

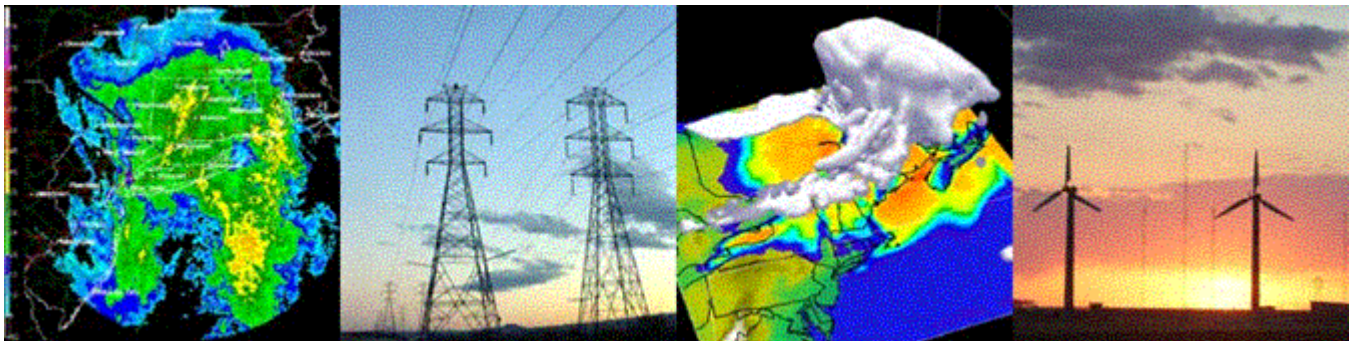


Xcel Energy Northern States Power (NSP)

**Renewable Energy Research and Development Project
(RD-57)**

Final Report

October 6, 2008



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Xcel Energy Northern States Power (NSP) Renewable Energy Research and Development Project (RD-57)

Final Report

1. EXECUTIVE SUMMARY

1.1 Project Objective

Xcel Energy Northern States Power (NSP) engaged a cross functional project team consisting of members from WindLogics, EnerNex, AREVA T&D and UWIG to develop a complete wind power forecasting system (both load-following and unit commitment timescales) for utility-wide use by Xcel system operators, including supplemental tools and forecast improvement technologies. In addition, system simulation and sensitivity analysis were to be conducted in order to determine the impact of wind variability on the grid. Finally, additional research and development topics relating to technologies that aid the scheduling and operating of wind heavy power systems was to be carried forward. The exact project goals were broken down into four major tasks summarizing the work that was to be completed.

- Task 1 – Development of a complete wind power forecasting system (both load-following and unit commitment timescales) for utility-wide use by Xcel system operators.
- Task 2 – Investigating techniques for improving wind power forecast accuracy and developing defensive system operating strategies.
- Task 3 – Analyze wind generation forecasting accuracy requirements for power system operations and control.
- Task 4 – Identify new tools and methodologies that might be used for scheduling and operating power systems with significant amounts of wind generation.

Allocation of the effort for these tasks was broken down along functional lines between the partner organizations. WindLogics assumed responsibility for tasks 1 and 2 which focused on the forecast system development and optimization, while EnerNex and AREVA shared the workload for tasks 3 and 4 which involved electrical system simulation, variability analysis and unit commitment simulation and planning. UWIG provided oversight and organizational assistance to the project team, and coordinated meetings between members as well as the Technical Review Committee.

The ultimate goals at the end of this effort were to have delivered an operational forecast tool to the Xcel system operators, to have demonstrated prototype products to improve the forecast accuracy and allow for defensive operation strategies, and to have completed the development all system simulations, assessments and new tools/methodologies to the satisfaction of Xcel.

1.2 Overview of Results

After meeting with Xcel system operators to gather their requirements, WindLogics embarked on the development of a system-wide forecast tool. The inputs to the forecasting system include a wide range of government produced weather datasets, 10-minute average wind power data for 17 power interconnect nodes, and 12 on or near site met towers that have been outfitted with satellite telemetry in order to facilitate real-time data delivery. The total 652 MW of wind energy production in the Xcel MN footprint were broken down into two separate modeling areas, Buffalo Ridge and Mower County, given their geographic separation, which allowed for sufficiently high resolution numerical weather modeling to be conducted on a regular schedule. Hour-ahead forecasts going out to 12 hours and day-ahead forecasts out to 84 hours were generated for each node as well as for the aggregate system. Due to confidentiality requirements with the participating wind farm operators, only the aggregate forecast was delivered to Xcel.

Making use of the high-resolution model data and on-site power and wind speed readings along with statistical artificial intelligence techniques allowed WindLogics to produce forecasts that outperformed the standard National Weather Service models by a significant margin. WindLogics hour-ahead forecast results at the one-hour mark generated a mean absolute error (MAE) over the 13-month forecast window of 8.09% compared to the NWS which was substantially higher at 15.48%. At the 24-hour mark for the day-ahead forecast, the WindLogics results continued to perform well compared to the standard forecast at 11.79% and 15.42% respectively.

Additional tuning of the forecast system was made possible by the presence of tall towers near the operational wind farms. Frequent lack of real-time operational data as well as a near total lack of curtailment information made forecasting an extremely difficult task in many cases. These tall towers were used successfully to aid in the identification of these curtailment periods and to improve the historical training of the forecast system as well as the real-time performance. This data was also used to good effect in identifying ramp events more quickly than an unaided forecast otherwise could.

As well as the standard forecast offerings, WindLogics developed a prototype High Wind Warning System (HWWS) which offered a unique visualization tool to the Xcel operators. This system is capable of displaying real-time NWS watches, warnings and advisories, meteorological tower outputs, radar, turbine locations, METAR data points, and potentially affected MW of production on an easy to read Google Earth GIS interface. Xcel system operators were particularly interested in the potential of this system, and with additional development (and potential integration with EMS offerings) could be a key clearinghouse for weather related information.

Investigation into the feasibility of a Mesoscale Rapid Update Cycle (MRUC) model was also conducted over the course of this project in order to test the potential for applying advanced, high-resolution modeling along with in-depth data assimilation techniques to improve short range forecast performance. Substantial advances were made in the initialization and configuration of this system, and test models were successfully run in order to ascertain the model's quality. The MRUC system, while still requiring substantial optimization and refinement before an operational system is available, shows potential for more accurate forecasting of short term weather events, ramp events in particular, in the future within the Xcel forecasting area.

EnerNex and AREVA went to considerable effort in developing an **e-terrasimulator** model of the MN utility control areas. Significant enhancements to the **e-terrasimulator** 2.3 product (including modifications made for the version 2.5 release) were made in order to facilitate this effort. Among other items, updates to the External Data Processor task were completed in order to enable the insertion of forecasted and/or actual wind power generation into the simulation engine. After these changes were complete, an implementation of the Xcel system was built which included several wind injection points. In parallel, while working and configuring the proof-of-concept simulation environment, EnerNex and AREVA investigated the use of geo-spatial User Interface products in order to improve the management of wind generation and situation awareness of real-time operators.

Since the submission of the proposal and eventual award, scheduling and unit commitment decisions for Xcel-NSP have been altered substantially by the start-up of the MISO energy markets. Due to these changes, the originally proposed sensitivity analysis was modified into an analysis of the forecasting system and the effects of wind variability at the MISO level. In this situation, day-ahead scheduling for Xcel has moved from a process that seeks to meet NSP load for the minimum cost while insuring reliability to one where the optimization takes place over the entire MISO market footprint. Target wind penetration levels of 15%, 20% and 25% were examined, and it was found that the addition of wind generation to supply 20% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system if sufficient transmission investments are made to support it. This analysis highlighted the following key conclusions:

1. Relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low of \$2.11 to a high of \$4.41 per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves and costs related to the variability and day-ahead forecast error for wind generation.
2. Consolidating into a single functional balancing authority has a significant impact on results. By sharing balancing authority functions, requirements for ancillary services such as regulation and load following are reduced (with or without wind generation) and the required amount of regulation capacity is reduced by almost 50%.

3. The expanse of the wind generation scenario provides for substantial smoothing of wind generation variations. This smoothing is especially evident at time scales within the hour, where the impacts on regulation and load following were almost negligible. Smoothing also occurs over multiple hour time frames, which reduces the burden on unit commitment and dispatch. The hours of very high or very low production are also reduced, allowing the aggregate wind generation to behave as a more stable supply of electric energy
4. The transmission expansion assumptions, as previously defined by the West Region Studies Group (RSG) report of May 2006, were adequate for transportation of wind energy in all of the scenarios. Under these assumptions, there were no significant congestion issues attributable to wind generation and no periods of negative Locational Marginal Price (LMP) observed in the hourly simulations.
5. The MISO energy market also played a large role in reducing wind generation integration costs. Since all generating resources over the market footprint are committed and dispatched in an optimal fashion, the size of the effective system for integrating the wind generation increases dramatically and the aggregate flexibility of the units on line during any hour is adequate for compensating for most of the changes in wind generation.
6. The contribution of wind generation to power system reliability is subject to substantial interannual variability. Annual Effective Load Carrying Capability (ELCC) values for the three wind generation scenarios from rigorous Loss of Load Probability (LOLP) analysis ranged from a low of 5% of installed capacity to over 20%.

In addition to these more concretely defined activities, AREVA initiated the development of **e-terravision** 1.0, a user-friendly, geo-spatial tool for the visualization of electrical and weather related data. This tool provides operators with the ability to identify and monitor violations and contingencies in the system and to monitor the transmission network with large overviews while assessing the grid's reliability using advanced visualization. In addition to the described key functionality, and focusing especially on the integration of Weather data into the real-time production system, AREVA is currently working with WindLogics to enhance the **e-terravision** product to be integrated with weather and wind forecasted system.

Finally, a thorough investigation into the impacts of a stochastic unit commitment solution was carried out by the AREVA team in order to better understand and manage uncertainty within this process. Extensive simulations were carried out under a variety of scenarios in order to include the effects of generation unreliability, load uncertainty and wind power uncertainty. It was found that combining scenarios with a proper amount of reserve requirements leads to very robust solutions with respect to both changes in model parameters and departures from the modeled realizations of the uncertain parameters. In addition, the optimal reserve requirements depend on the policy employed and the scenarios used. Typically, stochastic policies have lower optimal reserve requirements than their deterministic counterparts. However, reliability will typically improve if the scenarios are appropriately selected. For example, if the worst contingencies are captured by the scenarios, the solution accounts for them explicitly, and may even ensure the availability of some reserves in the post-contingency situations. Overall, it is expected that the desirable properties of stochastic solutions, the potential cost reductions, the improving algorithms and computational power, and the increased day-ahead uncertainty brought by the wind power generation being planned and installed, will lead to the use of stochastic unit commitment formulations in the future.

2. TASK 1 – FORECAST SYSTEM DEVELOPMENT AND IMPLEMENTATION

2.1 Wind Energy Forecasting Overview

System operators require accurate wind power estimates, both on the load following and unit commitment timescales, to deal with a variety of issues such as deciding which other power sources are needed in order to meet forecasted demand and reducing ancillary service costs. Accurate wind power forecasts will become increasingly important as wind energy market penetration increases. The wind resource varies over a large range of time and space scales, making it challenging to accurately estimate future wind power production. At a given wind plant location, very small features such as boundary layer eddies can alter the wind resource on timescales from seconds to minutes, while larger weather systems such as midlatitude cyclones can modulate the wind field over several days.

As a first attempt, simple persistence or climatology are often used to estimate the wind. While the persistence forecast (i.e., assuming that the future value equals the current value) works reasonably well for the coming one or two hours, the accuracy of a persistence forecast rapidly decreases in time. Under certain meteorological conditions, such as the passage of a weather front, the persistence forecast can be obsolete in just a few minutes. Similarly, climatological values (i.e., the long-term normal or average value) may be used to estimate power production. While climatological forecasts generally outperform persistence forecasts after 4-6 hours, the actual wind resource at any point in time often differs significantly from the climatological value.

Numerical weather forecast models are invaluable tools for wind forecasting. These models predict the evolution and movement of weather systems in three dimensions using the physical laws that govern atmospheric motion starting from the current known state of the atmosphere. The predictability of a given atmospheric feature is a function of its spatial and temporal scale. Very small features (such as boundary layer eddies) can't be resolved either by observations or by numerical models and hence cannot be accurately predicted. Forecast errors also grow over time in numerical forecast models and eventually contaminate the entire forecast, so the evolution of very large-scale features (such as wave patterns in the jet stream) that evolve over 1-2 weeks are also difficult to accurately predict. Thus statistical methods are still required for very short term (< 1-2 hours) and long term (> 10-14 days) wind energy prediction.

A variety of techniques can be applied in conjunction with numerical forecast models to help reduce error in wind energy predictions. Machine Learning software (such as Neural Nets or Support Vector Machines) can be applied to reduce systematic model forecast error at a given plant location. Model forecast errors can also be reduced through the use of an ensemble forecast where wind forecasts produced by a variety of physics-based numerical forecast models are combined in some way to make a single wind forecast. The basic premise behind the ensemble modeling approach is that some sort of model 'average' forecast will be more accurate than any individual forecast as forecast errors from individual models will tend to cancel each other out. Machine Learning techniques can also be applied to 'learn' the relationships between wind speed and direction and plant power output, thus implicitly including the effects of arrays losses in wind energy forecasts. Otherwise wind speed must be converted to power through the use of a power curve developed from plant output and meteorological towers or from the manufacturers' power curve adjusted for array and electrical losses.

2.2 Defining Customer Needs

WindLogics met with the Xcel NSP Transmission Operations and Reliability team and the Policy Analysis team in St. Paul on January 20, 2006 to begin to assess user requirements. WindLogics and EnerNex subsequently met with the Xcel Energy Trading and Marketing team and the Regulatory team in Denver on February 22, 2006 to assess in-depth the system operator needs. System operator needs were assessed from these two meetings and several subsequent conference calls. The user requirements have been defined from both the Energy Trading and Marketing and Transmission and Reliability perspectives.

The first step in assessing operator needs was to define what Xcel NSP is currently doing to forecast wind power and how this information is being used by the control room operators. Xcel NSP is currently generating day-ahead forecasts using the National Center for Environmental Prediction North American Model (NAM) forecasts and local surface observations and forecasts. This day-ahead forecast is performed manually by an in-house meteorologist in Denver. The Xcel meteorologist uses local observations and pseudo-modeling from the National Weather Service (NWS) observation sites in a forecast area using the MOS (Model Output Statistics) Hourly Adjusted Tables of temperature and wind speed. The NWS Hourly Forecast Output Table is tuned by the Xcel forecaster using local observations and is then used for the current day-ahead forecast. The meteorologist is correlating these hourly observations to power output by running them through power curves and feels relatively comfortable with the results for the day-ahead plan at this point in time, but they are interested in improvements. Xcel currently uses four wind forecasting points in the NSP footprint: Buffalo Ridge, Chanarambie, Garwin McNeillus, and East Ridge (SW Minnesota). The Xcel wind power forecasts currently assume all turbines are available as Xcel does not get any turbine availability or meteorological data from wind sites.

This forecast system is being used for only the day-ahead forecast, and the operators stated that they do not have a good system for generating for the hour-ahead real time forecast within the day. Additionally wind is currently treated as an intermittent resource intra-day by Xcel and is not reported on this time scale. Thus they are at present not generating a real-time hour-ahead forecast, but believe that an accurate hour-ahead forecast out to

at least four hours would be highly beneficial. In terms of forecast system accuracy, the operators consider a day-ahead 8% MAE (mean average error) of power delivered to be outstanding, however this is not achieved on a regular basis. They believe that 10-25% is more typical.

With regard to background information about the current state of the NSP wind portfolio, at the time of project initiation NSP had 652 MW of wind nameplate capacity on the system. Most of this is concentrated in western Minnesota along the Buffalo Ridge, although there are some wind farms in southeast Minnesota. To do aggregate wind power forecasting for the entire NSP footprint, WindLogics asked the operators what they are currently ingesting in the PI system in Denver. The data being returned to their system includes PI data at 4 or 6 second intervals for six Chanarambie, one Garwin, six Buffalo Ridge, 1 West Ridge (SW MN), 1 Rock County, 1 Woodstock, and 1 West Pipestone PI tag – 17 points in total. Xcel has historical PI data for these 17 interconnect nodes for approximately one year, which was subsequently transferred to WindLogics for use in this project. This historical PI power data was used in the initial training dataset for the forecast system. WindLogics has been able to retrieve real-time PI power data from the Xcel server in Denver and has been retrieving 10-minute average power in real-time from the PI system to feed the forecast system. During the meetings, it was recognized that clarification of the treatment of wind curtailment in the PI data will be an important issue (covered more in section 3.3), as wind power forecasting (both historical data and real time) must know when the value represents a curtailed power value rather than the full output of the wind plant.

After being briefed on the system capabilities and goals, the Xcel meteorologists in Denver wanted WindLogics to start issuing the forecasts as soon as possible. While it was outside of the project schedule, they expressed interest in a forecast for the summer season (2006) if possible due to it being a peak-load season. There was also a great deal of interest in the sensitivity analysis generated with the AREVA **e-terrasimulator**. The ability to make use of a tool that gives them access to the WindLogics enhanced hour-ahead and day-ahead wind and wind power forecasts within the framework of an advanced EMS presents a large amount of value. The issue of trading was also discussed with the Xcel Denver Energy Trading and Marketing group. Given access to the proposed systems, parties would be able to conduct virtual trades based on enhanced hour-ahead and day-ahead forecasts generated by WindLogics. A virtual trade is selling day ahead and buying back real time. This is really an arbitrage of the day-ahead/real-time spread and could potentially bring prices closer together, however virtual trading by other parties might drive up the day-ahead prices for Xcel. This will probably not create a big impact for Xcel over the long term, but could have short term impact.

WindLogics asked Xcel if confidence intervals around the forecast would be beneficial. The response was that while confidence intervals would be useful, they are not sure exactly how they should be used. They thought that this would potentially be a good reason to have a cost-based experiment using confidence intervals around the wind power forecasts. Xcel is currently using day-ahead forecasts for energy to make offers in the day-ahead MISO market which is still done on an hour-by-hour schedule and not as a total energy forecast. Given this process, the question of how confidence intervals could be used in trading still remained. Error creates real time price changes from the day-ahead plan, but this gets very complex with virtual trades and FTRs that you lose if you do not bid in fully. For FERC audits, Xcel would likely need to have a consistent and defined strategy on how to use the forecast uncertainty information. Xcel may prefer "one value" that automatically incorporates the uncertainty situation in the final analysis and would want hour specific day-ahead schedules to reduce forecasting errors. Hour-by-hour day-ahead prices could have a significant impact on real-time prices, while good forecasts would enable traders to document why they traded the way that they did.

Xcel was also asked if there is value in energy forecast for the day. The operators' responded that that is a part of the current process, but the values used are all hourly power. Getting 10-minute values from the enhanced WindLogics forecast would be a preferred solution, particularly with the higher proposed 6000 MW penetration. Wind forecasts are currently not being incorporated into load forecasts, and as a result units are being over-committed.

Other potential uses of wind and power forecasts were discussed with the Xcel operators. Capturing and validating curtailments of wind facilities directly with the reliability group would be a potential use that could return significant value. Right now the curtailment information comes directly from the wind farm owner, and it would be beneficial for Xcel to be able to self-validate curtailments based on the enhanced WindLogics forecasts. Curtailed energy does not appear in the point of interconnect data, so WindLogics would need to know that curtailment was in effect and could then calculate the difference between the forecast at the point of interconnect and actual interconnect power as the estimated curtailment amount. This could be used for a "shadow settlement" by Xcel to

see if the reported curtailment amount from the wind farm was reasonable. WindLogics can calculate the curtailment by determining what the wind power would have been at the curtailed site. Curtailments are currently initiated when the wind reaches a certain threshold. Xcel stated that curtailment is not usually a well-planned event and sometimes is the result of downed transmission lines or inadequate transmission capacity, but can be based on planned outages for maintenance.

Both the Marketing and Transmission and reliability Groups from Xcel are very interested in significant ramp events. High wind speed cutout events affect both the Transmission/Reliability and the Market Groups, and as such, they are interested in being able to more accurately forecast for significant ramp events that occur with high wind events that result from frontal passages or convective activity. In a previous meeting (Jan. 20) with the Xcel Transmission and Reliability (North) manager, he expressed interest in reliable high-wind forecasts for planning outages, repairs, and additional unit commitments. He also expressed interest in obtaining accurate temperature forecasts as temperature has a significant impact on transmission line efficiency and physical line impacts like stretching and sagging.

Timeframes within the day for real-time forecasting were discussed further with the operators and the Xcel meteorologist. The preferred timeframes expressed by Xcel were the next 30 min, the next 4 hours, and reserves going forward. For real-time trading purposes, short-term forecasts need to be issued every hour no later than 15 minutes after the hour, while the day-ahead forecasts, which need to be issued once per day, are required no later than 3 a.m. local Mountain Time. Xcel also requested a longer-range forecast going out 5 days for the purpose of extended planning. There is not currently a real-time optimization model running. What is occurring now is partly generated by MISO as a reaction/adjustment, but not as an optimization. For NSP, the timeframe issue is mostly a financial positioning benefit. It would potentially be useful to look at wind/load net deviations and roll these up to an aggregate of the portfolio and determine what impact this implies. Given the future interest in integrating WindLogics forecast output with AREVA's EMS capabilities, there is perceived value from Xcel in creating a net wind and load forecast.

Based on this feedback from the operational teams, the following action items were defined:

- WindLogics will forecast for the aggregate of the PI points to the extent possible. WindLogics will have more detailed data from some wind plants, but not all, so the interconnect point that WindLogics pulls from the PI system (power only) will be the common interchange point between WindLogics and Xcel.
- The need for enhanced day-ahead forecasts for unit commitment, energy trading, and defensive strategies is apparent and thus will be investigated.
- The need for hour-ahead forecasts going out to four hours and beyond is also apparent for energy trading, reliability, and wind farm defensive strategies. It would be valuable to show real time wind deviation from the day-ahead forecast more explicitly as well as the deviations between the short term forecasts and the day-ahead forecasts.

Given this end user feedback, the plan to meet the operators' needs was set in place. Once the forecast system was up-and-running for the aggregate NSP wind power footprint in Minnesota, an aggregate wind and power forecast was generated on both an hour-ahead and day-ahead basis and error statistics were generated for these two forecast types. The forecast data was formatted such that it could be fed into the AREVA **e-terrasimulator**, which the operator would then be able to use to better schedule unit commitment, set up defensive strategies, plan for curtailment, trade energy.

2.3 Development of a Wind Energy Forecasting System for Xcel Energy

At the time the forecast system was developed, Xcel Energy Northern States Power (NSP) wind generation sites in the state of Minnesota consisted of 81 individual wind plants for a total of 652 MW of installed capacity. The Xcel PI system provided WindLogics with real-time 10-minute average wind power data for 17 wind power interconnect nodes in the NSP service area. Since an interconnect node is representative of power generation at several wind farms and the data received from both Xcel and the participating wind farms did not have individual turbine availability data, the assumption was made that all turbines were available and on-line at any given time. The wind generation in the NSP region is generally clustered in two areas: the Buffalo Ridge area in southwest Minnesota, and a region of higher terrain in southeast Minnesota as shown in Figure 1.

Real-time meteorological data are also critical for forecast accuracy. Ten real-time data loggers were installed on meteorological towers around the Buffalo Ridge area of southwestern Minnesota as illustrated in Figure 2. These real-time met towers are used to validate the wind forecasts, to enable the Buffalo Ridge curtailment strategy, and to provide real-time data for the Mesoscale Rapid Update Cycle custom forecasts and the High Wind Warning System (discussed below). WindLogics also received the MADIS (Meteorological Assimilation and Data Ingest System) data set in real-time. MADIS comprises several different types of datasets, including standard observations from the National Weather Service (called METARs and SAOs), a high resolution meso-network of surface observations obtained by local, state, and federal agencies throughout the world (called Mesonets), the North American wind profiler network data (called Profilers), and the World Meteorological upper air observation network data (called RAOBs). The high spatial (and in some cases temporal) resolution of the METAR, SAO, and Mesonet data make them a valuable resource for forecasting.

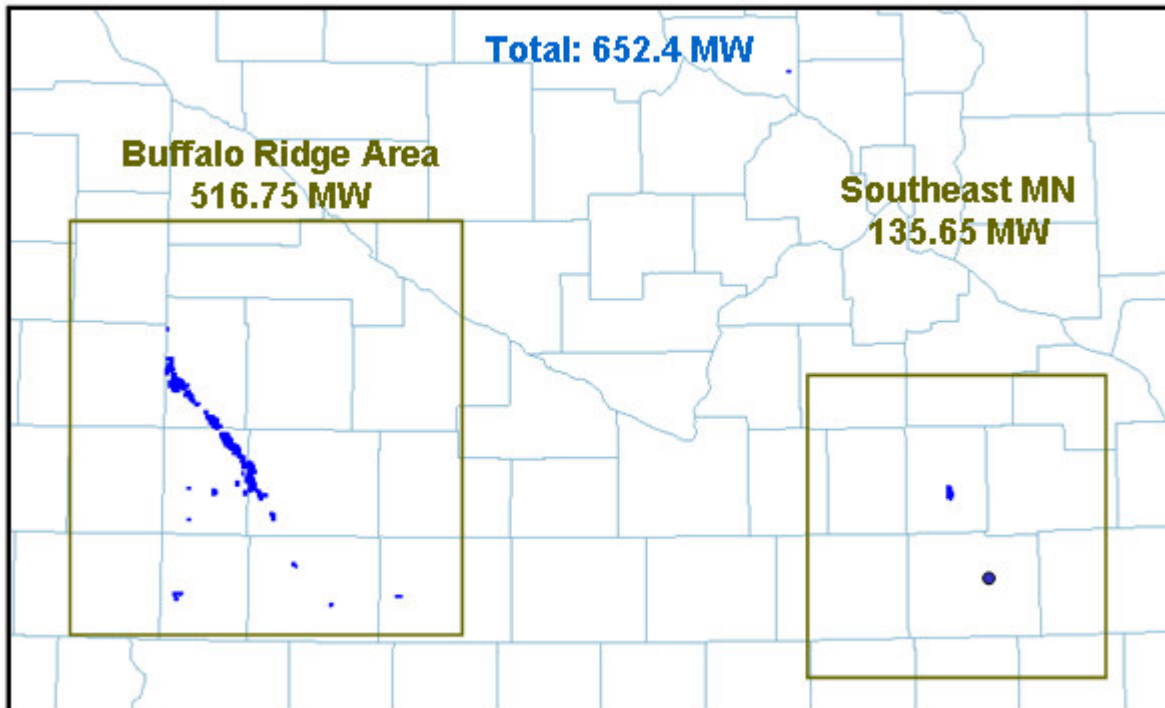


Figure 1: Wind Energy production sites in the NSP operating area. With the addition of the Mower County node in southeastern MN, the total production to be forecasted in the project is 652 MW.

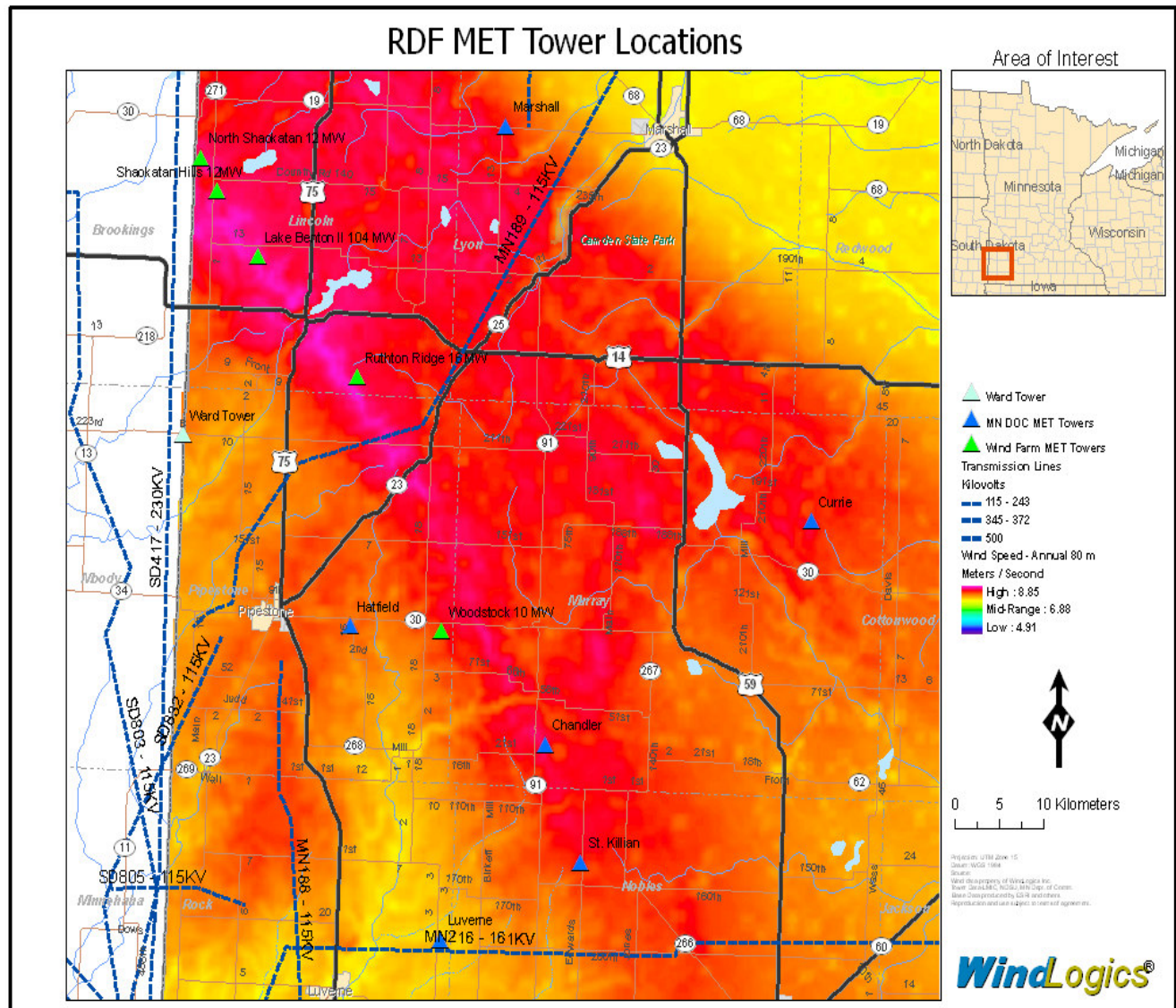


Figure 2: RDF Meteorological Tower Locations

There are several approaches one can take to making wind (power) forecasts as was discussed above, depending on the timescale and application. WindLogics has developed a combined approach of using numerical forecast models, meteorological tower data and National Weather Service (NWS) surface observing stations within a computational learning system (CLS) framework to make more accurate wind forecasts for a specific site (Support Vector Machine technology coupled with Physics-based Modeling for Wind Facility Power Production Forecasting, Moon et al. AWEA Conf presentation 2004). Computational learning systems are sophisticated methods for creating classification or regression functions from a set of labeled training data. They are able to 'learn' complex nonlinear relationships between hypothesis variables and target variables based on the training data provided. The computational learning system can be trained for each individual wind farm, providing more accurate site-specific wind (power) forecasts than would be provided by using meteorological tower data or a numerical forecast model alone. This combined approach allows us to design an integrated forecast system capable of creating wind (power) forecasts ranging from one hour to several days. The computational learning system used by WindLogics to train the forecasts is Support Vector Machine (SVM).

The forecasting system uses an ensemble of the National Center for Environmental Prediction (NCEP) North American Model (NAM) and the Global Forecast System (GFS) model for the day-ahead wind power forecast. These models are part of a suite of numerical forecast models that are routinely used by the National Weather

Service (NWS) for making 1-3 day forecasts. The GFS is also used to make 'medium-range' (3-14 day) forecasts. The models calculate wind, temperature, pressure, humidity, and precipitation along with a host of other meteorological parameters at various heights in the atmosphere ranging from 10 m to 20 km above the surface. The NAM model has horizontal grid spacing of 12 km, and produces a new 84-hour forecast every 6 hours. The GFS model has a horizontal resolution of 0.5 degree (~50 km in midlatitudes) and a new 10 day forecast is issued every 6 hours. (Note: the GFS forecasts extend out to 16 days, but the model is run at coarser resolution after forecast day 10.) The WindLogics day-ahead forecast is updated every six hours and provides hourly power values for an 84-hour time horizon.

The hour-ahead forecast provides finer time resolution for the next few hours. It is used by operators in the load-following time horizon and as input for defensive operating strategies during large ramps in wind power production. The hour-ahead forecast is an ensemble of the trained NCEP Rapid Update Cycle model (RUC) and the NCEP NAM. The RUC model is routinely used by the National Weather Service for making short-term (9-12 hour) forecasts. The model calculates wind, temperature, pressure, humidity, and precipitation along with a host of other meteorological parameters at various heights in the atmosphere ranging from 10 m to 20 km above the surface. The model utilizes a horizontal grid spacing of 13 km. New forecasts are generated every hour by taking the previous hour's forecast as a starting point, and then assimilating all of the most recent meteorological observations into the model initial fields before the start of the new forecast. Twelve-hour forecasts are made every three hours (00Z, 03Z, 06Z, etc.) and 9-hour forecasts are made at the 'in-between' hours (01Z, 02Z, 04Z, etc.). This forecast is updated hourly and provides 10-minute power values for the first 3 hours, and hourly power values thereafter out to 9-12 hours.

Separately optimized forecasts are generated for each of the seventeen PI nodes by using the real-time node power data along with weather model forecast data to train a computational learning system (SVM) to make more accurate site-specific forecasts. Since training is done on net energy at the meter point, wind plant net energy losses are implicit in these site forecasts.

Data quality tests have been performed on the PI data to allow filtering of suspicious data and known curtailment periods from the training set. When available, this forecast integrates the most recent site data as smart persistence, but when no good site data is available, a forecast is made without this additional input. An aggregate wind energy forecast is then generated for the entire Xcel NSP footprint by combining all of the individual site forecasts. If any of the individual sites have not generated a forecast, an aggregate forecast is not created.

The aggregate forecasts were delivered to Xcel in real-time through a web page interface. A few example aggregate forecasts are shown in Figures 3-9 where the aggregate of PI wind power data is the actual reference power. Figure 3 shows a snapshot of the actual web interface for Xcel RDF aggregate forecast and shows real forecast data from for the Xcel NSP footprint. Figure 4 shows an example of the hour-ahead wind power forecast, which can be used for load-following. The hour-ahead forecast currently goes out 9-12 hours beyond the time of issue, depending on the hour the forecast is issued. In addition to displaying the actual forecast, the web interface also displays recent forecast error statistics so that Xcel can gauge recent forecast performance. An example of the hour-ahead wind power forecast mean absolute errors (MAE) in both MW and percent of rated nameplate capacity are shown in Figures 5 and 6. The MAE for the hour-ahead forecast is a running average of the last 30 forecasts (1.25 days). Figure 7 shows an example of the day-ahead aggregate power forecast going out to 84 hours and the day-ahead mean absolute forecast error is shown in Figure 8. The MAE for the day-ahead forecast is a running average of the last 60 forecasts (15 days). For the day-ahead forecasts, an integrated energy forecast is also issued (see Figure 9). This forecast shows energy accumulation in MWh over a period of three days and can potentially be a useful planning tool for operators.

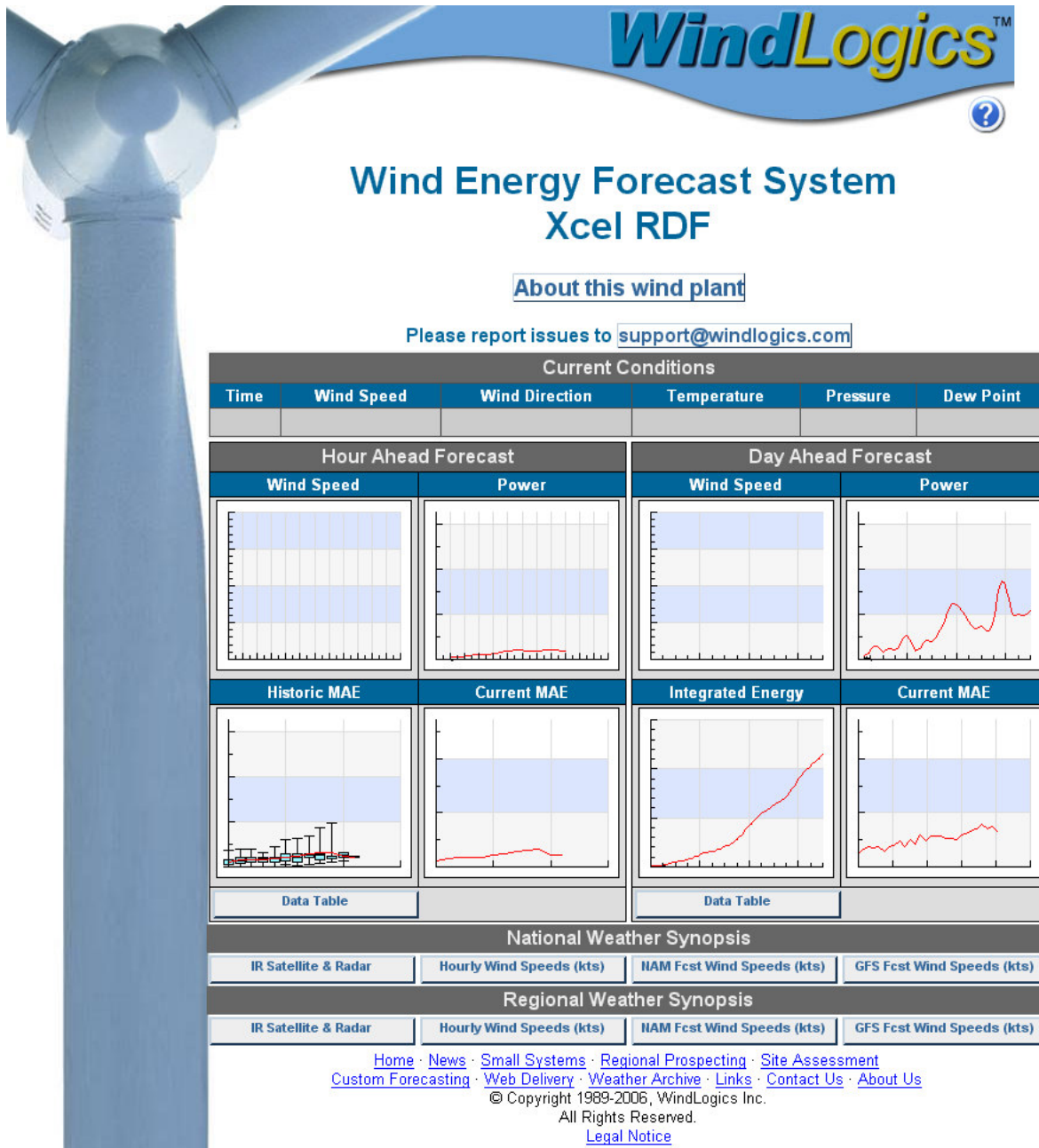
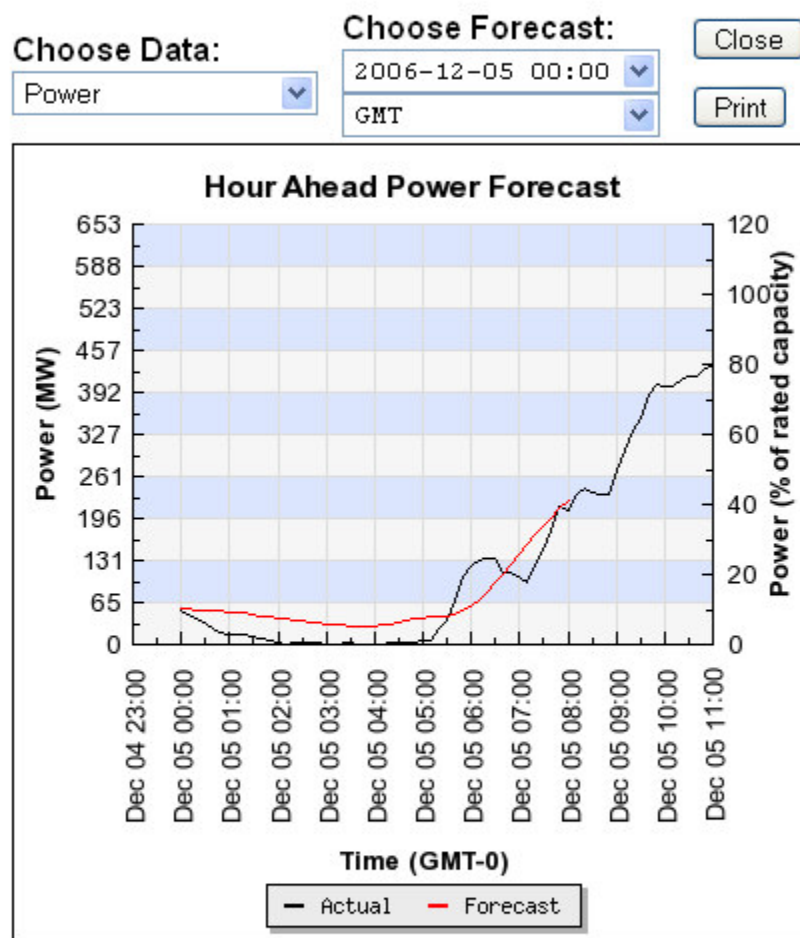


Figure 3: The web-based forecast interface for the aggregate NSP Xcel RDF forecast. Note that there is no wind speed data because this is an aggregate wind power forecast. The wind speed forecast data is contained in the individual node forecasts (not delivered to Xcel operators).

WindLogics Hour Ahead Forecast XCEL_RDF



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Figure 4: Hour-ahead NSP aggregate wind power forecast in GMT (Greenwich Mean Time) issued December 5, 2006.

WindLogics Hour Ahead Forecast XCEL_RDF

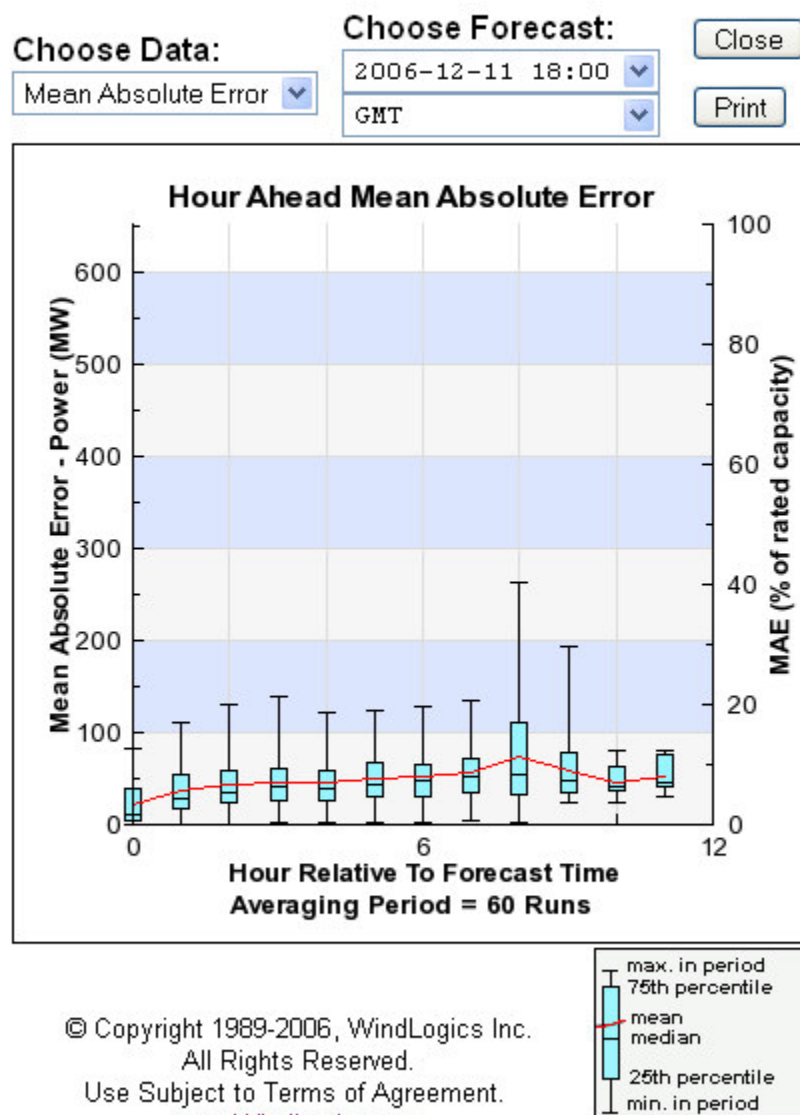
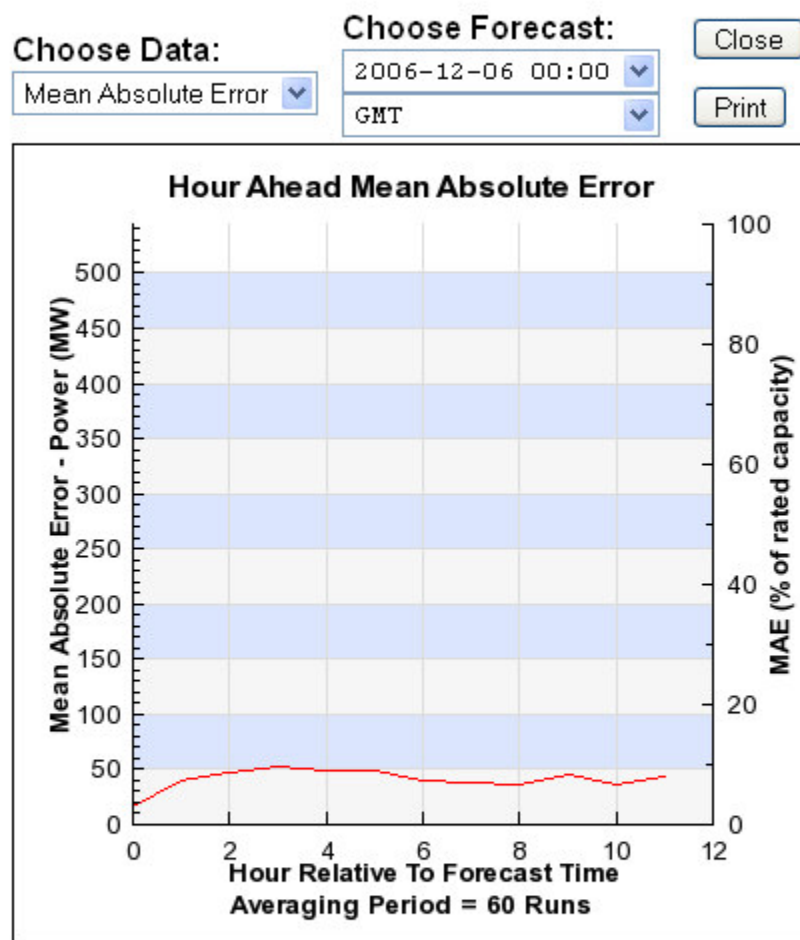


Figure 5: Hour-ahead NSP aggregate wind power forecast mean absolute errors issued December 11, 2006.

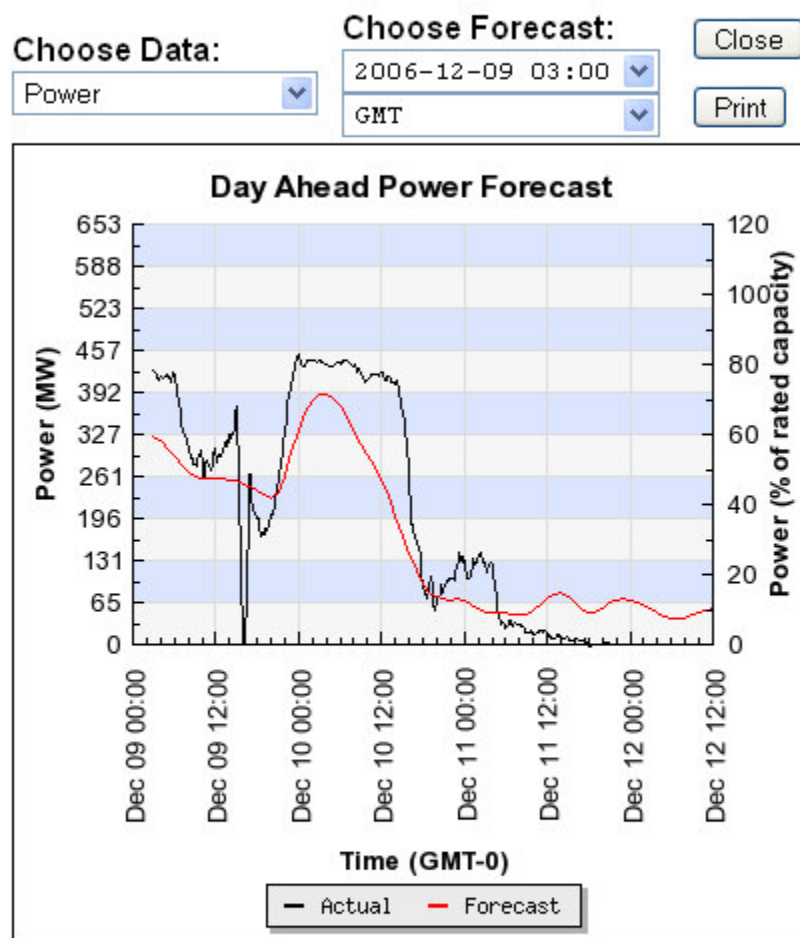
WindLogics Hour Ahead Forecast XCEL_RDF



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Figure 6: Hour-ahead NSP aggregate wind power forecast mean absolute errors issued December 6, 2006.

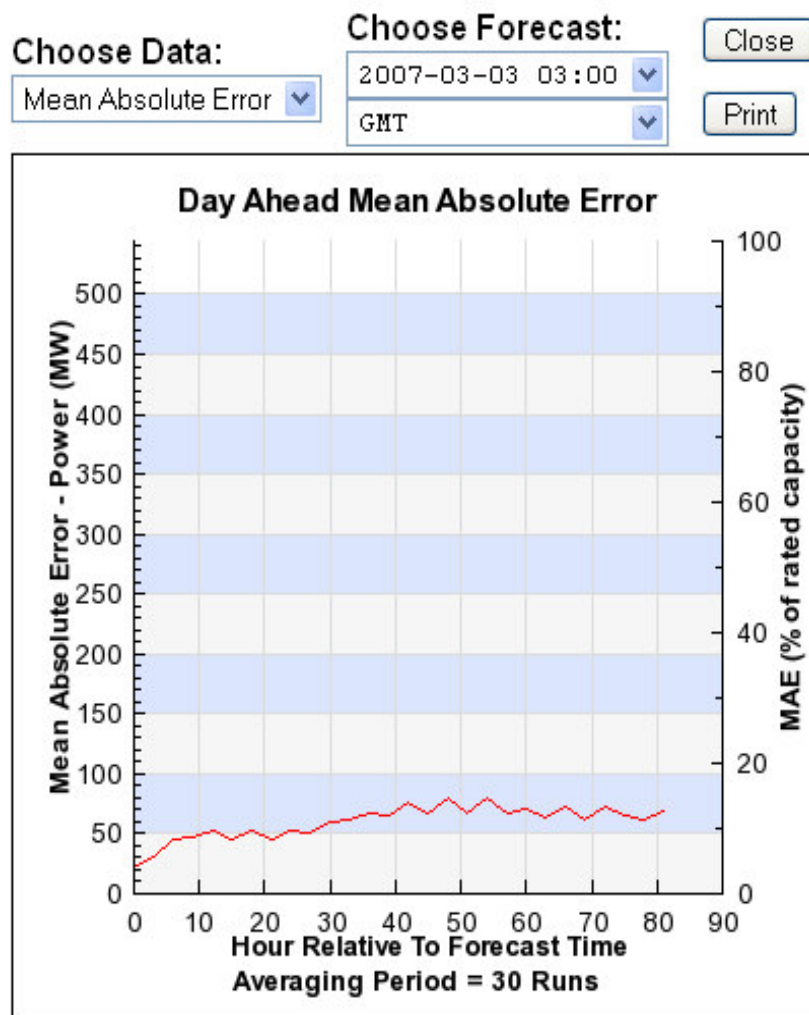
WindLogics Day Ahead Forecast XCEL_RDF



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Figure 7: Day-ahead NSP aggregate wind power forecast in GMT issued on December 09, 2006.

WindLogics Day Ahead Forecast Xcel RDF



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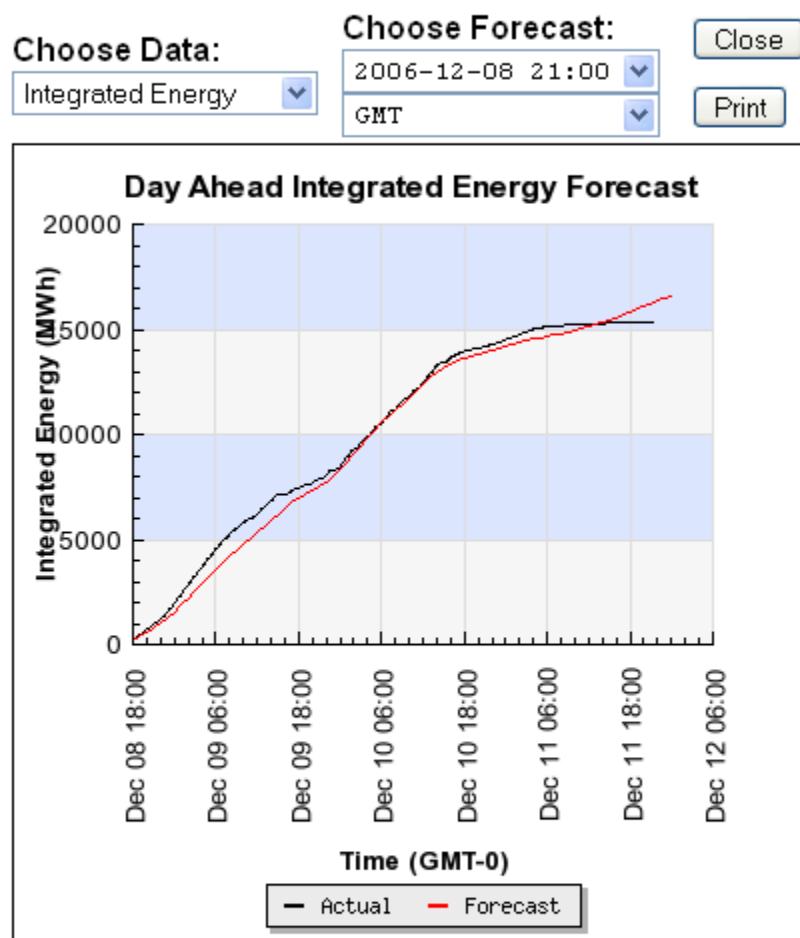
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Figure 8: Day-ahead NSP aggregate wind power forecast mean absolute errors issued on December 05, 2006.

WindLogics Day Ahead Forecast XCEL_RDF



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Figure 9: Cumulative integrated energy forecast for NSP aggregate in GMT for December 08, 2006.

The computational learning system is retrained monthly to incorporate new power and weather data as it becomes available. Although forecast error varies from month to month, the aggregate forecast has shown a general improvement during the course of the project due to monthly retraining of the forecast system and an improved understanding of PI node architecture that Xcel is operating in Minnesota.

In order to gauge the value of the SVM training utilizing the farm power data and the forecast models, a baseline forecast is also created based solely on the NWS forecast models. These 'NWS' forecasts are made by choosing the NWS forecast model point from a set of points surrounding the wind plant which best correlates with the wind plant power data. In the complete absence of any data from the wind plant, the nearest model grid point from the NWS model would be chosen. The forecast hub-height wind speeds from the NWS forecast model point are then run through the appropriate manufacturer's power curve(s) and scaled by the appropriate number of turbines to

create a power forecast. In essence, the NWS power forecast would be the best forecast we could make if power data were not available from the wind plant.

Plots comparing aggregate forecast error over the last 10-12 months for the WindLogics and National Weather Service day-ahead and hour-ahead forecasts are shown in Figures 10-14. The month-to-month variability in the accuracy of the hour-ahead forecast at the 1-hour mark is shown in Figure 10. The increase in the WindLogics error between September and October is due to a change in the timing of the arrival of the observations in the operational forecast system, so that the 'smart persistence' values were available less often at the time the forecast was issued. This change in the very short-term forecast accuracy underscores the importance of the inclusion of plant observations in the forecast. Even without smart persistence, the accuracy of the SVM-trained 1-hour forecast shows significant improvement over the NWS forecast.

The accuracy of the day-ahead forecast at the 24-hour and 48-hour marks from August 2007-May 2008 is shown in Figure 11 and 12 respectively. There is considerable variability in the monthly error statistics of the day-ahead aggregate forecasts, as some types of weather patterns are more difficult to forecast than others. A typical MAE for the 24-hour SVM-trained forecast is around 11.8% (normalized by the total rated capacity), while the untrained NWS forecast MAE averages around 15.4%. Likewise the 48-hour trained forecast performs significantly better than the untrained NWS forecast (13.88% MAE vs 17.52%). Forecast error generally increases with time, as seen in Figures 13 and 14 which show the mean absolute error as a function of forecast hour for the hour-ahead and day-ahead forecasts respectively. In both the day-ahead and hour-ahead forecasts, the trained forecasts consistently outperform the raw NWS model forecasts, with the trained hour-ahead forecasts showing the largest improvement. It should be noted that the mean absolute forecast error for the aggregate forecast is lower than those of the individual interconnect nodes due to geographic smoothing. For example, the MAE at the 24-hour mark for the day-ahead forecast typically runs around 11.7% of rated capacity for the aggregate, while for individual nodes the MAEs generally run in the 13-15% range of their respective rated capacities at the 24-hour mark. Note that the geographic area is still relatively small, with most of the wind plants clustered in the southwest corner of Minnesota, so the aggregation impact may grow with more diverse wind development in the region.

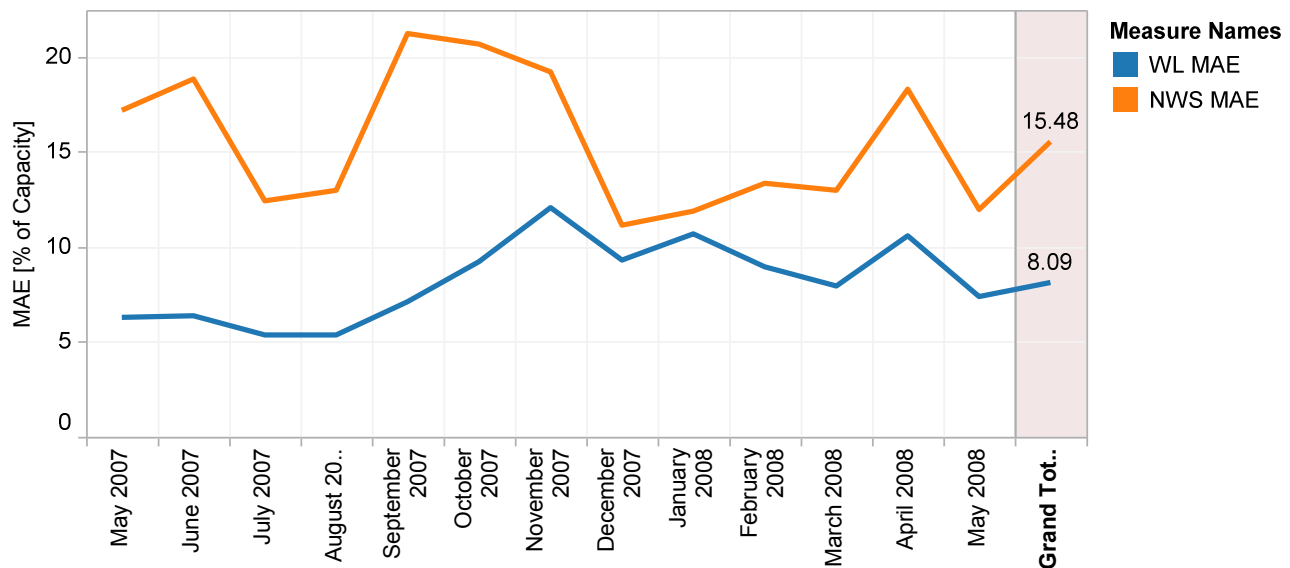


Figure 10: Mean absolute error (expressed as % of rated capacity) broken down by month for the WindLogics (blue) and National Weather Service model (orange) hour-ahead aggregate forecast at the 1-hour mark. The last point on the plot shows the overall MAE over the 13-month period shown.

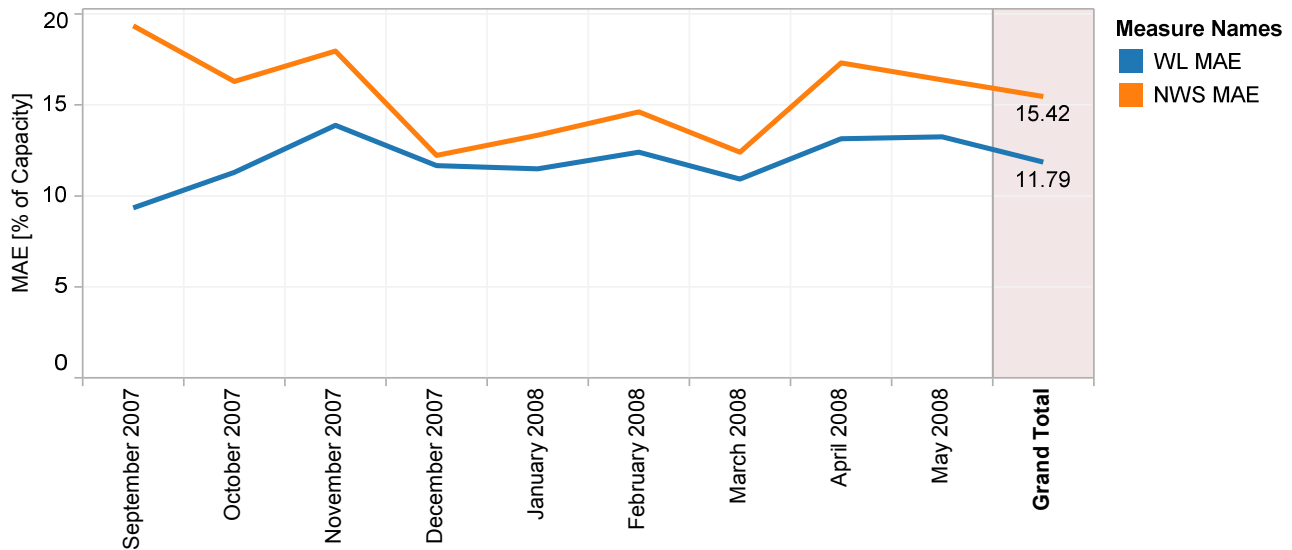


Figure 11: Mean absolute error (expressed as % of rated capacity) broken down by month for the WindLogics (blue) and National Weather Service model (orange) day-ahead aggregate forecast at the 24-hour mark. The last point on the plot shows the overall MAE over the 10-month period shown.

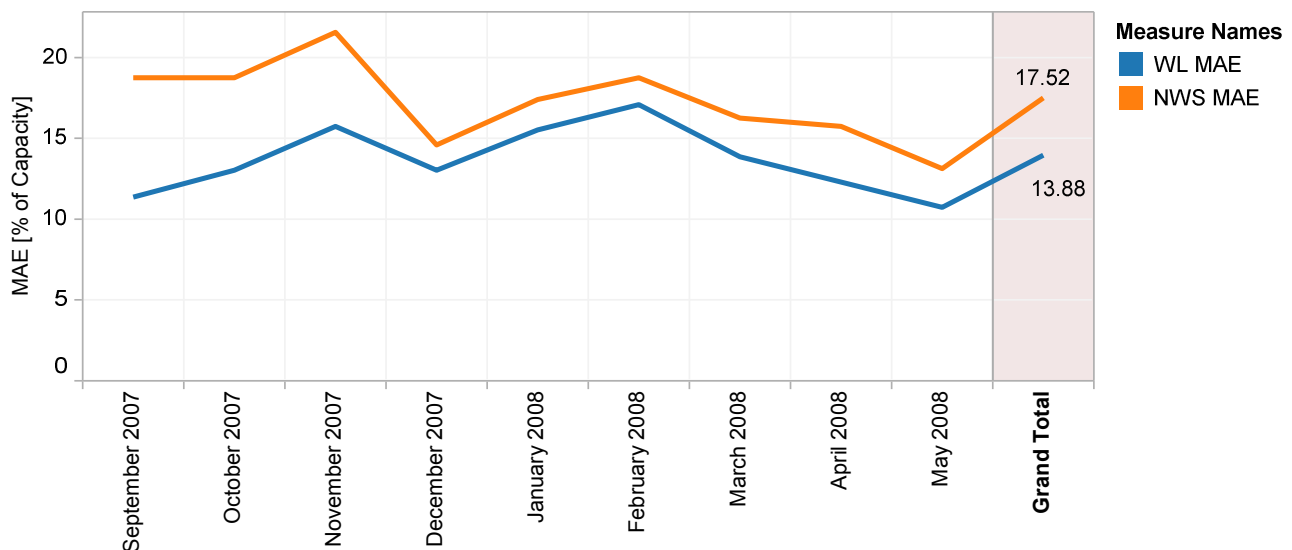


Figure 12: Mean absolute error (expressed as % of rated capacity) broken down by month for the WindLogics (blue) and National Weather Service model (orange) day-ahead aggregate forecast at the 48-hour mark. The last point on the plot shows the overall MAE over the 10-month period shown.

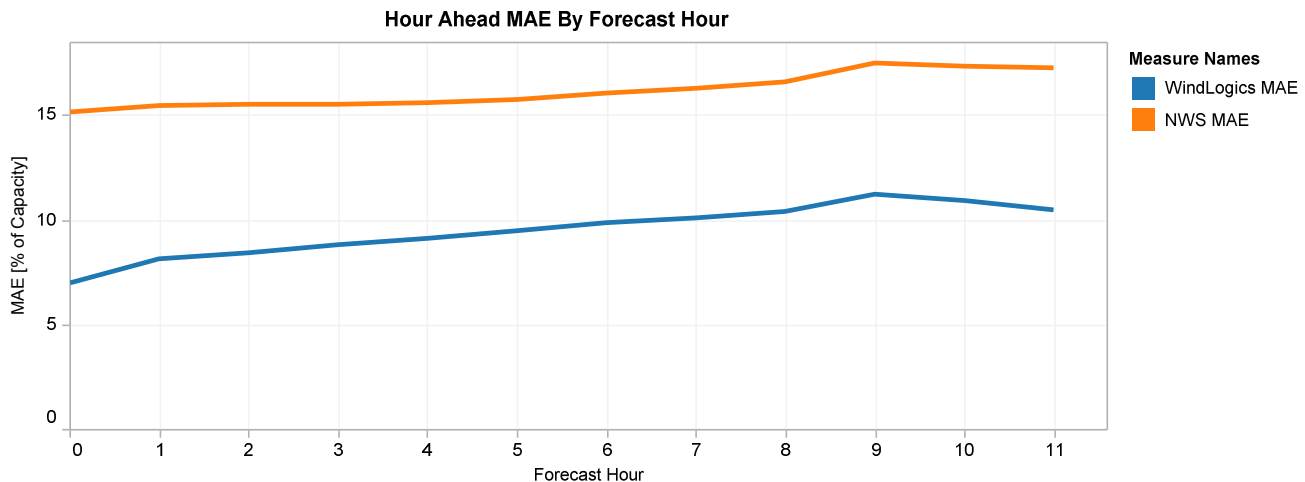


Figure 13: Mean absolute error (expressed as % of rated capacity) broken down by month for the WindLogics (blue) and National Weather Service model (orange) hour-ahead aggregate forecast as a function of forecast hour for the May 2007 – May 2008 time period.

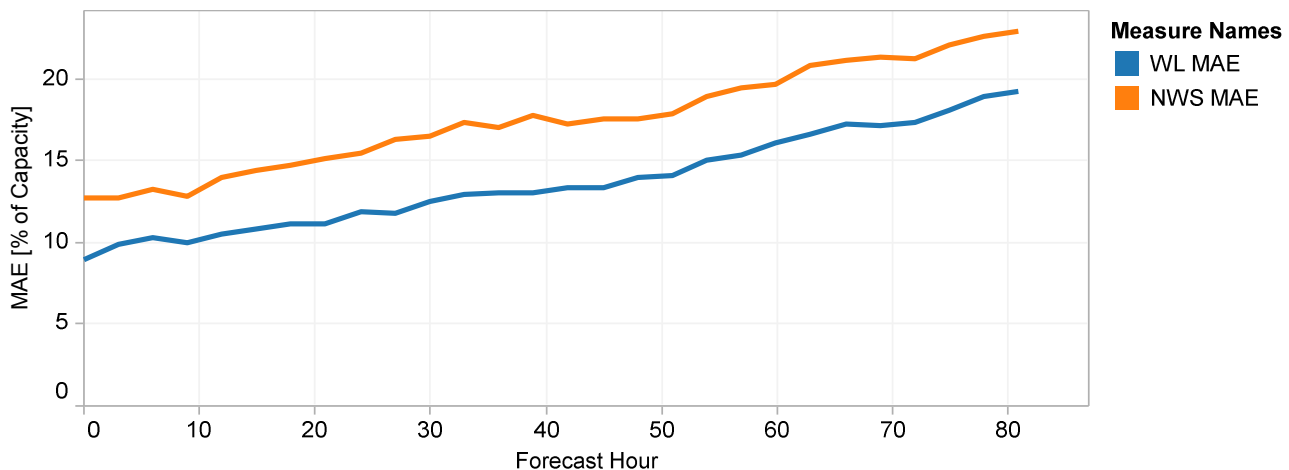


Figure 14: Mean absolute error (expressed as % of rated capacity) broken down by month for the WindLogics (blue) and National Weather Service model (orange) day-ahead aggregate forecast as a function of forecast hour for the August 2007 – May 2008 time period.

Feedback from the Xcel meteorologist users validated the value of a more accurate hour-ahead and day-ahead forecast, while highlighting opportunities for better implementation in future systems. Due primarily to rapid expansion of wind resources across the NSP system (as well as operator turnover to a lesser degree), it was difficult for operators to remember to differentiate which wind plants were a part of the aggregate forecast that was being delivered and which ones were not included in the forecast. Data confidentiality, a continual concern in this industry, prevented WindLogics from delivering individual nodal forecasts to the end user which would have ultimately provided the highest value. In many cases the nodes were being fed by only one wind farm which was providing data to the project under confidentiality agreements, thus the delivery of those nodal forecasts would have revealed the real-time production of those installations and would cause a breach of confidentiality. It is strongly recommended that future system implementations include data sharing clauses with plant owners in order to allow a more complete forecast delivery.

Given this limitation to operator use, the economic impact of this forecast's value can not be made at this time. However, the interface and forecast delivery methodology was well received, and future efforts built on this framework (assuming confidentiality concerns are dealt with) are expected to yield positive results given the superior error statistics seen throughout the span of this project.

2.4 Data Availability and Quality Compensation

Good data is critical to making the best possible forecasts. Forecasting is definitely an exercise in which “garbage in = garbage out” applies. During the course of this work, several issues were discovered with the Xcel node power data being provided for use in the RDF forecasting project. The first issue was that the observed node power output at many of the nodes did not match up with the stated rated capacity of the nodes. With the rapid growth of wind development in many regions of Xcel’s operating area, it is inevitable that the node capacities will change with time to accommodate new development. Xcel made corrections to the rated capacity of some of the nodes used in this study, but some discrepancies still exist. This will obviously affect the quality of the forecasts and the forecast error statistics since the rated capacities are often used as the basis for normalized error calculations.

The second issue is that the Buffalo Ridge area is transmission constrained, and curtailments appear to be a frequent occurrence during windy periods. Xcel provided information regarding total constraints on the wind production from the Buffalo Ridge area, but could not provide information about when curtailments (or other wind farm events) would occur, which node (or nodes) were being curtailed, or by how much. When curtailment periods or other major man-created farm events are included in the SVM training process, it makes it much more difficult for SVM to learn the physical relationships between the forecasted wind speed and power production, and it skews the forecast error statistics. Xcel also specifically requested a power forecast based solely on meteorological conditions. Thus, it became necessary to make use of all the data sources available to filter out as many of these curtailment periods as possible from the RDF forecast database.

An automated process for screening potential curtailments periods was developed and tested to attempt to screen out curtailment periods with other sources of data. The method utilizes the tall tower network as a data source independent of the Xcel node power data. The method using the tall tower network as a means of screening out curtailment periods is outlined below:

- The two best met towers (i.e. ones with the most/reliable data) were chosen – one to the north, one to the south of each node. Two towers were chosen to help reduce data screening due to phase differences in the passage of meteorological features.
- The node power was calculated based on the wind speed from each tower and number/type of turbines provided by Xcel. No attempt was made to shear any met tower data up or down to hub height, as this would only add uncertainty to a process where there is already considerable uncertainty. Elevation information for the node turbines was not available, so corrections for differences in elevation could not be performed.
- Actual power values from the node were then normalized by the *observed* node capacity. It was necessary to normalize the actual node power and the power calculated from the met towers because the power we observe produced from some of the nodes does not match the provided rated capacity.
- Power calculated based on the met tower wind speeds was normalized by the provided rated node capacity, taking into account the Z-48 deficits that were provided by Xcel operators (i.e. the max rated output for the Z-48s is 710KW based on WL power curves database – Xcel has it listed at 750KW).
- If the actual node (normalized) power was less than BOTH power values calculated from the met towers by an amount \geq some threshold, the data was flagged as a possible curtailment. The threshold values were calculated separately for each node, but generally fell in the 15-20% range of the node’s rated capacity.

This method is not perfect as it may not flag all curtailment periods, and may flag some legitimate data as being ‘curtailed’. Another issue is that it requires data from two met towers along with the node power. If either of the two towers is missing data, this method cannot be used. In our tests, if either tower was missing data for a given timestamp, the power data for that timestamp was flagged as a possible curtailment and not used for training or error statistics calculations.

The implementation of the curtailment screening procedure has a significant impact on the forecast accuracy. The improvement in the accuracy of the hour-ahead and day-ahead forecasts for a single node is shown in Figures 15 and 16. The unfiltered training/MAE lines show the MAE (expressed as a % of rated capacity) as a function of forecast hour, assuming no knowledge of curtailment periods. Since WindLogics does not receive information about the curtailments at specific nodes (or wind plants), this is representative of the forecasts that have been delivered to Xcel prior to the implementation of the curtailment strategy. The filtered training/MAE lines show the MAE (expressed as a % of rated capacity) as a function of forecast hour with the curtailment screening procedure in place. As can be seen in these figures, the hour-ahead forecast shows an MAE improvement of 1-1.5 % of rated capacity over most forecast hours, and the day-ahead forecast shows an improvement in the MAE of 1.5-2 % of rated capacity over most forecast hours. The reasons for the improvement are twofold: 1) the curtailed values are filtered from the training process in the computational learning system, so the learning system is better able to generalize the relationships between power production and predicted wind speed, and 2) the curtailed values are not used to calculate MAE in a forecast system designed to predict wind power production based only on atmospheric parameters as per Xcel's request. The aggregate forecast also shows significant improvement, but the improvement is somewhat less than that shown below since the nodes in southeastern MN and a few of the smaller nodes in southwestern MN are not subject to frequent curtailments.

Effect of Curtailment Filter on Hour Ahead Forecast

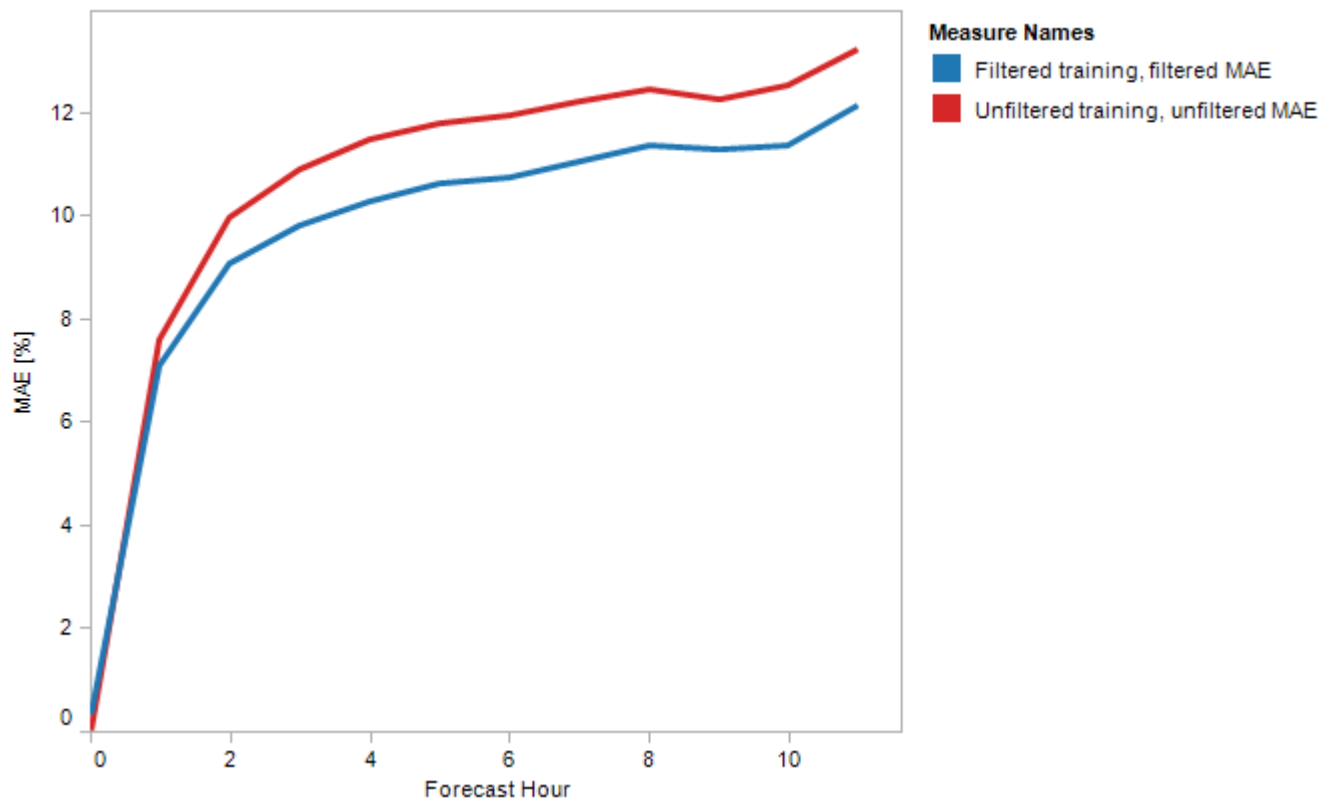


Figure 15: Mean absolute error (expressed as % of rated capacity) as a function of forecast hour for the WindLogics hour-ahead node forecast without filtering curtailment periods (red) and with the curtailment filtering process in place (blue).

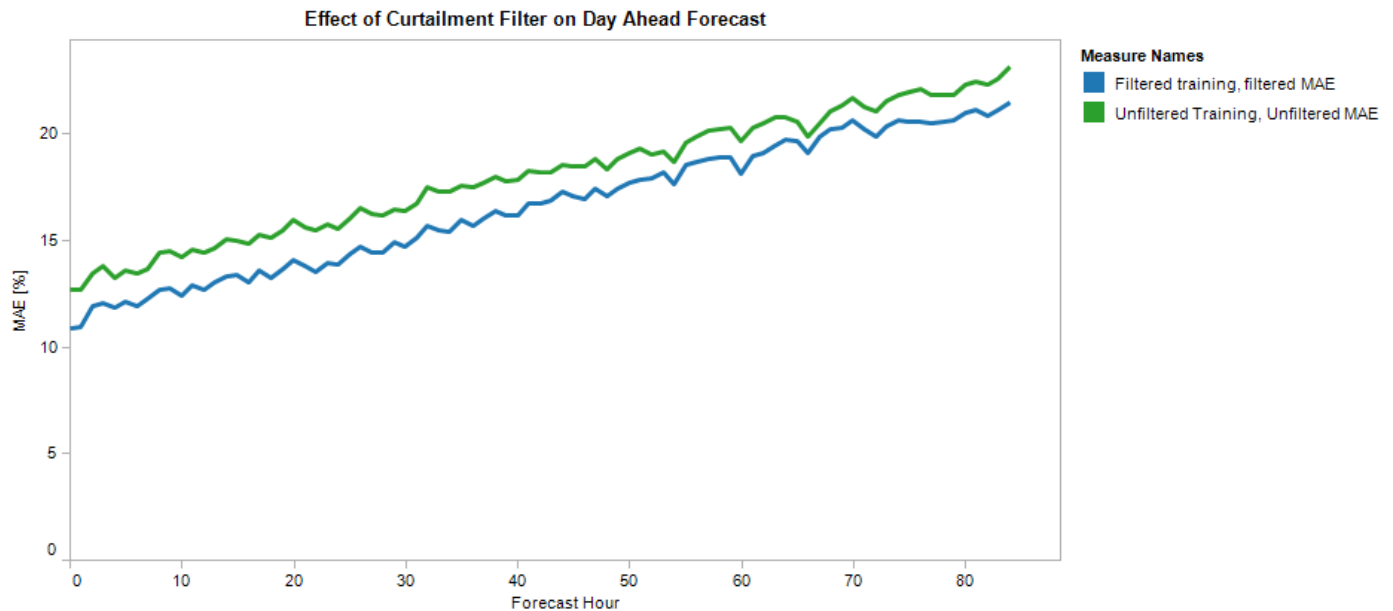


Figure 16: Mean absolute error (expressed as % of rated capacity) as a function of forecast hour for the WindLogics day-ahead node forecast without filtering curtailment periods (green) and with the curtailment filtering process in place (blue).

As wind energy continues to grow and becomes a larger fraction of energy production on a given electric grid, the more important the accuracy of wind energy forecasts becomes. The results presented above illustrate the importance of getting turbine availability and other data (such as met tower data) from wind plants in real-time if the best possible wind power accuracy is to be achieved. Ideally, this data set would include the turbine SCADA data as well as on-site meteorological data at 10-minute (or possibly 5 minute) intervals for the following variables:

- average power (total)
- turbine availability information (maintenance, curtailment, etc.)
- free stream wind speed and direction, preferably at hub-height
- speed standard deviation
- other meteorological data from tower (T, RH, pressure, etc.)

3. TASK 2 – INVESTIGATING TECHNIQUES FOR IMPROVING WIND POWER FORECAST ACCURACY AND FOR DEVELOPING DEFENSIVE OPERATING STRATEGIES

3.1 Evaluating the Impact of Additional Meteorological Tower Data on Accuracy of Short-Term Forecasts

One of the issues WindLogics proposed to investigate was the effect that a distribution of meteorological tower data has on the accuracy of short-term wind power forecasts. The wind power community has expressed interest in putting up additional meteorological towers in/around wind farms, but the benefits of doing so have not been investigated or documented. While numerical models are invaluable forecasting tools, short-term forecasts made with these models are based on data that is at least 1 hour old, as it takes time to collect and synthesize the data, and then run the model to create a forecast. Numerical forecast models also do quite well at predicting the passage of meteorological features (such as fronts), but frequently suffer timing errors (i.e. the fronts in the model move too quickly or slowly). Models also have difficulty predicting the exact location and timing of the development of thunderstorms which can produce local (or in some cases wide-spread) areas of high winds. Upstream meteorological data may provide value in helping to mitigate some of these issues.

As was discussed in Section 2.3, WindLogics erected a meteorological tower near Ward, SD to collect data for Task 2. This tower is ideally situated to provide advanced detection of frontal passages and other potential high

wind events. The Ward Tower, which was commissioned on 26 May 2006, is a 50 meter NRG tip-up tower. It is located just east of Ward, SD on the Minnesota side of the border. This tower transmits data in real-time via satellite telemetry to give the operators advanced warning of high wind events during which defensive operating strategies may be necessary. There are six additional meteorological towers that are owned by the Minnesota Department of Commerce that WindLogics is using under a cooperative agreement with the state. WindLogics hired Energy Maintenance Services of Gary, SD to install prototype SecondWind satellite loggers on six of the MN DOC meteorological towers in November, 2006. The MN DOC towers being used surround the Buffalo Ridge in Minnesota and provide data that is critical provide warnings for meteorological events that could potentially cause large and rapid ramp rates that could impact system reliability. The MN DOC towers where the additional loggers are installed are Marshall, Hatfield, Luverne, St. Killian, Chandler, and Currie (see figure 1). In addition to these towers, several wind plant operators along the Buffalo Ridge agreed to provide meteorological data in real-time to WindLogics for use in this project.

Maintaining meteorological towers is an expensive and time-consuming task, and though the course of this project there were many challenges to maintaining real-time data flow from the towers. Lightning strikes and ice storms destroyed several instruments and data loggers which needed to be replaced. One of the MN DOC towers lost instruments due to gunfire. The SecondWind satellite loggers underwent periodic firmware upgrades which required site visits to the towers, and sometimes led to periods of data loss. With a limited budget to replace equipment and make necessary repairs, lost data was unfortunately a fairly common occurrence. In some cases necessary repairs could not be made and several towers stopped transmitting viable data altogether.

As was stated in Section 2.4, reliable and accurate data is critical to any weather-related forecasting activity. For the purposes of assessing the impact of the tall tower network on short-term forecasting, seven of the original twelve towers available provided a long and reliable enough data record for use in this portion of the project. Of the seven towers, five provided two wind speed values (at the two highest tower levels where available) and one value for wind direction, while two towers provided only wind speed measurements. Limited thermodynamic data was available (i.e. temperature, pressure, humidity) from the tall tower network. In many cases thermodynamic information was not available, and from others the thermodynamic data was of dubious quality. Thus the thermodynamic data was not used in this study. The position of the towers relative to the wind generation along the Buffalo Ridge in southwest MN is shown in Figure 17. One node was chosen to investigate the impact of the tall tower on the short-term forecast. The node lies close the center of the tower network (see Figure 18).

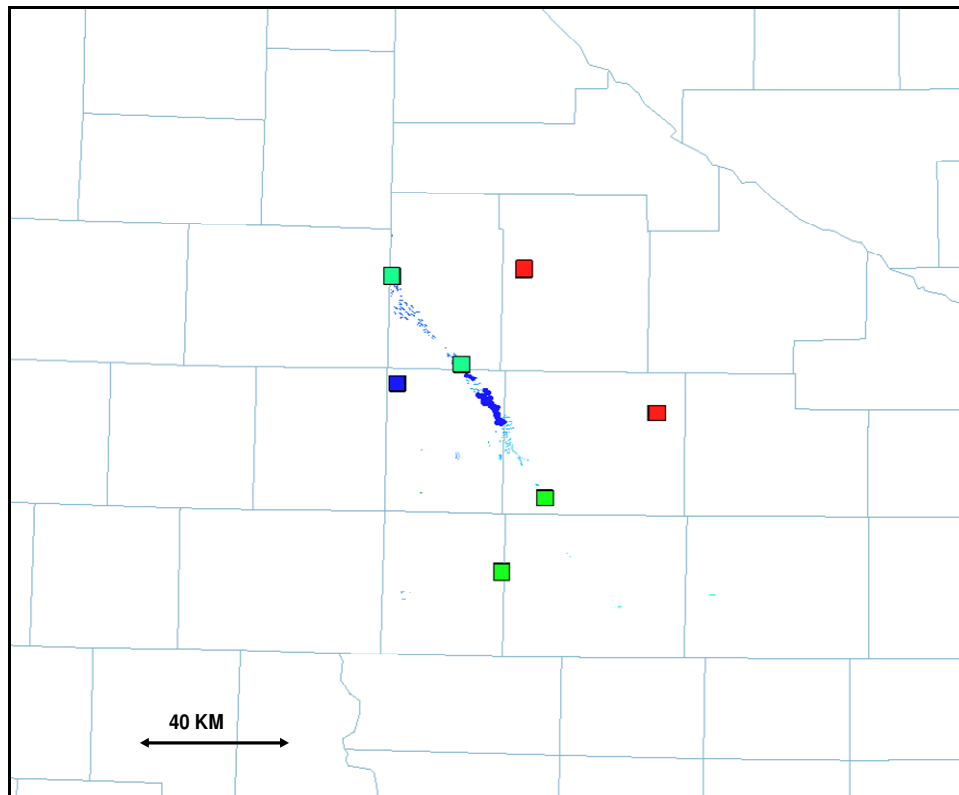


Figure 17: Position of the tall towers (colored squares) relative to the wind production along the Buffalo Ridge region of southwest MN. The light blue dots indicate the generation locations. The darker blue dots indicate the location of the wind generation facilities that comprise the node used in the short-term forecasting experiment. The color of the square indicates the maximum tower height: Red – 90m, Green – 65-70m, Blue – 50m. For scale the black line in the lower left corner indicates a distance of 40km.

The computational learning system was used to develop a short-term (0-2 hour) forecast using the ONLY tall tower data as inputs, and the node power as the target forecast variable. One disadvantage to computational learning systems is that they require large amounts of training data (in most cases) to learn the complex relationships that exist between the target and hypothesis input variables. To make a given forecast with the SVM method, all input variables must be present. This means if data from all towers were used as inputs in the training process, data from all the towers must be present to make a forecast using that training. With the various data outages due to the circumstances described above, only 30% of all available tower data was retained for training purposes if all seven towers were used in the training process (i.e. all seven had data present at a given time). With an average data record length of 2 years at each tower, this left ~ 7 months of data spread out over the 2-year period to both train SVM and test the accuracy of the forecasts. (Note that some of the data must be withheld from the training process to test the accuracy of the trained forecasts. Ideally, a year or more of data would be used in the training process.) Using a subset of the 3 towers which had the most reliable data reporting, 50-55% of all available data (~1 year) was retained.

Several experiments were performed in which the number of towers included in the training processes were varied, as well as the input hypothesis variables derived from the tower data. In one experiment a cluster analysis was performed on the data prior to training, and three separate trainings were performed based on the resulting clusters. In this experiment, only three of the seven towers with the longest overlapping data records were used as inputs to the training process. The results from all experiments were not greatly different, and the results from the cluster analysis trainings (which performed the best) are shown below.

As can be seen from Figure 18, the training process using the tall towers alone improves the MAE of the short-term forecast by only a few tenths a percent over a 2-hour period as compared to persistence. For comparison purposes, the MAE of the NWS forecast and the WindLogics operational hour-ahead forecast for the same set of forecasts are also shown.

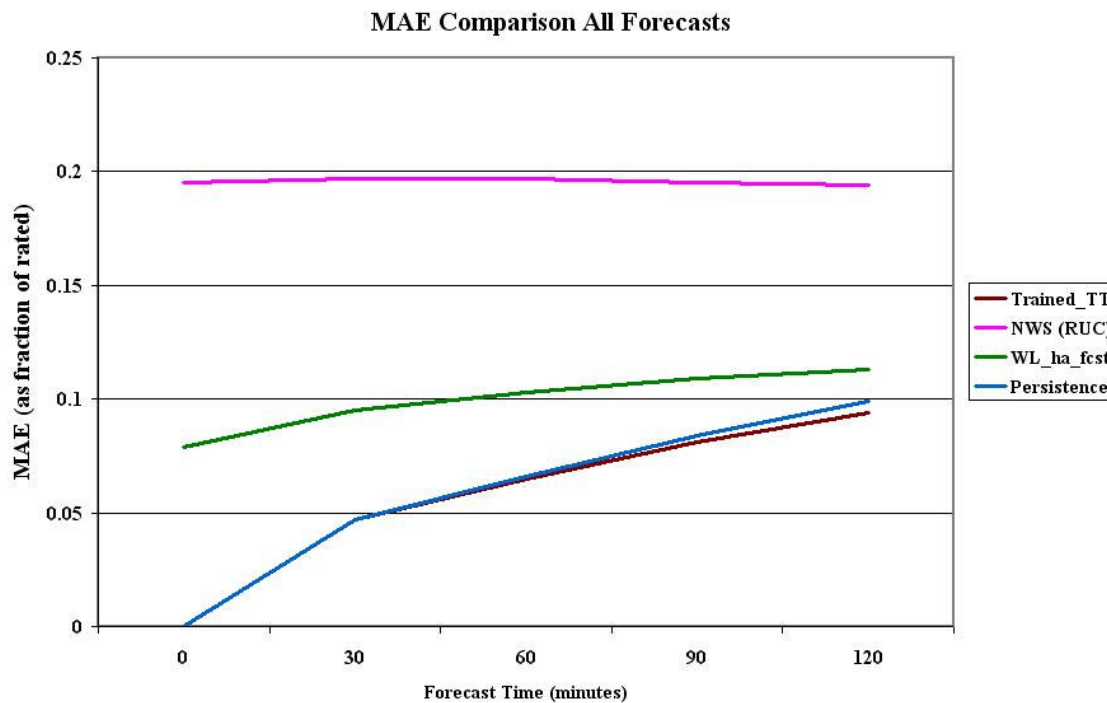


Figure 18: Mean absolute error (MAE) as a function of forecast time for the short-term forecast made with the tall tower data only (red) and persistence (blue). The MAE of the WindLogics operational hour-ahead forecast (green) and the NWS forecast (magenta) for the same set of forecast periods are shown for comparison.

Ramp events in which the wind resource changes rapidly in time is of particular interest to system operators as they may require defensive operating strategies to deal with the resulting impact on generation. What exactly defines a significant ramp event will depend on the particulars of a given system configuration. In the discussion that follows, a ramp event defined by: a change in energy production of at least 30% of rated capacity over a one hour period, or a change in energy production of at least 50% of rated capacity over a two hour period (or both). This is admittedly an arbitrary criteria, but additional tests with slight variations in the criteria produced similar results.

The MAE as function of forecast time for the ramp events as defined above is shown in Figure 19. For ramp events, the tower-trained forecast shows significant improvement over persistence at all forecast times, with an error reduction of 2.5% (of rated) by 30 minutes into the forecast. By 60 minutes, the tall tower trained forecasts reduce the error by 5% (or rated) when compared to persistence. However, between 30-60 minutes into the forecast, the WindLogics operational hour-ahead forecast performs better than either persistence or the tower-trained forecast, and between 60-90 minutes into the forecast, both numerical model-based forecasts (NWS and WL hour-ahead) perform better than the tower-based forecast and persistence. This indicates that meteorological features responsible for the majority of ramp events during this forecast period are being captured by the models, although the higher error rates (as compared to the entire forecast data set shown in Figure 18) indicate that ramp events are still difficult to forecast.

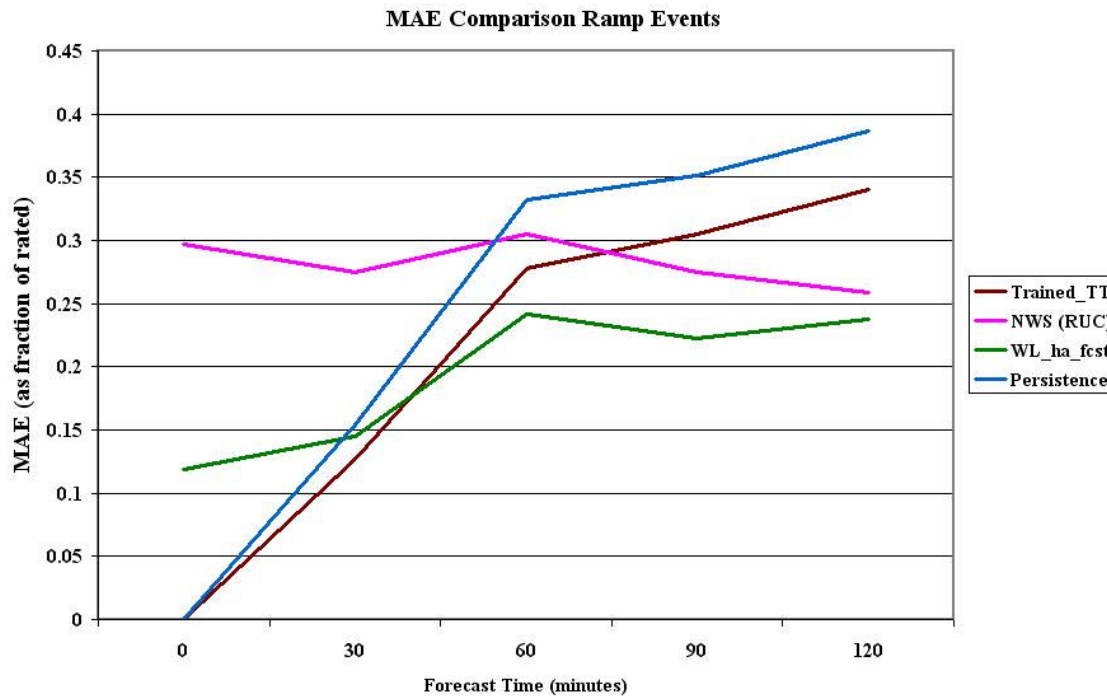


Figure 19: Mean absolute error (MAE) as a function of forecast time for the short-term forecast of significant ramp events made with the tall tower data only (red) and persistence (blue). The MAE of the WindLogics operational hour-ahead forecast (green) and the NWS forecast (magenta) for the same set of forecast periods are shown for comparison.

The error statistics shown in Figure 19 are for a single node. From a systems-operation perspective, it is also important to understand on what space scales the ramp inducing flows occur. Meteorological features that affect small areas, such as localized thunderstorm outflows, may cause a significant ramp event at one or perhaps several wind generation facilities, but if the wind generation is geographically disperse (in the sense that it extends over an area much larger than meteorological feature responsible for the ramp), it is unlikely that the events at a few plants will have a major impact on the system as a whole. Meteorological features that change the wind suddenly over large areas, such as a front or rapidly deepening low pressure system, are much more likely to cause significant ramp events system-wide. In the Xcel operating area, rapid changes in the wind can occur at many different scales.

The results above indicate that in the current configuration, the forecasts made with the tall tower training did not improve much upon the persistence forecasts in routine forecasting, but does provide significant improvement to the very short-term forecasts during ramp events, particularly when used in conjunction with trained forecasts based on numerical weather prediction models. It's likely that more value could be realized from the tower network if it were used in conjunction with a human forecaster. This is especially true during convective wind events in which a human forecaster can quickly assimilate multiple observations (such as radar data, tower data, surface data and satellite data) and ascertain patterns that could lead to the development of ramp events at a particular location. The tall tower network could also provide valuable information that would allow a human forecaster to fine-tune the timing of the passage of fronts, and the magnitude of the wind change at a given wind generation facility.

It is also important to note that the impact of upstream towers on short-term forecasts will depend on the geographic and meteorological conditions at any given site. In regions of complex terrain, terrain induced mesoscale wind flows (such as flow being channeled through a canyon) are not well resolved by forecast models, and a few judiciously placed meteorological towers could be valuable in detecting the onset and strength of these flows. Since the numerical forecast models depend on meteorological observations to determine the current state of the atmosphere, the short-term accuracy of the forecast models suffers in regions where there is little local and

upstream data. In these data sparse regions, upstream meteorological towers may have a larger impact on the short-term forecast, depending on the meteorological features that affect the wind at a give site.

The tall tower network was also used as inputs to the High Wind Warning System and the short-term MRUC forecast, the results of which are discussed below.

3.2 Testing the Feasibility of a High Wind Forecast and Warning System

In addition to the standard forecast system that is provided to Xcel operators, there is a need to better understand the larger weather situation with respect to meteorological events that may have a serious impact on generation resources. A geographically based forecast and warning tool will provide operators with an easy to reference update on existing weather conditions that can drive the decision making process in the event of severe weather. This tool was envisioned to be a visual clearinghouse of data that might be of interest to the operator. With this goal in mind, a High Wind Warning System prototype using the Google Earth GIS platform has been developed and demonstrated to key Xcel forecasting team members. Watches, warnings and advisories (WWA), real-time meteorological tower outputs, radar, turbine locations, and potentially affected MW of production have been added to the display. Testing has been conducted by WindLogics operational forecast staff, and the system was found to add significant benefits over traditional sources of watch and warning data.

Key weather indicators, including NWS watches, warnings and advisories (WWA) are being ingested by WindLogics and added to the Google Earth based High Wind Warning System (HWWS) in real-time. PHP code was developed to parse out NWS zone/county identifiers for the various NWS WWA delivered via the NOAA Port data feed. This information is put into kml format for display in the prototype Google Earth HWWS display. The kml files are currently being updated twice every hour, but could be made to update more frequently. Counties affected by the various WWA have their boundaries color coded based on the type of WWA that is currently in effect (or will be in the future). If there are wind turbines within those counties, the number of MW potentially affected by the WWA is also indicated. The text associated with the WWA can be obtained by clicking on the flag near the center of the counties as shown in Figure 20.

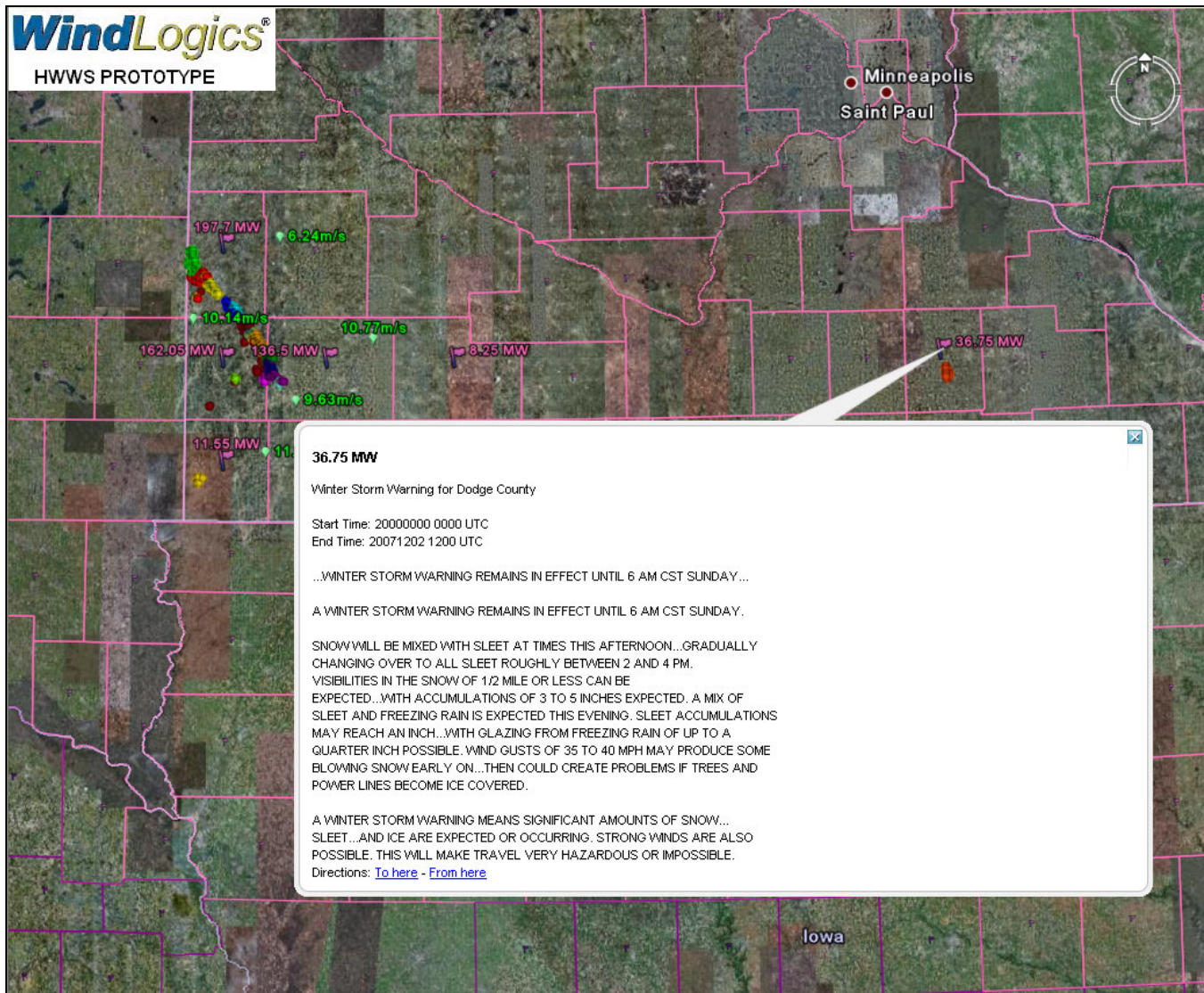


Figure 20: Winter storm warning for Dodge County including NWS description and MW of potentially affected capacity.

Additionally, output from the existing network of tall towers is being displayed on the HWWS. PHP code was developed to query the database to retrieve wind information from the publically available tall towers in southwestern Minnesota. This information is put into kml format for display in the prototype Google Earth HWWS. The kmIs are currently being updated twice an hour, but could also be made to update more frequently. The markers displayed are color coded based on the most recent reported wind speed (< 4 m/s white, 4 to 20 m/s green, 20 to 25 m/s yellow, > 25 m/s red). By clicking on the marker, information about the winds for the past 3 hours can be displayed (see Figure 21).

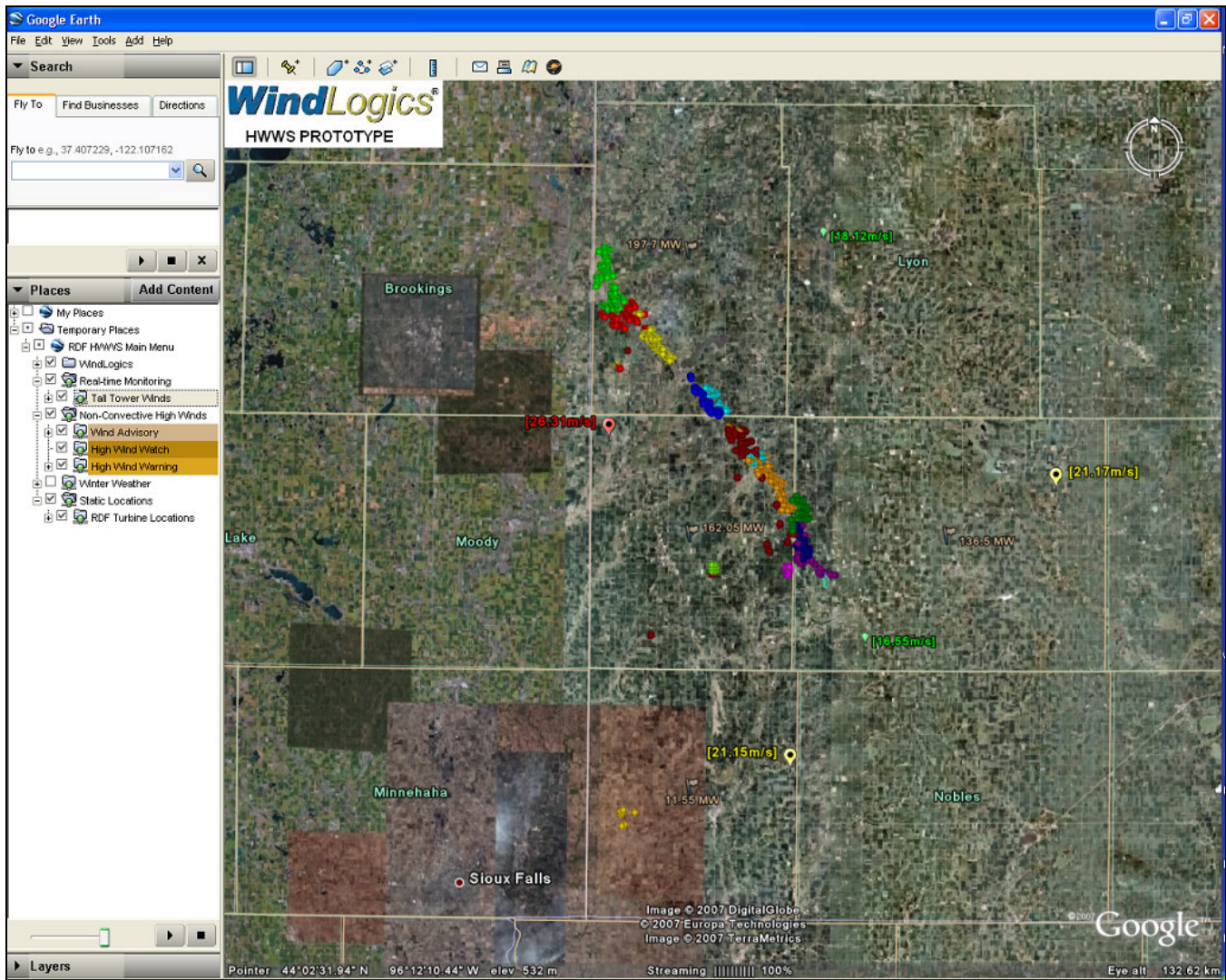


Figure 21: Real-time tall tower wind speeds with color coding to indicate strength of the wind at the tower location.

Turbine location data for wind farms within the forecasting area have also been added to the display. The markers for the turbine locations are color coded based on the substation associated with that particular turbine. Further general information about the specific towers can be obtained by clicking on the turbine markers.

Finally, real-time radar data was extracted and converted into kml format as an additional overlay for the HWWS. As seen in Figure 22, this information will allow the operator to quickly see the current weather conditions in terms of storm activity with respect to turbine locations. This last piece of data allows the system to display a comprehensive dataset that includes on-site readings, NWS watches and warnings, potentially impacted generation and real-time radar. While these individual data sources are not difficult to obtain, the holistic representation presented here creates the opportunity for an operator to take in a wide variety of data for use in situations where quick access to information is critical.

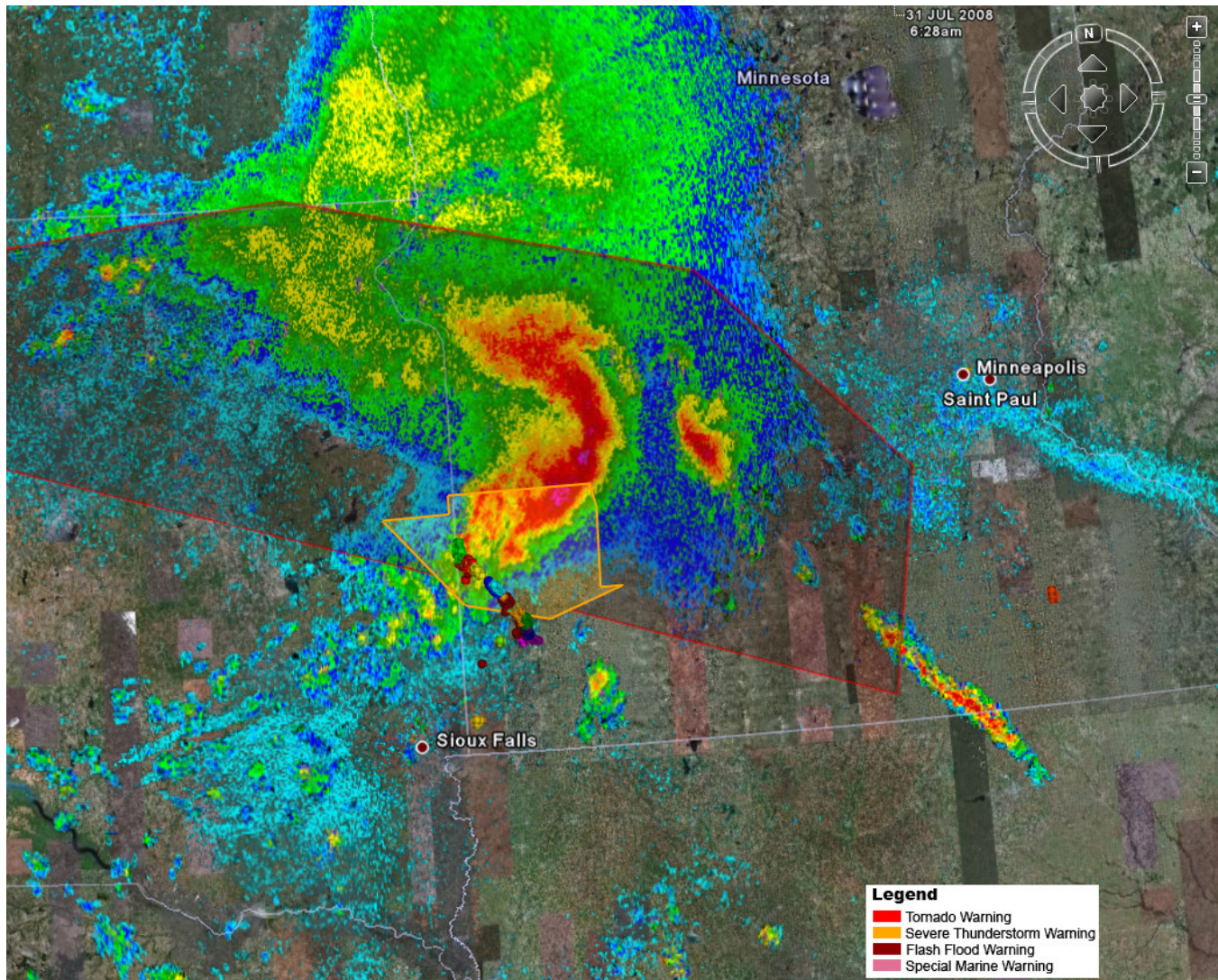


Figure 22: Real-time radar data overlaid with severe weather watches and warnings and existing turbine locations.

Testing of the HWWS has been conducted by the WindLogics operational forecasting team. While the system does not produce explicit predictions over the standard National Weather Service's WWA, it has proven valuable as a comprehensive source of data regarding potential high impact weather systems as well as on/off site met tower data, METAR readings and megawatts of potentially affected production. As there is no explicit predictive nature to the HWWS, a quantification of "hits and misses" would not add value over a similar analysis of NWS predictive accuracy. However, the ability to view this comprehensive dataset within a single, real time updated display saves the operator significant time and valuable screen real estate.

One additional benefit the system provides is the visualization of off site met tower data. In particular, the Ward tower is located to the southwest of the Buffalo Ridge and is in a position where weather systems will usually impact it before they arrive at the generation areas. Given the position of the Ward tower relative to production areas along the Buffalo Ridge, it could give 0.5 – 2.5 hour lead times for weather features with strong wind speed changes (such as fronts and thunderstorm outflows). The actual time would depend on the position of the turbines relative to the Ward tower, and the speed of the frontal movement which can vary between 15-50 km/hour (20-30 km/hour is typical). Met towers can be particularly expensive to install and maintain for long periods of time, but having towers positioned upstream in typical storm tracks can add significant value to any HWWS. Additionally, on site information compliments the NWS WWA very well and can help operators discern cases where warnings skirt the edge of a wind farm area and the effects of a given warning are uncertain. The impact of unpredicted

severe weather on an operational wind farm can be extremely expensive, so the costs involved in maintaining a moderate met tower fleet (8 -15 towers) will be more than recovered if damage to generators are avoided through their use.

The prototype system is currently not fully automated, but doing so is a feasible effort. This would allow users to view automatically updated maps that include real time WWA data, met tower readings and power forecasts for individual nodes. In order to complete this automation as well as the addition of forecast data to the HWWS, an estimated 3 months of dedicated development effort would be required in addition to the previously completed work. The development costs, while significant, are a one-time investment as the operation of the system after that point would ideally require very little input or support. The visualization of nodal power forecasts assumes that forecasting services are being purchased by the end user, but the HWWS itself has a low operational overhead cost and would provide significant benefits to operations or energy traders relative to the initial investment.

3.3 Development of a Mesoscale Rapid Update Cycle (MRUC) Model

Another technique proposed was to explore the use of a mesoscale Rapid Update Cycle (MRUC) model for short-term wind (power) forecasting. Using the RUC technique, a short-duration (3-6 hour) wind (power) forecast is made every hour using a mesoscale numerical model. The model initial conditions are created by using the one-hour forecast from the previous forecast cycle as a first guess field, and by assimilating any new observational data. This technique has the potential to provide more accurate short-term wind forecasts than using the standard NWS model wind forecasts.

The basic idea behind the MRUC is shown in Figure 23. The first step in any numerical weather prediction model is to generate a set of initial conditions that best represents the current state of the atmosphere using the most recent observations. Numerical weather prediction models utilize a three-dimensional grid on which atmospheric variables (such as pressure, temperature, wind, etc.) are stored, and new values are calculated based on physical laws during the production of the forecast. Since observations are not uniform in space, we need to ‘fill in the gaps’ based on the physical relationships between the variables so that there are representative values of all atmospheric variables at every model grid point. There are several ways that this can be done. In the rapid update cycle concept, the previous hour’s one hour forecast is used as the ‘first guess’ to the current state of the atmosphere. The most recent observational data is then assimilated into the first guess field to get a better representation of the current atmospheric state. Once this is complete, the forecast model is run to create a 6-hour forecast. At the beginning of the next hour, the one-hour forecast from the previous hour is used as a first guess field to the current state of the atmosphere, and the process begins again. In the event that the 1-hour model forecast is not available at the top of the hour, the most recent forecast fields from one of the National Weather Service forecast models are used.

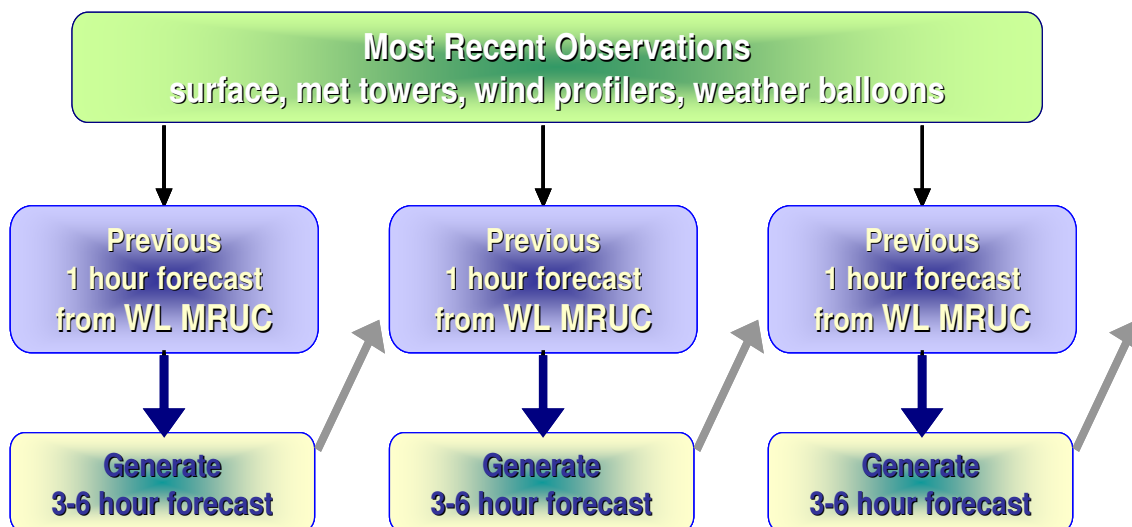


Figure 23: Schematic depicting the Mesoscale rapid update cycle (MRUC) model. See text for an in depth explanation.

It should be noted that the NWS RUC (which is used as the basis for the hour-ahead forecasts in the operational system) operates in the same way, the difference here being that a mesoscale model (MM5) is being used in the MRUC, which utilizes nested grids to get finer resolution in the areas of interest. To avoid confusion, when the term RUC is used, we are referring to the NWS RUC model (or forecasts), and when the term MRUC is used, it refers to the WindLogics Mesoscale RUC model (or forecast). The boundary conditions for the MRUC forecasts are derived from the RUC forecast fields. WindLogics is receiving MADIS data in real-time as was discussed in section 2.3. The data from this dataset along with the data from the tall tower network comprise the dataset being assimilated into MRUC. The density of the meteorological data in the Buffalo Ridge area is shown in Figure 24. Data assimilation is no trivial task, as the goal is to adjust the model fields in a physically consistent way over large areas with limited data. Any physical inconsistencies that occur as a result of data assimilation result in an adjustment of the model fields during the forecast period until a physically consistent state is reached. This adjustment process can negatively impact forecast accuracy.

The grid configuration for the MRUC is shown in Figure 25. The outermost grid (Grid 1) has horizontal grid spacing of 18 km, and covers a good portion of the central U.S. This grid captures the development and movement of large-scale weather features such as areas of low pressure and associated frontal systems. The first nested grid (Grid 2) has horizontal grid spacing of 6 km and is capable of resolving medium-scale (mesoscale) features such as squall lines and can better depict the position of frontal systems. The two innermost grids (Grid 3 and 4) have grid spacing of 2 km and are centered over the regions of wind energy production in Xcel's operating area. These grids can resolve smaller-scale features such as terrain driven flows and thunderstorms.

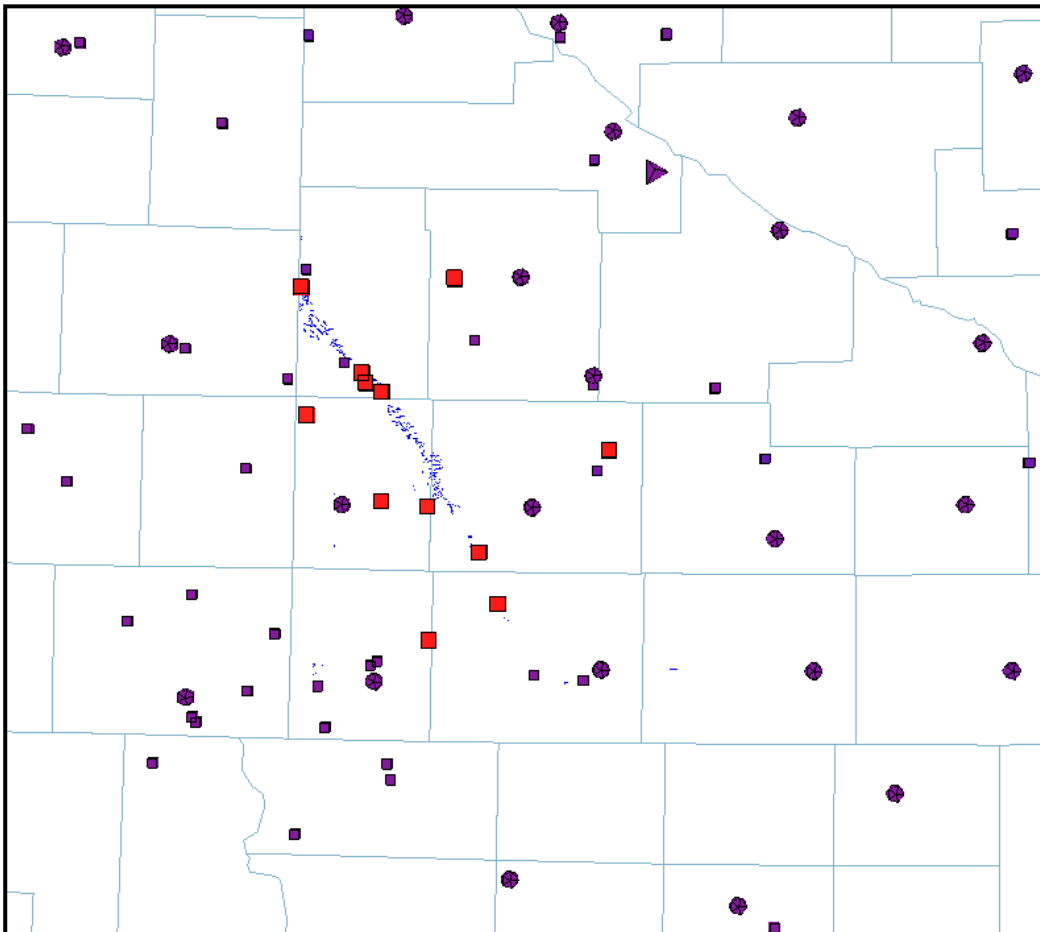


Figure 24: Meteorological data density in the Buffalo Ridge area. The light blue dots denote the wind turbines. The meteorological data include the tall tower network (red squares), NWS surface stations (blue circles), other

government agency or surface mesonet stations (blue boxes), and the NWS wind profilers or upper air stations (blue triangles).

The Mesoscale Rapid Update Cycle forecast system for Buffalo Ridge and Southeast Minnesota was installed on two operational Linux clusters in the St. Paul office of WindLogics. One installation was designated as the 'baseline' simulation in which no additional observations were assimilated into the model. The purpose of a baseline forecast is to provide a basis for comparison to assess the impact that the cycling and data assimilation has on the forecast. When compared with the NWS RUC forecasts, it also provides a measure of the impact of using a mesoscale model in wind energy forecasting in the midwest. The second installation was designated as the Mesoscale Rapid Update Cycle and uses the MADIS data set and tall tower data as part of its input. Both systems provide high resolution hour-ahead wind energy forecasts which are updated every hour. The forecasts cover the upcoming 6-hour time period at 10-minute intervals.

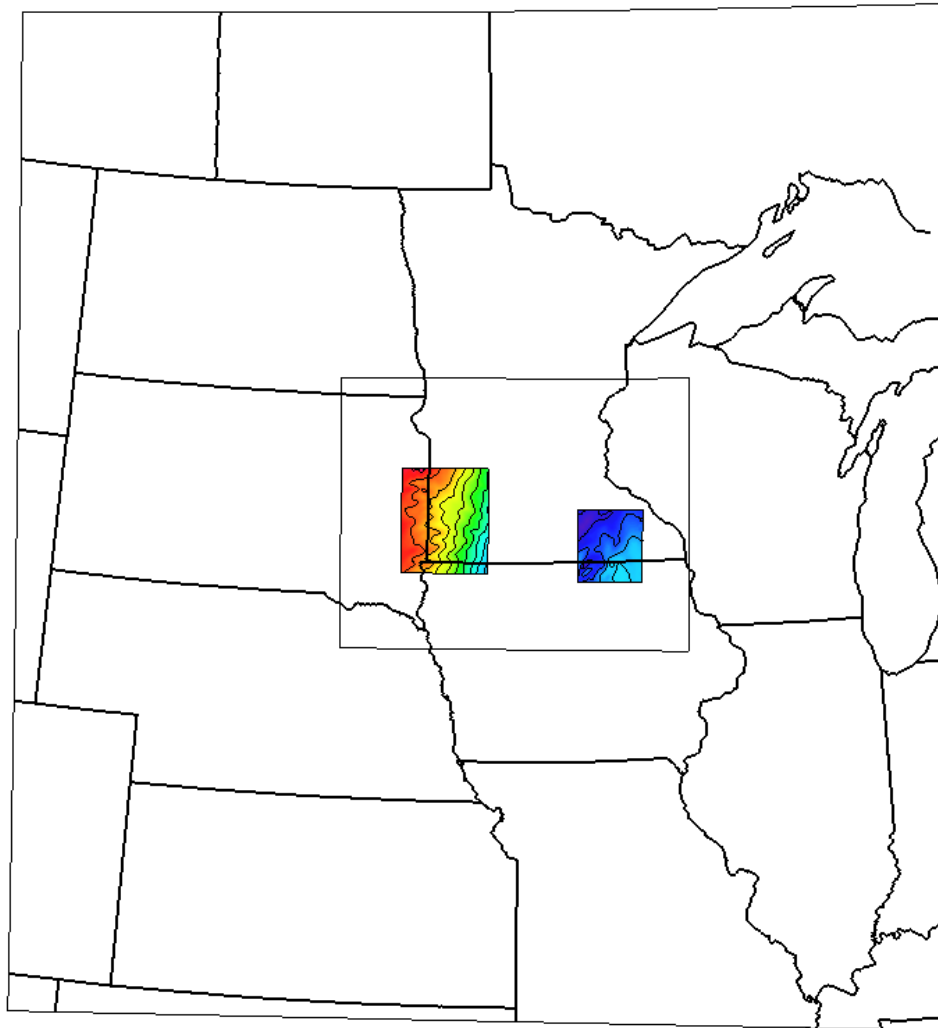


Figure 25: The four forecast MRUC grid domains. The two high resolution (2 km) grids over the wind production areas are shown in color.

Since forecast models produce wind speeds and not power, three nodes were chosen for the evaluation of the forecast models in which on-site meteorological tower data was also available. Hub-height level wind data is critical to the development of the MRUC system (as well as any other wind energy forecast system) because wind speeds can vary significantly between the surface (or the 10 m level) and hub height. An example of this is shown in Figure 34 below. The hub-height level winds were also extremely useful in determining better ways to assimilate surface observations. Unless stated otherwise, all results below are based on the forecasts from the

highest resolution MRUC and MM5 baseline forecast grids. *It should also be noted that the results presented in this section have NOT gone through any training processes using the computational learning system.* The goal of this work was to evaluate the forecast performance of the mesoscale models and to explore ways to improve them. All forecast wind speeds presented in this section come directly out of the model, and power forecasts are made by running the forecasted wind speeds through the appropriate power curves and then scaling by the number of turbines.

Error statistics during the evaluation period for MRUC and the baseline forecast (denoted as MM5 since the MM5 model is being used without data assimilation) and the NWS RUC model at the forecast node are shown in Figures 26 and 27. At this particular node, the MRUC speed MAEs lie between the MM5 baseline and RUC, with all models having speed MAEs in the 2-2.5 m/s range. The picture looks a little different in the power forecasts however. The MRUC has larger power MAEs than the other two forecasts (with the exception of the RUC in the first hour), indicating that either the MRUC has larger or more frequent wind speed errors in the steep part of the power curve, or the wind shear is larger between 65m (tower height) and 80m (hub height) than the other two models. The error statistics of the MRUC power forecasts varied somewhat between nodes, but the MRUC MAEs were always higher than the MM5 baseline and RUC forecasts beyond the 1-hour mark in the forecasts.

Note that the MM5 baseline forecast has lower errors than the NWS RUC forecasts. The value of using of mesoscale models for forecasting in the Midwest where the terrain is not very complex is unclear. However, these results indicate that using a mesoscale model for forecasting can improve the short-term forecasts in some locations in the Xcel operating area. Although the relative MAEs between the MM5 and the RUC forecasts varied from node to node, the MM5 baseline forecast had lower errors than RUC through at least the first 3 hours of the forecast at many (although not all) of the nodes during the evaluation period. This is likely because the MM5 model has a better representation of hub height, due to finer vertical resolution at the surface and a better representation of the actual terrain.

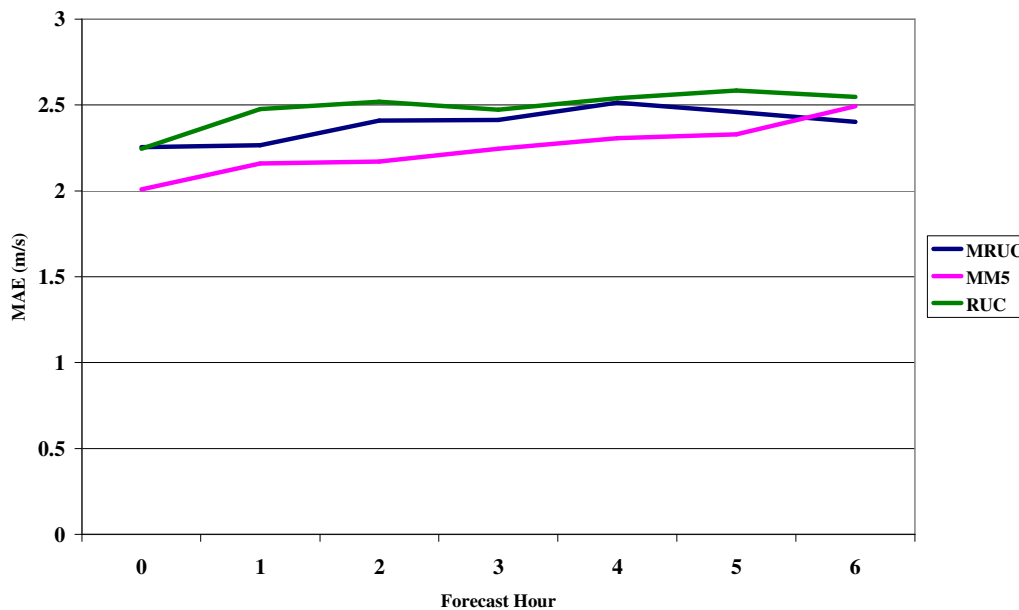


Figure 26: Mean absolute error (MAE) of wind speed at the forecast node as a function of forecast hour for the MRUC (blue), MM5 baseline forecast (magenta), and NWS RUC (green). The comparison is valid at the meteorological tower height (65m).

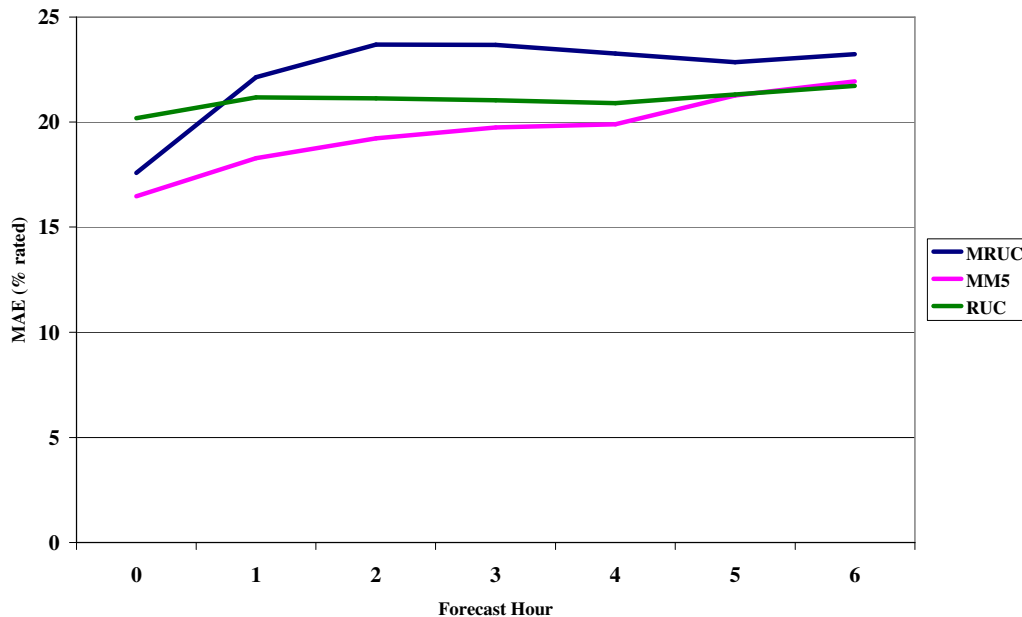


Figure 27: Mean absolute error (MAE) of power (expressed as a % of rated capacity) as a function of forecast hour for the MRUC (blue), MM5 baseline forecast (magenta), and NWS RUC (green) at the BRI321 node.

As was discussed in Section 3.1, numerical forecast models are a vital tool in predicting ramp events. Rapid changes in wind speed (and hence power production) can be difficult to predict and errors in the timing and magnitude of these events is a significant source of forecast error. The likelihood of predicting a given ramp event will depend on what is driving the event. In the Xcel operating area, ramp events can be driven by moving air masses (i.e. fronts), thunderstorm outflows, and under certain situations boundary layer processes that create (or inhibit) vertical mixing.

Part of the effort to improve the MRUC performance is identifying and understanding the situations in which the forecast model is performing well, the situations in which it is performing poorly, and the way that data assimilation is affecting the forecasts during these time periods. Meteorologically significant events (such as ramp events) often provide a good starting place for this investigation.

An example of a well predicted ramp event is shown in Figures 28 to 32. This event is a strong cold frontal passage with relatively weak winds ahead of it. Cold fronts themselves are usually well forecast, but the timing of frontal passage and the strength of the winds behind the front are often in error. This series of figures show the MRUC forecasted winds at 80m, and the observations made by the tall tower network during this time period. The forecasted winds are shown as color-coded wind barbs where the color denotes the wind speed (see the corresponding color bar in the figures). The tall tower network wind speeds are shown as color coded squares. At 06Z (midnight), the winds across southwestern Minnesota are very light (less than 5 m/s). Over the next few hours, the cold front sweeps across the area. The MRUC does a good job handling the timing of the frontal passage (forecasted frontal passage occurs ~ 20 minutes after the actual frontal passage at most locations), as can be seen by comparing the MRUC forecasted wind speeds and the tall tower observations.

To see if the MRUC forecast improves upon other short-term forecast models, a comparison was made with the forecast generated by the NWS RUC model for this event (the MM5 baseline forecasts for the first week of March 2008 were not available). The comparison of both the wind speed and power forecasts several hours prior to this event is shown in Figure 39. Three successive 6-hour forecasts (issued at 03Z, 04Z and 05Z) are displayed to get a feel for how well both models perform over the few hours prior to the event. The MRUC does a better job than the RUC with the timing of the front, but over predicts the wind speeds behind the front more so than the RUC forecast.

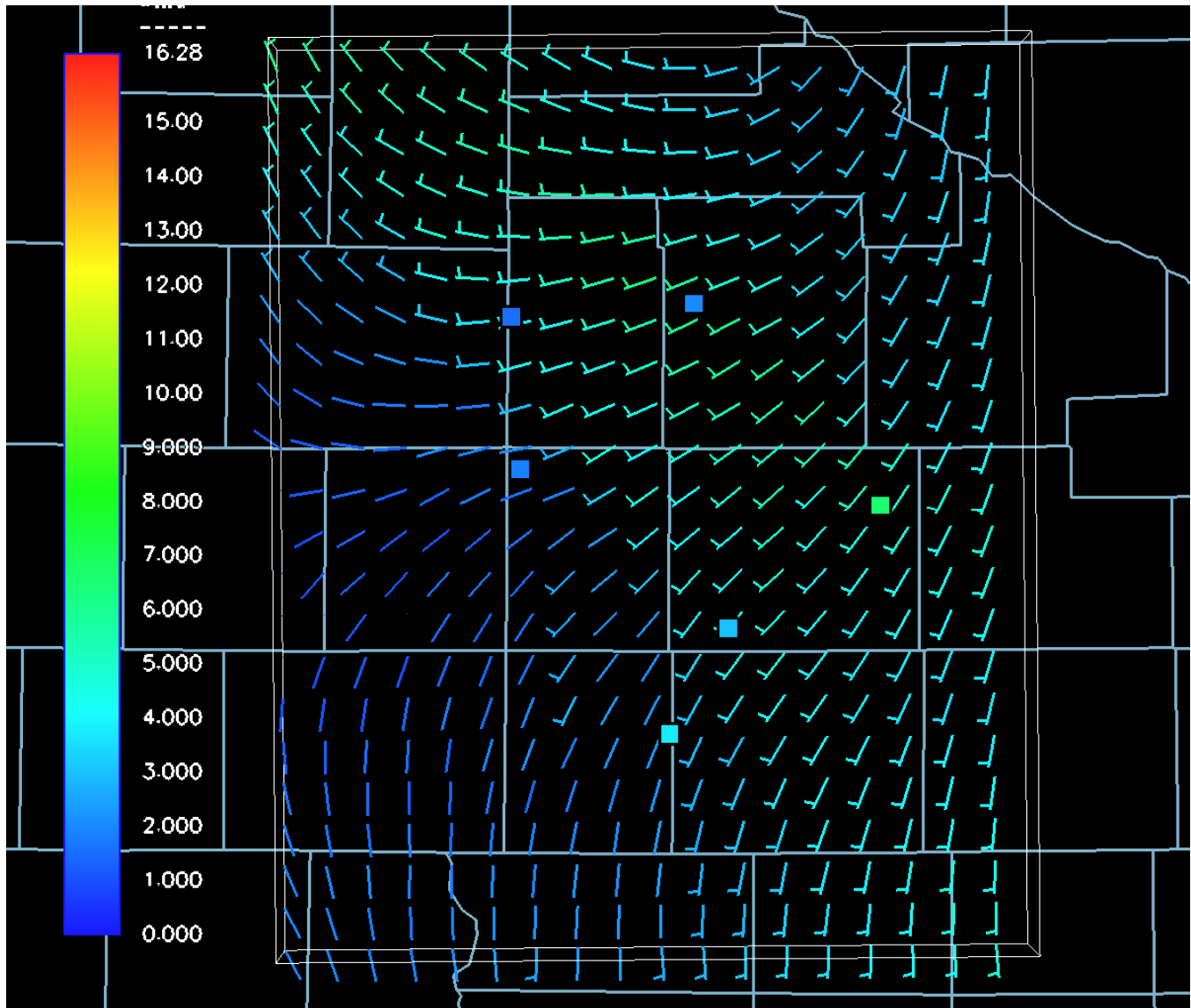


Figure 28: MRUC forecast 80 m wind speeds on Grid 3 (colored barbs – plotted at every fourth model grid point) and tall tower wind observations (colored squares) at 06Z on March 5, 2008. The forecast was issued at 05Z March 5, 2008. Forecasted and observed wind speeds are less than 5 m/s across southwest Minnesota.

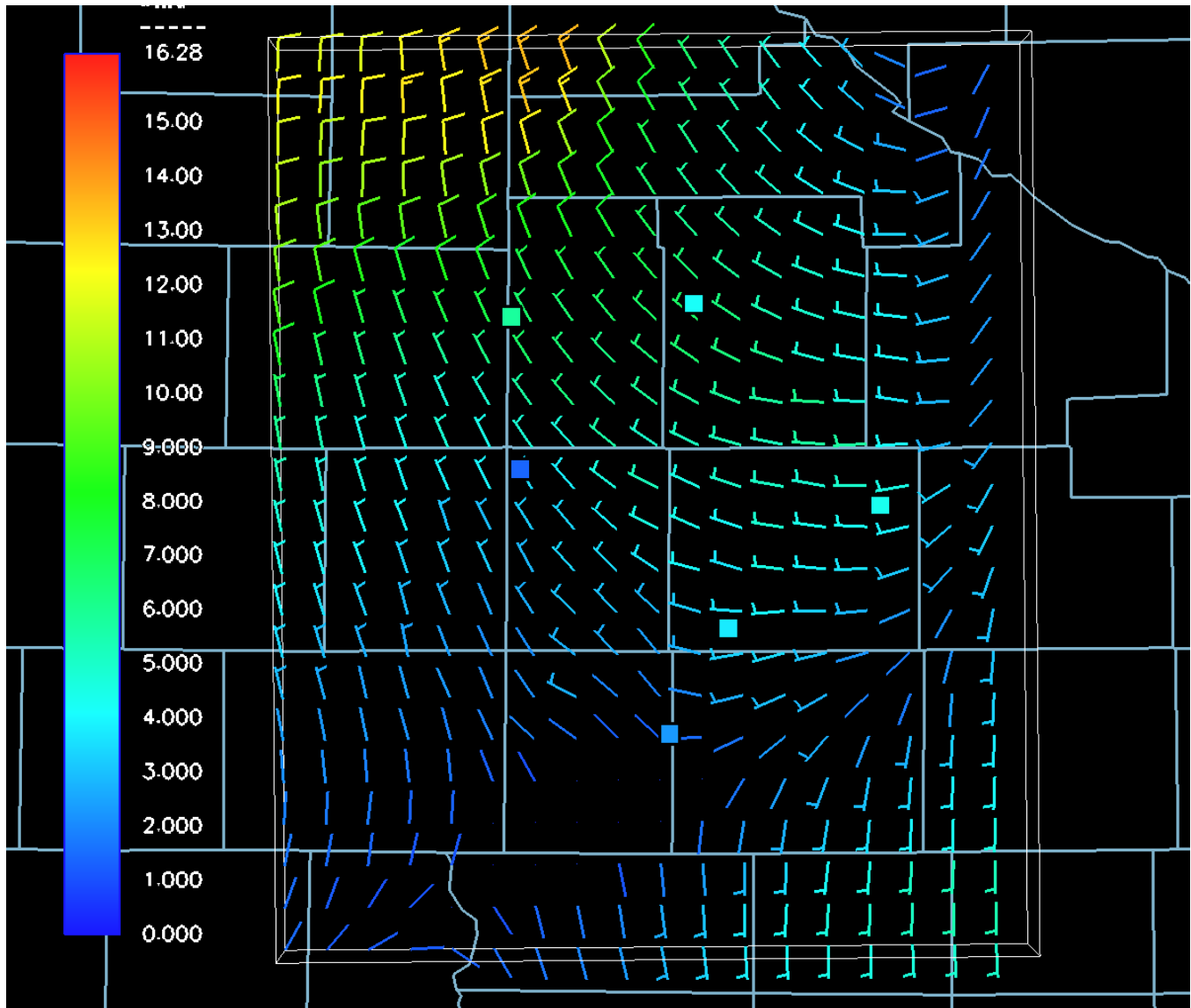


Figure 29: MRUC forecast 80 m wind speeds on Grid 3 (colored barbs – plotted at every fourth model grid point) and tall tower wind observations (colored squares) at 07:30Z on March 5, 2008. The forecast was issued at 05Z March 5, 2008. A strong cold front is approaching southwest Minnesota in the model forecast fields.

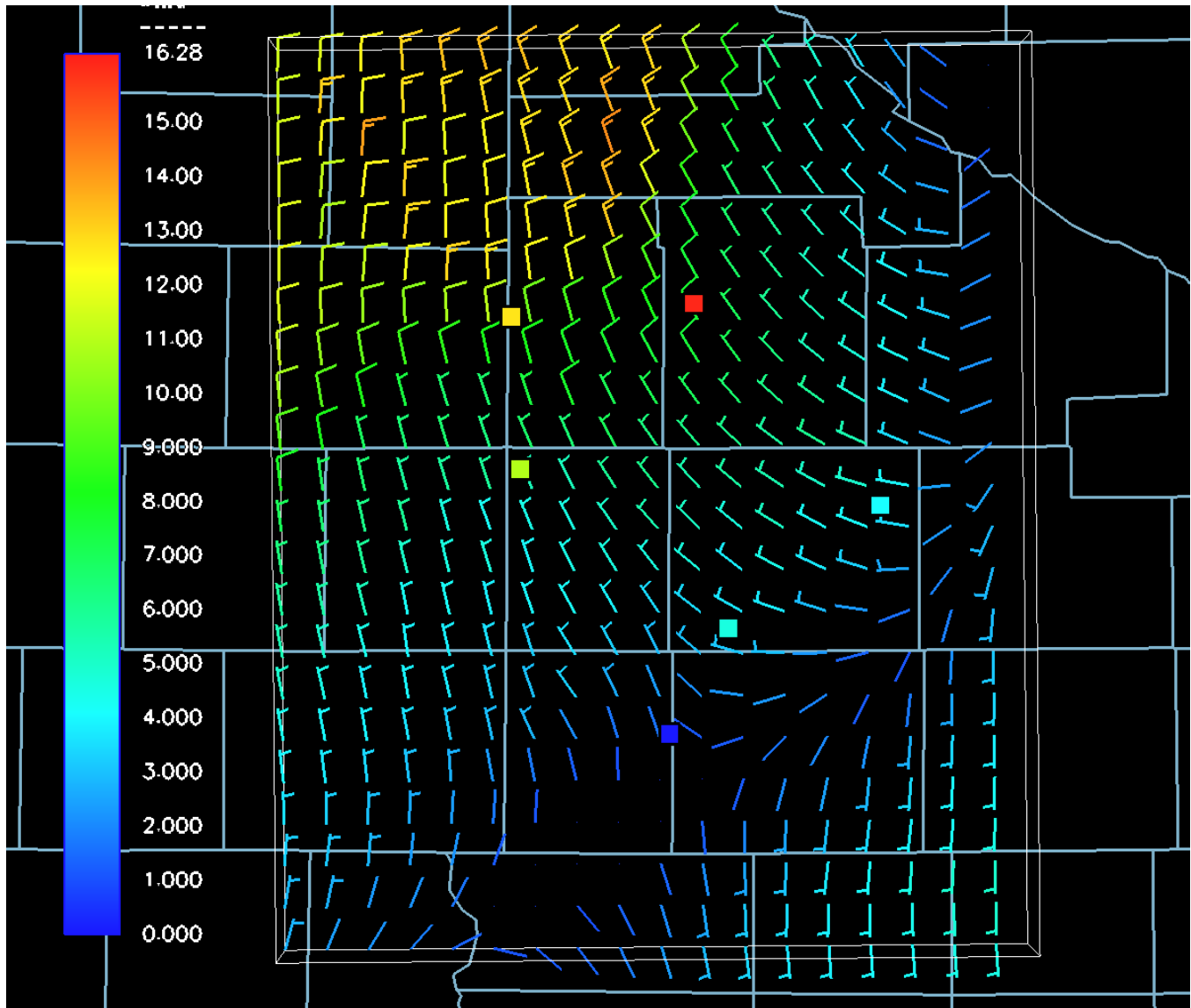


Figure 30: MRUC forecast 80 m wind speeds on Grid 3 (colored barbs – plotted at every fourth model grid point) and tall tower wind observations (colored squares) at 08Z on March 5, 2008. The forecast was issued at 05Z March 5, 2008.

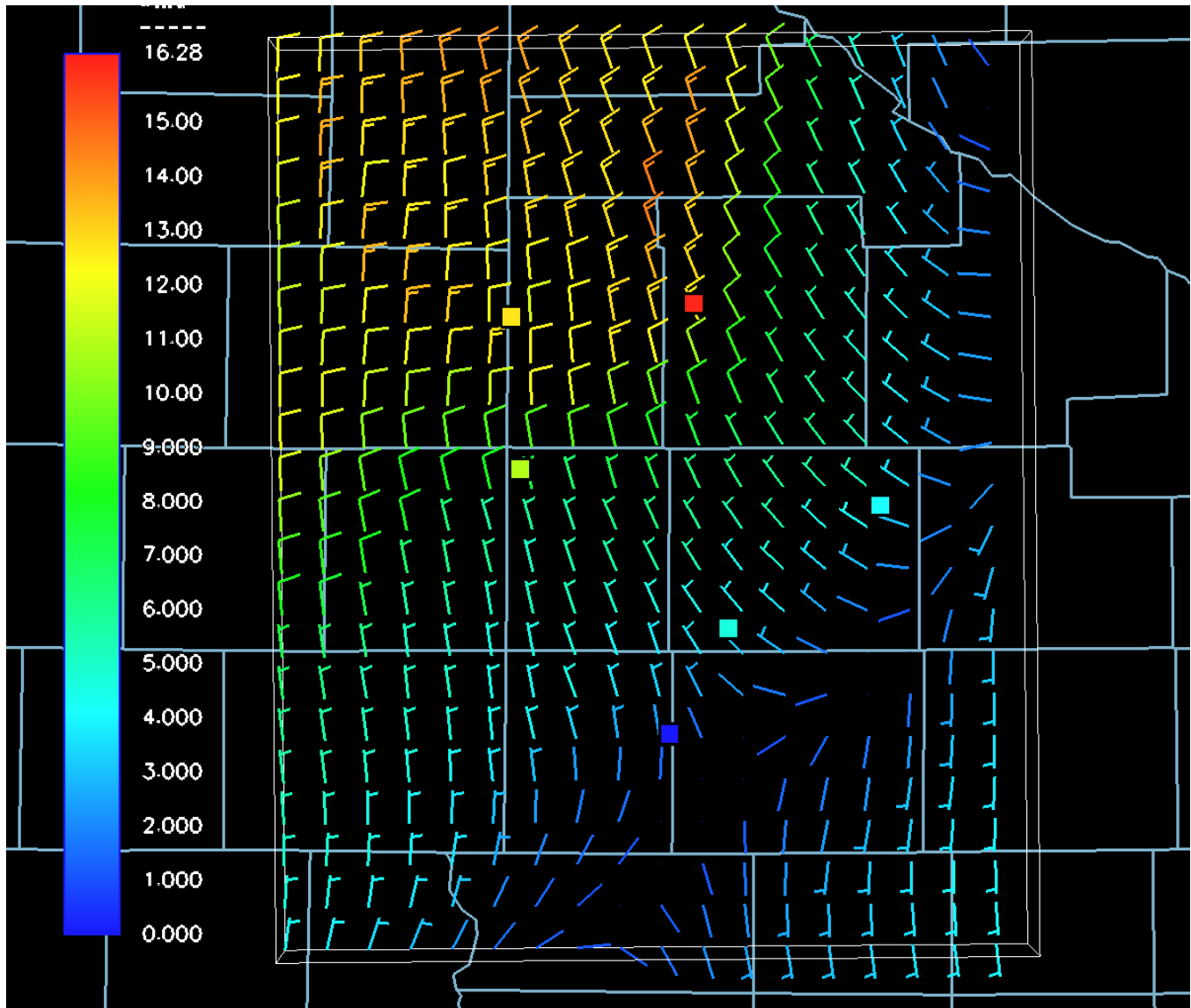


Figure 31: MRUC forecast 80 m wind speeds on Grid 3 (colored barbs – plotted at every fourth model grid point) and tall tower wind observations (colored squares) at 08:30Z on March 5, 2008. The forecast was issued at 05Z March 5, 2008. A strong cold front is sweeping across southwest Minnesota in the model forecast fields. The forecasted position of the front is very close to the observed position in the tall tower network.

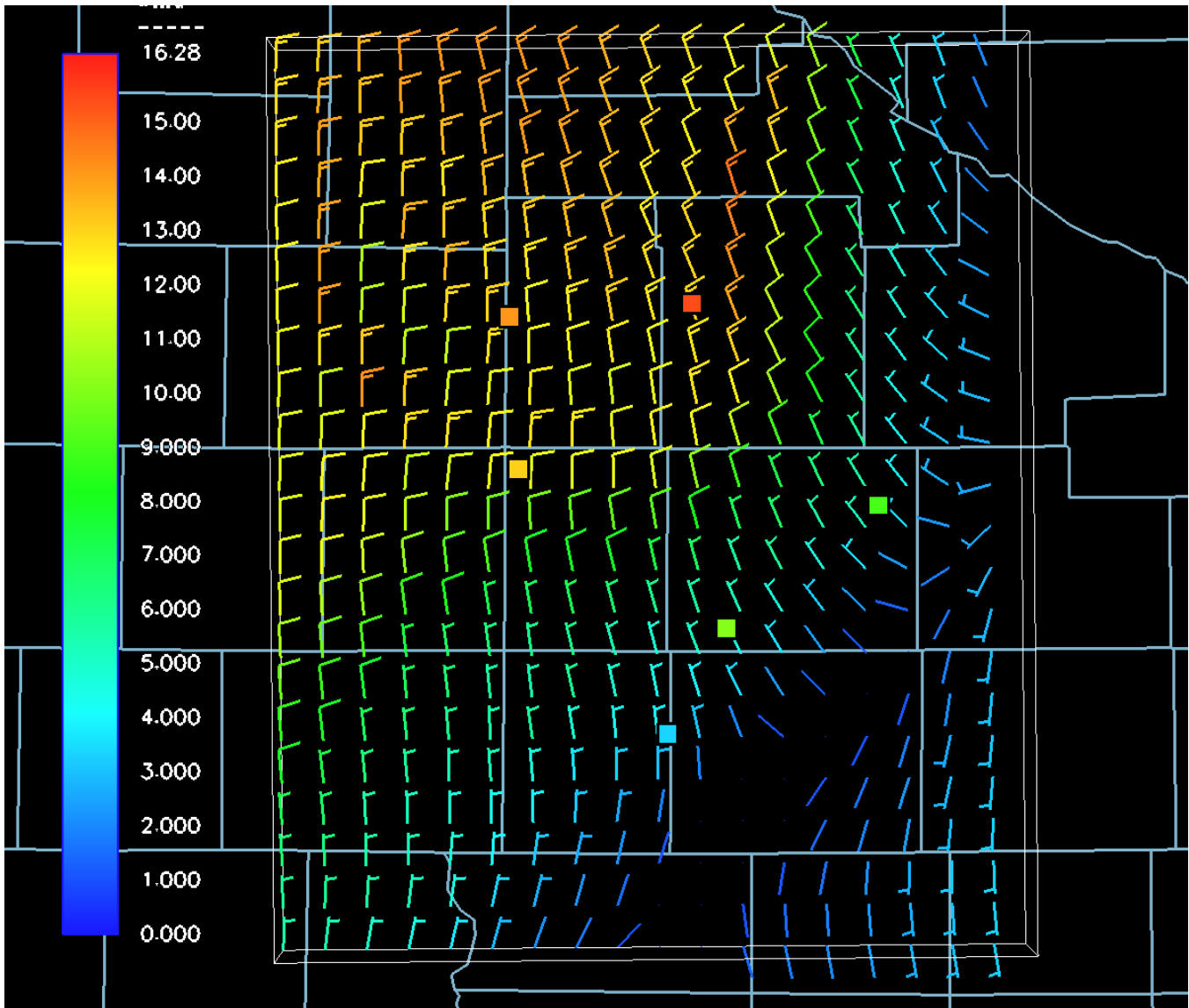
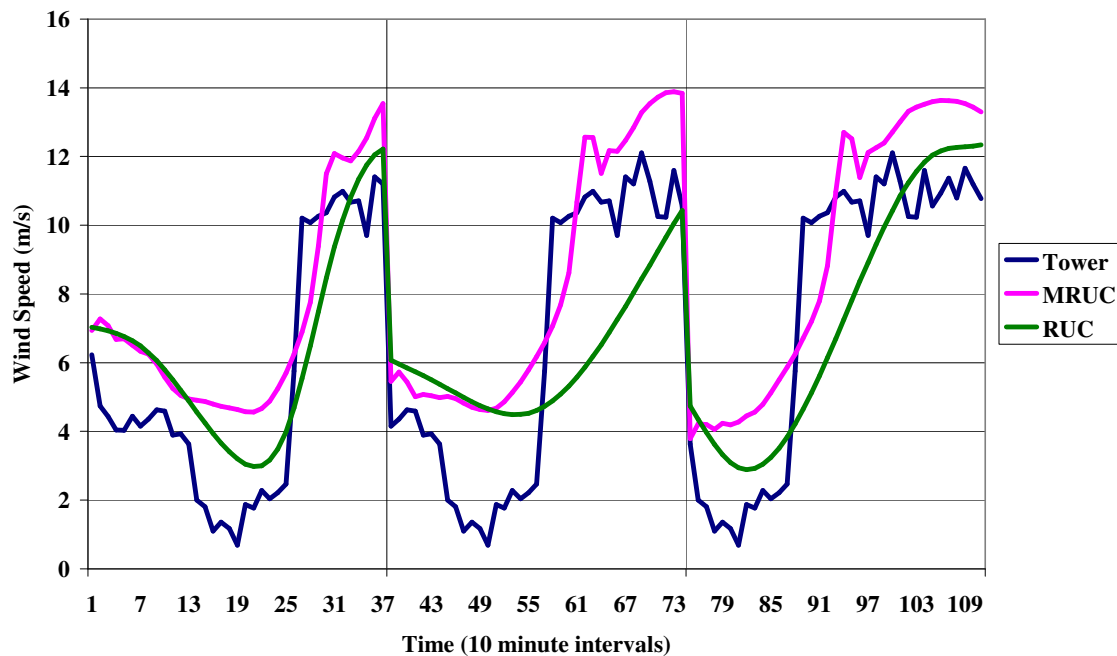


Figure 32: MRUC forecasted 80 m wind speeds on Grid 3 (colored barbs – plotted at every fourth model grid point) and tall tower wind observations (colored squares) at 09Z on March 5, 2008. The forecast was issued at 05Z March 5, 2008. A strong cold front is sweeping across southwest Minnesota in the model forecast fields. The forecasted position of the front is very close to (but slightly behind) the observed position in the tall tower network.

March 5 Wind Speed Forecasts (03-05Z)



March 5 Power Forecasts (03-05Z)

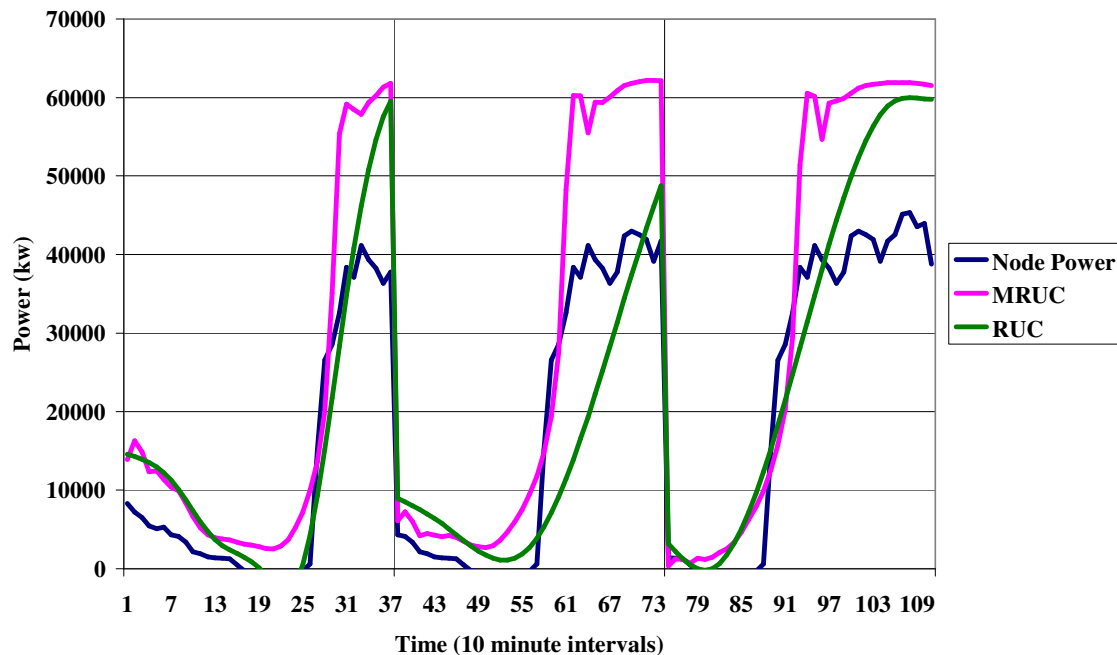
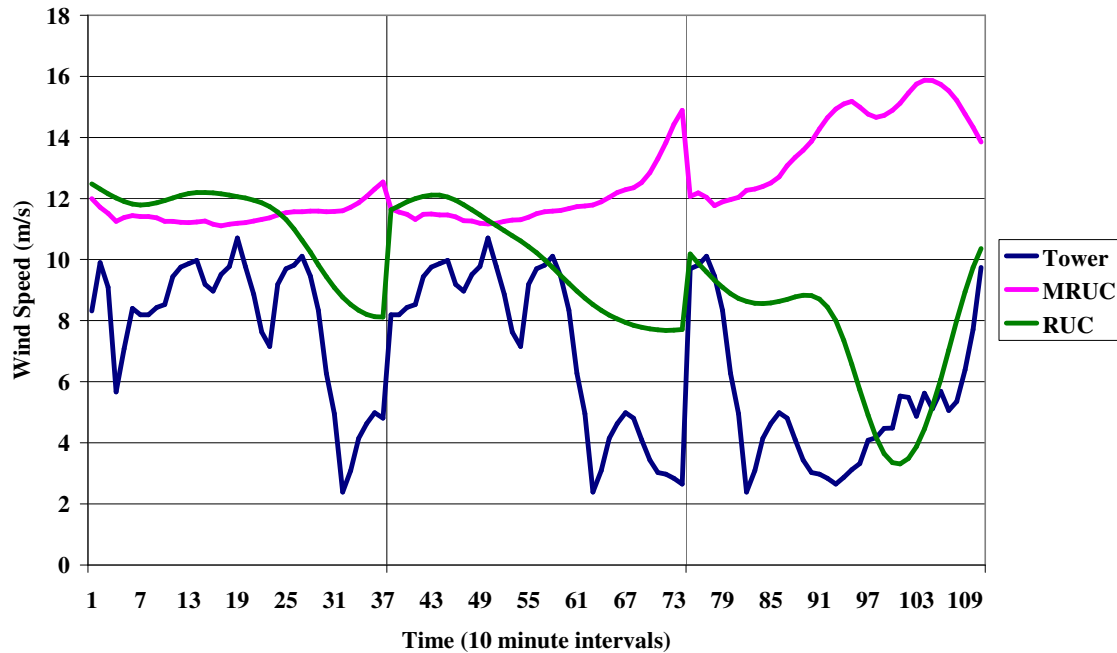


Figure 33: Comparison of three MRUC and RUC forecasts issued between 03-05Z March 5, 2008 with observations at the forecast node. Wind speed forecasts and the tall tower observation are shown in the top panel. Power forecasts and the observed node power are shown in the bottom panel. Different forecasts are delineated with the vertical black lines. Both models forecast the passage of the front, but the MRUC does a better job predicting the time of frontal passage. Both forecast models over predict the wind speeds behind the front.

March 2 Wind Speed Forecasts (06, 07, 10Z)



March 2 Power Forecasts (06, 07, 10Z)

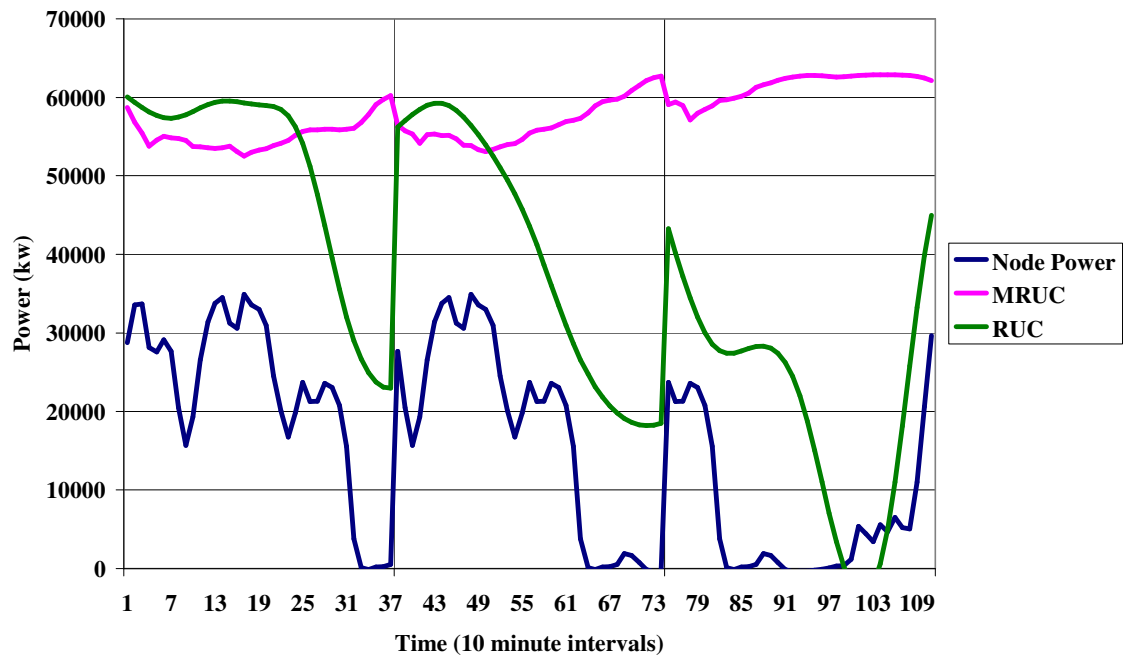


Figure 34: Comparison of three MRUC and RUC forecasts issued on 06Z, 07Z and 10Z March 2, 2008 with observations at the forecast node. Wind speed forecasts and the tall tower observations are shown in the top

panel. Power forecasts and the observed node power are shown in the bottom panel. Different forecasts are delineated with the vertical black lines. In this case, the NWS RUC forecast captures the deepening of the stable nocturnal boundary layer (and the sudden drop in the wind speed), while the MRUC model keeps the nocturnal boundary layer well mixed.

An example of a poorly predicted ramp event which occurred during the overnight hours of March 2, 2008, is shown in Figure 34. This event is interesting in that it was caused by boundary layer process and not by the movement of a particular weather feature. After sunset, air near the surface begins to cool due to the radiational cooling of the earth's surface. As this process progresses, a shallow layer of colder air develops first near the surface and then deepens through the night and early morning hours. This layer is extremely stable, meaning that the vertical movement of air is inhibited, and it effectively isolates the air near the surface from the rest of the atmosphere. We often refer to this layer as the stable nocturnal boundary layer and it is often characterized by weak surface winds. The depth of the stable nocturnal boundary layer is determined by the strength of two competing processes: mechanical mixing (i.e. strong winds and vertical wind shear) which promotes the vertical mixing of air, and radiational cooling which works to create a stable layer near the surface and inhibit vertical mixing. The depth of the nocturnal boundary layer (and the associated vertical wind profile) is extremely challenging to forecast as the amount of radiational cooling near the surface greatly depends on the characteristics of the underlying surface (for example, snow or no snow) and the amount and type of cloud cover. In the above case, the depth of the very stable nocturnal boundary layer increased during the night and eventually surpassed the height of the tower (and hub height) at which point the wind speed at the tower (and power production at the wind plant) rapidly dropped.

Neither the MRUC nor the NWS RUC model handles this event particularly well. The RUC model does give an indication of the event, although the wind speeds are too high throughout the forecast period in the 06Z and 07Z forecasts. The 10Z RUC forecast captures the event (which is already in process), but misses the timing of the event. The MRUC forecast does not capture this event at all, instead keeping the wind speeds high throughout the forecast period. There could be several possible reasons why the MRUC missed this event, including problems with data availability at the time the forecast was generated (note that there is no indication that the tall tower observations from this tower were assimilated during this forecast period). It's also likely that the representation of surface characteristics and processes played a large role in the forecast during this event. Snow cover has an enormous impact on the amount of radiational cooling (or heating) that can occur at surface, and perhaps a land surface model should be added to future iterations of MRUC to better represent the effects of snow cover and other surface processes. This case also illustrates that there is more to forecasting the wind than just knowing the wind. In situations such as this, having thermodynamic data such as temperature (in addition to wind) at hub height would be helpful.

The results presented above illustrate the challenges of forecasting wind power with numerical weather prediction models, although in many cases mesoscale models are the most accurate forecasting tools available. There are still some improvements that need to be made to the MRUC to improve the wind energy forecasts, and further refinements to the data assimilation process and improvements to the model representation of physical processes are ongoing. Unfortunately, the evaluation period (a few months) is too short to make sweeping conclusions about forecast model performance, but the results to date suggest that there is value in using mesoscale model forecasts (i.e. the MM5 baseline forecast) for short-term wind energy forecasting in the Xcel operating area.

4. TASK 3 – ANALYZING WIND GENERATION FORECASTING ACCURACY REQUIREMENTS FOR POWER SYSTEM OPERATIONS AND CONTROL

4.1 Developing an e-*terrasimulator* Model for Minnesota Utility Control Areas

After purchasing a dedicated server to host the simulation environment aimed at conducting a feasibility study, EnerNex and AREVA started enhancing the existing **e-*terrasimulator*** 2.3 release to satisfy the study's requirements.

The **e-*terrasimulator*** is the Dispatcher Training Simulator and is composed by the following three components:

- The Instructor Control component is used for setting up and controlling the simulation scenarios, reviewing the operator's performance, and teaching the operator.

- The Power System Simulation component provides the power system dynamic simulation functions.
- The Energy Management System component is a replication of the EMS functions, which include Network, Generation components that have been modified for the purpose of this study.

The following diagram highlights these components:

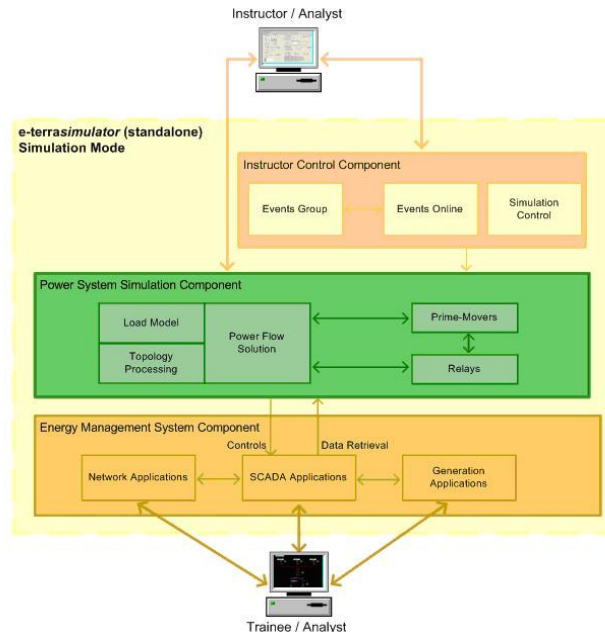


Figure 35: e-terrasimulator / Simulation Mode overview

The **e-terrasimulator** Power System Model task (PSM) is responsible for the dynamics and power-flow simulation. PSM therefore simulates the behavior of the actual power system, and provides the following:

- Real-time response to operator action.
- System frequency behavior that responds to load or generation changes.
- The randomness of loads is represented, as loads are dependent on voltage and frequency.
- Detailed modeling of prime movers using IEEE standard engineering grade models.
- Modeling of the effects of telemetry; delays, biases, variable scan rates, and random noise are all simulated.
- Modeling of device actions due to circuit breaker automatic logics.
- Modeling of the relaying effects due to overloads, transfer trip, voltage and frequency excursions.
- Modeling which provides a realistic representation of the tie-line bias mode of AGC operation of the interconnection. All operating areas are controlled by AGC.
- Modeling for normal, emergency, and restorative system operating conditions.

The following Activity Diagram provides an overview of the power system simulation processes which consist of two basic loops.

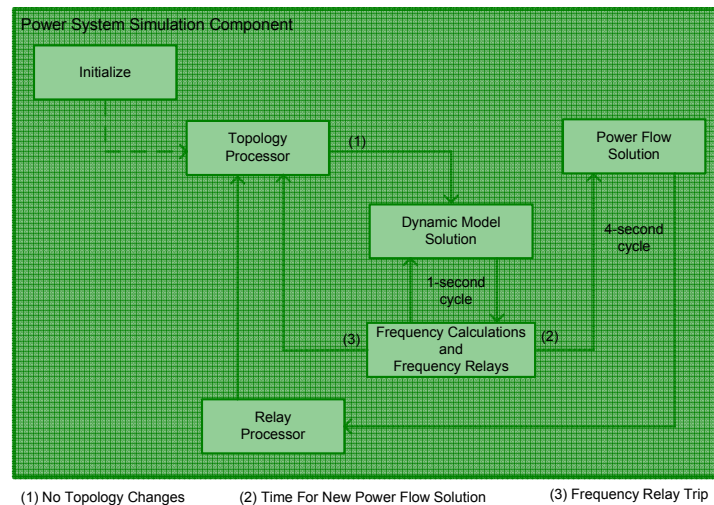


Figure 36: e-terrasimulator / Power System Simulation Component

The faster inner loop is the solution of the unit dynamics, calculation of frequency, and processing of frequency relays. Each time this loop is executed, simulation time is advanced by the amount of the integration time step; this time step is typically 1 second. The solution is based on the uniform frequency assumption (i.e., all units move at the same speed and that frequency is uniform across each electrical island of the system). This class of dynamics is commonly referred to as long-term dynamics. In this time range, the responses of steam supply systems, prime movers, generators, network configuration, loads, and Automatic Generation Control (AGC) have the predominant effect. The effects of shorter-term dynamics, such as synchronizing oscillations between the system generators, are only visible to the operator insofar as they may cause protective relay actions.

The following illustration presents the Generic Steam Turbine Prime Mover display, which defines key inputs to the dynamics simulation inner loop.

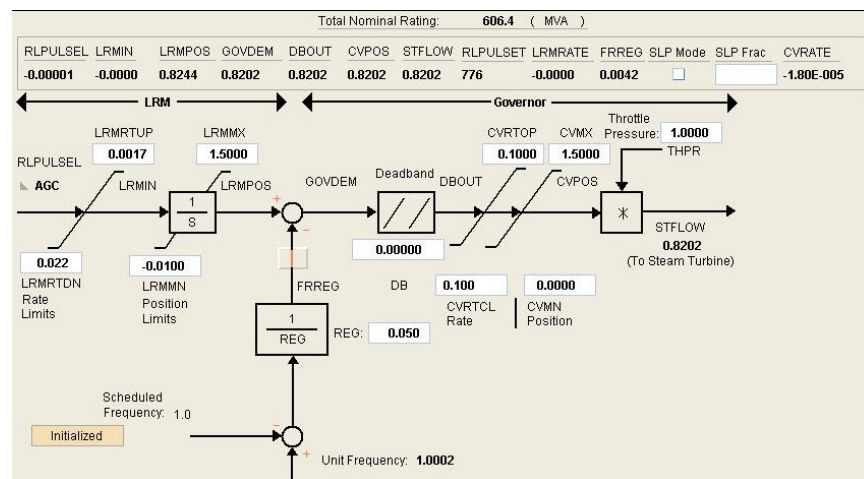


Figure 37: e-terrasimulator / Generic Steam Turbine Prime Mover display

The slower outer loop is the Power Flow loop. It is executed typically every 4-8 seconds (this rate is dependent on the CPU hardware and its computational loading), or whenever a topology change occurs (due to a frequency relay trip, or scheduled Event). This loop determines the network state: voltages, angles, and flows. It also processes relays which use network states as inputs, such as over current (directional and non-directional), frequency, and voltage relays. If any of these relays trip, their associated breakers are tripped, which causes a network topology change. The Topology Processor is immediately executed to determine the new configuration,

another Power Flow Solution is obtained, and the relays are processed again. If no topology changes occur, the faster dynamics loop is initiated again and simulation time begins to advance.

The following illustration presents the Power System Model Power Flow Solution Iteration display the instructor can leverage to analyze the simulation solution.

Powerflow Solution Iteration											
Area Mismatch and Solution Performance -- Bus Iteration Summary -- Iteration Mismatches											
DTS STUDY Running											
Iter#	Iteration Type	Island #	Total MW Error	#Unsolved	Worst Individual Error MW Error	Location	Iteration Status	Total MVAR Error	#Unsolved	Worst Individual Error MVAR Error	Location
	STATE	2	0	0	0.2	HDY 112	Converged	1	0	0.6	HDY 112
	STATE	1	51	0	0.3	ASTORIA4138	Converged	102	0	0.3	CANYON1 118
1	COLUMN	2	51	0	6.1	HDY 230	ELN Cvgd	68	0	37.7	HDY 230
1	COLUMN	1	3388	0	61.4	HOOSICK 115	ELN Cvgd	117	0	2.3	WAGNER 13

Figure 38: e-terraplatform / Power Flow Iteration display

Because the **e-terrasimulator** enables its instructor to drive the outputs of generating units using the embedded Online Events Subsystem, AREVA leveraged this standard interface to the **e-terrasimulator** Power System Model task (core of the simulation engine) to inject wind forecasted and/or actual generation Mw into the simulation environment.

Thus, the first step consisted in the design and implementation of a task responsible for injecting at the right time, at the appropriate injection point, the forecasted and/or actual wind generation output into the simulation engine: the **e-terrasimulator** External Data Processor.

e-terrasimulator External Data Processor

To enable the injection at the right time and at the appropriate injection point of forecasted and/or actual wind power generation into the simulation environment provided by the standard **e-terrasimulator** product, there was a need to enhance the **e-terrasimulator**. The **e-terrasimulator** External Data Processor (DTSEDP) was designed for this purpose and to support the **e-terrasimulator** 2.3 and to be part of the **e-terrasimulator** 2.5 release.

The objective of this task was to provide the simulation engine with an interface allowing external sources to provide inputs to the simulation.

Especially, for this study and future wind penetration studies, the external inputs to the simulation are the Wind Generating Unit outputs, plugged-in this external source of information to the standard **e-terrasimulator** ability to move Unit MW outputs via the **e-terrasimulator** Power System Model (PSM) task. In particular, the following requirements were considered when designing and implementing the **e-terrasimulator** External Data Processor:

- **e-terrasimulator** should be provided with the capability to consider as simulation inputs the Unit MW outputs.
- The **e-terrasimulator** External Data Processor is designed in a flexible manner to allow inputs from other external data sources (flat files, XML files, etc.)

The following Component Diagram illustrates how the **e-terrasimulator** External Data Processor was integrated to the **e-terrasimulator** architecture from both task and database standpoints, respectively:

- PSM: Power System Model, core of the simulation engine.
- SIMULATE: Simulate Database holding the simulation engine parameters.
- NETMOM: Network Model Database leveraged by the Power System Model task.

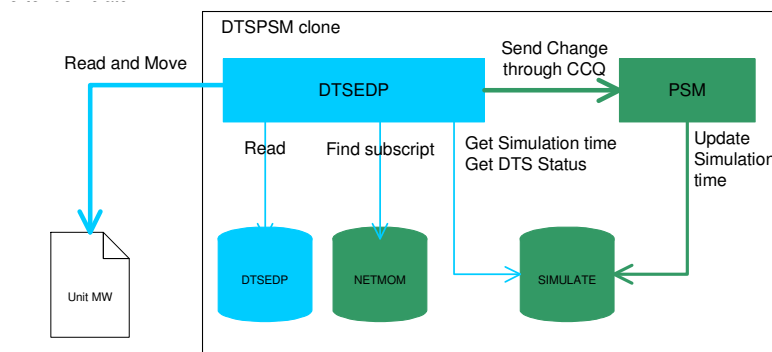


Figure 39: e-terrasimulator / External Data Processor Component Diagram

Additionally, when designing the **e-terrasimulator** External Data Processor, an architectural requirement was internally provided to ensure the flexibility and therefore the re-usability of this new component for other external inputs. As such, from a programming language standpoint, **e-terrasimulator** External Data Processor was implementing using an Object Oriented Programming Language, bringing the following advantages:

- The Object Oriented programming languages provide a full-concept of abstraction. Everything is an object. Every object has a type and its own memory. An object can receive a message, perform an operation and create other objects. Therefore, a program can be seen as a series of objects telling each other what to do by sending messages.
- All objects of a particular type can receive the same message. The inheritance allows a substitution of an object. This concept of polymorphism is one of the most powerful concepts in OOP.
- At last, source code reuse is one of the greatest advantages that Object Oriented Programming languages provide. Once an object type has been defined, it could be reused.

The following figure is the **e-terrasimulator** External Data Processor's User Interface, allowing the instructor or Support engineer to configure the Wind Generation inputs.

DTS External Data Processor Parameters						
Header	Extension	XML file?	Look-Ahead Parameter (min)	Relevant Periodicity (min)	Input Directory	
					Path	Environment Variable?
WDFF	TXT	<input type="checkbox"/>	1	1	DTS_WINDDIR	<input checked="" type="checkbox"/>

Figure 40: e-terrasimulator / External Data Processor Parameters Display

Once DTSEDP was implemented and deployed on the purchased hardware for the study, developer unit testing was successfully conducted using the standard AREVA T&D model, called the EMP60. In parallel, work was undertaken to build a model focusing on the Xcel Energy area.

Xcel Energy e-terrasimulator model

Once the implementation and deployment of the **e-terrasimulator** External Data Processor task into the study server – to enable the insertion of forecasted and/or actual wind power generation into the simulation engine – were completed, there was a need to demonstrate and validate this application using a significant simulation model. Thus, as part to the study, a model focusing on the Xcel Energy area was created.

After enhancing the **e-terrasimulator** 2.3 release to integrate the capability of injecting wind data into the simulation, Enernex retrieved the Xcel Energy Simulation model into the simulation environment. However, to enable the system to run with this extended model, modifications from the latest **e-terrasimulator** release (version 2.5) needed to be brought into the 2.3 version used by the study.

In particular, we focused on bringing the required enhancements to the power system model simulation engine to make the simulation more robust, accurate and realistic, as well as enhancements to the **e-terrasimulator** validation software. These enhancements impacted about 70 source files and involved the following **e-terrasimulator** components:

- The Simulation Engine: DTS, DTSCOM, DTSMODEL and DTSPSM.
- The Network Applications: NETCOM, NETMODEL, RTNET and PWRFLOW.
- The Automatic Generation Control Applications: GENCOM and RTGEN.
- The Power Systems Applications Common API (PSACOM) which, per design, includes the shared interfaces between the components.

Once the enhancements were implemented, a system build was performed. A system build consists in rebuilding both binaries and databases and can be described as follows:

- Back-up the current data and binaries (i.e.: the **e-terraplatform** libraries and executables).
This consisted in saving clones, applications, binaries, source codes and more importantly all the inputs for the simulation: models, datasets and wind generation input files.
- Modify the database sizes to match the new models.
This consisted in checking the existing record sizes (i.e.: maximum number of rows for one column), comparing them with the new models' records sizes and as needed, change the Maximum Value to allow the retrieval of new models into the updated application contexts, called clones.
- Update the application contexts (i.e.: updating the **e-terraplatform** clones).
After loading the updated database sizes, this step consisted in updating and replacing the clones, simply running an available configuration script.
- Update the **e-terrahabitat** and **e-terraplatform** with the latest critical fixes.
This consisted in merging the additional code changes made in the latest released **e-terraplatform** 2.3 patch, focusing on the Simulation related files only.
- Regenerate all the **e-terraplatform** libraries.
After merging the code changes addressing known issues, this activity consisted in compiling all static libraries forming the **e-terraplatform** product. To do so, we configured a Product Development Server in which the source code, database sizes were available as well as the necessary compilers: Intel Fortran Compiler and the Visual Studio .NET 2003 C++ compiler.
- Regenerate all **e-terraplatform** executables.
After regenerating the libraries, we compiled and linked the main module of **e-terraplatform** applications. This activity was performed on the same Product Development Server (PDS), which was different from the server leveraged to run the simulation.
- Check all the exit criteria for the system.
This consisted in verifying if all executables were properly built, starting **e-terrahabitat** and ensuring the **e-terrasimulator** was able to be started.

- Bring online the new models.
Once all the clones and binaries were updated, leveraging the **e-terrasimulator** Savecases Manager task, we retrieved the new models into the simulation running clones.
- Perform a system health-check.
This step checked if all the Simulation related major components are working properly: Power System Simulation component, the Automatic Generation Control component, etc.
- Propagate the updated **e-terrasimulator** on the running server.
Finally, once the PDS environment was stable, and had successfully passed the system health-check, this activity consisted in creating a Microsoft Windows Installation Kit on the PDS and installing it on the running server to enable the engineer to leverage the updated **e-terrasimulator**.

After installing the enhanced and resized **e-terrasimulator** on the EnerNex server, we worked on the validation of the Xcel Energy set of simulation models. This included:

- Supervisory Control And Data Acquisition Model (SCADAMOM)
- Network Model (NETMOM)
- Generation Model (GENMOM)
- Simulation Model (DTSMOM)

These four models needed to be validated as single model as well as cross-validated against each others as well as with utilities' models to be able to run the simulation. These utilities' models included:

- A Permission database.
- An Alarm database and the specific Real-Time Generation Alarm database.

Once all models were cross-validated, a Real-Time Case initialization was performed to accurately represent the operational conditions from the online system, such as: network topology, generation and load conditions, AGC manually entered data (PLC statuses, transaction schedules, unit schedules, etc.), and SCADA manually entered data (points put out of service, override values, etc.).

Then, starting from this initialized state, we successfully ran a stable simulation for about 24 hours. These 24 hours of simulation represented the baseline for our analysis and investigation on future enhancements to the standard **e-terrasimulator** platform to facilitate the scheduling and operating power systems with significant amounts of wind generation.

Running the simulation

As described in the previous section, the **e-terrasimulator** External Data Processor task (DTSEDP) is responsible for parsing and reading Wind Farm Generation inputs and injecting these MW inputs into the simulation. While the simulation is progressing through time, DTSEDP processes the input files and drives the Unit Mw outputs according to the read input data.

To demonstrate the functionality provided by the **e-terrasimulator** External Data Processor task on the Xcel Energy Simulation model, the following scenario was executed. Based on the actual captured from WindLogics for the Interconnect Node 2 (BRI312), DTSEDP drove the Unit MW output in the simulation environment.

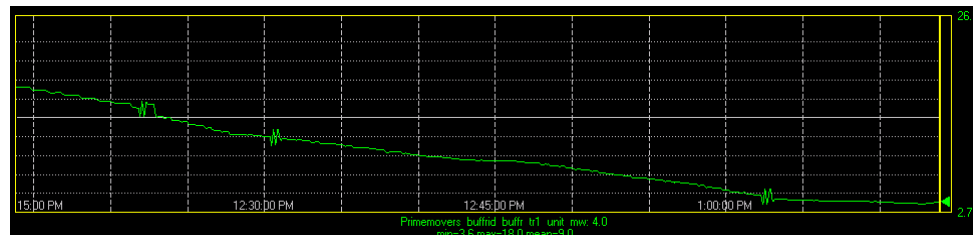
The results presented in this section enabled us to demonstrate the validity of the chosen and implemented approach to inject into a simulation environment forecasted and/or actual wind power generation.

The following table represents the original data provided by WindLogics, actual and forecast Power Mw as well as the Wind characteristics: wind speed and direction.

Time GMT	Actual Power MW	Forecast Power MW	Actual Wind Speed m/s	Forecast Wind Speed m/s	Actual Wind Direction	Forecast Wind Direction
10/15/2006 15:00	16.23	23.86	7.67	11.36	211.6	186.06
10/15/2006 15:10	16.68	24.04	7.33	11.37	215.8	185.77
10/15/2006 15:20	17.88	24.15	7.55	11.37	194.3	185.77
10/15/2006 15:30	18.21	24.13	8.03	11.34	198.7	185.71
10/15/2006 15:40	17.93	23.89	7.85	11.27	193	185.14
10/15/2006 15:50	19.91	23.38	7.42	11.14	218.3	185.14
10/15/2006 16:00	20.77	22.53	7.3	10.95	245	185.24
10/15/2006 16:10	17.97	21.3	6.93	10.68	237.6	185.14
10/15/2006 16:20	14.69	19.76	7.25	10.34	248.5	185.14
10/15/2006 16:30	12.28	18.02	7.08	9.97	263.5	185.71
10/15/2006 16:40	11.42	16.19	7.57	9.57	282.8	185.71
10/15/2006 16:50	10.2	14.37	6.68	9.16	253.1	186.34
10/15/2006 17:00	9.17	12.67	7.04	8.76	277.6	186.56
10/15/2006 17:10	8.74	11.19	6.72	8.39	278.8	186.91
10/15/2006 17:20	7.28	9.92	6.39	8.05	282.6	188.05
10/15/2006 17:30	6.19	8.87	6.44	7.75	283.5	188.62
10/15/2006 17:40	4.38	8.04	5.31	7.51	280.7	188.62
10/15/2006 17:50	4.08	7.41	4.68	7.32	279.4	189.18
10/15/2006 18:00	3.78	6.99	4.33	7.18	290.6	188.81
10/15/2006 18:10	4.74	6.76	4.66	7.12	282.8	188.05
10/15/2006 18:20	5.53	6.73	5.11	7.12	281	187.48
10/15/2006 18:30	6.11	6.88	5.18	7.17	279.2	185.77
10/15/2006 18:40	6.63	7.2	5.18	7.27	292.8	184.57
10/15/2006 18:50	6.86	7.69	4.97	7.42	292.5	182.86
10/15/2006 19:00	6.89	8.34	5.27	7.6	306.2	181.51

Figure 41: Xcel Energy Forecasted / Actual Wind Power data

The following diagrams, created using the existing **e-terrabrowser** 3.3 Trend Control component, represent the Interconnect Node 2 (BRI312) injection point through time.



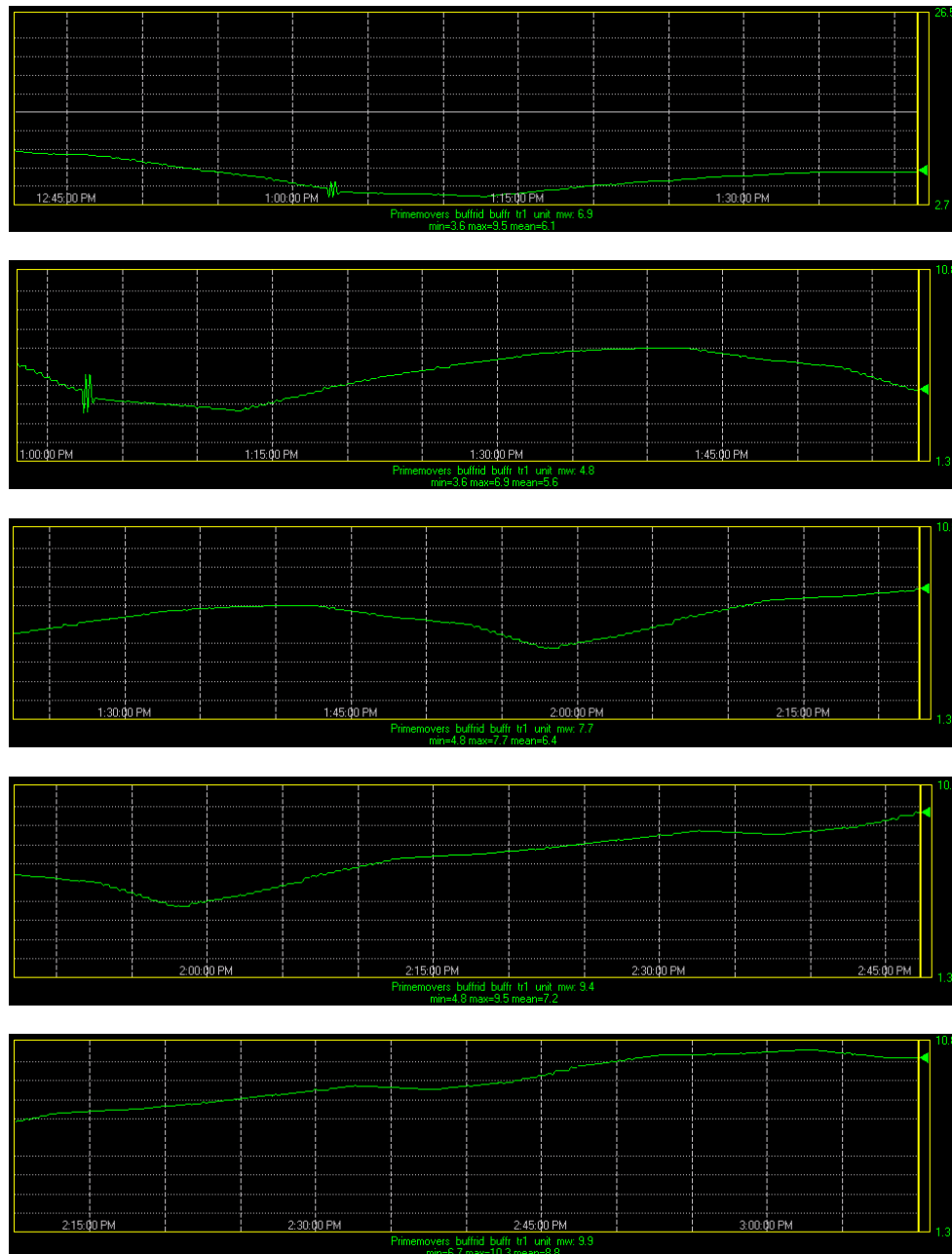


Figure 42: Xcel Energy / *e-terrabrowser* Trend Control displays

This demonstration completed the validation of the *e-terrasimulator* External Data Processor task functionality as well as the Xcel Energy simulation models.

In parallel, while working and configuring the proof-of-concept simulation environment, EnerNex and AREVA investigated the use of geo-spatial User Interface products in order to improve the management of wind generation and situation awareness of real-time operators.

4.2 Analysis of the MISO Market and of System Impacts Due to Changes in Wind Generation

Uncertainty of future wind generation production in operational planning processes contributes to the existing uncertainty of electric demand over these same time frames, and therefore results in an incremental cost that

must be carried. As the amount of wind energy production grows in proportion to the electric load and other resources in the generation portfolio, errors in wind generation forecasting can become very significant to operations.

An objective of the work in Task 3 is to assess how the uncertainty of wind energy production in operational planning time frames affects overall production cost and to investigate ways in which these impacts might be reduced. At the time of the original proposal, Xcel Energy performed a day-ahead optimization procedure, known as unit commitment, to determine which of their resources should be made available to serve anticipated load, and what level of transactions should be made with other utility companies to minimize production costs. The optimization procedure used hour-by-hour forecasts of load for the next day and a couple of days following.

The influence of wind generation forecast error in the unit commitment process was first observed in the initial wind integration studies for Xcel energy in 2004. In all, errors in the day-ahead forecast of wind generation for the Xcel were assigned an additional cost of about \$4.00/MWH of wind energy delivered. Further studies beginning in 2005 for Xcel Energy – Public Service Colorado began to reveal more about the nature of day-ahead wind generation forecast errors and their effect on cost of operations.

Integration costs over an annual period were calculated for a large sample of day-ahead wind production forecasts. The nature of the forecasts varied considerably, as did the gross performance statistics (such as accumulated error over the month, as indicated in Figure 43). The differences in the individual wind generation forecasts, with everything else in the commitment and dispatch simulation held constant, lead to a range of wind integration costs, as shown in Figure 44. The sample, comprised of over 30 versions of the day-ahead forecasts, resulted in a normally-distributed sample of integration costs.

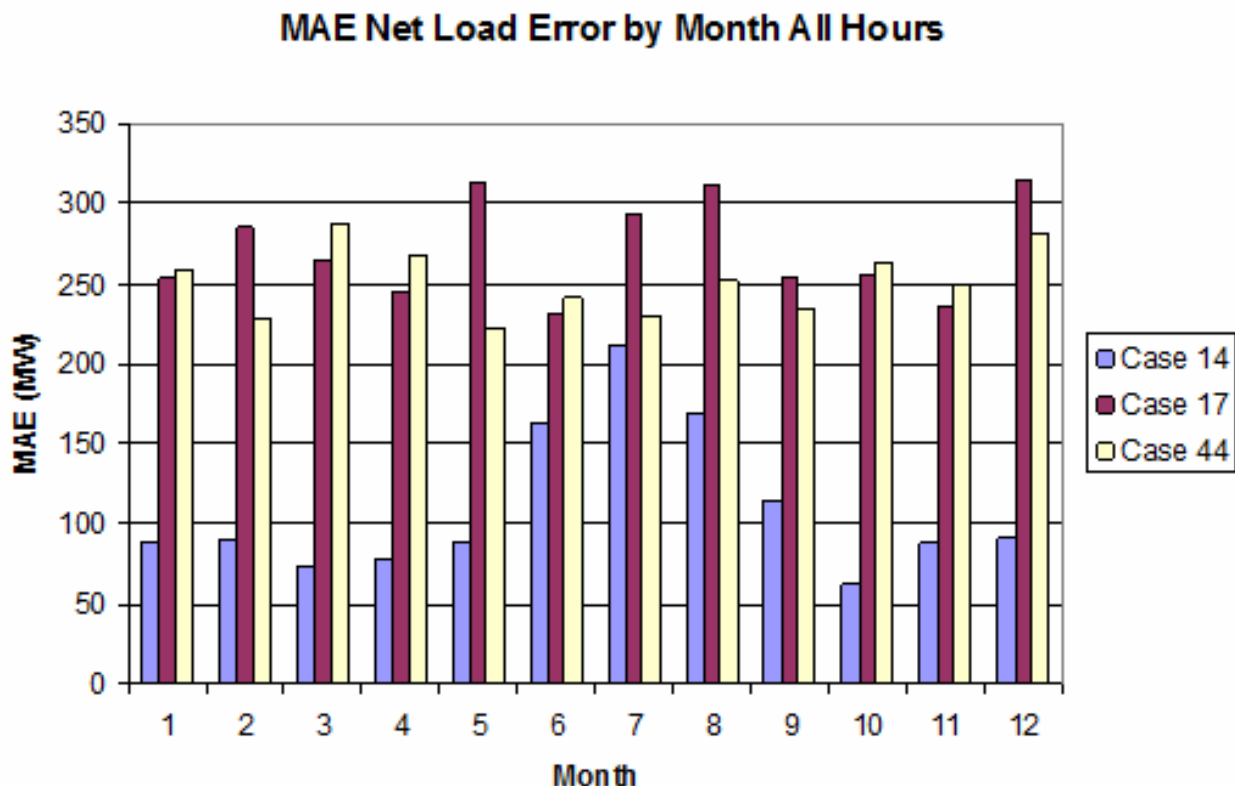


Figure 43: Monthly net error statistics for three versions of a day-ahead wind generation forecast

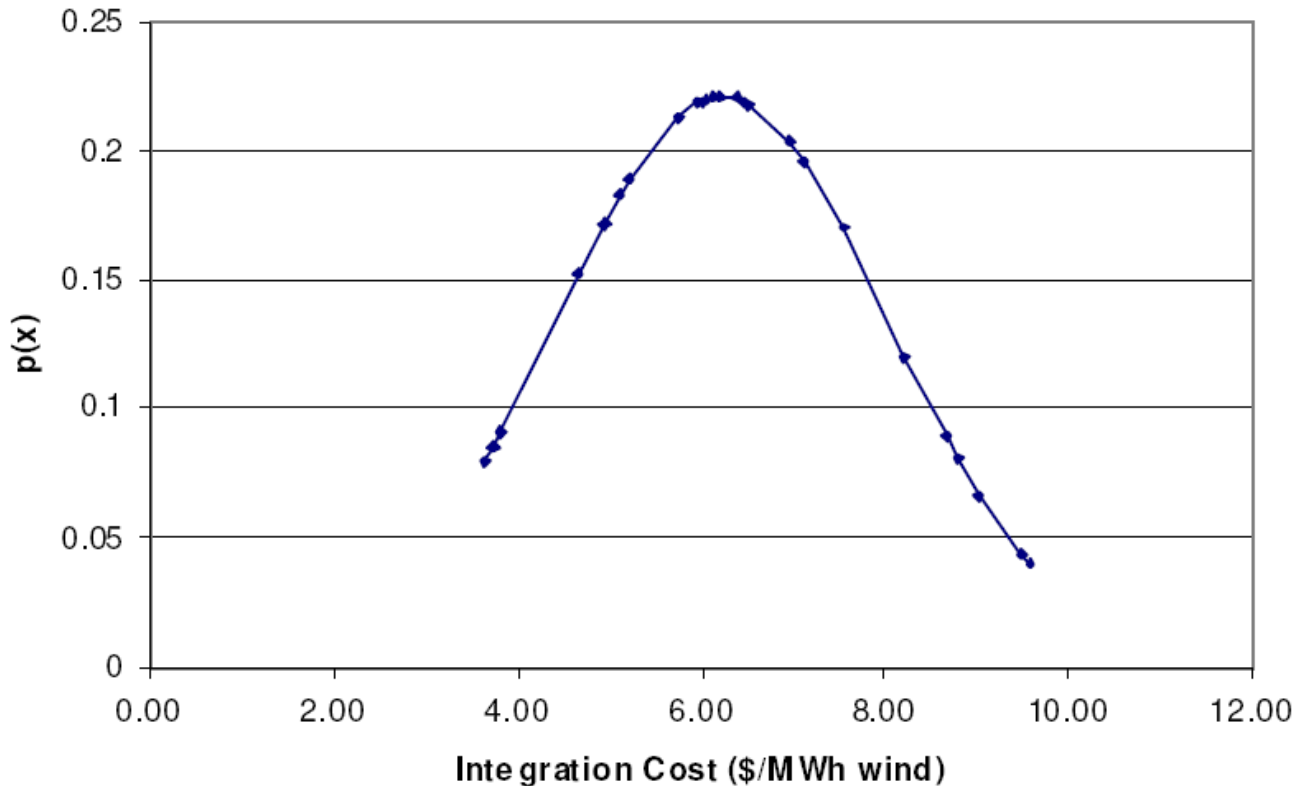


Figure 44: Distribution of wind integration costs for different day-ahead wind production forecasts

The obvious question that arises from the results of the Midwest Independent System Operator (MISO) analysis, and the one initially intended to be explored in this task, is how to insure that your forecast falls as near as possible to the left extremity of the integration cost distribution. Since the submission of the proposal and eventual award, scheduling and unit commitment decisions for Xcel-NSP have been altered substantially by the start-up of the MISO energy markets. The new process for Xcel traders is very briefly summarized as follows:

- Based on forecasts of load for the next day, availability of generating resources, forecasts of wind production, and other data such as fuel prices, Xcel Energy traders submit offers for supply to MISO on the morning prior to the operating day. The amount of generation offered does not have to be based on what NSP load is expected, but rather what will be competitive in the market. In the same way, participants placing “demand bids” (desired purchases for each hour of the next day) may be bidding based on actual load or some other bid based on a market strategy. Based on generation offers and demand bids from participants, MISO closes and “clears” the day-ahead market which establishes the day-ahead prices for each hour.
- Following market clearing, MISO analyzes the day-ahead position to insure that enough generation has been offered to reliably meet expected load. Here actual forecasts of load hour-by-hour are used. A security-constrained unit commitment optimization is performed late in the afternoon of the day before the operating day. If insufficient generation has been offered into the day-ahead market to insure system reliability, MISO will request and commit additional generation from the market participants to cover this deficiency. This procedure is known as the Reliability Assessment Commitment (RAC).
- On the operating day, deviations in actual load and generation from the day-ahead schedule are covered by the real-time energy market. This market is cleared at 5 minute intervals (and based on forecasts 15 minutes into the future). Prices in the real time market will be a function of the deviations from the day-ahead schedule, and may be lower or higher than the day-ahead price.

So, in short, day-ahead scheduling for Xcel-NSP has moved from a process that seeks to meet NSP load for the minimum cost while insuring reliability to one where the optimization takes place over the entire MISO market footprint. The use of day-ahead wind generation forecasts likewise takes on a different twist. The consequences of significant forecast errors, for example, are much less direct. If less wind energy is available than what was offered into the market, the difference can be made up in the real-time market by all participating resources, not just those owned Xcel Energy.

Uncertainty still has an impact however. If forecasts used by MISO in the RAC understate the net demand (i.e. forecast load minus forecast wind generation), more generation will be committed than is necessary. This effect has been quantified in recent wind integration studies through evaluations of operating economics where wind generation is “ignored” in the day-ahead commitment of units. The additional costs attributable to the extremely conservative position constitute the bulk of wind integration cost. If MISO were to discount wind generation completely in the RAC, the number of days with over commitment of generating resources would rise substantially, along with the RSG (revenue sufficiency guarantee) payments required to make whole those additional generators called upon for reliability purposes. This additional inefficiency in the market would be passed along to all players in the form of higher prices, thus the “indirect” impact on Xcel Energy.

After discussions with Xcel Energy traders who interact with MISO energy markets on an ongoing basis, a recommendation for the re-defining of this task was made. In place of the sensitivity analysis based on unit commitment optimization runs, the contractors have extended the concept of the wide-area wind generation forecasting system to the MISO level. Because the scope and schedule for this contract do not allow for actual implementation of such a system, the contractors held meetings with appropriate personnel from MISO to define the requirements for a system that could be used by MISO to manage wind energy deliveries to the market. Such a system would be based on the structure that is being demonstrated for Xcel under this RDF grant. Given MISO’s unique role, it is also likely that there will be some additional or modified requirements. These will be identified through the various interactions with MISO personnel. Additionally, some quantification of the value of market-wide wind generation forecasting is available from the raw output of the Minnesota Wind Integration Study completed in 2006, presented here.

Nearly 95% of the retail sales are within MISO. The contribution of the Midwest Independent System Operator to this effort was very significant. Wind energy has many attractive attributes and is becoming an increasing popular choice for new electricity generation around the world. But because the “fuel supply” is the wind, the power from a wind plant is variable and the power delivery schedule is subject to uncertainty. Energy from wind generating facilities must be taken “as delivered”, which necessitates the use of other system resources to keep the demand and supply of electric energy in balance. To the extent that wind generation increases the required quantity of these system services, additional costs are incurred.

The high reliability of the electric power system requires sufficient supply resources to meet demand at any moment. Conventional electric generating plants and units are not completely reliable, and there is always some probability that in a given unit will be unavailable. Even if the installed capacity in the control area exceeds the peak projected load, there is some non-zero probability that the available capacity might be insufficient to meet load in a given hour. 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 work reported in the MISO wind and power modeling performed addresses these two major questions:

1. To what extent would wind generation contribute to the electric supply capacity needs for Minnesota electric utility companies?
2. What are the costs associated with scheduling and operating conventional generating resources to accommodate the variability and uncertainty of wind generation?

For the purposes of this task, we are primarily concerned with the second question which addresses the sensitivity of the costs in the day-ahead MISO market for Xcel Energy when dealing with the variability and uncertainty of wind generation.

The critical first step in answering these questions is to determine what the wind generation would “look like” to the operators of the power system. This step is surprisingly difficult. The aggregate production from individual wind turbines spread out over thousands of square miles depends on the meteorology over the entire region as well as the influences of terrain and ground cover in the vicinity of a single turbine. In addition, the meteorological

patterns that dictate wind energy production also have an influence on electric demand. Periods of extended heat or cold significantly influence electric demand, and the meteorological patterns responsible for these conditions also effect the energy production from wind generation facilities.

The correlation between electric demand and wind generation has a significant effect on the costs associated with integrating wind energy. If the daily pattern of wind generation matched the daily load cycles, wind generation would likely have no integration cost. As previous studies and assessments have shown, however, this is not the case in most parts of the United States. Consequently, the wind generation model used for this study is critically important. Because of this sensitivity, and the large geographic expanse of Xcel's wind purchase portfolio, the latest technology for characterizing wind generation was employed in this study.

The technique used in this study to create the wind generation characteristics and profiles for this analysis comes from detailed simulations of the weather over the Upper Great Plains for historical years. Because the power system's detailed operating data is also available for the same historical periods, the complex weather correlations that drive wind energy, system load and other power system operating characteristics are captured in the time-synchronized results.

The baseline sensitivity analysis was conducted for the MISO market using Minnesota wind development scenarios to support the development of the wind generation model for the analytical tasks. The target wind penetration levels were based on 15%, 20%, and 25% of projected retail electricity sales in the study year 2020.

Data at 152 grid points (proxy wind plants, nominally 40 MW each) were calculated every 5 min as the simulation progressed through historical years 2003, 2004, and 2005. This process captured the character and variability of the wind resource across geographically dispersed locations.

The geographic dispersion of the wind plants was found to have many beneficial effects. Dispersion substantially smoothes the overall power variability, increases the capacity factor for the ensemble of wind plants and reduces the frequency of very large hourly ramp rates. For wind forecasting, forecasts for an ensemble of sites were substantially more accurate than for a single site.

The analytical results from this study show that the addition of wind generation to supply 20% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system if sufficient transmission investments are made to support it.

The degree of the operational impacts was somewhat less than expected by those who have participated in integration studies over the past several years for utilities around the country. The technical and economic impacts calculated are in the range of those derived from other analyses for smaller penetrations of wind generation.

Discussion of the analytical results with the Technical Review Committee and the Minnesota utility company representatives, including Xcel Energy and MISO, identified several key findings and observations:

1. These results show that, relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low of \$2.11 (for 15% wind generation with 2003 data) to a high of \$4.41 (for 25% wind generation with 2005 data) per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves and costs related to the variability and day-ahead forecast error for wind generation.
2. Consolidating into a single functional balancing authority has a significant impact on results. By sharing balancing authority functions, requirements for ancillary services such as regulation and load following are reduced (with or without wind generation) and the required amount of regulation capacity is reduced by almost 50%.
3. The expanse of the wind generation scenario provides for substantial smoothing of wind generation variations. This smoothing is especially evident at time scales within the hour, where the impacts on regulation and load following were almost negligible. Smoothing also occurs over multiple hour time frames, which reduces the burden on unit commitment and dispatch. The hours of very high or very low production are also reduced, allowing the aggregate wind generation to behave as a more stable supply of electric energy

4. The transmission expansion assumptions, as previously defined by the West Region Studies Group (RSG) report of May 2006, were adequate for transportation of wind energy in all of the scenarios. Under these assumptions, there were no significant congestion issues attributable to wind generation and no periods of negative Locational Marginal Price (LMP) observed in the hourly simulations.
5. The MISO energy market also played a large role in reducing wind generation integration costs. Since all generating resources over the market footprint are committed and dispatched in an optimal fashion, the size of the effective system for integrating the wind generation increases dramatically and the aggregate flexibility of the units online during any hour is adequate for compensating for most of the changes in wind generation.
6. The contribution of wind generation to power system reliability is subject to substantial interannual variability. Annual Effective Load Carrying Capability (ELCC) values for the three wind generation scenarios from rigorous Loss of Load Probability (LOLP) analysis ranged from a low of 5% of installed capacity to over 20%.

As a final point, it is useful to compare these results with the 2004 study for Xcel Energy. This earlier study found integration costs to be no higher than \$4.60/MWH for a 15% capacity penetration of wind generation (about 10% penetration on an energy basis). Due largely to the benefits of the new MISO energy market, this new 2006 study now shows that the costs are significantly reduced even with more than twice the level of wind energy penetration on the system.

5. TASK 4 – IDENTIFY NEW TOOLS AND METHODOLOGIES

5.1 New Generation of User Interfaces for Improving the Situational Awareness of Operators

With the continuous increasing amount of telemetered data available to the real-time operators, identifying areas facing potential risks and analyzing the current and future bottlenecks in the system become challenging activities. There is therefore a need to provide the operator with a set of tools facilitating the representation of the electrical data in a user-friendly manner and geo-spatial approach.

The next sections discuss the use of two existing tools.

e-terravision

e-terravision is a relatively new product from AREVA T&D that addresses the need for enhanced situation awareness in control centers. **e-terravision** was jointly developed with leaders of the power industry, including: AEP, Ameren, Entergy, First Energy, Northeast Utilities, SPP and TVA. Thanks to rapid prototyping and extensive use case analysis, the joint team was able to design **e-terravision** as a task-oriented system for Operators in a Utility Control Center. With **e-terravision** 1.0, control room operators can now:

- Monitor the transmission network with large overviews,
- Assess the grid's reliability using advanced visualization.

The following illustration represents sample displays **e-terravision** provides.

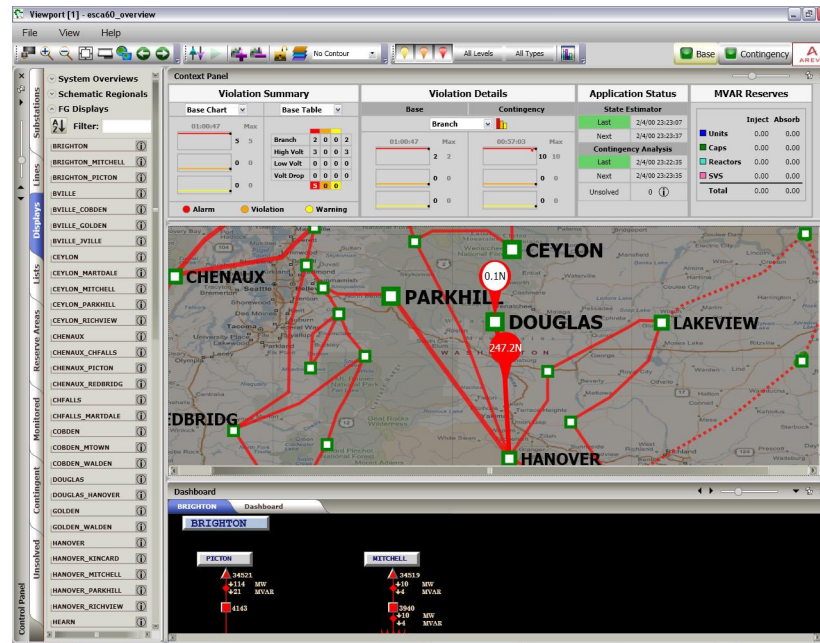


Figure 45: e-terravision / Typical Viewport

A typical layout of a viewport is shown above. In this figure, the alert panel is located at the top of the main display pane on the toolbar strip. The control panel is located on the left of the viewport and has a number of predefined tabs from which the user may select (e.g. stations, lines, contingencies). At the bottom of the viewport is a dashboard panel with a dashboard tab.

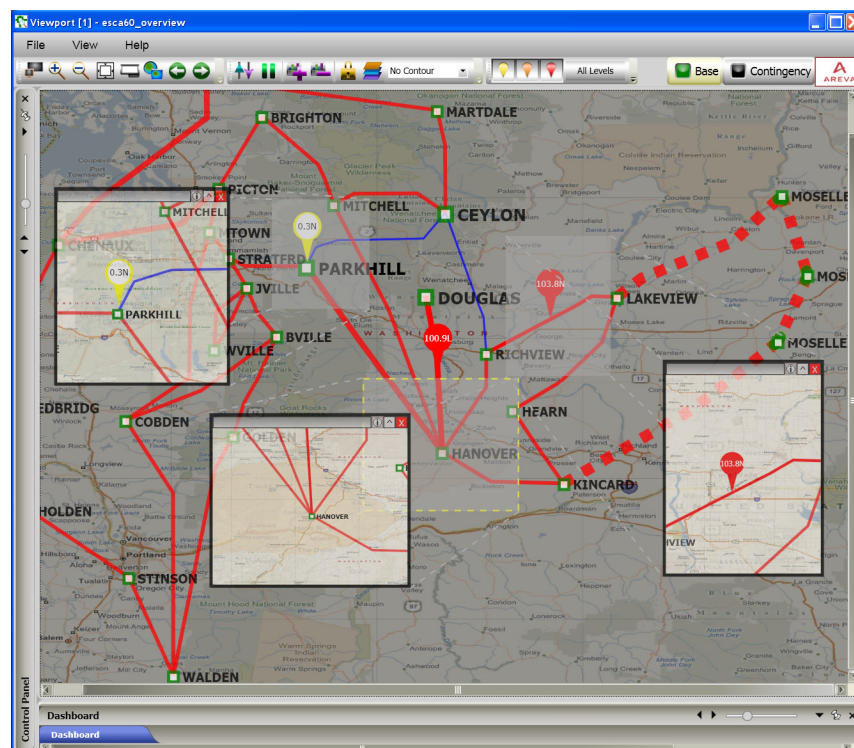


Figure 46: e-terravision / Multiple Fly-Outs

Fly-Outs contain selected areas of displays defined by rubber-banding an area and selecting the "Create Flyout" option from its context menu. Fly-Outs are animated to fly-out from the source display while keeping projection

lines to the selection on the source display. Fly-Outs are also created through context menu commands such as the “Show Station” command, accessed by right-clicking on a station in a System Overview display.

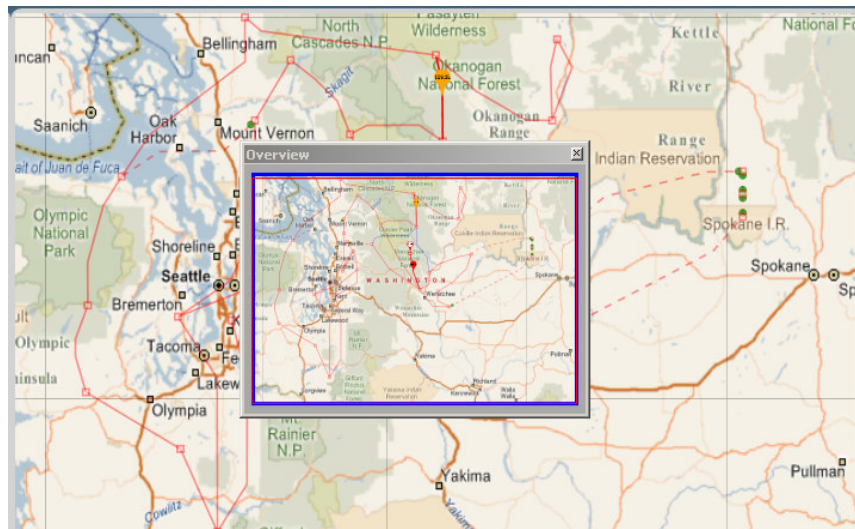


Figure 47: e-terravision / Overview Display with Navigation Window

The navigation window is a separate window that contains a reduced version of the entire display and a red rectangle which represents the viewport's relative size and position over the display.

e-terravision also provides the operators the ability to identify and monitor violations and contingencies in the system as illustrated below.

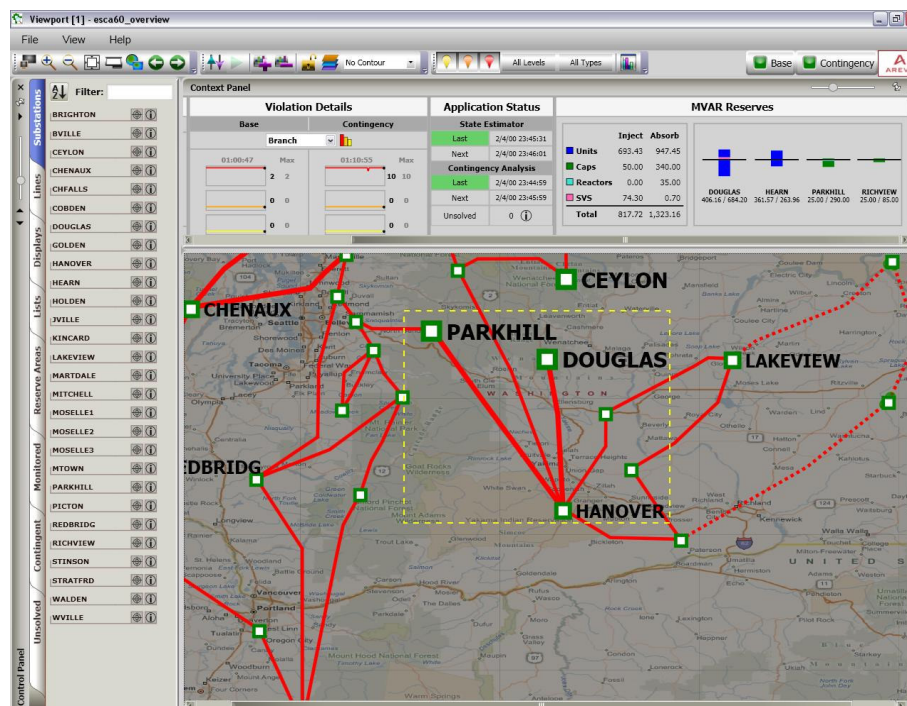


Figure 48: e-terravision / selected Area and associated MVARs

The Context Panel is where situational context specific information is presented. This section details the use and display of information as it relates to the “Assessment of Base Case and Post-Contingency Case Violations”.

The panel consists of four panes:

- Violations Summary pane
- Violations Detail pane
- Application (SE and CA) Status pane
- MVAR Reserves pane

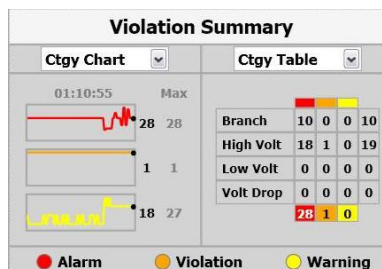


Figure 49: e-terravision / Violation Summary

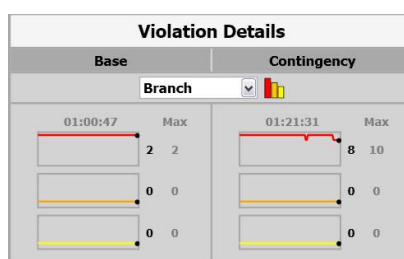


Figure 50: e-terravision / Violation Details

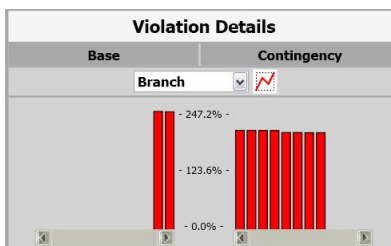


Figure 51: e-terravision / Violation Details

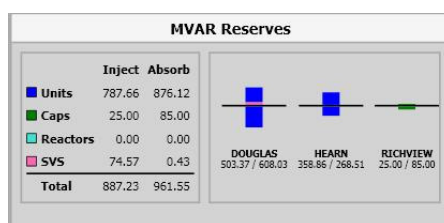


Figure 52: e-terravision / MVAR Reserves

From a technical standpoint, the **e-terravision** architecture comprises a server component, called **e-terravision** Server, a client component, called **e-terravision** Viewer (see the illustration above), and an off-line designer component, called the **e-terravision** Authoring tool for generation, creation and maintenance of overview displays (station one-lines are converted from ddl (FG displays) to XAML). The **e-terravision** Server is delivered as part of **e-terrplatform 2.5** which has been released last June 2008.

e-terravision is a high availability system that can interface with an AREVA EMS or a non-AREVA EMS. For an AREVA EMS, it directly re-uses the existing network model and database along with results from the real-time state estimator and contingency analysis.

More precisely, the design of **e-terravision** has the following characteristics:

- **Task Oriented User Interface:** The user interface is designed to meet specific use cases from operators and provides relevant goal-oriented information for faster decision making by using visual presentation such as animation contouring, markers, fly-outs, pods, context panel and dynamically created dashboard. It also provides navigation from assessing the big picture (system overview) down to the details of a substation (equivalent to the standard schematic SCADA one-line diagram).
- **Human Factors Design:** The user interface is built according to best practices in human factors design for an intuitive and fast learning curve that facilitates communication among personnel and between interconnected utilities.
- **Low Maintenance:** The system reuses the existing EMS as the main source of data and models; all displays are model driven and automatically generated; the design relies on standard technology such as Intel / Microsoft platforms.
- **High Availability:** The system is designed for mission-critical real-time applications with no single point of failure and a redundant scheme to meet 99.95 percent availability criteria.

In addition to the described key functionality, and focusing especially on the integration of Weather data into the real-time production system, AREVA is currently working with WindLogics to enhance the **e-terravision** product to be integrated with weather and wind forecasted system.

Thus, leveraging **e-terravision**, the real-time operators can easily identify the areas at risks. They can then drill down these specific regions, looking at the SCADA one-line Diagram, and Network Bus Summary Display to investigate further a specific branch violation, for instance, caused for by a Wind Farm Plant injecting too much or not enough power into the grid.

Because most EMS vendors provide a 2-dimensional Network Bus Summary, focusing only on the immediate connected devices to a specific bus, it is sometimes challenging for the real-time operators, from a bus in violation, to locate the actual source of problem, which could be located at 2, 3 or more substations away from the faulted bus.

Therefore, in addition to the **e-terravision** key displays, it is critical to provide the real-time operators with additional analytic graphical tools presenting detailed information and assisting the analysis of possible network issues.

The next section describes the Neighboring Bus Display, which helps the operators to analyze and troubleshoot network issues.

Neighboring Bus Display

As described in the previous section, leveraging the **e-terra**vision graphical and analytical capabilities, the real-time operators can identify the areas at risks and navigate, for instance, to traditional displays such as a Network Bus Summary Display to investigate further a specific issue. However, because most EMS vendors provide a 2-dimensional Network Bus Summary, focusing only on the immediate connected devices to a specific bus, it is sometimes challenging for the real-time operators, from a bus in violation, to locate the actual source of problem, which could be located at 2, 3 or more substations away from the faulted bus.

The Neighboring Bus Display enables the operators to quickly locate issues that are topologically related from a selected bus. Indeed, instead of searching through multiple one-line displays or an oversized overview display, the Neighboring Bus Display automatically generates an intelligent tree with enough depth of information to present relevant data instantaneously.

More precisely, this display can be used for:

- Searching for overload causes
- Searching for state estimator residual causes
- Understanding pattern of power flows
- Understanding pattern of voltages.

The Neighboring Bus Display is made of 2 components:

- The Neighboring Bus Display Server: This component, called NHOODSERVER, is an **e-terra**habitat task, running on the **e-terra**platform server. This component is responsible to query the required Network databases and send the gathered data to the User Interface to be displayed.
- The Neighboring Bus Display Client: This component is the User Interface portion, in other words, it is the visible part of iceberg. The end-users interact with this component to identify and localize the sources of electrical network issues.

As proof of concept, during the project, EnerNex and AREVA integrated the server component on top of the enhanced **e-terra**simulator 2.3 leveraged for this study. The integration completed, it was possible to connect the Neighboring Bus Display Client with the server, extract and display the simulated data.



Figure 53: e-terrasimulator / Integrated Neighboring Bus Display Server

The Neighboring Bus Display Client is called from the 2-dimensional Network Bus Summary display, using the added poke points as illustrated below.

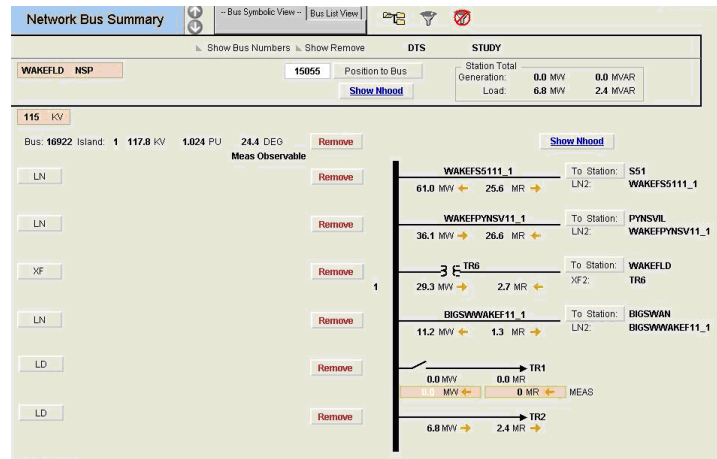


Figure 54: Neighboring Bus Display / Enhanced Network Bus Summary Display

Selecting the “Show Nhood” button calls the Neighboring Bus Display Client. Important information is shown graphically using advanced concepts such as animating, coloring, and flashing. Objects such as gauges are used to also indicate current value versus physical limits. The figure below is a mock-up display of the Neighboring Bus Display Client.

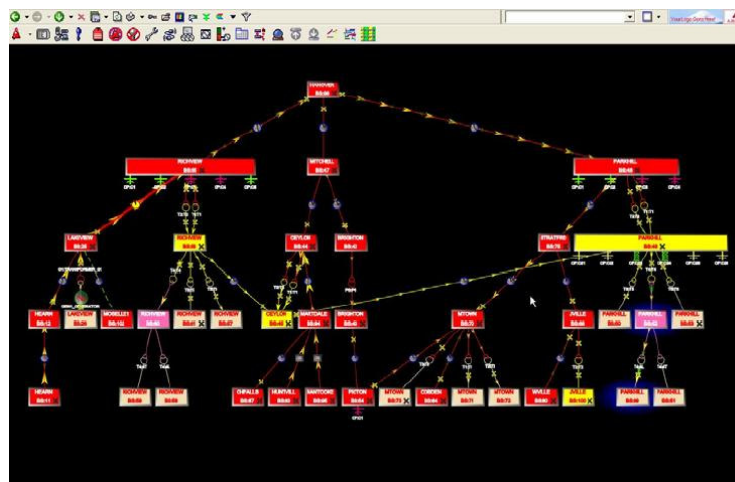


Figure 55: Neighboring Bus Display Client

From a product release standpoint, during the Xcel Energy Renewable Grant Fund project, AREVA has integrated the Neighboring Bus Display Client as part of the standard **e-terra**browser 3.5 release.

To conclude on this investigation, both **e-terravision** and Neighboring Bus Display are complementary tools enabling the real-time operators to improve their situation awareness of electrical system, therefore facilitating the management of grid with high volume of data, including wind power generation.

In addition to these geo-spatial and analytical tools, EnerNex and AREVA have worked on defining the requirements and functional design for a Prediction and Analysis Simulator platform, which will provide the operators with a mid-term look-ahead simulation capability, essential for them to manage wind power generation as part of their operations.

Real-time Prediction and Analysis e-*terrasimulator* Platform

As described in the previous chapters, the **e-*terrasimulator*** has been enhanced to enable the injection of forecasted and/or actual wind power generation coming from external systems (wind forecasted system or web-services) into the simulation engine. In addition, new geo-spatial and analytical tools, such as **e-*terra*vision**, are being developed to facilitate the identification of possible power system issues into complex electrical systems. Leveraging the results from these enhancements, the Prediction and Analysis Simulator platform brings an additional operational level: provide the operators with a mid-term look-ahead simulation capability, essential for them to manage wind power generation as part of their operations.

The Real-Time System Prediction and Analysis Simulator functionality is based on the standard AREVA **e-*terrasimulator*** simulation engine, which is enhanced to satisfy the raising requirements in regards to mid-term look-ahead simulation.

In particular, this Real-Time System Prediction and Analysis Simulator platform is aimed at:

- Improving Situational Awareness
- Providing mid-term look-ahead Simulation
- Predicting a realistic mid-term trend of network state.
- Preventing and mitigating major contingencies
- Validating operation plans

In this platform, an instance of **e-*terrasimulator*** becomes part of the real-time operation system. Periodically and, with no action from the operator, **e-*terrasimulator*** captures the Real-Time System conditions (current network state, existing savecases and files containing forecasted data (i.e.: forecasted wind generation data), output files, etc.). The captured data is then automatically transferred over to the **e-*terrasimulator*** platform, which gets initialized with it.

Leveraging existing Ultra-Fast simulation capabilities with all processes marching faster through time on the full model, the simulation is then continued as fast as possible until the defined look-ahead period is completed.

While the realistic look-ahead simulation is performed, critical data (frequency, voltage, contingencies, alarms, vulnerability indexes and any other user-definable critical data) is recorded, gathered and replayed for the transmission operators and dispatchers managing the Real-Time Production System through a set of high-performance and intuitive displays offering graphical functionality:

- Geo-Spatial visualization of voltage contours and most important contingencies. Voltage contours and contingencies are managed in layers and can be turned on and off.
- Trend of selected critical data via simple and intuitive drag and drop from the one-line displays or from the GIS displays.
- Chart the Reactive Reserve and Generation Capacity.
- Display the current replayed look-ahead simulation time within the look-ahead simulation period, with capabilities to pause the replay of look-ahead simulated data and select a specific time for further analyzing the predicted situation with What-If scenarios.

Practically, a few new key displays are updated on a constant basis allowing anyone in the control center to understand at one glance what is coming up in the next 10, 20, 30, 40 minutes or more.

The Real-Time System Prediction and Analysis Simulator concepts can be summarized with the following system overview diagram:

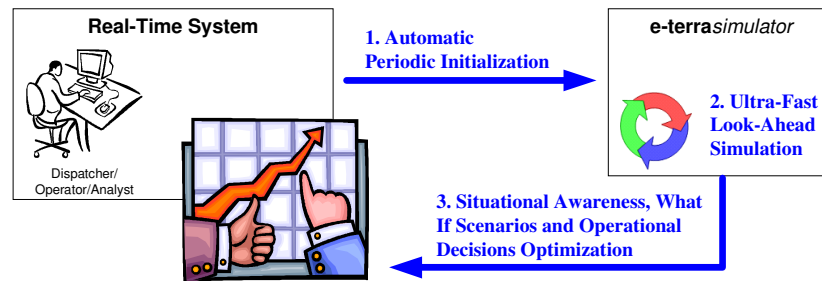


Figure 56: Real-Time System Prediction and Analysis Simulator Overview

Thus, in this future platform, **e-terrasimulator** automatically (without user involvement) keeps on taking real-time system snapshots on a periodic (user definable) basis and runs a fast forward simulation for a look-ahead period of choice.

If we detail a little further this overview, including the required Actual and Forecasted data as well as a replica of a Market Management System within the Real-Time System Prediction and Analysis Simulator, this mid-term look-ahead platform can be described with the following diagram:

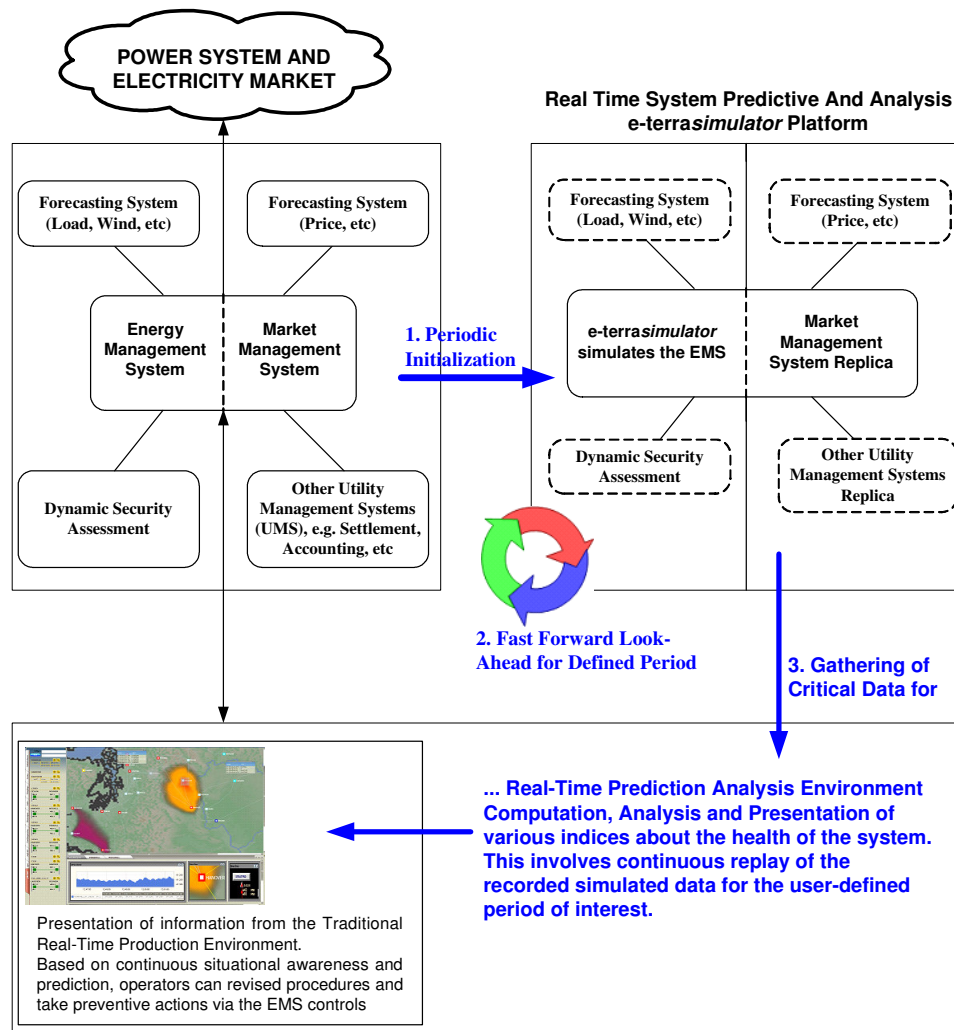


Figure 57: Real-Time System Prediction and Analysis Simulator Overview including Market System

To control and sequence the execution of required processes, an advanced sequencer is required. This sequencer is the **e-terrasimulator** Automatic Launcher task, which can start, stop, send messages to these processes and check the status completion or values into the databases verifying if the requested activity has successfully completed. The following section describes the **e-terrasimulator** Automatic Launcher, which is a new feature in the **e-terraplatform 2.5** release.

In regards to the Simulation Snapshot Creation and One-Step Initialization features, during this project, AREVA has enhanced these existing functions to not only capture the current real-time conditions but, as well as, to capture the User Interfaces currently in use in the Real-Time Production System. This enhancement, which is available in the **e-terraplatform 2.5** release, has the major advantage to ensure that Data and User Interface (and especially Substation and SCADA One-Line Diagrams) are always consistent.

While completing this enhancement, AREVA also configured on the study **e-terrasimulator** server the Simulation Snapshot Creation. The next sub-section illustrates how the Simulation Snapshot Creation and One-Step Initialization features can be leveraged within this Real-Time System Prediction and Analysis Simulator platform.

Lastly, as all tools dealing with a large amount of data, to provide the operators with an easy way to analyze the mid-term look-ahead simulation results, the visualization of results is key. The last sub-section of this chapter discusses the usage of a new geo-spatial **e-terravision** display.

e-terra*simulator* Automatic Launcher task

The **e-terra*simulator*** Automatic Launcher task will be responsible for scheduling and monitoring all activities involved in the Real-Time System Predictive and Analysis **e-terra*simulator*** Platform are supported.

During the project's schedule, AREVA completed the implementation and successfully tested this new **e-terra*platform* 2.5** feature. In particular, this new task is implemented using an Object-Oriented Programming Language, providing the advantage to be database dimension independent.

From an end-user standpoint, this task provides the following functionalities illustrated by the Uses Case Diagram below:

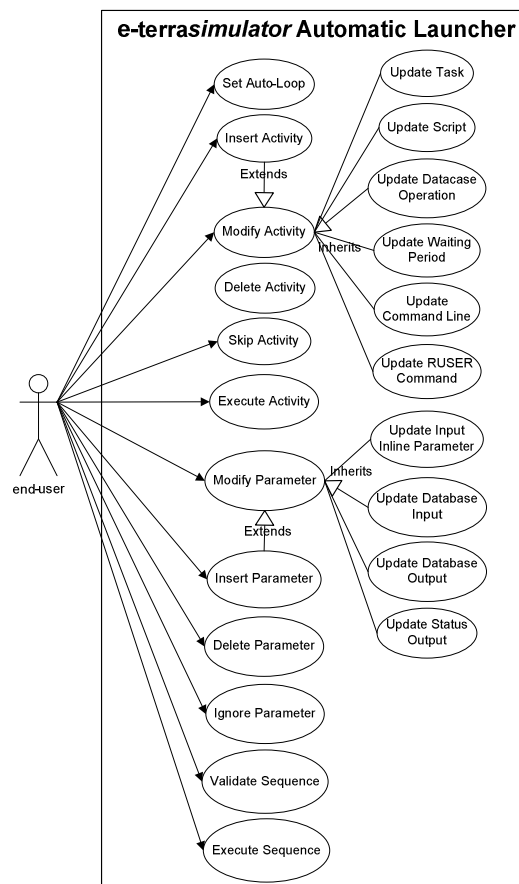


Figure 58: e-terra*simulator* Automatic Launcher Use Cases Diagram

After completing the validation of the **e-terra*simulator*** Automatic Launcher task as part of the **e-terra*platform* 2.5** release effort, AREVA integrated this new task on top of the enhanced **e-terra*simulator* 2.3** system used for the study, as proof-of-concept, creating a simple sequence consisting in the following steps:

- 1) Pause the Simulation.
- 2) Wait until the Simulator is in the paused state.
- 3) Launch a Simulation Snapshot Creation.
- 4) Check the Simulation Snapshot Creation.
- 5) Continue the Simulation.
- 6) Wait for 30 seconds.
- 7) Repeat automatically the steps 1 to 6.

This Sequence has been modeled using the **e-terra*simulator*** Automatic Launcher Modeling display:

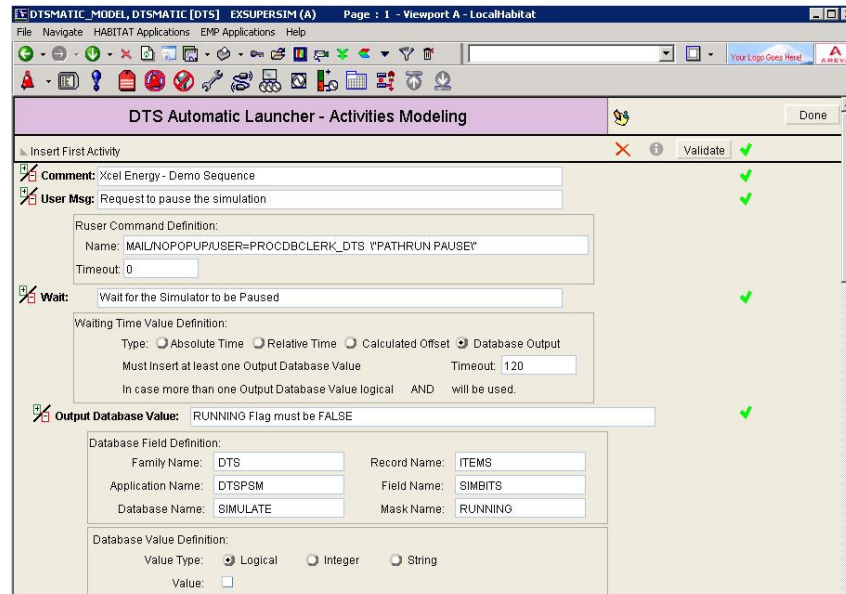


Figure 59: e-terrasimulator / Automatic Launcher Modeling Display

Once modeled, the sequence does not need to be modified. When starting the **e-terrasimulator** Automatic Launcher task, the user can specify to automatically start executing the defined sequence, making it very easy for the end-user as all processes are automated as soon as the task is started.

The end-user can however monitor the sequence looking at the **e-terrasimulator** Automatic Launcher Master display as seen below when nothing is currently executed.

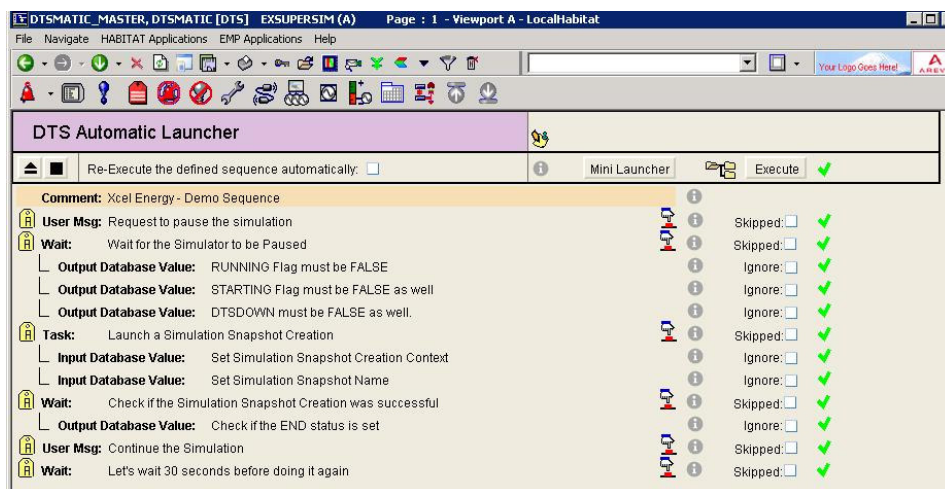


Figure 60: e-terrasimulator / Automatic Launcher Master Display

When executing the following sequence, the **e-terrasimulator** Automatic Launcher task requests the Simulator to pause, then starts the Simulation Snapshot Creation task to capture the current simulated conditions. Once completed, the Simulation is automatically continued.

The following snapshot illustrates the state of the Simulator prior executing the sequence.

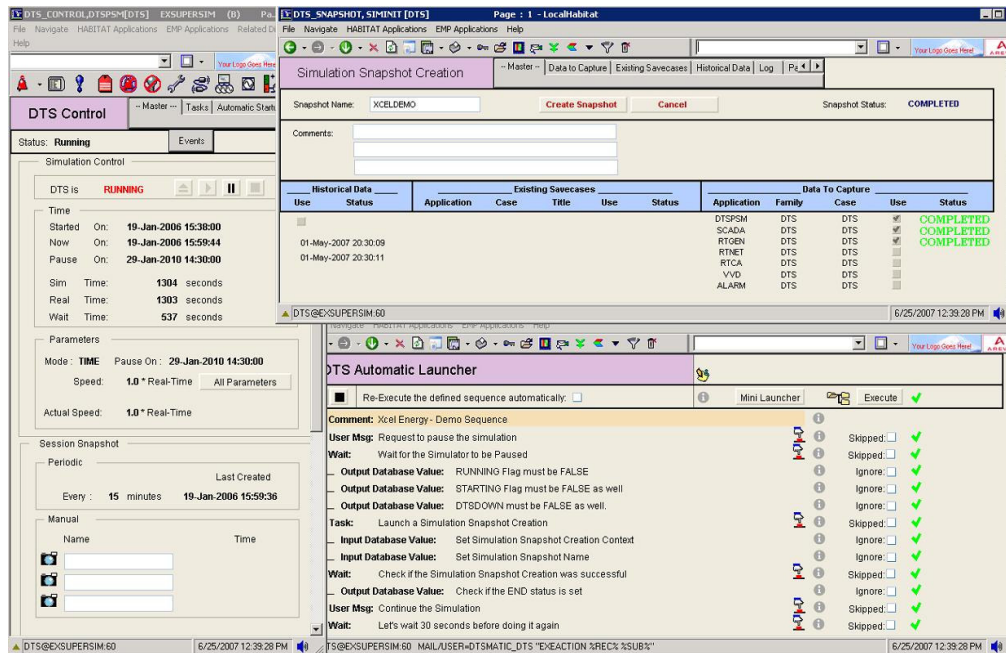


Figure 61: e-terrasimulator / Automatic Launcher Sequence – Part 1

Once the sequence is started, the Simulator pauses, and the Simulation Snapshot Creation is automatically executed.

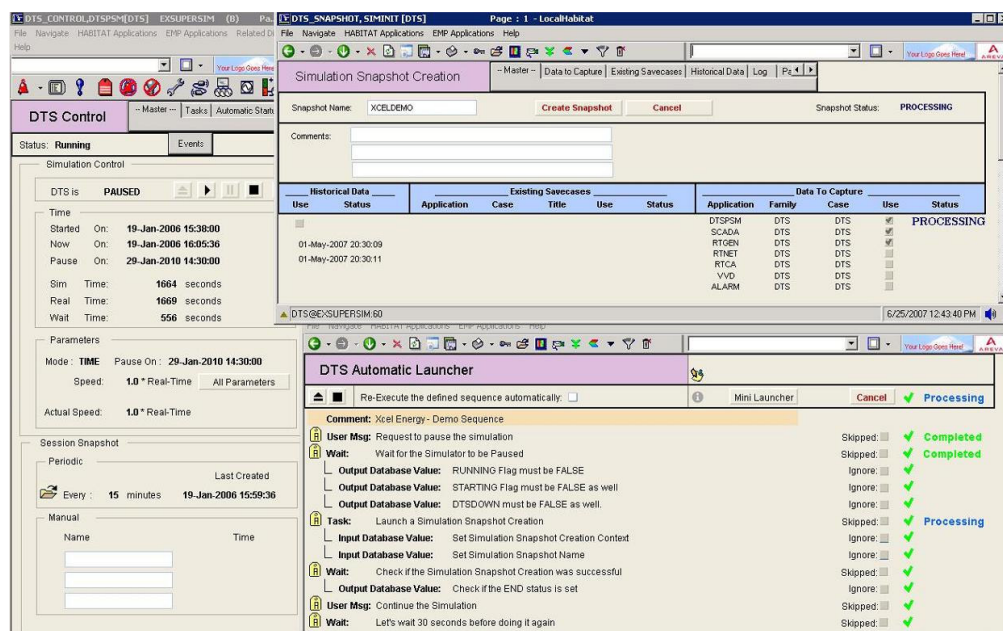


Figure 62: e-terrasimulator / Automatic Launcher Sequence – Part 2

Finally, the Simulation is resumed, and continued for 30 seconds. Then, thanks to the “Auto-Loop” option provided by the e-terrasimulator Automatic Launch task the sequence, the entire sequence is automatically re-executed.

The screenshot displays the e-terrasimulator software interface, specifically the DTS Control and DTS Automatic Launcher windows.

DTS Control Window:

- Status:** Running
- Simulation Control:** DTS is RUNNING. Time: Started On: 19-Jan-2006 15:30:00, Now On: 19-Jan-2006 16:07:44, Pause On: 29-Jan-2010 14:30:00. Sim Time: 1792 seconds, Real Time: 1798 seconds, Wait Time: 570 seconds.
- Parameters:** Mode: TIME, Pause On: 29-Jan-2010 14:30:00, Speed: 1.0 * Real-Time, Actual Speed: 1.0 * Real-Time.
- Session Snapshot:** Periodic, Every: 15 minutes, Last Created: 19-Jan-2006 15:59:36.
- Manual:** Name, Time.

DTS Automatic Launcher Window:

- Simulation Snapshot Creation:** Snapshot Name: XCELDEMO, Create Snapshot, Cancel, Snapshot Status: COMPLETED.
- Comments:** [Empty text box]
- Historical Data Table:**

Use	Status	Application	Case	Title	Use	Status	Application	Family	Case	Use	Status
							DTSPSM	DTS	DTS	✓	COMPLETED
							SCADA	DTS	DTS	✓	COMPLETED
							RTGEN	DTS	DTS	✓	COMPLETED
							RTNET	DTS	DTS	✓	COMPLETED
							RTCA	DTS	DTS	✓	COMPLETED
							VVO	DTS	DTS	✓	COMPLETED
							ALARM	DTS	DTS	✓	COMPLETED

- DTS Automatic Launcher:** Re-Execute the defined sequence automatically: ☐ Mini Launcher, Cancel, Processing.
- Comment:** Xcel Energy - Demo Sequence.
- User Msg:** Request to pause the simulation. Skipped: ✓ Completed.
- Wait:** Wait for the Simulator to be Paused. Skipped: ✓ Completed.
- Output Database Value:** RUNNING Flag must be FALSE. Ignored: ✓
- Output Database Value:** STARTING Flag must be FALSE as well. Ignored: ✓
- Output Database Value:** DTSDOWN must be FALSE as well. Ignored: ✓
- Task:** Launch a Simulation Snapshot Creation. Skipped: ✓ Completed.
- Input Database Value:** Set Simulation Snapshot Creation Context. Ignored: ✓
- Input Database Value:** Set Simulation Snapshot Name. Ignored: ✓
- Wait:** Check if the Simulation Snapshot Creation was successful. Skipped: ✓ Completed.
- Output Database Value:** Check if the END status is set. Ignored: ✓
- User Msg:** Continue the Simulation. Skipped: ✓ Completed.
- Wait:** Let's wait 30 seconds before doing it again. Skipped: ✓ Processing.

Figure 63: e-terrasimulator / Automatic Launcher Sequence – Part 3

Simulation Snapshot Creation and One-Step Initialization features

The Simulation Snapshot Creation enables the operators and the instructor to capture, respectively, the current conditions of the real time production system and the simulation environment. The capture can be configured to include Historical Data Recorded files, existing savecases, and the current state of databases in use as well as, starting from the **e-terraplatform** 2.5 release, the User Interfaces currently linked to the **e-terraplatform** and **e-terrasimulator** platforms.

The One-Step Initialization from Real Time System/Snapshot feature enables the instructor, from the Simulation Environment, to initialize the starting conditions of the simulation or replay training session based on the current conditions of the Real Time Production System. In the similar manner, the One-Step Initialization functionality can be configured to include Historical Data Recorded files, existing savecases, and the current state of databases in use as well as, starting from the **e-terraplatform** 2.5 release, the User Interfaces.

As part of this project, since there was no Real-Time Production System available to capture data from, both the Simulation Snapshot Creation and One-Step Initialization from Real Time System/Snapshot features had been integrated to the enhanced **e-terrasimulator** 2.3 used as proof-of-concept for this study. Once integrated, the Simulation Snapshot Creation and One-Step Initialization from Real-Time Snapshot features were configured and exercised as illustrated below.

From the EMP Applications/DTS Applications submenus, the end-users (the instructor in our study case) calls-up the Simulation Snapshot Creation display.

Historical Data		Existing Savecases		Data To Capture							
Use	Status	Application	Case	Title	Use	Status	Application	Family	Case	Use	Status
							DTSPSM	DTS	DTS	<input checked="" type="checkbox"/>	COMPLETED
							SCADA	DTS	DTS	<input checked="" type="checkbox"/>	COMPLETED
							RTGEN	DTS	DTS	<input checked="" type="checkbox"/>	COMPLETED
							RTNET	DTS	DTS	<input type="checkbox"/>	
							RTCA	DTS	DTS	<input type="checkbox"/>	
							VVD	DTS	DTS	<input type="checkbox"/>	
							ALARM	DTS	DTS	<input type="checkbox"/>	

Figure 64 Simulation Snapshot Creation / Master Display

For demo purpose, the Simulation Snapshot was configured to capture the most important databases for the current simulation:

- The DTSPSM clone includes the Dynamics and Power Flow simulation results.
- The SCADA clone contains the current state of the **e-terrasimulator** platform's Supervisory Controls And Data Acquisition subsystem.
- The RTGEN clone includes the Automatic Generation Control results for all the balancing authorities (i.e.: internal and external areas).

The following figure illustrates the display allowing the instructor or support engineer to define the clone to capture as part of a Simulation Snapshot Creation.



DTS Control

Status: **Paused** Events

Simulation Control

DTS is **PAUSED** [Start] [Pause] [Stop] [Reset] [R]

Time

Started On:	19-Jan-2006 16:08:56
Now On:	19-Jan-2006 16:08:56
Pause On:	29-Jan-2010 14:30:00

Sim Time: 0 seconds
Real Time: 0 seconds
Wait Time: 0 seconds

Parameters

Mode: **TIME** Pause On: 29-Jan-2010 14:30:00

Speed: 1.0 * Real-Time All Parameters

Actual Speed: 0.0 * Real-Time

Session Snapshot

Periodic Last Created

Every : 15 minutes

Manual

Name	Time

Savecase Management

Savecase In Use: **XCEL_DEMO** [Up] [Down]

Not doing any case work

Base Case Title: CASE_6JUL05_1130AM

Last Created: XCEL_DEMO on: 22-Jun-2007 19:52:27

Last Retrieved: MISO_INIT_JGR_FINAL on: 22-Jun-2007 19:43:09

Create Savecase ... (The DTS must be PAUSED to allow a savecase creation)

Simulation Initialization

☐ From Base Case **Initialize** LAUNCHED Initialization Status: INITIALIZED
☐ From Real-Time Case Cancel Parameters
☐ 1-Step from RT System
☒ 1-Step from RT Snapshot Snapshot Name: xceldemo ⓘ
 Comments:
 Show Initialization Messages or 1-Step Statuses

Step Description	Status
Check DTS state	✓
Unzip Snapshot	✓
Read Snapshot Configuration	✓
Retrieve Snapshot	✓
Start Procman DTS	✓
Procman registration	✓
Check Data Validity	✓
Launch DTS Initialization	✓

Figure 66: DTS Control Display

Obviously, if the underlying core components of the Real-Time System Predictive and Analysis **e-terrasimulator** Platform (such as the **e-terrasimulator** Automatic Launcher, the Simulation Snapshot Creation and One-Step Initialization From Real Time System) will provide the main engine for the mid-term look-ahead capability, from a real-time operator standpoint, the focus point is how the User Interface will present the results of the look-ahead simulation.

Thus, after configuring and customizing an **e-terrasimulator** 2.3 release with an Xcel Energy Simulation model, EnerNex and AREVA validated the capability of injecting wind power generation from external sources (such as the WindLogics Forecasted system) into the simulation engine. The platform available for the study also allow the investigation and the proof-of-concept validation of new geo-spatial User Interfaces the real-time operators will in

the future be able to leverage to mitigate the risks associated with the management of electrical systems in which an increasing amount of wind power will be available.

In addition, looking further down the road and building on top of new components available in the **e-terra**platform 2.5 release, EnerNex and AREVA has designed a Real-Time Prediction and Analysis **e-terra**simulator platform that will provide the operators with a mid-term look-ahead simulation of current electrical system, based on the available forecasted information.

Lastly, AREVA has worked on investigating the use of Stochastic Unit Commitment vs. the Deterministic Monte Carlo Unit Commitment methodology when the system includes wind generation. The next chapter discusses this fourth track of research and development conducted as part of the Xcel Energy Renewable Grant Fund project.

5.2 Stochastic Unit Commitment

AREVA conducted stochastic Unit Commitment studies. These studies have been published in different IEEE papers (see below). AREVA cordially suggests the reader to refer to the published papers for additional information on the studies and results.

1. P. A. Ruiz, E. Zak, C. R. Philbrick, K. W. Cheung, and P. W. Sauer, "Modeling the unit commitment problem with uncertainty," in *Proceedings of the X International Conference on Probabilistic Methods Applied to Power System*, Mayagüez, PR, May 2008.
2. P. A. Ruiz, E. Zak, C. R. Philbrick, K. W. Cheung, and P. W. Sauer, "Uncertainty management in the unit commitment problem," *IEEE Trans. Power Syst.*, submitted for publication.
3. P. A. Ruiz, C. R. Philbrick, and P. W. Sauer, "Wind power day-ahead uncertainty management through stochastic unit commitment policies," submitted to 2009 IEEE Power Systems Conference and Exposition, Seattle, WA

In addition to the stochastic Unit commitment, specific studies have performed on various implementations and scenarios, including the effects of generation unreliability, load uncertainty and wind power uncertainty. The investigation leads to the following concluding remarks:

- Combining scenarios with a proper amount of reserve requirements leads to very robust solutions with respect to both changes in model parameters and departures from the modeled realizations of the uncertain parameters.
- Enforcing reserve requirements on the scenarios recognizes the limitation of using a few scenarios to model the whole spectrum of uncertainty and serves to build confidence on the stochastic unit commitment solution by the operators.
- Solution robustness leads to reduce expected costs and, typically, reduced cost variance and increased reliability.
- The improvements come from having more flexible commitments, i.e., units with higher ramp limits, lower minimum up and down times and lower economic minimum capacity are weighted more favorably with stochastic formulations than with deterministic formulations.
- Extreme scenarios in capacity deviations, such as the single outage of the largest units and the largest observed deviations from load forecasts, and randomly generated scenarios were used. The extreme scenarios yielded the best results. Further research is needed in the construction of scenarios.
- The optimal reserve requirements depend on the policy employed and the scenarios used. Typically, stochastic policies have lower optimal reserve requirements. However, reliability will typically improve if the scenarios are appropriately selected. For example, if the worst contingencies are captured by the scenarios, the solution accounts for them explicitly, and may even ensure the availability of some reserves in the post-contingency situations.
- There is no obvious rule for the selection of optimal reserve requirements in a stochastic formulation. Substantially more research is needed in this area.
- The inclusion of a few extreme scenarios brings the most benefit. It has been found that the incremental benefit of each scenario is reduced significantly after a few scenarios are considered.

- Due to the solution robustness, in general there is a sizable range of parameters, such as the probability and reserve requirements associated to each scenario, which leads to improved solutions over the optimal deterministic unit commitment policy.
- It is important to model all significant sources of uncertainty in the stochastic formulations. Otherwise, the improvements over a deterministic formulation may not be attained.
- The computational times can be reduced to a manageable magnitude by using a modeling approach, in spite of solving the equivalent deterministic program of the stochastic program.
- The use of decomposition techniques and the fine tuning of the solution engine should lead to further reductions in the computational times.
- It is expected that the desirable properties of stochastic solutions, the potential cost reductions, the improving algorithms and computational power, and the increased day-ahead uncertainty brought by the wind power generation being planned and installed will lead to the use of stochastic unit commitment formulations in the future.