costs on the Operating Time Frame - Overview and Results

At significant levels relative to loads and other generating resources in the control area, wind generation has the potential to increase the burden of managing the power system, thereby increasing overall costs. The economic consequences of this increased burden are term "integration costs", and are the ultimate focus of this research effort. Integration costs for wind generation stem from two primary factors:

- Wind generation exhibits significant and mostly uncontrollable variability on all of the time scales relevant to power system operations – seconds, minutes, hours, days;
- The ability to predict or forecast wind generation for forward time periods is lower than that for conventional resources, and declines as the forecast horizon moves outward.

How the combination of these characteristics can impact the overall cost of operating the system can be thought of in the following way: For a given control area, the uncertainties associated with scheduling and operating generating resources, namely errors in load forecasts or unexpected outages or operating limitations of certain generating units - are well known based on history and experience. Procedures have evolved to accommodate these uncertainties, such that for a particular load magnitude or pattern, the supply resources are deployed and operated in a manner that minimizes the total production cost. The additional variability that comes with a significant amount of wind generation in the control area requires that the existing supply resources be used in a different manner. Increased uncertainty related to the probable errors in wind generation forecasts for future periods can lead to either more conservatism in the deployment of generating resources (and more cost) or operating problems that arise due to the differences between the forecast and actual wind generation in a particular hour (again, with possibly added cost).

The "value" of wind generation is separate from the integration costs. The objective here is to determine how the cost to serve load that is not served by wind generation is affected by the plans and procedures necessary to accommodate the wind generation and maintain the reliability and security of the power system.

In this project, the integration costs are differentiated by the time scale over which they might be incurred, with the total integration cost being the sum of the individual components. The time frames and operating functions of interest include:

- **Regulation**, which occurs on a very short time scale and involves the automatic control of a sufficient amount of generating capacity to support frequency and maintain scheduled transactions with other control areas;
- **Unit commitment and scheduling**, which are operations planning activities aimed at developing the lowest cost plan for meeting the forecast control area demand for the next day or days;

- **Load following and other intra-hourly operations** that involve the deployment of generating resources to track the demand pattern over the course of the day, and adjustments to compensate for changes in the control area demand as the load transitions through the hours and periods of the daily load pattern.

A variety of analytical techniques were employed to quantify the impacts of 1500 MW of wind generation on the Xcel control area. The following sections describe the methods used in each of the three time frames along with the results and conclusions.

***Regulation***

The aggregate load in the control area is constantly changing. The fastest of these changes can be thought of as temporary ups and downs about some longer term pattern. Compensating in some way for these fast fluctuations is necessary to meet control area performance standards and contribute to the frequency support for the entire interconnection. Regulation is that generating capacity that is deployed to compensate for these fast changes.

The regulation requirement for the Xcel system load in 2010 was projected by analyzing high-resolution measurements of the current load. By applying appropriate smoothing techniques, the fluctuating component responsible for the regulating burden can be isolated. Figure 9 shows the result of this algorithm for one hour of the Xcel load. The blue line is actual instantaneous load, sampled once every four seconds; the red line is the computed trend through the hour. The difference between the actual load and the trend is the regulating characteristic.

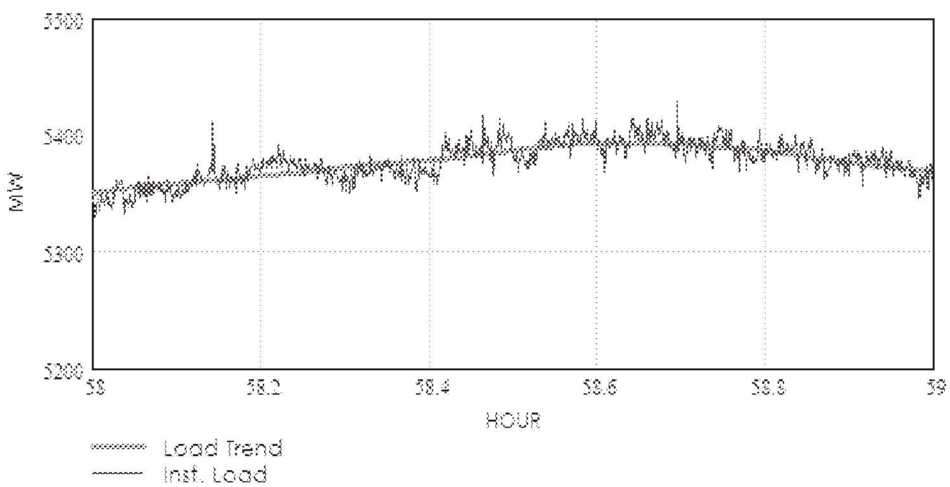


Figure 9: Actual load (blue) and hourly trend (red) for one hour.

Wind generation also exhibits fluctuations on this time scale, and thereby may increase the requirement for regulating capacity. The regulation trends are nearly energy neutral (the incremental energy for the time spent above the trend is equal to that spent below the trend), so the economic impact is the opportunity cost related to reserving the necessary amount of generation capacity to perform this function.

Data from NREL monitoring at the Lake Benton wind plants and the Buffalo Ridge substation was used to estimate the regulation requirements for the 1500 MW of wind generation in this study. Figure 10 contains a short sample of this data, which is collected at one second intervals. The graph shows actual wind generation(in percent of rated capacity) over a 24-hour period for several different collections of wind turbines, each of which is connected to the Buffalo Ridge substation.

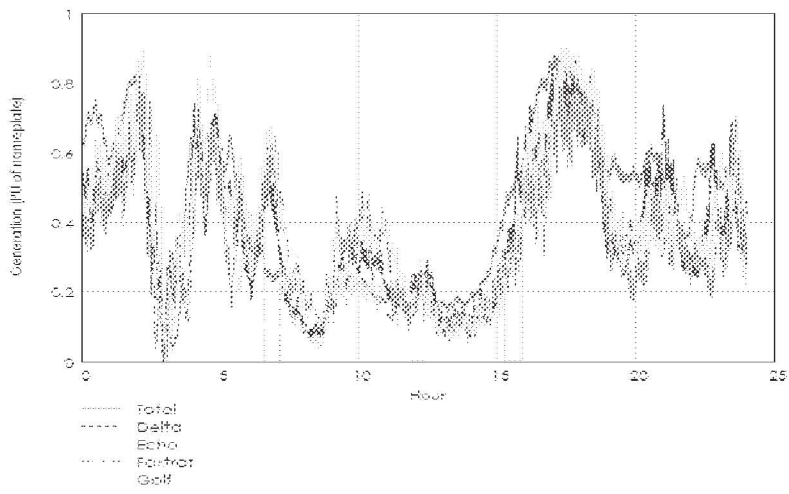


Figure 10: Typical daily wind generation for Buffalo Ridge plants data sampled at one second intervals for 24 hours.

The significant item to note from the figure is that the red trace corresponds to a measurement of 280 individual turbines. The other traces area from subsets of this overall number. Analysis of the data clearly shows that the fast fluctuations, when expressed as a percentage of the rated capacity of the turbines comprising the group, declines substantially as the number of turbines increases.

Because of the factors responsible for these fast fluctuations, it can be reasonably concluded that variations from one group of turbines are not dependent on or related to those from a geographically separated group. In statistical terms, the variations are uncorrelated.

It is further assumed that the fast fluctuations from a group or groups of wind turbines are not related to the fast fluctuations in the system load, since there is no plausible explanation for why they would be related. Of interest here is how the fluctuations of the system load with wind generation added compare to those from the system load alone.

For uncorrelated variations, statistics provides a straight-forward way to estimate the characteristics of the system load and wind combination. For normally-distributed random variables, the standard deviation of the combination can be computed from the standard deviations of the individual variables with the following formula:

$$\sigma_T = \sqrt{\sum \sigma_i^2}$$

The standard deviation of the combination of the variables is the square root of the sum of the squares of the individual standard deviations.

This statistical property can be applied to the random variables representing the fast fluctuations in wind generation and the load. In the study scenario, it was assumed that the 1500 MW of wind generation was actually comprised of 50 individual 30 MW wind plants. The regulation requirement for each of these plants was estimated to be 5% of the nameplate rating, based on the analysis of the measurement data from Buffalo Ridge. The standard deviation of the load fluctuations alone was calculated to be 20.2 MW for 2010. Applying the formula from above, the standard deviation of the Xcel system load in 2010 plus 1500 MW of wind generation is 22.8 MW.

A translation to regulating requirements can be made by recognizing that for the random, normally-distributed variables, over 99% of all of the variations will fall within plus or minus three standard deviations. So multiplying the results above by three leads to the conclusion that the addition of wind would increase the regulation requirement by (22.8 – 20.2) x 3 = 7.8 MW.

The "cost" of this incremental regulating requirement can be estimated by calculating the opportunity cost (revenue less production cost for energy that cannot be sold from the regulating capacity) for 7.8 MW of generating capacity. Xcel currently employs large fossil units for regulation, so the production cost is relatively low, around $10/MWH. If it is assumed that this energy could be sold at $25/MWH, the opportunity cost over the entire year would be just over $1,000,000.

Dividing the total cost by the expected annual energy production of the 1500 MW of wind generation (using an average capacity factor of 35%) yields an incremental regulation cost of $0.23/MWH.

Capacity value provides an alternative method for costing the incremental regulation requirement. Using a value of $10/kW-month or $120/kw-year, the annual cost of allocating an additional 7.8 MW of capacity to regulation duty comes out to be $936,000, about the same as the number arrived at through the simple opportunity cost calculation. This number and the previous result are not additive, however. By either method, the cost to Xcel for providing the incremental regulation capacity due to the 1500 MW of wind generation in the control area is about $1 million per year.

***Unit Commitment and Scheduling - Hourly Impacts***

Because many generating units cannot be stopped and started at will, forward-looking operating plans must be developed to look at the expected demand over the coming days and commit generation to meet this demand. This plan should result in the lowest projected production cost, but must also acknowledge the limitations and operating restrictions of the generating resources, provide for the appropriate amount of reserve capacity, and consider firm and opportunity sales and purchases of energy.

The approach for quantifying the costs that could be incurred with a significant amount of wind generation was based on mimicking the activities of the system schedulers, then calculating the costs of the resulting plans. The input data for the analysis consisted of hourly load data, wind generation data, and wind generation forecast data for a two year period. Figure 11 contains a block diagram of the process. For each day of the two year data set, a reference case was developed that assumed that the daily energy from wind generation was known precisely, and that it was delivered in equal amounts over the 24 hours of the day. This reference case was selected since it represents wind as a resource that would have the minimum impact on the operation of other supply resources.

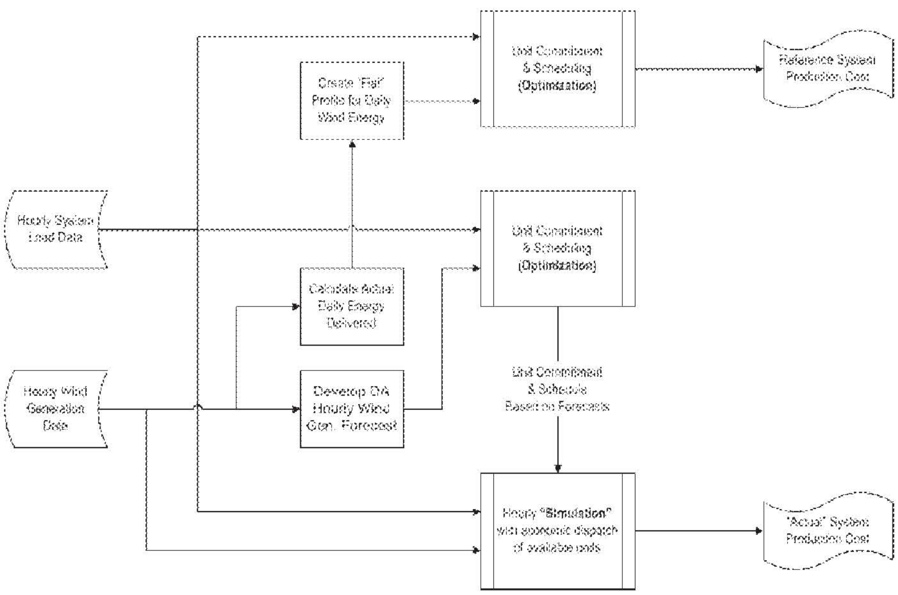


Figure 11: Block diagram of methodology used for hourly analysis.

The next set of cases represented the actions of the system schedulers. The projected load and an hour-by-hour wind generation forecast were input to the unit commitment and scheduling program. The program then determined the lowest cost way to meet the load and accommodate the wind generation as it was forecast to be delivered. The forecast wind generation was then replaced by "actual" wind generation. Then, a simulation of the same day was conducted. However, instead of allowing the program to change the planned deployment of generating resources, only the resources available per the plan developed with the wind generation forecast data could be used to meet the actual load, minus, of course, that load served by wind generation on an hourly basis.

This method was applied to 730 individual days that represented actual loads from 2002 and 2003 (scaled so that the peak matches that for 2010). Wind generation data from the numerical simulation model for each of the days over those two years represented "actual" wind generation. Using results from the forecasting experiment of Task 1, an additional time series was created to represent wind generation forecast data for those years (a comparison of forecast vs. actual as used in this study is shown in Figure 12). This set contained errors that are consistent with what would be expected from a wind generation forecast developed on the morning of the previous day (a time horizon of 16 to 40 hours).

Table 4 shows the results by month for the hourly analysis. The average hourly integration cost based on simulation of the commitment and scheduling process for 24 months is calculated to be $4.37/MWH of wind energy. The assumptions used in the hourly analysis make that cost a relatively conservative estimate – they are on the higher end of the range of results that could be generated by varying the assumptions. There appear to be a number of opportunities and mechanisms that would reduce those costs. The more important of these are related to the emergence of liquid wholesale markets administered by MISO which would provide an alternative to using internal resources to compensate for the variability of wind generation. Another is the analysis and development of algorithms for unit commitment and scheduling that explicitly account for the uncertainty in wind generation forecasts and lead to operating strategies that "win" more than they "lose" over the longer term. Closely related to such algorithms are further developments of wind generation forecasting techniques and analyses that would provide the appropriate input data.

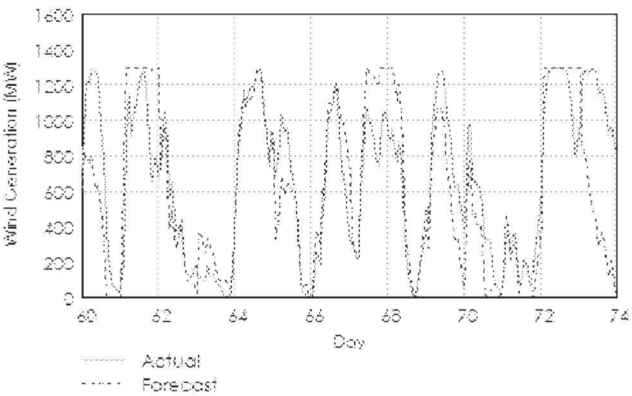


Figure 12: Wind generation forecast vs. actual for a two week period.

Table 4: Hourly Integration Cost summary

| | Wind Generation (MWH) | Net Load Served (MWH) | Incr. Prod. Cost (k$) | HA Energy Cost (k$) | Hourly Integration Cost (per MWH) | Load served by Wind (of Total) |
|---|---|---|---|---|---|---|
| January | 465,448 | 3,765,189 | 1,949 | 0 | 4.19 | 11.0% |
| February | 472,998 | 3,295,060 | 1,560 | 313 | 3.96 | 12.6% |
| March | 491,883 | 3,417,066 | 1,104 | 94 | 2.43 | 12.6% |
| April | 485,379 | 3,139,152 | 2,564 | 118 | 5.52 | 13.4% |
| May | 400,220 | 3,294,088 | 916 | 240 | 2.89 | 10.8% |
| June | 316,798 | 3,699,027 | 930 | 226 | 3.65 | 7.9% |
| July | 427,006 | 4,246,909 | 3,228 | 144 | 7.90 | 9.1% |
| August | 301,811 | 4,546,729 | 2,992 | 332 | 11.01 | 6.2% |
| September | 516,199 | 3,434,343 | 1,151 | 539 | 3.27 | 13.1% |
| October | 478,654 | 3,382,287 | 1,607 | 63 | 3.49 | 12.4% |
| November | 602,016 | 3,180,262 | 1,499 | 149 | 2.74 | 15.9% |
| December | 625,926 | 3,508,015 | 4,186 | 0 | 6.69 | 15.1% |
| January | 532,870 | 3,476,721 | 2,003 | 8 | 3.77 | 13.3% |
| February | 581,258 | 2,917,429 | 1,431 | 139 | 2.70 | 16.6% |
| March | 511,552 | 3,416,137 | 1,618 | 89 | 3.34 | 13.0% |
| April | 501,014 | 3,122,346 | 1,579 | 85 | 3.32 | 13.8% |
| May | 465,686 | 3,240,090 | 604 | 160 | 1.64 | 12.6% |
| June | 509,564 | 3,824,551 | 198 | 749 | 1.86 | 11.8% |
| July | 411,140 | 4,574,548 | 4,416 | 426 | 11.78 | 8.2% |
| August | 430,083 | 3,982,906 | 1,732 | 276 | 4.67 | 9.7% |
| September | 485,658 | 3,569,729 | 2,260 | 162 | 4.99 | 12.0% |
| October | 395,261 | 3,447,750 | 1,997 | 362 | 5.97 | 10.3% |
| November | 435,350 | 3,295,648 | 1,309 | 76 | 3.18 | 11.7% |
| December | 507,473 | 3,494,610 | 1,699 | 299 | 3.94 | 12.7% |
| **Totals** | **11,351,247** | **85,270,590** | **44,531** | **5,048** | **4.37** | **11.7%** |

### *Load Following and Intra-hourly Effects*

Within the hour, Xcel generating resources are controlled by the Energy Management System to follow the changes in the load. Some of these changes can be categorized as "regulation", which was analyzed in a previous section. Others, however, are of longer duration and reflect the underlying trends in the load – ramping up in the morning and down late in the day. Still others could be due to longer-term variations about general load trend with time. The nature of these changes can be simply quantified by looking at the MW change in load value from one ten minute interval to the next.

Energy impacts would stem from non-optimal dispatch of units relegated to follow load as it changes within the hour. The faster fluctuations up and down about a longer term trend, determine the regulation requirements as discussed before. These fluctuations were defined to be energy neutral – i.e. integrated energy over a period is zero. The energy impacts on the load following time frame thus do not include the regulation variations, but are driven by longer term deviations of the control area demand from an even longer term trend. Additional production costs (compared with those calculated on an hourly basis, for control area load that remains constant for the hour) result from the load following units dispatched to different and possibly non-optimal operating levels to track the load variation through the hour.

The additional costs of this type attributable to wind generation are related, then, to how it alters the intra-hourly characteristic of the net control area demand. High-resolution load data provided by Xcel Energy and scaled to the year 2010 along with wind generation data from the numerical simulation model were analyzed to elicit the characteristics of this behavior at ten-minute intervals.

Figure 13 shows a weekly trend of the changes from one ten-minute interval to the next for the system load and wind generation. It is apparent from the plot that the load exhibits significantly more variability than does wind generation.

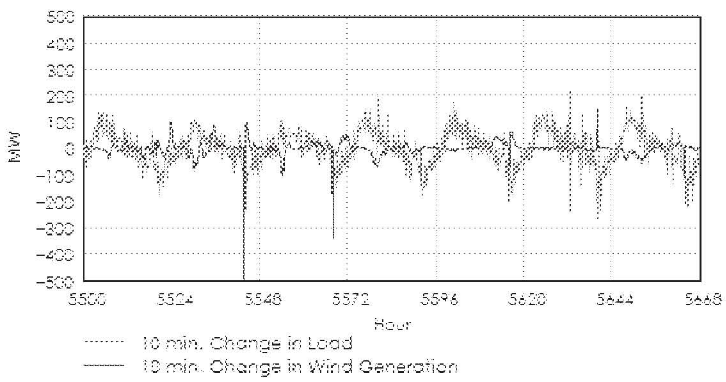


Figure 13: Weekly time series of ten-minute variations in load and wind generation.

An entire year of data – almost 50,000 ten-minute data points - was analyzed to develop a statistical distribution of these changes (Figure 14). The results show that wind generation has only a minor influence on the changes from one interval to the next, and most of the effect is to increase the relatively small number of larger-magnitude changes.

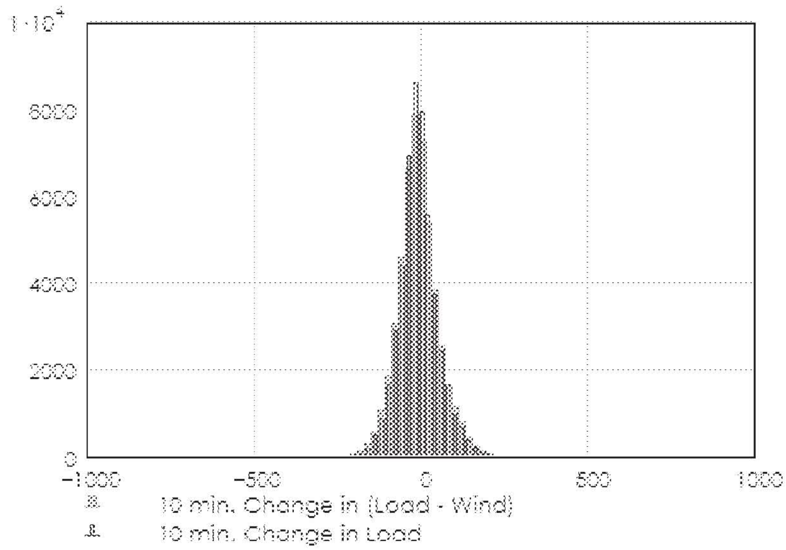


Figure 14: Control area net load changes on ten minute intervals with and without wind generation.

The same data was also analyzed to examine the variation from a longer term trend that tracks the hour-by-hour daily load pattern. The distributions of these variations with and without wind generation over the year of data are shown in Figure 15.

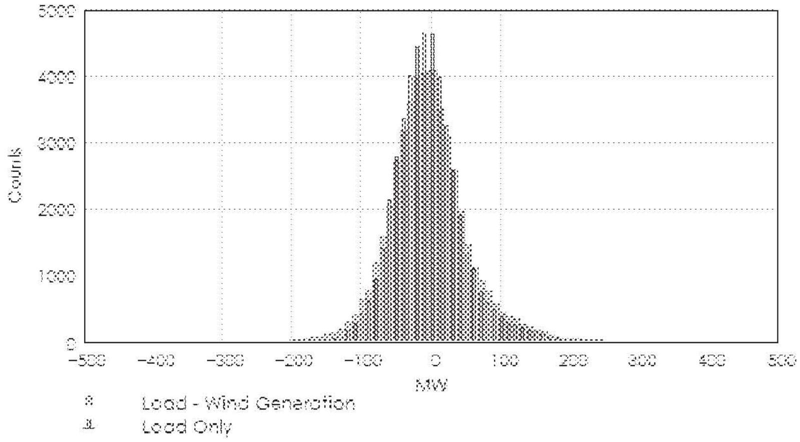


Figure 15: Variation at ten-minute increments from daily "trend" pattern, with and without wind generation.

The numerical results are similar to those described previously that considered the absolute changes on ten-minute increments. The standard deviation of the distribution of deviations from the hourly trend for the load only is 53.4 MW; with wind generation in the control area, the standard deviation increases to 64 MW.

In the earlier study, results from simulations of a limited number of "typical" hours along with several simplifying assumptions were extrapolated to annual projections. A cost impact of $0.41/MWH was assigned to wind generation due the variability at a time resolution of five minutes. However, one of the major simplifications was that only the wind generation exhibited significant variability from a smooth hourly trend, so that all costs from the intra-hourly simulations beyond those calculated at the hourly level could be attributed to wind generation.

The data analyses here lead to a different conclusion. The system load does vary significantly about a smoother hourly trend curve, and may also vary substantially from one ten-minute interval to the next. With this as the backdrop, it was shown that the addition of wind generation to the control area would have only slight impacts on the intra-hour variability of the net control area demand. It also appears that the corresponding changes in wind generation and those in the system load are uncorrelated, which substantially reduces the overall effect of the variations in wind generation within the hour.

In quantitative terms, for the system load alone, just over 90% of the ten-minute variations from the hourly trend value are less than 160 MW. With wind generation, that percentage drops to 86%, or stated another way, 90% of the ten-minute variations from the hourly trend value are less than 180 MW.

The original project plan called for simulations to be used for quantifying the energy cost impacts at the sub-hourly level. This was the approach taken in the earlier study of the Xcel system, and thought to be the most direct method for this assessment. In light of the results of the intra-hourly data analysis, it was determined detailed chronological simulations would be of very limited value for determining any incremental cost impacts for intra-hourly load following. With a very slight effect on the characteristics of the intra-hourly control area demand characteristic as evidenced by the approximately 10 MW change in the standard deviations, calculated effects on production cost would likely be in the "noise" of any deterministic simulations.

Based on the analysis here, it is concluded that the $0.41/MWH of wind generation arrived at in the previous study was artificially high since the load was assumed to vary smoothly during the hour. Also, the statistical results presented here support the conclusion that the increase in production cost on an intra-hourly basis due to the wind generation considered here would be negligible.

The results do show, however, that wind generation may have some influence on control performance as the number of large deviations from one interval to the next or from the longer-term trend of the net control area demand is significantly increased. An expansion of the distributions of ten-minute changes with and without wind generation is shown in Figure 16. Wind generation substantially increases the number of larger-magnitude excursions over the course of the year.

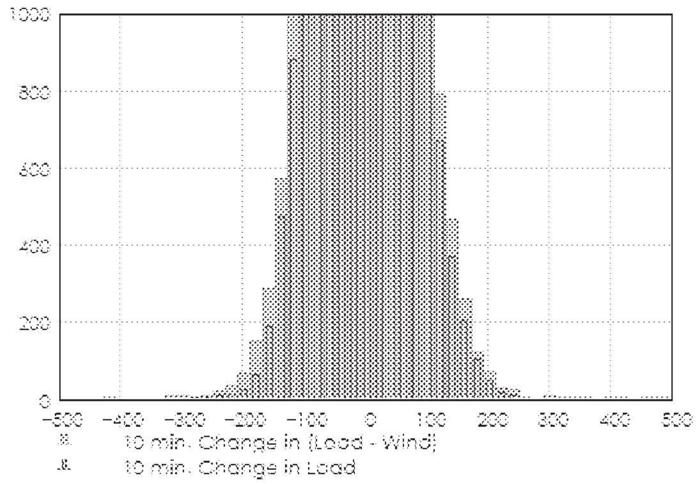


Figure 16: Expanded view of Figure 14.

The total number of these large excursions is not significant from an energy standpoint, since the number is a small fraction of the total number over the year. There are implications, however, for control performance of the Xcel system. To assess this potential impact, increases in the occurrences of control area demand change of a given magnitude were "counted". Table 5 shows the number of occurrences over the sample year of data where the net control area load (load minus wind generation) changed more than a given amount (up or down) in one ten minute period.

Table 5: Ten-minute Variations in Control Area Demand, with and without Wind Generation

| 10 min. Change | # of Occurrences | | |
|---|---|---|---|
| | System Load | System Load with Wind | Difference |
| greater than +/- 100 MW | 5782 | 7153 | 1371 |
| greater than +/- 120 MW | 3121 | 4148 | 1027 |
| greater than +/- 140 MW | 1571 | 2284 | 713 |
| greater than +/- 160 MW | 730 | 1246 | 516 |
| greater than +/- 200 MW | 165 | 423 | 258 |
| greater than +/- 400 MW | 26 | 92 | 66 |
| greater than +/- 600 MW | 18 | 44 | 26 |

With a ramping capability of 140 MW per ten minute period, control performance (CPS2, in NERC terminology) would be comfortably above the minimum requirement with or without wind generation. Or, from another perspective, if the current CPS2 performance is 94%, maintaining that performance level with the addition of 1500 MW of wind generation would require somewhere between 1 and 2 MW/minute of additional load following capability.

## Conclusions

The analysis conducted in this task indicates that the cost of integrating 1500 MW of wind generation into the Xcel control area in 2010 are no higher than $4.60/MWH of wind generation, and are dominated by costs incurred by Xcel to accommodate the significant variability of wind generation and the wind generation forecast errors for the day-ahead time frame.

The total costs include about **$0.23/MWH** as the opportunity cost associated with an 8 MW increase in the regulation requirement, and **$4.37/MWH** of wind generation attributable to unit commitment and scheduling costs. The increase in production cost due to load following within the hour was determined by a statistical analysis of the data to be negligible. The intra-hour analysis also showed that an incremental increase in fast ramping capability of 1-2 MW/minute would be necessary to maintain control performance at present levels. This specific impact was not monetized.

The analytical approach for assessing costs at the hourly level in this study compares the actual delivery of wind energy to a reference case where the same daily quantity of wind energy is delivered as a flat block. In addition to costs associated with variability and uncertainty, the total integration cost then will contain a component related to the differential time value of the energy delivered. If more wind energy is actually delivered "off-peak" relative to the reference case, when marginal costs are lower, this differential value will show up in the integration cost. The total integration cost calculated by this method is still a meaningful and useful value, but care must be taken not to ascribe all of the integration cost to uncertainty and variability of wind generation output.

Wind generation also results in a much larger ramping requirement from hour to hour. The costs associated with this impact are captured by the hourly analysis, as the unit commitment and schedule must accommodate any large and sudden changes in net control area demand in either the forecast optimization case, or in the simulation with actual wind generation. In the optimization case that utilizes wind generation forecast data, generating resources must be committed and deployed to follow control area demand while avoiding ramp rate violations. In the simulation cases with actual wind generation, changes due to wind generation that cannot be accommodated result in "unserved energy" in the parlance of the unit commitment software, which really means that it must be met through same-day or more probably next-hour purchases.

Some specific conclusions and observations include:

1. While the penetration of wind generation in this study is low with respect to the projected system peak load, there are many hours over the course of the year where wind generation is actually serving 20 to 30% (or more) of the system load. A combination of good plans, the right resource mix, and attractive options for dealing with errors in wind generation forecasts are important for substantially reducing cost impacts.
2. That said, the cost impacts calculated here are likely to be somewhat overstated since little in the way of new strategies or changes to practices for short-term planning and scheduling were included in the assumptions, and since the hour-ahead adjustments in the study are made at a price closer to the marginal cost of internal resources than those in a liquid wholesale energy market.
3. The incremental regulation requirement and associated cost for accommodating 1500 MW of wind generation, while calculable, is quite modest. The projected effect of geographic diversity together with the random and uncorrelated nature of the wind generation fluctuations in the regulating time frame, as shown by the statistical analysis, have a dramatic impact on this aspect of wind generation.
4. Large penetrations of wind generation can impact the hourly ramping requirements in almost all hours of the day. On the hourly level, this results in deployment of more resources to follow the forecast and actual ramps in the net system load, thereby increasing production costs.
5. Wind generation integration costs are sensitive to the deployment of units, which is also a function of the forecast system load. The results seem to indicate that these costs can be high over a period when expensive resources are required to compensate for the hourly variability, even when the total wind generation for the period might be low.
6. For the study year of 2010, the cost of integrating 1500 MW of wind generation into the Xcel-NSP control area could be as high as $4.60/MWH of wind energy where the hour-by-hour forecast of wind for 16 to 40 hours ahead has a mean absolute error of 15% or less. The total integration cost is dominated by the integration cost at the hourly level, and assumes no significant changes to present strategies and practices for short-term unit commitment and scheduling.
7. The MISO market cases demonstrate that the introduction of flexible market transactions to assist with balancing wind generation in both the day-ahead scheduling process and the day one hour ahead has a dramatic positive impact on the integration costs at the hourly level. For example, in August the hourly cost was reduced by two thirds.

Results of the hourly analysis are considered to be quite conservative – they are on the high end of the range of results that could be generated by varying the assumptions. While the methodology is relatively robust and thought by the researchers to be straightforward and consistent with industry practice, a number of assumptions were made to facilitate analysis of a large set of sample days – two years of days unique in peak load, load pattern, actual and forecast wind generation. The input data for the hourly analysis was developed in such a way that any correlations between Xcel control area load and the wind resource in the upper Midwest are actually embedded in the datasets.

Much of the conservatism in the hourly analysis stems from the simplification of many decisions that would be made by knowledgeable schedulers, traders, and system operators to reduce system costs and/or increase profits. This leads to the use of resources which are under the control of the unit commitment program to accommodate the variability of wind generation and the day-ahead wind generation forecast errors. In months with higher electric demand, these resources can be relatively expensive.

Energy purchases and sales are a potential alternative to internal resources. In the hourly analysis, these transactions were fixed, not allowing for the day-ahead flexibility that might currently exist for judicious use of inexpensive energy to offset the changes in wind generation. Optimizing these transactions day by day would have prevented evaluation of the statistically significant data set of load and wind generation, and would have been to difficult to define objectively.

Given the likely sources of the integration cost at the hourly level, it is apparent that a better strategy for purchase and sale transactions scheduled even day-ahead would reduce integration costs at the hourly level. This leads naturally to considering how wholesale energy markets would affect wind integration costs.

The planning studies conducted by MISO show that wholesale energy is relatively inexpensive in the upper Midwestern portion of their footprint. Transmission constraints do come into play on a daily and seasonal basis, but interchange limits for most of Minnesota are reasonably high relative to the amount of wind generation considered in this study. The ability to use the wholesale energy market as a balancing resource for wind generation on the hourly level has significant potential for reducing the integration costs identified here.

Wholesale energy markets potentially have advantages over bi-lateral transactions as considered simplistically in this study. In day-ahead planning, for example, it would be possible to schedule variable hourly transactions consistent with the forecast variability of the wind generation. Currently, day-ahead bi-lateral transactions are practically limited to profiles that are either flat or shapeable to only a limited extent. Hour-ahead purchases and sales at market prices would provide increased flexibility for dealing with significant wind generation forecast errors, displacing the more expensive units or energy fire sales that sometimes result when relying on internal resources.