Joint Intervenors
CORRECTED Exhibit 4

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Otter Tail Power Company on behalf of the Big Stone II Co-owners for an Energy Conversion Facility Siting Permit for the Construction of the Big Stone II Project	))))	Case No EL05-022

Direct Testimony of

David A. Schlissel and Anna Sommer

Synapse Energy Economics, Inc.

On Behalf of

Minnesotans for an Energy-Efficient Economy

Izaak Walton League of America – Midwest Office

Union of Concerned Scientists

Minnesota Center for Environmental Advocacy

PUBLIC VERSION
PROTECTED INFORMATION REDACTED

May 26, 2006

CORRECTED VERSION June 23, 2006

EXHIBIT NO. 4
C. BACHAND

INDEX

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Ms. Sommer, please state your name position and business address.

A. My name is Anna Sommer. I am a Research Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of Minnesotans for an Energy-Efficient Economy, Izaak Walton League of America – Midwest Office, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy ("Joint Intervenors").

Q. Have you previously filed testimony in this proceeding?

A. Yes. We filed testimony on May 19, 2006 on the issue of whether the Big Stone II Co-owners have appropriately reflected the potential for the regulation of greenhouse gases in the design of the proposed facility and in their analyses of the alternatives.

Q. What is the purpose of this testimony?

A. This testimony reports on the results of our investigations of the other three issues that Synapse was asked to examine by Joint Intervenors:

A. The need and timing for new supply options in the utilities' service territories.

B. Whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

C. Whether the applicants have included appropriate emissions control technologies in the design of the proposed facility.

This testimony presents the results of our investigations of these issues.

Q. Please summarize the conclusions of this testimony.

A. Our conclusions are as follows:

1. The Co-owners have not demonstrated that there is a regional need for new baseload generating capacity in 2011.

2. The Co-owners have not demonstrated that they each need new baseload generating capacity beginning in 2011.

3. The Co-owners have not shown that the addition of Big Stone II is the lowest cost option as compared to portfolios of renewable and demand-side alternatives, either in the three jointly sponsored analyses submitted as part of their testimony in this proceeding or in the analyses carried out by the individual project participants.

4. The Co-owners *Phase I Report Big Stone II* summarily dismisses renewable alternatives (that is, wind) in a single paragraph.

5. Although the Co-owners' September 2005 *Generation Alternatives Study* evaluated the economics of a wind alternative to Big Stone II, the results of that study were flawed and biased against wind and in favor of the 600 MW supercritical coal-fired option. Moreover, that Study did not examine the economics of undertaking a combination of renewable and demand-side resources to meet the projected needs of the Co-owners.

6. The assumption in the September 2005 *Generation Alternatives Study* that wind will have a zero capacity value is unreasonable and is contrary to (a) the testimony of Co-owner witnesses in this proceeding, (b) the assumptions made in the Integrated Resource Plans filed by Big Stone II Co-owners in 2005, and (c) the results of the recent *Wind Integration Study* prepared for Xcel Energy and the Minnesota Department of Commerce and other studies.

7. If the Co-owners' *Generation Alternatives Study* is revised to reflect the fact that wind conservatively has a 15 percent to 25 percent capacity value, the installation 800 MW or 1200 MW of wind would have a lower levelized cost than Big Stone II under Synapse's most likely Mid CO_2 price forecast

8. There is no credible evidence that the non-Big Stone II resource plan examined in Co-owners' February 2006 Supplemental Filing in the Minnesota PUC Certificate of Need proceeding actually reflects the individual Co-owners' "next best" resource scenarios.

9. Instead, the alternative resource plan examined in the Co-owners' February 2006 Supplemental Filing can be characterized as a highly risky plan that, other than Otter Tail Power Company, depends exclusively, or, at best, almost exclusively, on coal-fired and natural gas-fired generation and on purchases of power that probably also would be generated at fossil-fired facilities.

10. The Co-owners have not adequately reflected the potential for demand-side management ("DSM") either in their projections of need for new generating capacity or in their analyses of alternatives to the Big Stone II Project.

11. For the reasons discussed in this testimony, the testimony we filed on May 19, 2006 and the testimony filed on May 19th by our colleague, Dr. Ezra Hausman, the South Dakota Public Utilities Commission should reject the Co-owners' Application for An Energy Conversion Facility Siting Permit for the Big Stone II Project.

The Need for Capacity

Q. Have the Big Stone II Co-owners demonstrated in their Application and Testimony that there will be a region-wide need for another 600 MW of baseload generating capacity in 2011?

A. No. At most, the Co-owners have shown a regional need for some additional capacity in MAPP-US during the peak summer hours. They have not shown that there is any regional need for 600 MW of new baseload capacity in 2011 or anytime soon thereafter.

In fact, the September MRO *2005 Ten-Year Reliability Assessment* projects that during winter peak periods the MAPP-US region will have very substantial capacity reserves **above** the 15 percent required levels of reserves. Indeed, the Midwest Reliability Organization ("MRO") September 2005 Assessment projects that MAPP-US will have approximately 4,000 MW of capacity reserves above the regional reserve capacity obligation ("RCO") during the winter of 2011-2012, approximately 3,600 MW of capacity reserves above the RCO during the winter of 2012-13, and approximately 3,300 MW of capacity reserves above the RCO during the winter of 2012-2013.[1] These capacity reserves show that the MAPP-US region will not require any new increments of capacity to ensure adequate reliability during the winter periods for years after 2013.

Consequently, it may be that instead of requiring baseload capacity, the need for capacity during peak summer periods starting in 2011 can be met by the installation of peaking capacity, the implementation of more aggressive demand side management programs, or through the import of additional capacity from MAPP-Canada or other regions surrounding MAPP-US.

Q. How much excess generating capacity does MRO currently project for the MAPP-Canada subregion?

A. MRO currently projects that the MAPP-Canada subregion will have between 1,384 MW of surplus capacity in the summer of 2011, decreasing to about 1,350 MW by the summer of 2014.

Q. Does the Co-owners' assessment of regional capacity need reflect this projected excess capacity in MAPP-Canada?

A. No.

1 MRO *2005 Ten-Year Reliability Assessment*, Table 5, at page 10 of 42.

Q. If this projected excess capacity in MAPP-Canada is considered, does the total MAPP system (MAPP-US and MAPP-Canada) show a need for new baseload capacity during the summer of 2011?

A. No. The total MAPP system (both MAPP-US and MAPP-Canada) does not need any new capacity until the summer of 2013.

Q. Have the Big Stone II Co-owners identified or quantified the amounts by which proposed transmission system upgrades and improvements will increase the amount of capacity that can be imported into the geographic areas included in the MAPP system?

A. No. Interrogatory 71(l) in Joint Intervenors' Sixth Set of Interrogatories in this Docket asked the Big Stone II Co-owners to list the new transmission interconnections with the regions around MAPP that Co-owner witness Koegel believes are likely to be in service by the summer of 2011, and to specify the amount by which such additional interconnections will increase the capability to import power into MAPP during peak summer and peak winter conditions. Unfortunately, the Big Stone II Co-owners refused to provide this information.

Q. Have the Big Stone II Co-owners presented evidence that demonstrates the need for capacity in 2011?

A. If we accept their load forecasts as a given, CMPPA is projecting that it will have sufficient capacity through 2012.[2] With its new demand-side management ("DSM"), MRES will have sufficient capacity through 2012.[3] The other Co-owners project some capacity deficits in the summer of 2011.

---

2 Response to our Information Request 38 in Minnesota Docket No. CN-05-619, incorporated by reference in Co-owners' response to Intervenors' Fourth Set of Requests for Production of Documents.

3 Response to Interrogatory 44 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Q. Have the Big Stone II owners presented evidence that demonstrates that all of the utilities actually need their MW shares of the proposed plant in 2011?

A. No. The seven Big Stone II Co-owners have repeatedly claimed that they "share a common need for baseload resources in the 2011 timeframe."[4] However, assuming for the sake of argument that the Co-owners' demand forecasts are reasonable, the most that the Co-owners have shown in their Application and Testimony in this proceeding is that almost all of them are currently projecting some levels of capacity deficits during summer peak hours starting in 2011. The Co-owners have not shown that they individually or as a group have any need beginning in 2011 for 600 MW of new baseload capacity that would operate at an 88 percent capacity factor.

Q. Please summarize the evidence that forms the basis for this conclusion.

A. First, none of the Co-owners has presented any analysis that goes beyond looking at system loads and capacity during the summer, or in some cases summer and winter, peak demands. Second, the data provided by certain Co-owners shows that they do not need very much of their MW shares of Big Stone II capacity even during peak hours in 2011. For example, CMMPA is forecasting that it will have sufficient capacity without Big Stone II to meet projected peak demands in 2011 and 2012 and that it will only have deficits of 2 MW in 2013 and 9 MW in 2014.[5] Despite this, CMMPA wants to acquire 30 MW of Big Stone Unit II in 2011.

Similarly, based on its April 2006 forecasts, which assume extreme weather instead of normalized weather,[6] MRES projects an 11 MW capacity surplus (including new DSM) in the peak summer hours of 2011 without Big Stone II. This summer capacity surplus declines to a 35 MW deficit in the peak summer

---

4 For example, see the South Dakota Siting Permit Application, at pages 39 and 41.

5 South Dakota Siting Permit Application, Exhibit 3-4.

6 The assumption of extreme weather biases MRES' demand forecast to the high side by a significant amount.

hours of 2015.[7] MRES' forecasts do not suggest a need for its entire 110 MW of Big Stone II until 2016 when it will assume the load of Marshall, Minnesota from Heartland. Despite this, MRES contends that it needs its share of Big Stone II starting in 2011.

Q. Do you have any comment on the claim by several of the Co-owners that there is inadequate transmission capacity to allow them to enter into firm contracts to purchase power from third parties?

A. Yes. Beyond simply making this claim, the Co-owners have not presented any evidence showing that the planned transmission system upgrades (including 807 miles of new 345 kV and 230 kV transmission lines, as noted by Co-owner witness Koegel[8]) cannot relieve the constraints that have prevented any of the Co-owners from entering into firm contracts to purchase power from third parties.

Moreover, the Co-owners have not presented any evidence that the creation of MISO and the expansion of MAPP into the Midwest Reliability Organization will not improve their ability to buy firm power from third parties. Finally, the Co-owners have not presented any evidence that building a $1 billion coal plant is a more economic option than undertaking grid system enhancements to relieve any existing transmission constraints.

The Co-owners Economic Analyses Concerning Their Participation in Big Stone II and Evaluation of Alternatives

Q. Is it possible that the addition of a new baseload generating facility can be the lowest cost option even if all of the capacity is not immediately needed to ensure that an owner has adequate capacity to serve loads or for system reliability?

A. Yes.

---

[7] Response to Interrogatory 44 of Joint Intervenors' Sixth Set of Interrogatories and Combined Set of Request for Production of Documents.

[8] Applicants' Exhibit 9, at page 7, lines 10-13.

Q. Have the Co-owners demonstrated that the addition of Big Stone II is the lowest cost baseload option?

A. No. The Co-owners have not shown that the addition of Big Stone II is the lowest cost option as compared to portfolios of renewable and demand-side alternatives either in the three jointly sponsored analyses submitted as part of their testimony or in the analyses carried out by individual project participants.

Q. What are the three jointly sponsored analyses were submitted as part of the Co-owners' testimony in this proceeding?

A. The three jointly sponsored analyses include Applicants' Exhibit 24-A which is the July 2005 *Phase I Report Big Stone Unit II* that was prepared for Otter Tail Power Company by Burns & McDonnell.

Applicants' Exhibit 23-A is the September 2005 *Analysis of Baseload Generation Alternatives*, also prepared by Burns & McDonnell.

Finally, Applicants' Exhibit 25-B presents an economic analysis that was submitted to the Minnesota Public Utilities Commission in the February 28, 2006 *Applicants' Supplemental Information Required by Commission's Order of December 19, 2005*.

None of these analyses compared Big Stone II to renewable alternatives in a complete and unbiased manner. Consequently, their results are not credible.

Q. Were renewable alternatives considered in the July 2005 Burns & McDonnell *Phase I Report Big Stone II*?

A. No. As Co-owner witness Grieg has testified, seven generation alternatives were considered in the economic evaluation of the *Phase I Report*.[9] Six of the seven generation alternatives were coal-fired. One was a natural gas-fired combined cycle facility.

[9] Applicants' Exhibit 23, at page 13, lines 13-18.

Q. Does the *Phase I Report* explain why no renewable alternatives were evaluated?

A. Yes. The Report dismisses the potential use of wind turbines in a single paragraph:

> The most common and economically viable renewable resource technology employed in the region, wind turbines, is not appropriate for this project, primarily because it cannot reliably provide base load capacity. According to the American Wind Energy Association (www.awea.org), North Dakota, South Dakota and Minnesota rank 1, 3 and 9, respectively, among the states with the best wind resource. But even in this relatively windy region, wind turbines typically generate electricity only 30 to 40 percent of the time. Additionally, it is not possible to schedule the dispatch of wind turbines, as their operation is as unpredictable as the wind. Base load capacity must be reliable and able to provide virtually continuous output (with only scheduled short-term outages). In conclusion, wind turbines are not recommended.[10]

Q. Do you agree that wind turbines cannot be relied upon as a viable alternative to a new fossil-fired baseload facility because they cannot reliably provide base load power, are a variable resource and cannot be scheduled for dispatch?

A. No. The arguments raised against wind power in the *Phase I Report* and the data responses from individual Co-owners merely rehash the same tired old arguments against reliance on wind power.[11] As the 2004 *Wind Integration Study – Final Report* prepared for Xcel Energy and the Minnesota Department of Commerce has noted:

> Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research studies and empirical understanding gained from

[10] Applicants' Exhibit 24-A, at page 2-2.

[11] For example, see the Co-owners' responses to Interrogatories Nos. 17, 33 and 34 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

> the installation and operation of over 6000 MW of wind generation in the United States.[12]

Contrary to what the Co-owners are claiming, wind power can reduce the need for other capacity and provide low cost energy. GRE agrees, stating in discovery in the Minnesota Certificate of Need proceeding for the transmission line that "GRE believes that renewables and conservation could serve at least a portion of future baseload power needs."[13] In fact, when combined with other energy resources, wind can produce energy in patterns comparable to a baseload generation facility. At the same time, the effects of short term wind variability can be mitigated by building a larger number of wind turbines and by siting the wind turbines in different geographic locations.

Moreover, studies and actual operating experience has shown that fairly high penetrations of wind generation can be integrated into the electricity system (up to 20% of system peak demand[14] or more) without having adverse impacts on the reliability or stability of the electric grid. Some additional regulation or load-following support may be needed if large amounts of wind are added to the grid, but that can be provided by existing facilities.[15] Co-owner witness Mark Rolfes has admitted the same, saying "The [Balancing Area Authority] simply must have enough generation available to handle variations between expected and actual generating level of wind on a second-by-second basis. Presuming some type of

---

12 *Wind Integration Study-Final Report*, prepared for Xcel Energy and the Minnesota Department of Commerce by EnerNex Corporation and Wind Logics, Inc., dated September 28, 2004, the Project Summary portion of which is included as Exhibit JI-4-A, at page 19.

13 Response to MCEA IR No. 73 in MNPUC Docket No. CN-05-619. Joint Intervenors' have requested that this response be incorporated by reference into this docket.

14 Exhibit JL-4-B, the "Utility Wind Integration State of the Art" report prepared by Utility Wind Integration Group in cooperation with American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, dated May 2006.

15 Exhibit JI-4-C, "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States," Parson, Mulligan, et al., presented at the 2006 European Wind Energy Conference.

pre-scheduling was performed based upon wind forecasts, this amount can be a relatively small fraction of the nameplate capacity of the wind."[16]

We also would make two comments regarding the claim that the Co-owners need a fully dispatchable facility. First, the electric grid and, indeed, many of the Co-owners, already have fully dispatchable facilities. They have not shown any evidence why new generation also must be fully dispatchable. Second, none of the Co-owners' economic studies that we have seen reflected any dispatching of the proposed Big Stone II facility, in response to changes in demand or any other factor(s). Instead, these studies have assumed that Big Stone II will operate "flat-out" at an 88 percent average annual capacity.

Q. Did the September 2005 *Generation Alternatives Study* (Exhibit 23-A) evaluate the economics of a wind alternative to Big Stone II?

A. Yes. Among the six alternatives considered, the *Generation Alternatives Study* did examine a wind-gas alternative. However, the evaluation of the wind alternative in the *Generation Alternatives Study* had two flaws which substantially biased its results in favor of the 600 MW supercritical PC alternative that was essentially Big Stone II.

Q. What were the two flaws which critically biased the economic analyses presented in the *Generation Alternatives Study* against the wind-gas alternative?

A. First, the *Generation Alternatives Study* assumed that the wind resources had no capacity value and, therefore, required a 600 MW backup natural gas-fired combined cycle facility. Second, the *Study* limited the amount of wind in the alternative to 600 MW which meant that substantially more than half of the energy provided by the alternative would be produced by the more expensive

---

[16] Response to Interrogatory 33 of the Joint Intervenors' Sixth Set of Interrogatories and Combined Set of Request for Production of Documents.

combined cycle facility. Together, these assumptions significantly increased the cost of the wind-gas alternative in the *Generation Alternatives Study*.

Q. Is the assumption that wind facilities have no capacity value, and therefore require 100 percent backup, consistent with the testimony sponsored by the Big Stone II Co-owners in this proceeding?

A. No. The testimony of Heartland witness McDowell notes that wind generation is accredited to be available 20 percent of the time for MAPP load and capability planning purposes.[17] Similarly, SMMPA witness Geschwind suggests a 20 percent capacity value for wind when he testifies that "SMMPA would have to install approximately 5 MW of nameplate wind capacity for every 1 MW of nameplate capacity from Big Stone Unit II to arrive at the same level of MAPP-accredited capacity."[18]

Q. Is the assumption that wind facilities have no capacity value, and therefore require a 100 percent backup, consistent with the assumptions made in the most recent Integrated Resource Plans filed by the Big Stone II Co-owners?

A. No. The MRES' recent Supplement to its 2006-2020 Resource Plan filing in Minnesota assigns wind a 15 percent capacity value.[19] Similarly, the capacity tables in Otter Tail Power's 2006-2020 Resource Plan credit wind with a capacity value of approximately 15 percent in the summer and approximately 20 percent in the winter.[20]

---

17 Applicants' Exhibit 4, at page 8, lines 7-8.

18 Applicants' Exhibit 5, at page 10, line 22, to page 11, line 2.

19 MRES Supplement to 2006-2020 Resource Plan, dated May 8, 2006, at page 69.

20 Otter Tail Power Company's 2006-2020 Resource Plan, dated June 28, 2005, Table 4-B, at page 4-9.

Q. Is the assumption that wind facilities have zero capacity value, and therefore require 100 percent backup, consistent with the results of the recent study by Xcel Energy and the Minnesota Department of Commerce?

A. No. The detailed modeling study sponsored by Xcel Energy and the Minnesota Department of Commerce concluded in September 2004 that wind resources in the same general geographic area as South Dakota have capacity values of between 27 percent and 34 percent.[21]

Q. Please explain how limiting the amount of wind resources to 600 MW biases the *Generation Alternatives Study.*

A. Each of the alternatives considered in the *Generation Alternatives Study* were designed to provide the same amounts of capacity for reliability (600 MW) and energy (approximately 4,625 GWh). Because it assumes that the wind resources have zero capacity value, in the wind alternative examined, the *Study* added 600 MW of natural-gas fired combined cycle capacity to "back up" the 600 MW of wind it assumed would be built. By limiting the amount of wind resources to 600 MW, the Study limits the energy that would be produced by that wind capacity to 2,102 GWh (assuming a 40 percent capacity factor for wind). This means that 2,523 GWh, or more than half of the required energy, would be generated by the far more expensive natural gas-fired combined cycle facility. This increases the overall cost of the wind-gas alternative.

Instead of assuming that only 600 MW of wind would be built, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 800 MW of wind resources. In this scenario, wind would be expected to provide 2,803 GWh of energy, or approximately 61 percent of the total required 4,625 GWh. The remaining 1,822 GWh, or 39 percent, of the required energy would be generated by the significantly more expensive natural gas-fired facility.

---

[21] Exhibit JI-4-A, at page 27.

Or, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 1200 MW of wind resources. In this scenario, wind would be expected to provide 4,205 GWh, or approximately 91 percent, of the total required 4,625 GWh. Only 420 MWh, or less than ten percent of the total, would have to be generated at the more expensive natural gas-fired facility.

Q. Are there any circumstances under which a utility would undertake a wind project with a dedicated gas backup constrained to run when wind is not generating energy, as the Co-owners have assumed in the *Generation Alternatives Study*?

A. For the Co-owners, it is difficult to imagine that such a situation would ever occur. First, it is illogical and contrary to customary practice to build one generating unit to "back up" a second unit. Usual practice is to back up the entire pool of generation, not just an individual unit.

Second, to have, but not to bid a gas unit, could be a violation of the current MISO rules since the Co-owners could be accused of withholding capacity from the market. This example also violates the principles of economic dispatch since a unit will run when it is economic to do so, not simply in cases where it would be supplying energy not generated by a wind turbine. So, in practice, the gas "backup" would not be constrained.

Q. Have you corrected the economic analyses presented in the *Generation Alternatives Study* for these flaws?

A. To the extent possible. However, the combination of wind and gas in any proportion would conservatively bias a levelized cost comparison against wind since, for the reasons we just discussed, it is not representative of the manner in which the plants would likely be operated.

We have examined several wind-gas alternative plans which include 800 MW or 1200 MW of wind. We also have very conservatively assumed that the wind resources have a capacity value of 15 percent or 25 percent. This reduces the amounts of natural gas-fired combined cycle capacity that would be added.

In particular, we have examined the following four wind-gas plans:

Alternative One:	800 MW of wind and 480 MW of Combined Cycle Gas Turbine (CCGT) (assumes 15 percent capacity value for the wind).
Alternative Two:	800 MW of wind and 400 MW of CCGT (assumes 25 percent capacity value for the wind)
Alternative Three:	1200 MW of wind and 420 MW of CCGT (assumes 15 percent capacity value for the wind)
Alternative Four:	1200 MW of wind and 300 MW of CCGT (assumes 25 percent capacity value for the wind)

Q. Please explain why you have assumed that the wind resources would have a capacity value of between 15 percent and 25 percent.

A. We have used this range in this analysis to be extremely conservative. The 15 percent low end of the range is based on the Big Stone II Co-owner Integrated Resource Plan filings we noted earlier. The 25 percent high end of the range is, again, very conservatively based on the results of the 2004 *Wind Integration Study* prepared for Xcel Energy and the Minnesota Department of Commerce. We easily could have used a low end wind capacity value above 15 percent and/or a high end wind capacity value above 25 percent based on the results of the *Wind Integration Study* and other studies.

Q. Are the results of your analyses conservative?

A. Yes. The results of our cost analyses are very conservative, i.e. high on the wind/gas side. For the purpose of these analyses, we have accepted all of the Co-owners' assumptions except for the amounts of wind and gas capacity in each alternative scenario. These assumptions include assuming Burns & McDonnell's $50/MWh cost of wind which does not appear to vary with the ownership structure of the wind plant. That is, as with the coal plant a wind facility (without the PTC) owned by a public power utility would have a lower cost because of the lower cost of financing than a wind facility owned by a taxable entity. In addition, we have not reflected any increases in the cost of operating Big Stone II, any potential increases in coal costs, and have accepted the Co-owners' claimed 88 percent annual capacity factor. Clearly, the levelized cost of the coal option could be higher if the costs of building and/or operating the coal facility are assumed to be higher and/or the plant is assumed to operate at less than an average 88 percent capacity factor.

Finally, we have adopted Burns & McDonnell's assumed levelized value of $12/MWh for the Production Tax Credit ("PTC") for wind facilities, which may understate the value of the PTC by not counting the additional tax benefit of the PTC because it is a credit on tax liability rather than a dollar of taxable income. Unfortunately, because there are no spreadsheets or workpapers to support the wind cost, despite our having asked for these in discovery, or to support the PTC calculation we cannot verify whether this tax effect was accounted for or not.

For example, a 2005 study by the Energy Information Administration ("EIA") shows that the PTC is worth approximately $28/MWh levelized over a 10-year period or $21/MWh levelized over a 20-year period, assuming a 38% marginal tax rate. Another study by the National Renewable Energy Laboratory found that the PTC could be worth as much as $23/MWh levelized over a 15-year period, assuming a 40% tax rate.

Q. Please summarize the results of your revisions to the analyses in the *Generation Alternatives Study*.

A. The results of our revisions to the analyses in the *Generation Alternatives Study* are presented in Table 1 and Table 2 below:

Table 1 Levelized Cost Comparison Coal vs. Wind-Gas Combination – for Investor Owned Utilities

Resource Option	Low CO2	Mid CO2	High CO2
Coal 600 MW	$65.60	$81.20	$97.23
Wind 800 MW + CCGT - No PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$68.53	$71.22	$73.98
Alternative Two - 800 MW wind + 400 MW CCGT	$67.32	$69.82	$72.57
Wind 800 MW + CCGT with PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$61.26	$63.95	$66.70
Alternative Two - 800 MW wind + 400 MW CCGT	$60.05	$62.55	$65.30
Wind 1200 MW + CCGT - No PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$59.68	$60.32	$60.95
Alternative Four - 1200 MW wind + 300 MW CCGT	$57.58	$58.21	$58.85
Wind 1200 MW + CCGT & PTC with PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$48.77	$49.41	$50.04
Alternative Four - 1200 MW wind + 300 MW CCGT	$46.67	$47.30	$47.94

The Low CO2, Mid CO2 and High CO2 figures reflect the Synapse carbon price forecasts presented in Exhibit JI-1-F to our May 19, 2006 testimony.

Table 2 Levelized Cost Comparison Coal vs. Wind-Gas Combination – for Public Power Utilities

Resource Option	Low CO2	Mid CO2	High CO2
Coal 600 MW	$57.54	$74.81	$92.08
Wind 800 MW + CCGT - No PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$67.19	$70.16	$73.12
Alternative Two - 800 MW wind + 400 MW CCGT	$66.16	$69.13	$72.10
Wind 800 MW + CCGT with PTC			
Alternative One - 800 MW wind + 480 MW CCGT	$59.91	$62.88	$65.85
Alternative Two - 800 MW wind + 400 MW CCGT	$58.89	$61.86	$64.82
Wind 1200 MW + CCGT - No PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$57.87	$58.55	$59.24
Alternative Four - 1200 MW wind + 300 MW CCGT	$56.32	$57.01	$57.69
Wind 1200 MW + CCGT & PTC with PTC			
Alternative Three - 1200 MW wind + 420 MW CCGT	$46.96	$47.64	$48.33
Alternative Four - 1200 MW wind + 300 MW CCGT	$45.41	$46.10	$46.78

The results in these Tables show the following:

- Under our Mid CO_2 price forecast, which we believe is the most likely, and our High CO_2 price forecast, all of the wind and CCGT alternatives we have examined would have lower levelized costs than the 600 MW coal plant (Big Stone II).

- For the investor owned utilities, under our Low CO_2 price forecast, the 800 MW wind and CCGT alternatives would have lower levelized costs than the coal plant if the PTC is renewed. Both of the 1200 MW wind and CCGT alternatives have lower levelized costs than the coal plant whether or not the PTC is renewed.

- For the public power utilities, under our Low CO_2 price forecast, the coal plant would have a lower levelized cost than the 800 MW wind and CCGT alternatives whether or not the PTC is assumed to be renewed.[22] Under our Low CO_2 price forecast, the coal plant and the 1200 MW wind and CCGT alternative would have about the same levelized costs if the PTC is assumed to be not renewed. If the PTC is renewed, the 1200 MW wind and CCGT alternatives would have lower levelized costs than the coal plant.

- Under all scenarios, the 1200 MW wind and CCGT combination is approximately the same or cheaper than Big Stone Unit II.

Q. Is it reasonable to assume that the Production Tax Credit will be renewed before it expires at the end of 2007?

A. Yes. We believe it is reasonable to assume that the Production Tax Credit will be renewed given (1) its history, (2) increasing concern over U.S. dependence on foreign sources of energy and (3) mounting concern over global warming and climate change and a resulting interest in providing subsidies to non-carbon emitting technologies.

---

22 This conclusion accepts the modeling of the effects of the PTC in the *Generation Alternatives Study*. However, if EIA's levelized PTC value of $21/MWh were used in this analysis, the 800 MW wind and CCGT combination would be more economic for the public power utilities than the coal plant.

Q. Is it possible that there are wind with hydro and/or demand-side management measures that would have lower costs than the wind-gas combinations you have looked at in your revisions to the Co-owners' *Generation Alternatives Study*?

A. Yes. For example, as we discuss later in this testimony, there is evidence of additional, very low cost demand-side management measures available to the Co-owners.

Q. Did the *Generation Alternatives Study* examine a combination of renewable resources, other than the 600 MW wind–600 MW gas mix, to meet the projected needs of the Co-owners?

A. No. The *Generation Alternatives Study* did not examine, with the exception of gas and wind, any combinations of resources, such as a portfolio of wind, demand-side measures, and hydro, to meet the projected needs of the Co-owners.

Q. Do you have any comments about the usefulness of this type of levelized cost comparison, particularly regarding the following claim by the Co-owners:

> **It must be noted that simply comparing $/MWh busbar costs of dissimilar projects is misleading and violates the most basic principles of integrated resource planning. Such a comparison completely ignores the impact of the costs and benefits a single resource can have on other resources, and provides only limited information on how any particular resource matches up with a utility's existing resource mix, the existing load requirements, or the electrical system in total.**[23]

A. Yes. Our first comment is that we believe that the use of levelized costs is a useful tool in the screening of possible alternatives to be studied in greater detail to capture the various factors noted by the Co-owners. We have merely revised the levelized cost analysis presented in the *Generation Alternatives Study* to show that under more reasonable, but still extremely conservative assumptions,

[23] Response to Interrogatory 17 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

different amounts of wind and CCGT capacity can be more economic than Big Stone Unit II. Our revisions show that there are wind-gas alternatives that would have lower levelized costs than the 600 MW coal option (that is, Big Stone II) and that wind, in general, deserved to be studied in greater detail by the Co-owners.

Secondly, it is important to note that if the Co-owners believed this way about the limits of levelized cost analyses it begs the question of why did the Co-owners prepare and submit the September 2005 *Generation Alternatives Study* to justify their selection of Big Stone II. Their comments, noted above, appear to undercut the validity of their own justification for choosing to build a 600 MW coal-fired facility.

Q. The third joint economic analysis presented by the Co-owners is included in Applicants' Exhibit 25-B and sponsored by Co-owner witness Harris. Is there any credible evidence that the non-Big Stone II resource plans considered in this economic analysis are really the Applicants' individual next best resource scenarios, as Mr. Harris claims?

A. No. There is no evidence to support the claim that the individual utility alternatives to Big Stone II reflected in this economic analysis represent what would be the Co-owners' "next best" resource scenarios. Indeed, there is no evidence that in their development of their purported "next best" resource scenarios, any of the Co-owners, perhaps other than Otter Tail Power, examined additional wind projects in place of Big Stone II. In addition, other than Otter Tail Power, none of the other Co-owners appears to have considered any hydro purchases. None of the Co-owners considered additional demand-side management efforts in place of Big Stone II.

Consequently, there is no evidence that what the individual Co-owners are calling their "next best" resource plans actually would be. That is, there is no evidence that these "next best" plans have lower costs than alternative plans that would include more wind, more aggressive implementation of cost-effective demand side measures and increased purchases of hydro capacity and energy.

In fact, the alternative non-Big Stone II "plan" studied by Mr. Harris really can be characterized as, other than for Otter Tail Power, a highly risky plan that depends almost exclusively on coal-fired and natural gas-fired generation and on purchases of power that probably also would be generated at coal-fired or natural-gas fired facilities.

Q. Why do you consider the alternative to Big Stone II plan studied by Mr. Harris to be "highly risky?"

A. The alternative plan is highly risky because it depends to a very substantial extent on coal-fired generation which almost certainly will be subject to greenhouse gas regulations, as we have explained in our May 19, 2006 Testimony, and on natural gas-fired generation which is likely to be subject to high fuel price levels and volatility. Wind, at a minimum, significantly reduces fuel price and environmental risks.

In addition, new coal-fired facilities, like Big Stone II, may be subject to some of the same production and coal deliverability problems that have recently plagued the existing coal-fired units throughout the Midwest that depend upon coal from the Powder River Basin. Such problems could adversely affect the reliability of Big Stone II and its ability to operate at a consistent 88 percent average annual capacity factor.

Remarkably, the Big Stone II Co-owners refused to acknowledge that future coal shortage issues (caused by rail and production issues) *may* diminish Big Stone II's reliability.[24] The Big Stone II Co-owners similarly refused to acknowledge that recent coal shortage issues *may* increase the risk associated with developing the Big Stone II power plant.[25]

---

[24] Responses to Questions Nos. 5 and 39 of South Dakota Staff's Third Data Request.

[25] Response to Question No. 38 of South Dakota Staff's Third Data Request.

Q. Please comment on the claim by Co-owner witness Harris that if Big Stone II is not constructed, there is no single best resource alternative that the Co-owners would collectively pursue. Instead, each Co-owner would pursue a variety of strategies to meet their obligations.[26]

A. It is true that we have seen no evidence that the Co-owners have studied a joint supply and demand-side plan that they would implement if they were denied permission to build Big Stone II. However, we still believe that if Big Stone II were not built, it would be prudent for the Co-owners to cooperate to develop an optimal alternatives plan that minimized rate impacts on their ratepayers and impacts on the environment. Instead, Mr. Harris has studied an extreme and imprudent situation where there appears to be absolutely no cooperation among the Co-owners to find the most cost-effective alternative plan(s) to Big Stone II.

Q. Please summarize the alternatives that the individual Co-owners considered in developing their "next best" alternatives to Big Stone II.

A. Later in this testimony we will discuss in some more detail the economic analyses that each individual Co-owner has presented as the justification for their participation in Big Stone II and as evidence of their consideration of alternatives to that Project. However, to summarize:

- Montana-Dakota has said that it only considered three possible alternatives to Big Stone II – two of these were coal-fired and the third was to purchase power from the market. Moreover, Montana-Dakota did not perform any economic analyses to quantitatively compare the revenue requirements of these alternatives or to examine any other possible alternatives to Big Stone II.
- Otter Tail Power developed an alternative that assumed it would purchase 120 MW of hydro capacity from Manitoba Hydro.
- Great River Energy's July 2005 *Alternatives Evaluation for the Construction of Big Stone II* only quantitatively considered three resource types, all of which were coal or natural gas-based resources.[27] GRE's

[26] Applicants' Exhibit 25, at page 2, lines 16-19.

[27] Great River Energy *Alternatives Evaluation for the Construction of Big Stone II*, dated July 2005, at pages 54, 90 and 91.

2005 Integrated Resource Plan similarly modeled only three supply side options: a coal plant, a natural gas-fired combined cycle plant and a gas-fired combustion turbine.[28] Although some scenarios included some wind resources, neither the timing nor the size of the proposed fossil additions were modified.[29]

- MRES' 2006-2020 Resource Plan filing examined a number of scenarios. However, all but two of these scenarios assumed some participation in Big Stone II.[30] Of these two non-Big Stone II scenarios, one modeled participation in a coal-fired facility and a combustion turbine as alternatives. The other substituted an IGCC plant for Big Stone II without re-optimizing the resources. No non-coal or natural gas alternatives were evaluated.

- CMMPA only **[CONFIDENTIAL MATERIAL BEGINS** **CONFIDENTIAL MATERIAL ENDS]**

- Heartland has said that it will purchase energy from the market to replace the energy that would have been provided by Big Stone II. Heartland says that it will continue to rely on the market until it can participate in another lower cost resource option, most likely another pulverized coal baseload unit.[31]

- SMMPA's alternative plan to Big Stone II appears to include a 50 MW combustion turbine but no additional wind or other renewable resources or demand-side management.[32]

Because their analyses focused so exclusively on fossil-fired alternatives and/or power purchases from a market that is heavily dominated by fossil-fired generation, the Co-owners collectively failed to consider whether portfolios of wind, hydro and demand-side options would be lower cost alternatives than Big Stone II or the "next best" resource scenarios they posit for the economic analysis presented in Applicants' Exhibit 25-B. This collective failure is particularly egregious given that the Co-owners are located in an area of the nation with

---

28 Great River Energy, Integrated Resource Plan, dated July 1, 2005, at page 80.

29 Ibid, at page 108.

30 MRES 2006-2020 Resource Plan, dated June 30, 2005, at page 14.

31 Applicants' Exhibit 25-B, at page 13.

32 See Applicants' Exhibit 25-B, at pages 17 and 18.

significant wind potential and near Manitoba Hydro with its substantial hydro resources.

Q. What impact does Montana-Dakota's failure to seriously consider non-fossil-fired alternatives have on the results of the economic analysis presented in Applicants' Exhibit 25-B?

A. Even though it is proposing to own only 116 MW, or about 19 percent, of Big Stone II, Montana-Dakota's alternate resource plan, involving participation in a lignite plant, inordinately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** the economic analysis presented in Applicants' Exhibit 25-B. In fact, Montana-Dakota's alternate plan with the lignite-fired facility would be **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** than its participation in Big Stone II. This means that Montana-Dakota on its own would be responsible for approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the $669 million net present value benefit to Big Stone II shown in Table 8 of Applicants' Exhibit 25-B. This result lacks any credibility given that Montana-Dakota only considered coal-fired options, including power purchases from the market, and failed to perform any quantitative analyses to investigate what would be its lowest cost alternative.

Montana-Dakota's lignite alternative **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]**the NO_x, CO_2, CO and mercury emissions in the non-Big Stone II case. Using the year 2016 as an example, Montana-Dakota's alternative would be responsible for approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the NO_x emissions, approximately **[CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL MATERIAL ENDS]** percent of the CO_2 and CO emissions, and [**CONFIDENTIAL MATERIAL BEGINS CONFIDENTIAL**

MATERIAL ENDS] percent of the mercury emissions in the non-Big Stone II case.

Q. Does the economic analysis presented in Applicants' Exhibit 25-B consider the potential for any greenhouse gas regulations?

A. No. The failure to consider the potential for greenhouse has regulations is another substantial flaw in the analysis.

Q. Turning now to the analyses cited by the individual Co-owners as justification for their participation in Big Stone II. Has Otter Tail Power shown that Big StoneII is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. No.

Q. What analyses does Otter Tail Power rely on for the decision to participate in the Big Stone II Project?

A. Otter Tail Power relies on its recent IRP analyses.[33]

Q. Have you had a full opportunity to review the modeling conducted by Otter Tail Power as part of its July IRP filing?

A. No. Back in January we initially asked Otter Tail Power for the input and output computer files for each of the scenarios discussed in its July 2005 IRP filing. In response, the company provided the requested input files but only gave us the output files for its base case scenario.

Despite repeated requests, Otter Tail Power insisted for several months (including as late as May 3, 2006) that there were no additional output files for any other scenarios. Then, on May 5, 2006, counsel for Otter Tail Power revealed that, in fact, there were output files for other scenarios but they couldn't give all of them to us because they contained confidential information that had been obtained from

[33] Response to Interrogatory No. 4 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Manitoba Hydro. After about a week of negotiations, we subsequently received portions of those output files. However, we have had only a partial opportunity to review and evaluate the approximately 80 additional files provided by Otter Tail Power in the very short time since we received them on May 12th and 16th.

Q. Does Otter Tail Power's July 2005 IRP compare the cost of participating in Big Stone II with the cost of obtaining an equivalent amount of capacity and energy from renewable and demand side alternatives?

A. No. The Company's 2005 IRP filing does examine two scenarios that are designated as the 50% and 75% Renewable and Conservation scenarios.[34] These scenarios apparently were designed to address the Minnesota planning requirement that it obtain 50 percent and 75 percent of future growth from a combination of renewable sources and conservation. In the 50% Renewable and Conservation scenario, 85 MW of Big Stone II was replaced by a hydro capacity and energy purchase. In the 75% Renewable and Conservation scenario, Otter Tail Power's share of Big Stone II was replaced by 130 MW of hydro capacity from Manitoba Hydro.

Otter Tail Power's filing did show that the PVRR cost of each of these two Renewable and Conservation cases was higher than the cost of the Base Case including Big Stone II.[35] However, this comparison was misleading because, in the 75% scenario, more renewable capacity is purchased than would be necessary merely to replace Otter Tail Power's share of Big Stone II. Moreover, and probably more significantly, the comparison between Big Stone II and the 50% and 75% Renewable and Conservation cases in the 2005 IRP filing did not reflect any environmental externality costs. Nor did it reflect future greenhouse gas regulations. Therefore, the comparison undoubtedly understated, and perhaps by

---

34 Otter Tail Power Company 2006-2020 Resource Plan, June 28, 2005, at pages 9-9 to 9-11.

35 Table 4-E in Otter Tail Power's 2006-2020 Resource Plan filing, dated June 28, 2005, notes that the 50% Renewable & Conservation scenario is $56.02 million (or 1.6%) more expensive, in 2004 dollars, than the Base Case. The 75% Renewable & Conservation scenario is reported to be $120.01 million (or 3.5%) more expensive, in 2004 dollars, than the Base Case.

a very significant margin, the relative cost of Big Stone II for Otter Tail Power and its customers as compared to renewables and demand-side alternatives.

Q. Had Otter Tail Power examined the total cost, including environmental externalities, of similar 50% and 75% Renewable and Conservation cases in its earlier IRP Filings?

A. Yes. The Company's 2002 IRP filing evaluated the total cost of the base case and the 50% and 75% conservation and renewable cases including environmental externalities. Thus, the 2005 filing represented a departure from Otter Tail Power's prior practice.[36]

Q. Has Great River Energy shown that participation in Big Stone II is a lower cost option than a portfolio of renewables and demand-side alternatives?

A. No. In its *Alternatives Evaluation for the Construction of Big Stone Unit II*, Great River Energy only examined the economics of three capacity alternatives, two of which were coal-based and one was natural gas-fired.[37] Other alternatives, such as demand side management, renewables including wind, biomass, hydro, solar, landfill gas, and IGCC were eliminated after a qualitative screening.[38] Unfortunately, no economic analyses were prepared for these eliminated alternatives. Consequently, the only economic analyses in GRE's *Alternatives Evaluation* compare Big Stone II to coal and natural gas-fired options.

Q. Do the scenarios examined by GRE in its 2005 Integrated Resource Plan filing in Minnesota offer any insights into whether Big Stone II is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. No. Most of GRE's 2005 Integrated Resource Plan filing focused on an examination of thirteen scenarios, all of which included Big Stone II beginning in

36 Otter Tail Power 2003-2017 Resource Plan, dated June 28, 2002, at page 4-14.

37 *Great River Energy Alternatives Evaluation for the Construction of Big Stone II*, dated July 2005, at page 54.

38 Ibid, at pages 32-39 and 54

2011.[39] These scenarios clearly provide no information as to the relative economics of participation in Big Stone II as compared to renewable and demand-side alternatives.

GRE did examine two renewable resource plans required by Minnesota's planning statute in its 2005 Integrated Resource Plan filing that it found to have higher PVRR costs than its lowest cost base cases with Big Stone II. However, it is clear from reading GRE's 2005 Integrated Resource Plan that the comparison between these 50% and 75% renewables cases and the cases with Big Stone II probably offer few, if any, insights into the relative economics of GRE's participation in the Big Stone II Project because they do not reflect (1) any environmental externalities or (2) any greenhouse gas regulations. Therefore, the comparison gives a biased and incomplete view of the relative economics of Big Stone II.

Q. Have you had a reasonable opportunity to review the computer modeling performed by GRE in the preparation of its 2005 Integrated Resource Plan filing?

A. No. Despite repeated requests for the output data files for each of the scenarios examined in its 2005 Integrated Resource Plan filing, beginning as far back as January of this year, by May 8th, GRE had only provided the actual model output files for its base case scenario. In response to GRE's continued refusal to provide the actual output files for the other scenarios it had examined in its 2005 IRP filing and under the pressure of having to file this testimony without a significant delay, we revised our request to cover certain summary information. GRE has provided that summary information but not the actual model output files for any scenarios other than their base case scenario.

---

[39] Great River Energy, Integrated Resource Plan, dated July 1, 2005, at pages 99-101.

Q. Do you have any comments on the recent RFP that GRE issued for 120 MW of power?

A. Yes. GRE issued an RFP for renewable resources last fall. GRE has publicly stated that thirty-one developers responded with more than 50 proposals.[40] According to GRE, wind energy projects were the most competitively priced and, with such a strong response, GRE may accept more bids than planned and delay adding baseload resources.[41] Unfortunately, GRE, to date, has refused to provide us copies of the proposals it has received in response to that RFP.

Q. Did Montana-Dakota Utilities prepare any economic analyses showing that Big Stone II is the lowest cost option?

A. No. Montana-Dakota's 2003 Integrated Resource Plan selected 120 MW of new combustion turbines and some improvements to existing CTs to meet the company's demand through 2021.[42] However, in its 2005 Integrated Resource Plan, where it does not appear to use any model or to perform any quantitative analysis, the company concludes that "subsequent to the filing of the 2004 IRP, Montana-Dakota determined that the plan's heavy reliance on gas-fired generation exposed our customers to considerable price and reliability risk associated with fuel cost and availability. The company believes that coal-fired generation, which has lower and less volatile fuel prices and a more stable fuel supply than natural gas, provides a better value for our customers."[43]

Indeed, Montana-Dakota apparently did not prepare any economic analyses when considering whether to participate in Big Stone II. Instead, it qualitatively evaluated four options, three of which were coal-fired with the fourth being

---

40 *U.S. Utility Could Defer Baseload After Strong Renewables Showing*, Platt's Renewable Energy Report, dated March 6, 2006, at page 22.

41 *Great River May Delay Adding to Baseload*, Electric Power Daily, February 22, 2006, at page 8.

42 Montana-Dakota Utilities 2003 Integrated Resource Plan, at page iv.

43 Montana-Dakota Utilities 2003 Integrated Resource Plan, at page 4-2.

reliance on purchased power.[44] As Montana-Dakota explained in its response to Interrogatories 28 and 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents:

- The reference [in the testimony of MDU witness Stomberg] to a "model" was generic, and was intended to convey the concept of a hypothetical, purely quantitative model.[45]
- Montana-Dakota did not perform a purely quantitative model. The statement refers to the fact the expert judgment is required in resource planning; not just quantitative modeling.[46]
- For its 2005 IRP, Montana-Dakota did not use a computer model to compare supply-side and demand-side resources.[47]

We agree with Montana-Dakota that expert judgment is required in resource planning but that is **in addition to** quantitative modeling. Thus, we find that the Company's decision to commit to a more than One Billion Dollar coal-plant without having examined the economics of the various supply-side (let alone both supply- and demand-side) options to have been imprudent. As a result of this imprudence, Montana-Dakota has absolutely no economic studies that can show that participation in Big Stone II is the lowest cost option against any renewable and demand-side alternatives.

Q. What is the expected impact of Big Stone II on Montana-Dakota's residential customer rates?

A. Montana-Dakota has estimated that the addition of Big Stone II will increase its residential customer rates by approximately 20 percent, or about 1.9 cents/kWh[48] excluding the potential impact of greenhouse gas regulation.

---

44 Response to Interrogatory 27 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

45 Interrogatory 28 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

46 Ibid.

47 Response to Interrogatory 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents.

Q. What alternatives to Big Stone II were examined in MRES's 2006-2020 Resource Plan filing?

A. MRES's 2006-2020 Resource Plan filing examined a number of scenarios. However, all but two of these scenarios assumed some participation in Big Stone II.[49] Of these two non-Big Stone II scenarios, one modeled participation in a coal-fired facility and a combustion turbine as alternatives. The other substituted an IGCC plant for Big Stone II without re-optimizing the resources. No non-coal or natural gas alternatives were evaluated.

Q. Have you had a full opportunity to review the modeling performed in the analysis of the generation alternatives discussed in MRES' 2006-2020 Resource Plan?

A. No. Despite repeated requests for the output data files for each of the scenarios examined in its 2005 Integrated Resource Plan filing, beginning as far back as January of this year, by May 8th, MRES had only provided several summary files but not any actual model output files. In response to MRES's failure to provide the actual output files for the scenarios it had examined in its 2005 IRP filing and under the pressure of having to file this testimony without a significant delay, we revised our request to cover certain summary information. MRES has provided that summary information but not the actual model output files for any scenarios that it examined in its 2005 IRP filing.

Q. Have you had a reasonable opportunity to review MRES' Supplemental Filing for its 2006-2020 Resource Plan?

A. No. This Supplemental Filing was made just two weeks ago. Due to the limited time available and our need to focus on completing this testimony and the testimony we filed on May 19, 2006, we have not had any opportunity to review the MRES Supplemental Filing in any significant detail.

---

[48] Response to MCEA Information Request 44 in MPUC Docket No. CN-05-619.

Q. What economic analyses does CMMPA cite in support of its decision to participate in Big Stone II?

A. CMMPA has cited two studies by R.W. Beck as forming the basis for its decision to participate as a Big Stone II Co-owner: An April 2002, *Generation Resources Planning Study* and a December 2004 *Power Supply Analysis*.[50]

Q. Do the results of these analyses provide any insights as to whether CMMPA's participation in Big Stone II is a lower cost option than a portfolio of renewable and demand-side alternatives?

A. **[CONFIDENTIAL MATERIAL BEGINS**

CONFIDENTIAL MATERIAL ENDS]

Q. What alternatives has SMMPA considered as alternatives to Big Stone II?

A. SMMPA's testimony in this proceeding and the summary of its planning provided in Applicants' Exhibit 25-B suggest that SMMPA considered natural gas-fired resources as alternatives to Big Stone II.[53] It is unclear whether SMMPA evaluated wind, demand-side management and landfill gas as alternatives to Big Stone II or only as complementary resources.

---

[49] MRES 2006-2020 Resource Plan, dated June 30, 2005, at page 14.

[50] Applicants Exhibit 6, at page 5, lines 12-18.

[51] At page 9.

[52] At pages 1 and 2.

[53] Applicants' Exhibit 5, at page 10, lines 10-14, and Applicants' Exhibit 25-B, at pages 17 and 18.

Q. What alternatives did Heartland consider when evaluating whether to participate in Big Stone II?

A. **[CONFIDENTIAL MATERIAL BEGINS**

CONFIDENTIAL MATERIAL ENDS].

However, as we have demonstrated earlier in this testimony, even with overly conservative and the Co-owners' unrealistic operating assumptions, a combination of wind and gas can be cheaper on a cost basis than Big Stone Unit II.

Demand-Side Management

Q. Have the Co-owners adequately considered demand-side management alternatives in their evaluations of the need for new baseload generating capacity and their analyses of the economics of alternatives to Big Stone II?

A. No.

---

54 *Power Supply Study*, dated February 17, 2003, at pages 47 and 53.

55 Ibid, at pages 41-46.

56 Ibid, at page 41.

Q. Please explain how the Co-owners have evaluated demand-side management alternatives?

A. CMMPA did not compare DSM against any supply-side resource including Big Stone Unit II. In fact, CMMPA does not perform integrated resource planning,[57] has not evaluated the potential for DSM on its system and does not offer DSM programs. CMMPA states that "DSM programs are approved and funded by the individual city within CMMPA."[58]

Similarly, HCPD did not compare DSM against any supply-side resource such as Big Stone Unit II. Neither does HCPD do integrated resource planning.[59] Nor has it has not evaluated the potential for DSM on its system. HCPD also does not offer DSM programs although its customers offer some energy efficiency and conservation programs.

MRES does not offer DSM programs, its members do. To our knowledge, it had not undertaken any analysis of DSM programs until **[CONFIDENTIAL MATERIAL BEGINS**

57 Response to Interrogatory 3 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

58 Response to Interrogatory 15 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

CONFIDENTIAL MATERIAL ENDS]

Indeed, as explained in the May 2006 Supplement to MRES' 2006-2020 Resource Plan, MRES' capacity expansion model picked the full level of DSM available to it as part of its least-cost, base case plan.[61]

Montana-Dakota performed a combination of qualitative and quantitative screening to arrive at a set of four DSM programs in its 2005 IRP: 1) ENERGY STAR® Partnership, 2) Promote electric heat (North Dakota only), 3) Promote high efficiency residential central air conditioning, and 4) Promote commercial lighting T-8 retrofit.[62] Montana-Dakota has not evaluated the potential for DSM on its system,[63] the programs it evaluated in its 2005 IRP were limited to a set of 19 and even the programs it found to be cost-effective were not all chosen for implementation.

---

59 Response to Interrogatory 3 of Joint Intervenors' First Set and First Amended Set of Interrogatories.

60 Supplement to Missouri River Energy Services 2006-2020 Resource Plan, May 8, 2006 at page 53.

61 Ibid.

62 Page iii of Montana-Dakota Utilities Co. 2005 Integrated Resource Plan, September 15, 2005.

63 Based on lack of MDU response to Joint Intervenors' Third Set of Request for Production of Documents, Request No. 4.

According to SMMPA's 2003-2018 IRP, it evaluated DSM measures using the EGEAS model which compares those measures to supply-side resources. It screened the measures evaluated in EGEAS using a methodology that appears to have been based upon a DSM potential study done in 1993.[64] While we have not reviewed the 1993 study (and have not been supplied with a copy of it), we find it very difficult to believe that a 13-year old study could yield reliable and credible DSM potential results given the changing characteristics of SMMPA's load, resources and particularly DSM measures themselves. The cost of DSM measures, their impacts and even the DSM measures that one would implement are very likely to have changed between 1993 and 2006.

Otter Tail Power most recently analyzed the potential for DSM in 2002 but only for its commercial and industrial customers in its Minnesota service territory. In modeling DSM programs for other sectors of customers, it appears to rely upon a 1994 DSM potential study, *Draft Report: DSM Potential Study and Commercial Survey*. While we have not reviewed the study, as with SMMPA's 1993 study, it is very difficult to believe that a 12-year old study could yield reliable and credible DSM potential results for integrated resource planning in 2006.

Most recently, GRE **[CONFIDENTIAL MATERIAL**

CONFIDENTIAL MATERIAL ENDS] DSM should be implemented if it is cost-effective regardless of the budget a utility would prefer to allocate to such activities; to do otherwise, that is, acquire more expensive resources, is an imprudent use of ratepayer money.

---

64 SMMPA Integrated Resource Plan 2003-2018 at pages VI-15 and VIII-8.

Q. What does it mean to "evaluate the potential for DSM" on a Co-owner's system?

A. A study of "DSM potential" would quantify the level of DSM which could be achieved under different scenarios and assumptions. For example, the study might quantify the potential for DSM under different levels of incentives to adopt DSM measures, different customer penetration levels and other factors. The primary goal is to identify the level of cost-effective DSM that could be achieved, and how.

Q. Does the Co-owners' claimed need for Big Stone Unit II account for all cost-effective DSM that could be done on their systems?

A. No. In addition to the lack of any recent DSM potential studies on the part of the Co-owners (with the exception of GRE), there is other evidence that the Co-owners are not leveraging all cost-effective DSM on their systems. One metric to assess the aggressiveness of a utility's DSM portfolio is the "cost of saved energy." The cost of saved energy is the cost of the measure compared to the MWh it saves over the measure's life. Like electricity prices, this cost is represented in $/MWh. If a utility were to maximize cost-effective DSM, one would expect to see a cost of saved energy roughly equal to the cost of the supply-side resource it is adding. In this case, one would expect to see a cost of saved energy roughly equivalent to the levelized cost of Big Stone Unit II.

Another metric to assess DSM performance is the ratio of annual energy savings from DSM activities to customer energy requirements. The lower the ratio, the less likely the utility is to be maximizing its available cost-effective DSM.

Q. Is the Co-owners' cost of saved energy roughly equivalent to the cost of Big Stone Unit II?

A. No. We do not have complete information on the cost of saved energy from the DSM activities of all Co-owners because, in many cases, the Co-owners themselves do not have this information. For those which have provided this information the cost of saved energy is a fraction of the cost of Big Stone Unit II.

With such a large gap between the cost of saved energy and the cost of Big Stone II there are likely to be many cost-effective energy efficiency resources available at a cost within that gap.

In response to Staff's Third Data Request, Interrogatory 31, GRE responded that from 2002 – 2007 its lifetime cost of saved energy ranges from \$14.10/MWh to \$21.10/MWh.[65] GRE did not provide cost of saved energy data for future years beyond 2007.

However, according to Applicants' Exhibit 23-A, *Analysis of Baseload Generation Alternatives*, the twenty-year levelized busbar cost of Big Stone II to GRE will be \$40.85/MWh (2005\$), excluding the cost of greenhouse gas regulation. This \$19.75/MWh to \$26.75/MWh gap in costs between the busbar cost of Big Stone II and GRE's cost of saved energy is a strong indication that additional cost-effective DSM is available to GRE.

As an investor-owned utility, Otter Tail Power's twenty-year levelized busbar cost of Big Stone Unit II is \$50.71/MWh. Otter Tail Power's cost of saved energy through 2011 ranges from a low of \$8.79/MWh[66] to a high of \$27.28/MWh.[67] Like GRE, it is reasonable to expect that there would be many cost-effective energy efficiency measures in the range between Otter Tail Power's highest cost of saved energy, \$27.28/MWh, and the cost of Big Stone Unit II without greenhouse gas regulation, \$50.71/MWh, a difference of \$23.42/MWh!

Similarly, we have calculated Montana-Dakota's cost of saved energy from the two DSM programs selected in its 2005 IRP for which the information necessary to make this calculation was available. The cost of saved energy from Montana-Dakota's programs is \$14.31/MWh which is \$36.4/MWh less than the levelized

---

65 GRE did not state in which year's dollars its cost of saved energy is reported, but we assume 2005\$ is likely.

66 We assume an average ten-year measure life in making this calculation.

67 OTP did not state in which year's dollars its incremental cost of energy is reported, but we assume 2005\$ is likely.

cost it proposes to pay for Big Stone Unit II, excluding greenhouse gas regulation costs.

Q. You stated that another metric indicating whether a utility is achieving a cost-effective level of DSM is to compare energy savings from DSM to energy sales to customers. Do you have any comments on the Co-owners' DSM programs in that regard?

A. Yes, we do. It is particularly useful in this regard to compare the Co-owners to each other since the characteristics of the customers they serve are not so radically different that the energy savings from DSM that one achieves would not be indicative of the DSM savings that another could achieve. If we use 2007 as a snapshot year, for example, Table 3 shows the energy savings achieved from four of the Co-owners' DSM programs versus the energy requirements in that year.

Table 3. 2007 Energy Savings per MWh of Energy Sales to Customers[68]

Montana-Dakota	GRE	OTP	SMMPA
0.016%	0.276%	0.172%	0.837%

The Co-owner with the smallest cost of saved energy, Montana-Dakota, also achieves the lowest ratio of energy savings to energy sales, less than a tenth of one percent of energy sales to customers. Montana-Dakota, GRE and OTP do not even come close to achieving energy savings in proportion to states with more aggressive portfolios of DSM like California, Connecticut, Rhode Island, Oregon and Wisconsin as illustrated in Table 4, and under-perform compared to SMMPA. After 2007, SMMPA's percentage savings drop off to 0.685% in 2011 and 0.117% in 2020.

68 Based on response to Interrogatory 30 of Staff's Third Data Request and response to Interrogatory 17 of Joint Intevenors' First Set and First Amended Set of Interrogatories.

Table 4. Energy Efficiency Savings by State[69]

State	Savings (MWh)	Savings (% of sales)	Savings Year
California	933,365	0.8	2003
Connecticut	24,600	0.8	2002
RhodeIsland	50,568	0.8	2002
Vermont	38,400	0.8	2002
Massachusetts	241,000	0.7	2002
Oregon	112,100	0.4	2002
Wisconsin	214,800	0.4	FY2003
Maine	25,500	0.3	2003
New York	290,000	0.3	2002
New Jersey	171,692	0.2	2002
Texas	455,700	0.2	2002
New Hampshire	12,039	0.1	2002-2003

Rate Impact of Big Stone II

Q. Have the Co-owners estimated the rate impact to South Dakota customers from Big Stone II?

A. No, the response to Interrogatory 41 of Staff's Third Data Request was "There exists no projected rate impact information for the Applicants' South Dakota customers based on Big Stone Unit II alone."

We asked the Co-owners a similar rate impact question, "Quantify the expected average rate impact to residential customers from the BSII project for each of the seven Co-owners."[70] With the exception of Montana-Dakota, none of the Co-owners could say what the impact to residential customers will be. Many said that this was due to the fact that they do not serve end-use customers. Montana-Dakota did say that Big Stone Unit II would cause a 20% rate increase.

Q. Have the Co-owners estimated the rate impacts from any portion of Big Stone Unit II?

A. Apparently not from Big Stone Unit II itself, but they did estimate the rate impacts to customers from the associated transmission line. Every single one of

---

69 ACEEE 2004. *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Martin Kushler, Dan York and Patti White, Report No. U041, April 2004.

70 Response to Information Request 44 in Minnesota PUC Docket No. CN-05-619.

the Co-owners estimated this rate impact in Appendix K of the Co-owners application for a Certificate of Need from the Minnesota PUC for the transmission line in support of Big Stone Unit II.

Q. Those rate impact estimates were required as part of the Co-owners' application. Is it possible that the Co-owners are simply not concerned about the rate impact of Big Stone Unit II?

A. It seems unlikely. For example, OTP witness Ward Uggerud states in his testimony "I know first hand [customers'] concern about the price of all their inputs and I understand the relationship between each component of the cost and reliability of the electricity our company provides to customers."[71]

In response to a question about what general factors Otter Tail considered in determining that it needed to add new base load capacity in 2011, Mr. Uggerud further states that

> The first and paramount factor was the fact that Otter Tail's customers live and operate businesses in rural areas and in small towns and cities. The company's residential customers live on relatively modest incomes and, by and large, do not have the economic means to absorb unnecessary rate increases. Thus, the first factor considered was the necessity of maintaining affordable rates.[72]

Q. Do you see any explanation as to why the Co-owners, with the exception of Montana-Dakota, seem not to have quantified the rate impact from Big Stone Unit II?

A. No.

---

[71] Applicants' Exhibit 1, at page 3, lines 11-13.

[72] Applicants' Exhibit 1, at page 7, lines 6-10.

Emission Control Technologies

Q. Have the Applicants' included appropriate emissions control technologies in the proposed design of Big Stone Unit II?

A. The answer is "yes, in part." We examined this issue purely from the perspective of whether the Co-owners can meet applicable, existing rules governing emissions of SO_2, NOx and Hg. We did not, for example, consider whether Big Stone Unit II will meet opacity limits, if applicable, or whether it will meet any future regulations further limiting SO_2, NOx or Hg. Neither did we examine whether the "netting" of increased emissions at Big Stone II is legally supportable. While we do believe that CO_2 will be regulated in the future, we are not aware of any currently economic or commercial method to capture and sequester CO_2 emissions from Big Stone Unit II, and so this issue cannot be reasonably addressed in response to the question.

We expect that with the proposed design of Big Stone Unit II, the Co-owners could meet the SO_2 and NOx requirements based on existing regulations. The Co-owners, however, seem to doubt their ability to achieve mercury reductions necessary to meet the requirements of the Clean Air Mercury Rule (CAMR). While CAMR does allow for the trading of mercury allowances, purchasing allowances instead of making those reductions at the Big Stone site would result in local environmental and public health impacts from mercury deposition.

Witness Terry Graumann states on page 12, lines 7-9 of his testimony, that South Dakota has been allocated an annual mercury budget of 144 pounds beginning in 2010 and dropping to 58 pounds in 2018 and beyond. We presume that South Dakota will ultimately decide to allocate these allowances to Big Stone Unit I and to Big Stone Unit II, should it come online.

At present, the Co-owners project that the design of Big Stone Unit II, in combination with Big Stone Unit I, would result in the emission of 399 pounds of mercury per year.[73] Since the commercial operation date of Big Stone Unit II post-dates the requirement to limit mercury emissions to 144 pounds, this represents a compliance issue for the Co-owners. Even if the Co-owners adopt activated carbon injection (ACI) to further control mercury emissions (in addition to the scrubber/SCR co-benefit reduction), the combined mercury emissions from both Big Stone units may very well exceed the 144 pound cap. If Big Stone Unit I's mercury emissions remain static at their 2004 level of 189.6[74] pounds and Big Stone Unit II achieves a mercury emission rate of .00002lb/MWh,[75] annual mercury emissions would be 92.5 + 189.6 = 282 lbs, exceeding the cap by 138 pounds. Assuming that Big Stone Unit I could also achieve a mercury emissions rate of .00002/MWh, it would have to operate at a capacity factor of no more than 64% in order to achieve annual net emissions of 144 lbs.

The Co-owners have not discussed their strategy for meeting the limits of CAMR nor have they discussed the potential environmental impact of the increased emissions, should they purchase mercury allowances to meet the CAMR limit. Given the costs associated with mercury emissions, such as prenatal intellectual impairment, increased morbidity and mortality from myocardial disease, and economic damage to impaired fisheries, we recommend that these issues be addressed in this proceeding prior to a decision regarding the siting permit.

Q. What is your overall recommendation to the South Dakota Public Utilities Commission?

A. We recommend that the Commission deny the application for an energy conversion facility siting permit for Big Stone II because:

- The facility will represent a significant threat to the environment.

---

73 From the chart bates stamped chart JCO0002254 and clarified in response to Joint Intervenors' Fourth Set of Request for Production of Documents, which incorporated the Co-owners' response to Information Request No. 26 in MN PUC Docket No. CN-05-619.

74 Ibid.

75 From Applicants' Exhibit 24-A, page 2-4.

- The Co-owners have not demonstrated that they need 600 MW of additional baseload generating capacity beginning in 2011.
- The Co-owners have not demonstrated that Big Stone is the lowest cost option as compared to a portfolio of wind, other renewable and demand-side alternatives.

Q. Does this complete your testimony?

A. Yes.

EnerNex CORPORATION

Xcel Energy and the Minnesota Department of Commerce

Wind Integration Study - Final Report

Prepared by

EnerNex Corporation
144-E Market Place Boulevard
Knoxville, Tennessee 37923
tel: (865) 691-5540
fax: (865) 691-5046
www.enernex.com

Wind Logics, Inc.
1217 Bandana Blvd. N.
St. Paul, MN, 55108
www.windlogics.com

September 28, 2004

Joint Intervenors
Exhibit 4 – A

Preface

In June of 2003 the Minnesota Legislature adopted a requirement for an Independent Study of Intermittent Resources, which evaluates the impacts of over 825 MW of wind power on the NSP system[1]. The Public Utilities Commission requested that the Department of Commerce take responsibility for oversight of the Study with the understanding that the Office of the Reliability Administrator would represent the Department[2].

After the conclusion of the 2003 Legislative session a thorough and complete research of the current status and understanding of integrating wind power into electric power systems, including a comprehensive literature search, was completed. A broad-based workgroup was assembled to guide the initial development of the Study. This group included representatives of Xcel Energy, Minnesota municipal utilities, Minnesota cooperative utilities, the Minnesota Chamber of Commerce, the American Wind Energy Association, Minnesota environmental organizations, the U.S Department of Energy / National Renewable Energy Laboratory, and the Department of Commerce.

Members of that workgroup included:

Jim Alders	Xcel Energy
Rory Artig	Minnesota Department of Commerce
Bill Blazar	Minnesota Chamber of Commerce
Laura Bordelon	Minnesota Chamber of Commerce
Jim Caldwell	American Wind Energy Association
Bob Cupit	Minnesota Department of Commerce
Chris Davis	Minnesota Department of Commerce
Bill Grant	Izaak Walton League of America
Clair Moeller	Xcel Energy
Michael Noble	ME3
Brian Parsons	National Renewable Energy Laboratory
Judy Poferl	Xcel Energy
Larry Schedin	Reliant Energy Integration Services
Matt Schuerger	Energy Systems Consulting Services
Craig Turner	Dakota Electric Association
Greg Woodworth	Rochester Public Utilities
Ken Wolf	Minnesota Department of Commerce

[1] Minnesota Laws 2003, 1st Special Session, Chapter 11, Article 2, Section 21.
[2] MN PUC Docket No. E-002/CI-03-870, Order Requiring Engineering Study

The workgroup met several times to develop the Statement of Work for the study. Xcel Energy competitively bid the study and contracted with the successful bidder, a team lead by EnerNex Corporation.

This study is a significant advance in the science and understanding of the impacts of the variability of wind power on power system operation in the Midwest. For example, the application of sophisticated, science-based atmospheric models to accurately characterize the variability of Midwest wind generation is a vast improvement over previous methods.

The study benefited from extensive expert guidance and review by a Technical Review Committee (TRC).

Thank you to all of the participants in the TRC, which included:

Jim Alders	Xcel Energy
Steve Beuning	Xcel Energy
Laura Bordelon	Minnesota Chamber of Commerce
Jim Caldwell	American Wind Energy Association/PPM Energy
Bob Cupit	Minnesota Department of Commerce
Ed DeMeo	Utility Wind Interest Group/ Renewable Energy Consulting Services, Inc.
John Donatell	Xcel Energy
David Duebner	Midwest Independent System Operator
Bill Grant	Izaak Walton League
Walt Grivna	Xcel Energy
Mark Haller	American Wind Energy Association/ Haller Wind Consulting
Rick Halet	Xcel Energy
Larry Hartman	Minnesota Environmental Quality Board
Mike Jacobs	American Wind Energy Association
Stephen Jones	Xcel Energy
Mark McGree	Xcel Energy
Mike McMullen	Xcel Energy
Michael Milligan	National Renewable Energy Laboratory
Michael Noble	Minnesotans for an Energy Efficient Economy
Dale Osborn	Midwest Independent System Operator
Brian Parsons	National Renewable Energy Laboratory
Lisa Peterson	Xcel Energy
Rick Peterson	Xcel Energy
Greg Pieper	Xcel Energy
Larry Schedin	Technical Advisor to the MN DOC

Matt Schuerger	Technical Advisor to the MN DOC
Steve Wilson	Xcel Energy
Ken Wolf	Minnesota Department of Commerce

The aggressive schedule for completion of this study prevented investigation of several critical next steps. The study outlines several important next steps needed to develop effective solutions to mitigate these impacts including improved strategies and practices for unit commitment and scheduling as well as improved forecasting and markets.

Ken Wolf

Reliability Administrator
Minnesota Department of Commerce

Project Team

EnerNex Corporation

Robert M. Zavadil – Project Manager

Jack King

Leo Xiadong

WindLogics

Mark Ahlstrom

Dr. Bruce Lee

Dr. Dennis Moon

Dr. Cathy Finley

Lee Alnes

Arreva T&D

Dr. Lawrence Jones

Fabrice Hudry

Mark Monstream

Stephen Lai

NexGen Energy LLC

J. Charles Smith

Contents

List of Tables

List of Figures

Project Summary

Introduction

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

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

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

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

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

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

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

Overview of Utility System Operations

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

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

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

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

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

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

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

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

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

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

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

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

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

Characteristics of Wind Generation

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

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

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

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

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

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

Wind Generation and Long-Term Power System Reliability

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

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

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

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

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

Objectives of this Study

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

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

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

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

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

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

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

Organization of Documentation

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

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

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

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

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

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

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

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

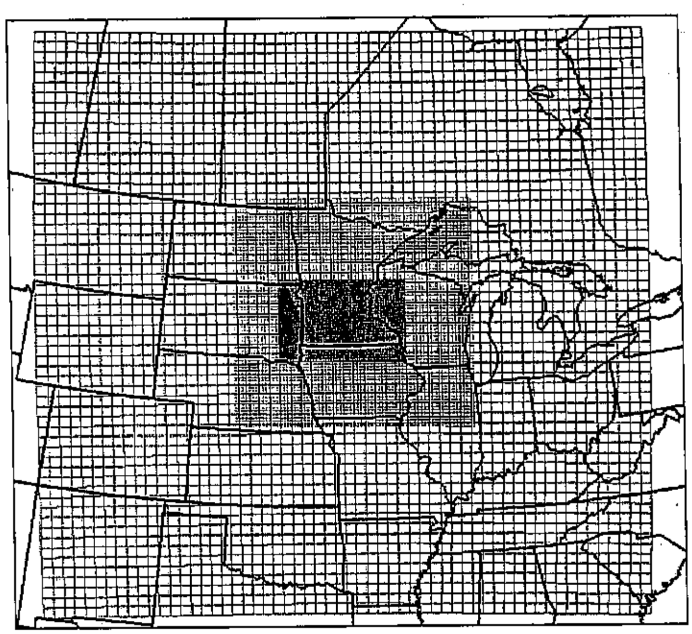


Figure 1: MM5 nested grid configuration utilized for study area. The 3 grid run includes 2 inner nested grids to optimize the simulation resolution in the area of greatest interest. The grid spacing is 45, 15 and 5 km for the outer, middle and innermost nests, respectively.

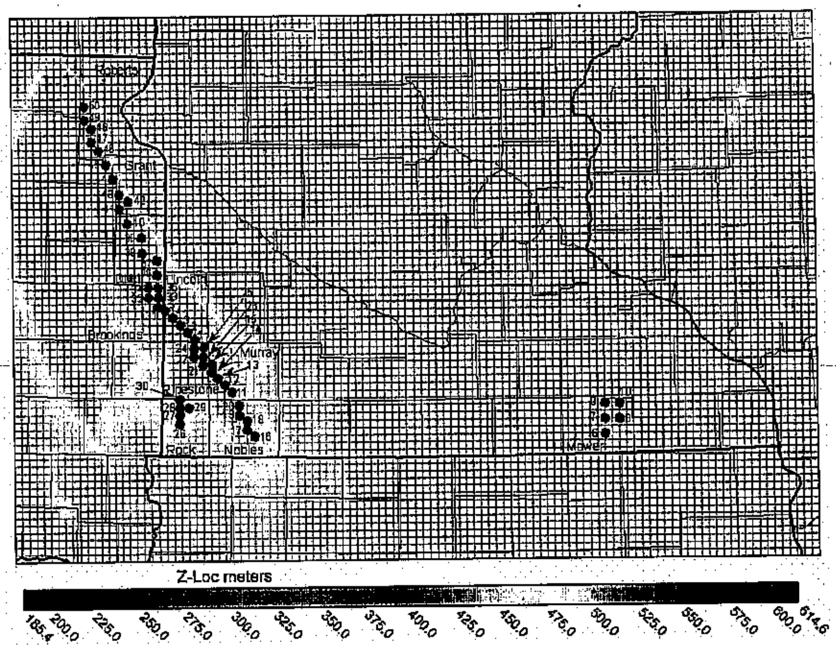


Figure 2: "Tower" locations on the innermost MM5 model grid where wind speed data and other meteorological data were captured and archived at ten-minute intervals.

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

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

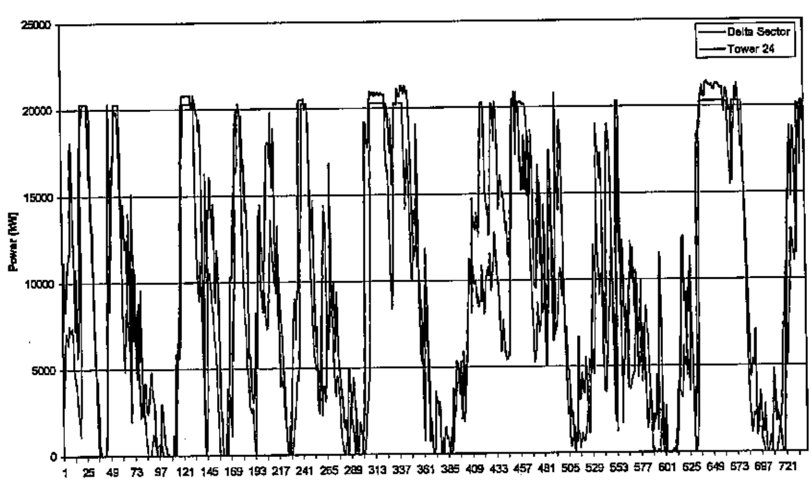


Figure 3: Comparison of simulated wind generation data to actual measurements for a group of wind turbines at Lake Benton, MN on the Buffalo Ridge

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

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

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

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

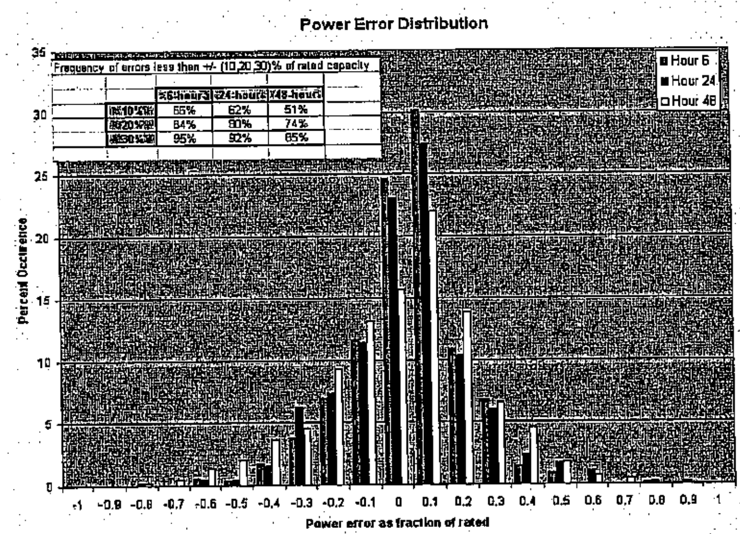


Figure 4: Frequency distribution of power error as a percent of rated capacity for 6, 24 and 48 hour forecasts. Inset table shows the frequency of power errors less than 10, 20 and 30 percent of rated capacity for the CLS 6, 24 and 48 hour forecasts.

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

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

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

Table 1: Minnesota Wind Generation Development Scenario – CY2010

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

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

Table 2: Xcel Capacity Resources for 2010

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

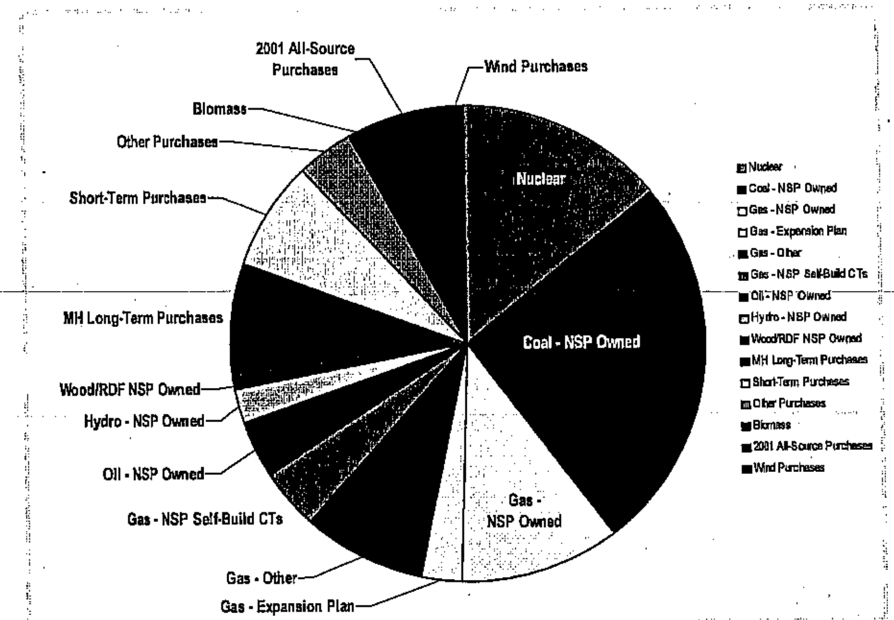


Figure 5: Xcel supply resources for 2010 by type and fuel.

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

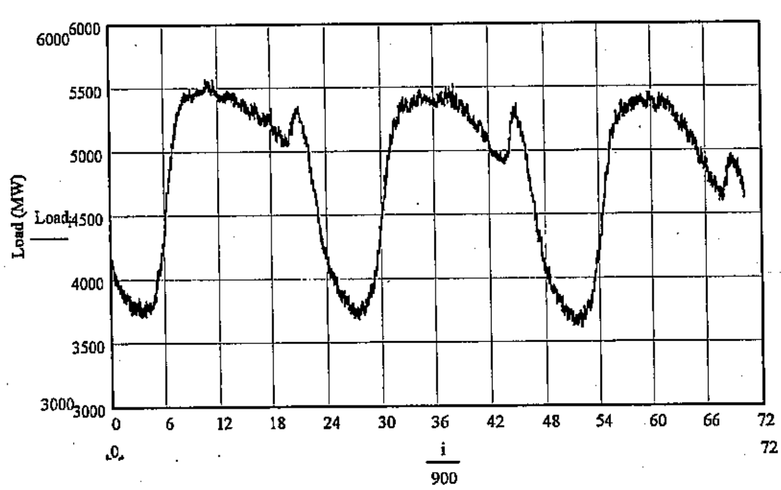


Figure 6: Measurements of existing load data used for characterizing expected load in 2010. Graph shows 72 hours of data collected at 4 second intervals by the Xcel Energy Management System (EMS)

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

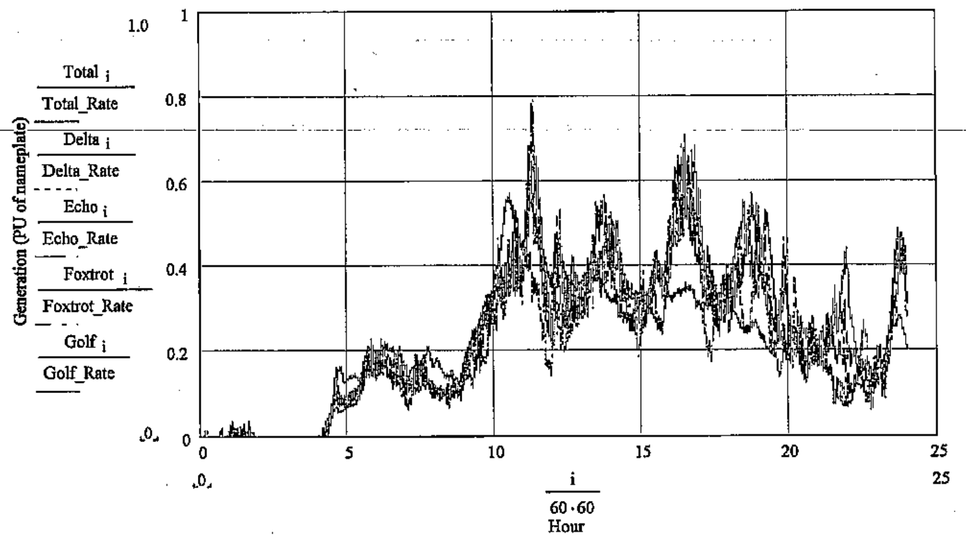


Figure 7: NREL high-resolution measurement data from Lake Benton wind plants and Buffalo Ridge substation. Data show is power production sampled at one second intervals.

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

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

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

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

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

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

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

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

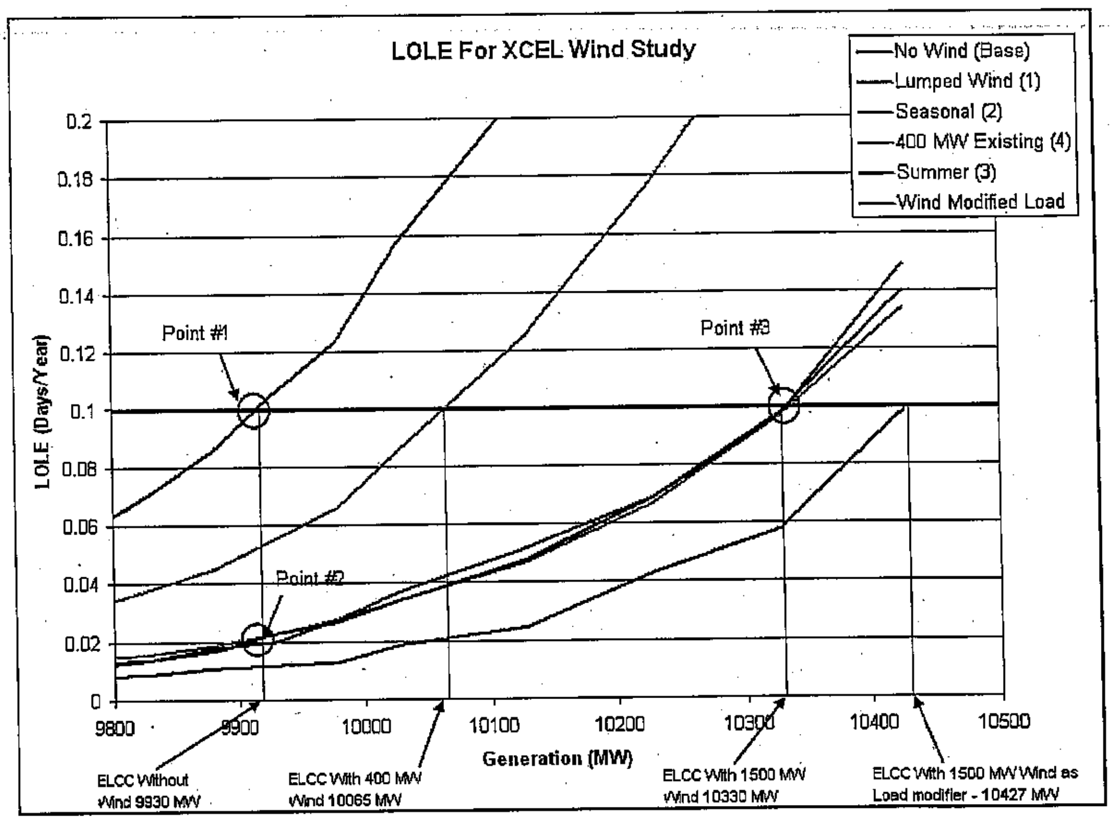


Figure 8: Results of reliability analysis for various wind generation modeling assumptions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Regulation

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

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

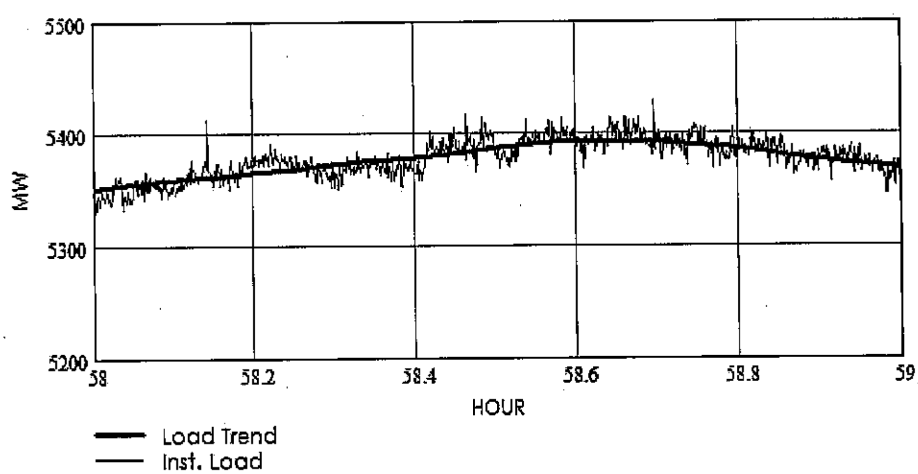


Figure 9: Actual load (blue) and hourly trend (red) for one hour.

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

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

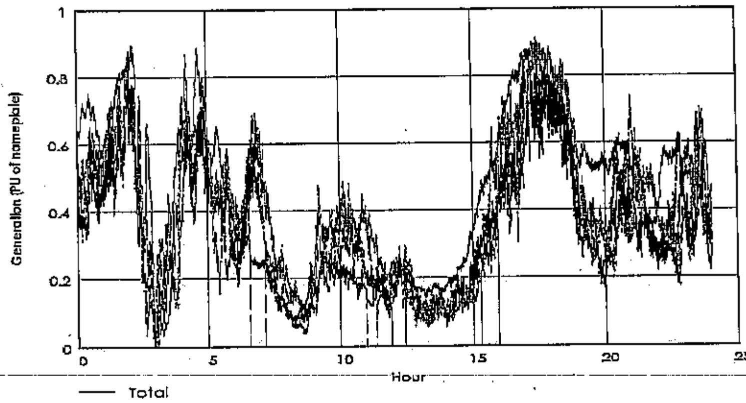


Figure 10: Typical daily wind generation for Buffalo Ridge plants data sampled at one second intervals for 24 hours.

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

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

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

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

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

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

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

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

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

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

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

Unit Commitment and Scheduling - Hourly Impacts

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

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

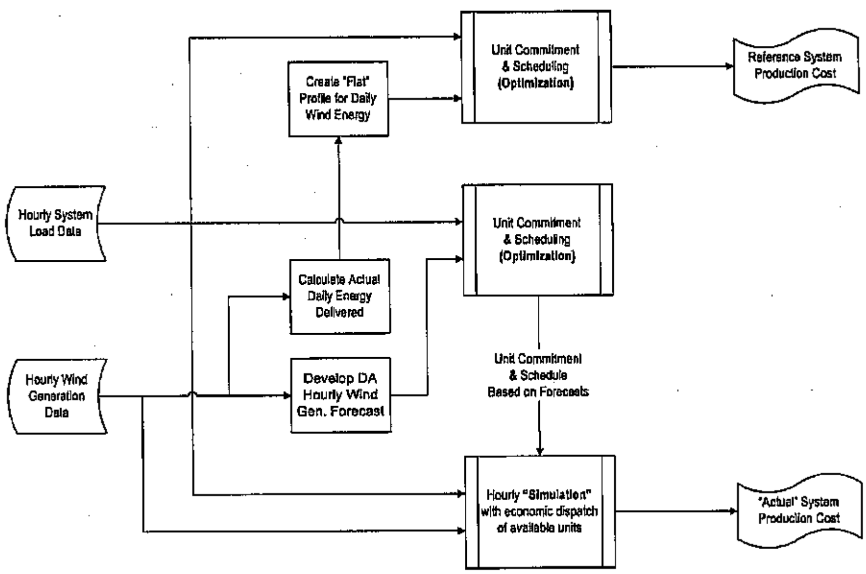


Figure 11: Block diagram of methodology used for hourly analysis.

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

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

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

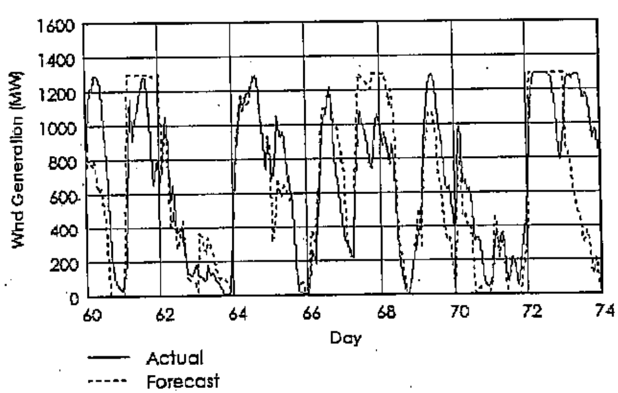


Figure 12: Wind generation forecast vs. actual for a two week period.

Table 4: Hourly Integration Cost summary

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

Load Following and Intra-hourly Effects

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

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

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

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

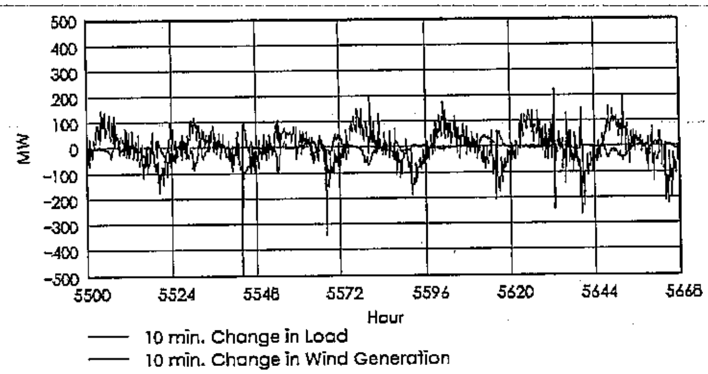


Figure 13: Weekly time series of ten-minute variations in load and wind generation.

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

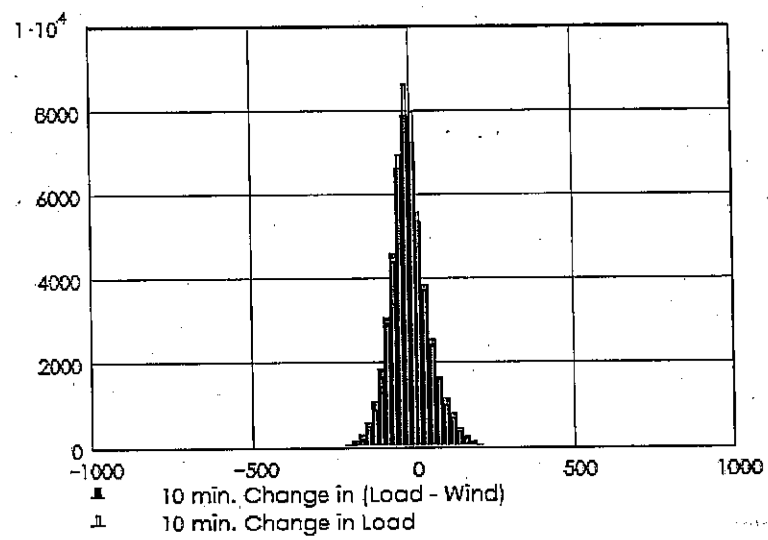


Figure 14: Control area net load changes on ten minute intervals with and without wind generation.

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

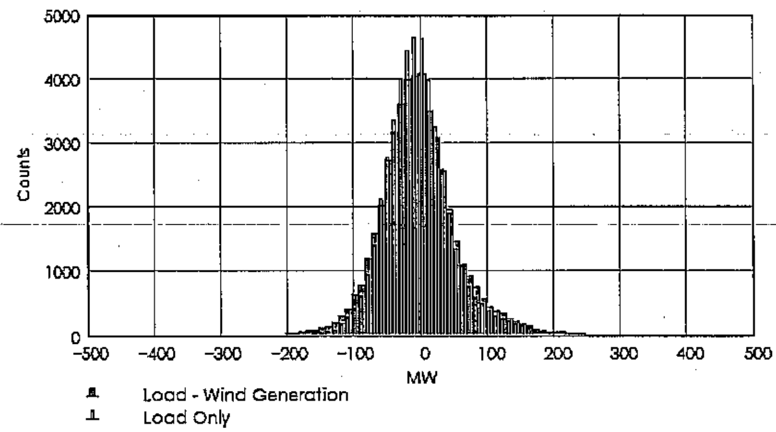


Figure 15: Variation at ten-minute increments from daily "trend" pattern, with and without wind generation.

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

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

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

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

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

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

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

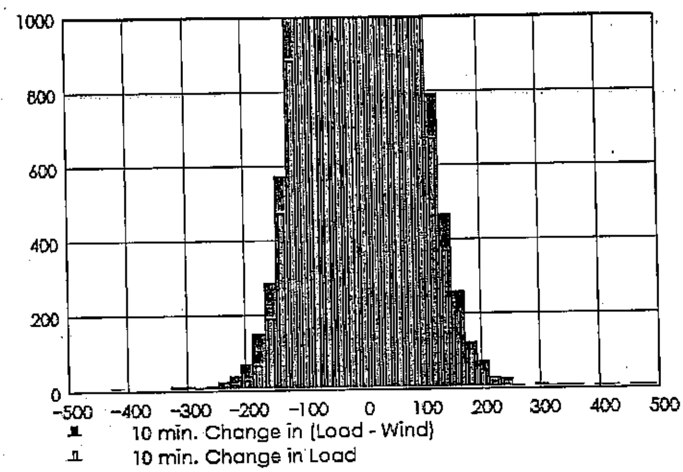


Figure 16: Expanded view of Figure 14.

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

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

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

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

Conclusions

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

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

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

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

Some specific conclusions and observations include:

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

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

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

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

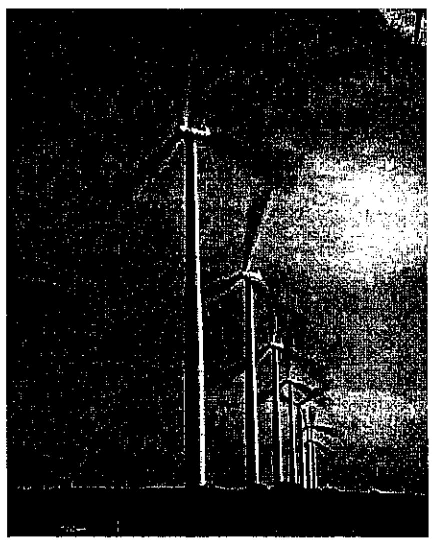
Given the likely sources of the integration cost at the hourly level, it is apparent that a better strategy for purchase and sale transactions scheduled even day-ahead would reduce integration costs at the hourly level. This leads naturally to considering how wholesale energy markets would affect wind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

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

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

UWIG
Utility Wind
Integration Group

Utility Wind Integration State of the Art



Prepared by

Utility Wind Integration Group

in cooperation with

American Public Power Association (APPA)
Edison Electric Institute (EEI)
National Rural Electric Cooperative Association (NRECA)

Utility Wind Integration Group
P.O. Box 2787 Reston, VA 20195
703-860-5160
www.uwig.org

May 2006

Joint Intervenors
Exhibit 4 -- B

Overview and Summary

In just five years from 2000-2005, wind energy has become a significant resource on many electric utility systems, with over 50,000 MW of nameplate capacity installed worldwide at the end of 2005. Wind energy is now "utility scale" and can affect utility system planning and operations for both generation and transmission. The utility industry in general, and transmission system operators in particular, are beginning to take note. At the end of 2005, the Power Engineering Society (PES) of the Institute of Electrical and Electronic Engineers (IEEE) published a special issue of its ***Power & Energy Magazine*** (Volume 3, Number 6, November/December 2005) focused on integrating wind into the power system. This document provides a brief summary of many of the salient points from that special issue about the current state of knowledge regarding utility wind integration issues. It does not support or recommend any particular course of action or advocate any particular policy or position on the part of the coöperating organizations.

The discussion below focuses on wind's impacts on the operating costs of the non-wind portion of the power system and on wind's impacts on the electrical integrity of the system. These impacts should be viewed in the context of wind's *total* impact on reliable system operation and electricity costs to consumers. The case studies summarized in the magazine address early concerns about the impact of wind power's variability and uncertainty on power system reliability and costs. Wind resources have impacts that can be managed through proper plant interconnection, integration, transmission planning, and system and market operations.

On the cost side, at wind penetrations of up to 20% of system peak demand, system operating cost increases arising from wind variability and uncertainty amounted to about 10% or less of the wholesale value of the wind energy.[1] These incremental costs, which can be assigned to wind-power generators, are substantially less than imbalance penalties generally imposed through Open Access Transmission Tariffs under FERC Order No. 888. A variety of means – such as commercially available wind forecasting and others discussed below – can be employed to reduce these costs. In many cases, customer payments for electricity can be decreased when wind is added to the system, because the operating-cost increases could be offset by savings from displacing fossil fuel generation.

Further, there is evidence that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation. Since wind is primarily an energy – not a capacity – source, no additional generation needs to be added to provide back-up capability provided that wind capacity is properly discounted in the determination of generation

[1] These conclusions will need to be reexamined as results of higher-wind-penetration studies -- in the range of 25% to 30% of peak balancing-area load -- become available. However, achieving such penetrations is likely to require one or two decades. During that time, other significant changes are likely to occur in both the makeup and the operating strategies of the nation's power systems. Depending on the evolution of public policies, technological capabilities, and utility strategic plans, these changes can be either more or less accommodating to the natural characteristics of wind power plants.

capacity adequacy. However, wind generation penetration may affect the mix and dispatch of other generation on the system over time, since non-wind generation is needed to maintain system reliability when winds are low.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution is likely to be up to 40% of a typical project's nameplate rating, depending on local wind characteristics and coincidence with the system load profile. Wind generation may require system operators to carry additional operating reserves. Given the existing uncertainties in load forecasts, the studies indicate that the requirement for additional reserves will likely be modest for broadly distributed wind plants. The actual impact of adding wind generation in different balancing areas can vary depending on local factors. For instance, dealing with large wind output variations and steep ramps over a short period of time could be challenging for smaller balancing areas, depending on the specific situation.

The remainder of this document is divided into four sections: wind plant interconnection, wind plant integration, transmission planning and market operation, and accommodating more wind in the future.

Wind Plant Interconnection

- Wind power plant terminal behavior is different from that of conventional power plants, but can be compatible with existing power systems. With current technology, wind-power plants can be designed to meet industry expectations such as riding through a three-phase fault, supplying reactive power to the system, controlling terminal voltage, and participating in SCADA system operation.
- Increased demands will be placed on wind plant performance in the future. Recent requirements include low voltage ride-through capability, reactive power control, voltage control, output control, and ramp rate control. Future requirements are likely to include post-fault machine response characteristics more similar to those of conventional generators (e.g., inertial response and governor response).
- Better dynamic models of wind turbines and aggregate models of wind plants are needed to perform more accurate studies of transmission planning and system operation.
- In areas with limited penetration, modern wind plants can be added without degrading system performance. System stability studies have shown that modern wind plants equipped with power electronic controls and dynamic voltage support capability can improve system performance by damping power swings and supporting post-fault voltage recovery.
- Because of spatial variations of wind from turbine to turbine in a wind plant – and to a greater degree from plant to plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event.

Wind Plant Integration

- Utility planners traditionally view new generation primarily in terms of its *capacity* to serve peak demand. But wind is primarily an *energy* resource. Its primary value lies in its ability to displace energy produced from the combustion of fossil fuels and to serve as a hedge against fuel price risk and future restrictions on emissions.

- The addition of a wind plant to a power system does not require the addition of any backup conventional generation since wind is used primarily as an energy resource. In this case, when the wind is not blowing, the system must rely on existing dispatchable generation to meet the system demand.
- Wind plants provide additional planning reserves to a system, but only to the extent of their capacity value. Capacity for day-to-day reliability purposes must be provided through existing market mechanisms and utility unit commitment processes.
- The capacity value of wind generation is typically up to 40% of nameplate rating, and depends heavily on the correlation between the system load profile and the wind plant output.
- The addition of a wind plant to a power system increases the amount of variability and uncertainty of the net load. This may introduce measurable changes in the amount of operating reserves required for regulation, ramping and load-following. Operating reserves may consist of both spinning and non-spinning reserves. In two major recent studies, the addition of 1,500 MW and 3,300 MW of wind (15% and 10%, respectively, of system peak load) increased regulation requirements by 8 MW and 36 MW, respectively, to maintain the same level of NERC control performance standards.
- Fluctuations in the net load (load minus wind) caused by greater variability and uncertainty introduced by wind plants have been shown to increase system operating costs by up to about $5/MWH at wind penetration levels up to 20%. The greatest part of this cost is associated with the uncertainty introduced into day-ahead unit commitment due to the uncertainty in day-ahead forecasts of real-time wind energy production.
- The impact of adding wind generation can vary depending on the nature of the dispatchable generating resources available, market and regulatory environment, and characteristics of the wind generation resources as compared to the load. Dealing with large output variations and steep ramps over a short period of time (e.g., within the hour) could be challenging for smaller balancing areas, depending on their specific situation.
- Wind's variability cannot be treated in isolation from the load variability inherent in the system. Because wind and load variability are statistically uncorrelated, the net increase of variability due to the addition of wind is less than the variability of the wind generation alone.
- Commercially available wind forecasting capability can reduce the costs associated with day-ahead uncertainty substantially. In one major study, state-of-the-art forecasting was shown to provide 80% of the benefits that would result from perfect forecasting.
- Implementation of wind-plant-output forecasting in both power market operation and system operations planning in the control room environment is a critical next step in accommodating increasing amounts of wind penetration in power systems.

Transmission Planning and Market Operation

- Upgrades or additions to transmission facilities may be needed to access locations with large wind-energy potential. Current transmission planning processes are able to identify solutions to transmission problems, but the time required for implementation of solutions often exceeds wind-plant permitting and construction times by several years.
- Well-functioning hour-ahead and day-ahead markets provide the best means of addressing the variability in wind plant output.
- Energy imbalance charges based on actual costs or market prices provide appropriate incentives for accurate wind forecasting. Since wind plant operators have no control over the wind, penalty charges applied to wind imbalances do not improve system reliability. Market products and tariff instruments should properly allocate actual costs of generation energy imbalance.
- Wind turbine output or ramp rates may need to be curtailed for limited periods of time to meet system reliability requirements economically.
- Consolidation of balancing areas or the use of dynamic scheduling can improve system reliability and reduce the cost of integrating additional wind generation into electric system operation.

Accommodating More Wind in the Future

- Understanding and quantifying the impacts of wind plants on utility systems is a critical first step in identifying and solving problems.
- A number of steps can be taken to improve the ability to integrate increasing amounts of wind capacity on power systems. These include:
    - Improvements in wind-turbine and wind-plant models
    - Improvements in wind-plant operating characteristics
    - Carefully evaluating wind-integration operating impacts
    - Incorporating wind-plant forecasting into utility control-room operations
    - Making better use of physically (in contrast with contractually) available transmission capacity
    - Upgrading and expanding transmission systems
    - Developing well-functioning hour-ahead and day-ahead markets, and expanding access to those markets
    - Adopting market rules and tariff provisions that are more appropriate to weather-driven resources
    - Consolidating balancing areas into larger entities or accessing a larger resource base through the use of dynamic scheduling.

The ***Power & Energy Magazine*** articles summarized in this document are available to IEEE PES members at the following link:
http://www.ieee.org/portal/site/pes/menuitem.bfd2bcf5a5608058fb2275875bac26c8/index.jsp?&pName=pes_home

and to UWIG members at www.uwig.org through the Members link.

Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*

Brian Parsons and Michael Milligan**, Consultant
National Renewable Energy Laboratory

J Charles Smith
Utility Wind Integration Group

Edgar DeMeo
Renewable Energy Consulting Services, Inc.

Brett Oakleaf
Xcel Energy

Kenneth Wolf
Minnesota Public Utilities Commission

Matt Schuerger
Energy Systems Consulting Services, LLC

Robert Zavadil
EnerNex Corporation

Mark Ahlstrom
WindLogics

Dora Yen Nakafuji
California Energy Commission

Introduction and Background

During 2005 approximately 2,500 MW of wind capacity was added in the United States, which brought installed wind capacity to about 9,150 MW. Although the total wind capacity in the United States is less than in some countries, wind energy has caught the attention of some utilities that depend on natural gas to generate power. There is evidence that wind development will continue at significant levels in the United States for the next several years, although it may be sensitive to a number of factors that include transmission availability, wind turbine availability, prices of wind technology and competing fuels, production tax credit availability, and states' renewable portfolio standards (RPSs).

This trend has helped induce electricity providers to investigate the potential impact of wind on the power system. Because of wind power's unique characteristics, many concerns are based on the increased variability that wind contributes to the grid, and most U.S. studies have focused on this aspect of wind generation. Grid operators are also concerned about the ability to predict wind generation over several time scales.

In this report we discuss some recent studies that have occurred in the United States since our previous work [2, 3]. The key objectives of these studies were to quantify the physical impacts and costs of wind generation on grid operations and the associated costs. Examples of these costs are (a) committing unneeded generation, (b) allocating more load-following capability to account for wind variability, and (c) allocating more regulation capacity. These are referred to as "ancillary service" costs, and are based on the physical system and operating characteristics and procedures. This topic is covered in more detail by Zavadil et al. [4].

Time Frames of Wind's Impact

Wind can have an impact on several time scales that correspond to grid operations. The shortest is generally in the range of milliseconds to seconds, and is the domain of system dynamic stability studies. Most wind integration studies

* Portions of this paper have been adapted from IEEE Power & Energy, November/December 2005 [1].

** Employees of the Midwest Research Institute under Contract No. DE-AC36-99GO10337 with the U.S. Dept. of Energy have authored this work. The United States Government retains, and the publisher, by accepting the article for publication, acknowledges that the United States Government retains a non-exclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for the United States Government purposes.

Joint Intervenors
Exhibit 4 -- C

focus on longer time scales, but the stability time frame is a concern and recent developments in the United States have addressed this issue. The most important is the Federal Energy Regulatory Commission (FERC) limited grid code for wind plants, contained in FERC Order 661A, issued in December 2005 [5]. This ruling addresses the issues of low-voltage ride-through, reactive power supply, and Supervisory Control and Data Acquisition (SCADA) system requirements

Figure 1 illustrates the key time frames that correspond to utility/grid operations and that have been the focus of most integration studies. In the United States, the regulation time frame is the period during which generation automatically responds to deviations in load or load net wind. This capability is typically provided via automatic generation control, and is a capacity service generally covering seconds to several minutes. Integrating wind into the system would have an impact on regulation requirements for the system, and might require additional regulation capability. In the United States there are two controlled performance standards, CPS-1 and CPS-2*, control area operators/balancing authorities follow.

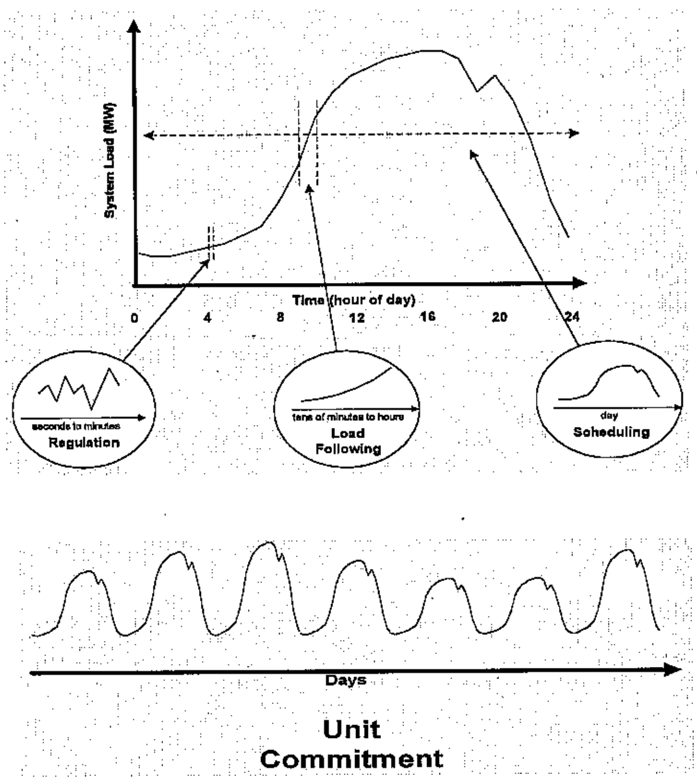


Figure 1. Time frames for wind impacts

The second time frame is load following. This is a longer period during which generating units are moved to different set points of capacity, subject to various operational and cost constraints. Load following involves capacity and energy, and corresponds to time scales that may range from 10 minutes to a few hours. Loads can typically be forecast with reasonable accuracy and overall correlation between individual loads tends to be high in this time frame. Generating units that have been previously committed, or can be started quickly, can provide this service, subject to physical constraints. Beyond the maximum and minimum generation constraints, the ramping constraint (ability to move in MW/minute) may be affected by significant wind generation on the system. In systems with little or no wind, the changes in load in this time frame can be predicted with varying degrees of accuracy. To the extent that forecasts are wrong, the system operator must deal with the resulting system imbalance. Significant wind capacity can increase the uncertainty and cost in this time frame.

* These control performance standard cover short-term frequency variations (CPS-1) and longer term imbalance limits (CPS-2) on a statistical basis.

Planning for the required quantity of generation and load following capability involves the unit commitment time frame, which can range from several hours to a few days. Scheduling too much generation can increase costs needlessly, whereas insufficient generation could have a cost component (buying at high market prices or running expensive quick-start units) and a reliability component (if sufficient generation has not been started and is not available on short notice).

Most of the studies described here estimate the increased cost of managing a system with significant wind generation. The studies approach the cost question by starting with the physical behavior of the system without wind, then detailing how that physical behavior is affected by wind power plants. The primary objective of the studies is to take the view of the system operator, whose goal is to obtain system balance within required limits. Although U.S. terminology differs somewhat from that in Europe, the key physical issues and time frames are very similar. The imbalance impacts of wind are seen as unscheduled interchanges or frequency changes on the system when the balancing area cannot respond quickly enough to changes in load or wind. The impacts of wind on conventional generation are best analyzed over several time scales that correspond to system operation, ranging from automatic response (regulation in the United States) of units on automatic generation control, to spinning or standing reserve response (load-following in the United States). From the control room, wind variability is combined with load variability over these time scales, along with unscheduled deviations from some conventional generators. This net load is seen by the operator and must be balanced. Although the analytical tools differ somewhat, several common elements in the analyses have taken place in the United States.

Most of the studies we summarize here are cost-of-service studies that examine the cost of wind in the context of regulated utilities. Other studies, such as the one carried out in New York (discussed below) are market studies that do not directly calculate cost impacts. Because of this approach, the results of the market-based studies cannot be directly compared with ancillary cost studies.

Xcel Energy North (Minnesota)

Xcel Energy North serves parts of North Dakota, South Dakota, Minnesota, Michigan, and Wisconsin. The power system is summer peaking with a peak demand of approximately 8,000 MW in 2002 projected to rise to approximately 10,000 MW by 2010. Total system generation is approximately 7,500 MW with the difference made up by power purchases.

Minnesota Department of Commerce Study (September 2004)

In 2004, a follow-up to an earlier study of the Xcel North system was completed by EnerNex Corporation on behalf of Xcel Energy and the Minnesota Department of Commerce. This study also focused on operating impacts but at the higher level of 1,500 MW of wind generation (15% penetration in 2010). It determined the incremental costs that resulted from plans and procedures needed to accommodate wind generation and maintain the reliability and security of the power system.

Meteorological simulations were carried out by WindLogics, then combined with archived weather data to recreate the weather for use in the study analysis. Benefits of geographic dispersion of the wind plants and of wind forecasting were also demonstrated. Figure 2 illustrates the area of meteorological modeling that was used to simulate 3 years of 10-minute wind speed data, subsequently converted to wind power output for the system simulations.

The costs of integrating 1,500 MW of wind generation into the Xcel North control area in 2010 are no higher than $4.60/MWh of wind generation and are dominated by costs incurred by Xcel Energy in the day-ahead time frame to accommodate the variability of wind generation and associated wind-generation forecast errors. The total costs include about $0.23/MWh resulting from an 8-MW increase in regulation requirements and $4.37/MWh resulting from scheduling and unit commitment costs. The study characterized these results as conservative, since improved strategies for short-term planning and scheduling and the full impact of new regional markets were not considered. Load following impacts were calculated, but because they were quite small, the cost was judged to be insignificant. Figure 3 shows the impact of wind on morning load pickup and evening ramp-down.

This study also calculated wind capacity credit as a percentage of installed wind. Several modeling approaches and different wind configurations were used to determine the capacity values, which were 26%–34%.

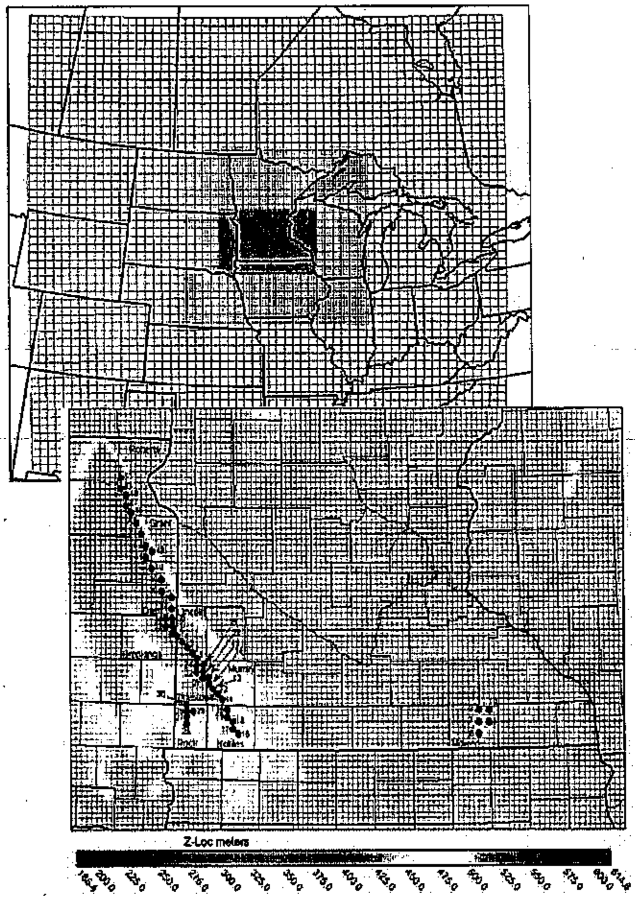


Figure 2. Area of meteorological modeling for Xcel Energy North study

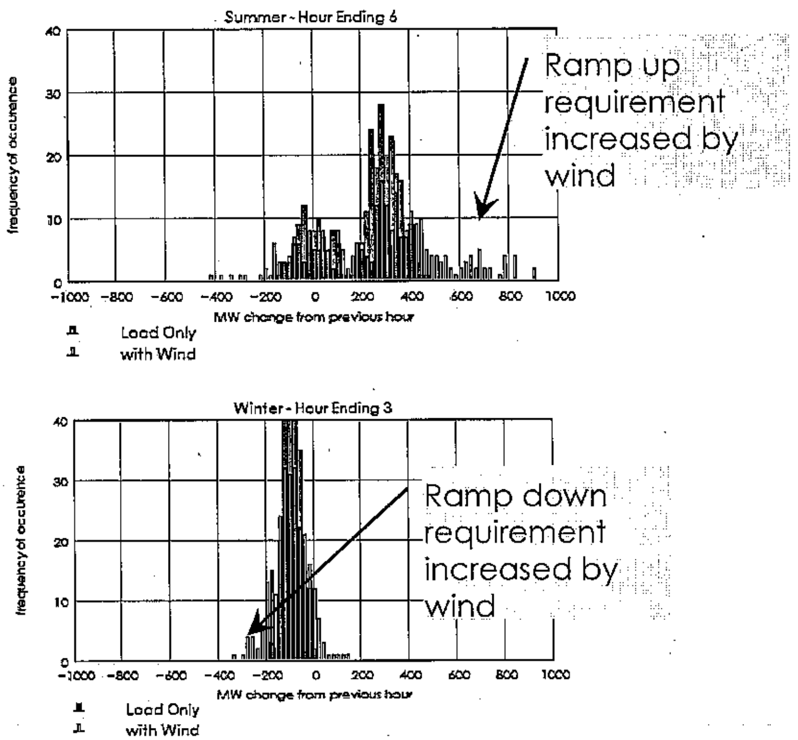


Figure 3. Load following impact on morning/evening ramps for Xcel Energy North

California Independent System Operator (CAISO)

In response to legislation in California that established an RPS, the California Energy Commission (CEC) and California Public Utilities Commission established a team to examine the integration costs of all existing renewable power sources in the state. The analysis of wind generation was based on the three main California wind resource areas—Altamont, San Gorgonio, and Tehachapi—for 2002. The contribution that wind (and the other renewables) makes to system variability was estimated and CAISO regulation prices were used to estimate the cost of wind's regulation impact. The maximum regulation costs were $0.46/MWh of wind generation, but varied somewhat depending on the resource area.

To estimate the impact on the load-following time scale, data on system load and renewable generation were analyzed. The energy market operated on a 10-minute interval during the study period. The analysis focused on potential distortions to the dispatch stack that would result from swings in renewable generation. However, because of the numerous conventional generators available for redispatch, no measurable impact was found.

Unit commitment is not the responsibility of the CAISO. Once bids have been accepted, generators assume this responsibility, and associated costs are assumed to be reflected in bids. Hence, the impact of wind variability on costs in the unit-commitment time frame was not assessed.

Capacity value for wind was 23%–25% of rated capacity. However, because discrepancies surrounded the actual installed capacity, these values are felt to be somewhat imprecise. Capacity value was sensitive to hydro dispatch, interchange schedules, and conventional unit maintenance schedules. The Phase I and Phase III reports discuss these and other results.

During the analysis, several data anomalies were uncovered. Most data were obtained from the CASIO plant information (PI) database, which records massive quantities of power system data from various metering systems. Because of the large volume of data, the PI data are fed through a compression algorithm to save storage space. Some irregularities in the system data suggested that the compression algorithm may have artificially smoothed some of the high-rate (1-second) data. During early parts of Phase III, some additional anomalies appeared in some data sets during data dropouts. The automatic data correction algorithms appeared to interpolate between good data points even if the dropout period spanned long periods of time (in some cases, several months). Additional data were obtained from the utilities to address these issues and were incorporated in a subsequent multi-year study (below). The Phase III report made specific recommendations for quality assurance and testing of data that would be critical to assessing the impact of wind and other renewable energy technologies as penetration continues to increase on the CAISO system.

A multiyear study of the RPS integration cost that covers 2002–2004 is complete and is presently under review by the CEC. This final project report will be released very soon. An additional, separate study is also underway to analyze the operational issues that would be posed by higher penetrations of wind than are on the California system. This study is on behalf of the CEC, managed by Kevin Porter, Exeter Associates, with principal analytic work by GE Energy, Davis Power Consultants and AWS TrueWind. Results are anticipated in late 2006. This new study will analyze the impact of wind from a market-based approach, and is anticipated to be similar to the NYISO study that was carried out by GE Energy in New York, as discussed below.

New York Independent System Operator (NYISO)

This work, completed in early 2005, was conducted by GE Energy for the NYISO with primary support from the New York State Energy Research and Development Authority (NYSERDA). Wind resource projections were provided by AWS TrueWind. The project was motivated by an RPS that may result in some 3,000 MW of new wind generation in New York within the next ten years. In light of wind's natural variability, the NYISO wanted to understand the impacts of a substantial amount of wind generation on the operation of the New York electric power network. The study addressed 3,300 MW of wind in a system that serves a customer load projected at about 34,000 MW in the 2008 study year. The key question was whether the system would be able to handle 10% wind penetration without major difficulties. Figure 4 shows the relative locations of wind plants used in the analysis.

This study is the most comprehensive U.S. wind integration assessment conducted to date. It encompassed all the time frames discussed above, and estimated system operating costs, impacts on customer payments, reductions in emissions from conventional power plants, and the impacts of wind forecasting. The New York system is operated as a single large balancing authority, and has well-functioning hour-ahead and day-ahead wholesale markets into which generators bid energy. Bids are accepted until projected demand is met on an hour-by-hour basis, and all accepted bidders—including wind plants, which bid at zero price—are paid the highest accepted bid price.

This study has estimated wind's total cost impact on the operation of the system. Increases in costs associated with regulation, load following, and generation scheduling that stem from wind's variability are combined with savings resulting from fossil fuel displacement. The wind resource was modeled from weather data for the period 2001 and 2002, and was combined hourly with corresponding coincident load and generation data scaled to the projected 2008 peak demand. Geographic diversity of the wind was captured by using wind data that corresponded to a number of locations. Figure 5 shows an hourly trace of wind generation and load for one week.

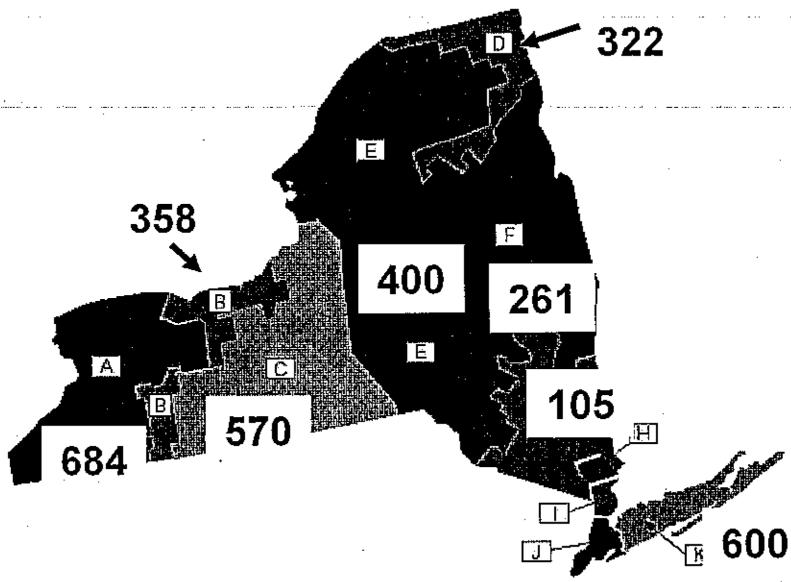


Figure 4. Location of NY wind plants from NYISO/GE Study

The overall conclusion from the study was that the New York State power system can reliably accommodate at least 3,300 MW (10%) of wind generation with only minor adjustments to its planning, operating, and reliability practices. No increase in spinning reserve would be required, and 36 MW of additional regulation would be needed to maintain frequency at the no-wind level. The total impact on variable operating costs for the study year—including impacts of wind variability and fuel savings—was a reduction of $335 million. Fuel displaced by wind was primarily natural gas, which was conservatively priced at $6.50–6.80/MMBtu. Total system variable cost savings increase from $335 million to $430 million when state of the art forecasting is considered in unit commitment. Perfect forecasting provided an additional benefit of about $25 million.

Reductions in load payments ranged from $515 million to $720 million, with higher savings resulting from state of the art forecasts. Revenue paid to the wind generators was $305 million, or about $0.035/kWh. This amount is consistent with the terms of typical power purchase agreements between wind plant owners and purchasing utilities that were in effect during the study period. This indicates that wind offers a viable business opportunity in New York.

A loss of load probability approach was used to calculate the capacity credit of wind. A unique feature of the analysis was the recognition of the transmission constraint between some wind areas and load areas. Average on-shore capacity value was about 9% of rated capacity, and off-shore was 36%.

Xcel Energy West (Colorado)

The EnerNex-WindLogics team is conducting this study for Xcel Energy's Public Service of Colorado unit. Wind penetrations of 10% and 15% have been studied, and a 20% case was performed by scaling up the 15% wind generation case (this scaling likely overestimates the additional variability imposed by wind on the power system). The methodology is similar to that employed in the MN DOC study, although an additional element was required to assess the impacts on gas purchases, consumption, and storage. Traditionally, gas decisions must be made—and lived with—every day. As a result, higher penetrations of wind are likely to require additional gas storage, which results in an additional cost impact from wind's variability. As in the Minnesota study, the intra-hour load-following cost was negligible, and the major impact was related to differences between the hour-by-hour commitment schedule and the net of load and wind.

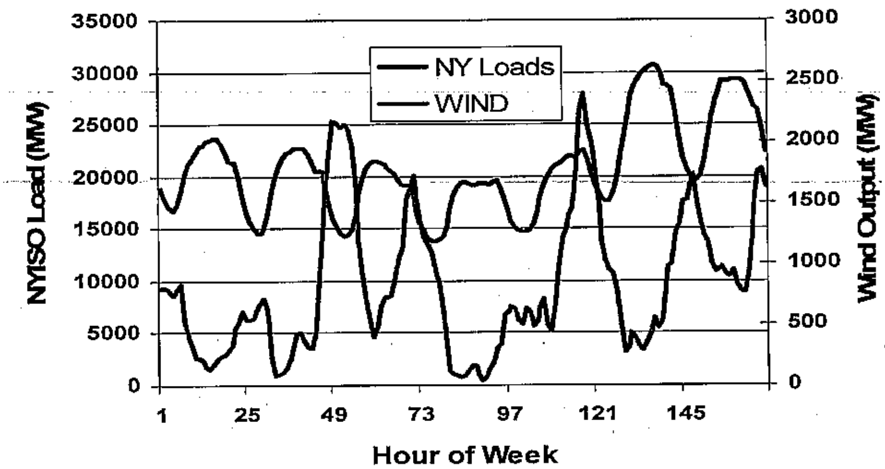


Figure 5. One week of load and wind generation from NY study

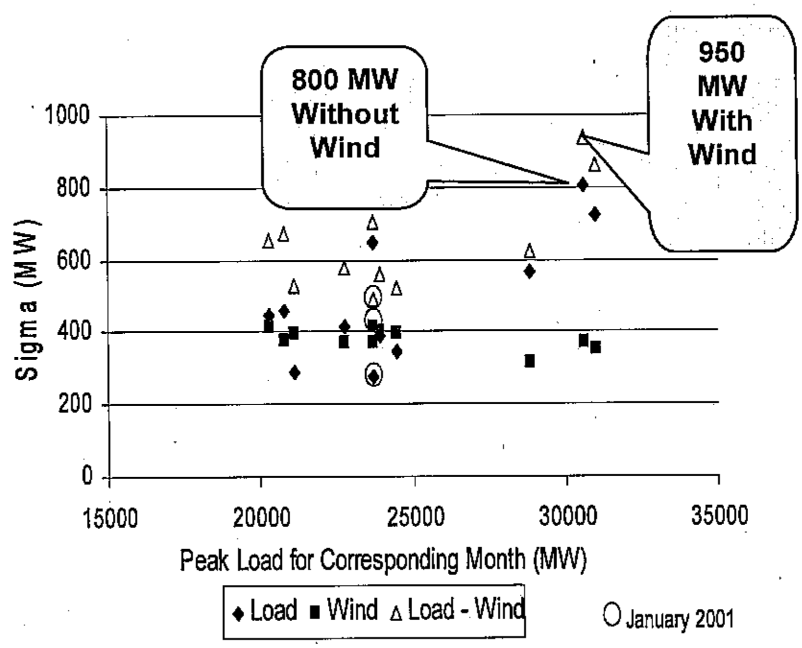


Figure 6. Standard deviation of day ahead forecast errors in NY

Another interesting aspect of this study is the 300 MW pumped-storage unit in Xcel's service territory. At 10% wind penetration, the flexibility offered by the pumped storage unit reduced the integration cost by $1.30/MWh.

Figure 7 shows the region in Colorado that was used for prospective wind plant locations, and Table 1 illustrates some of the results from the integration cost study.

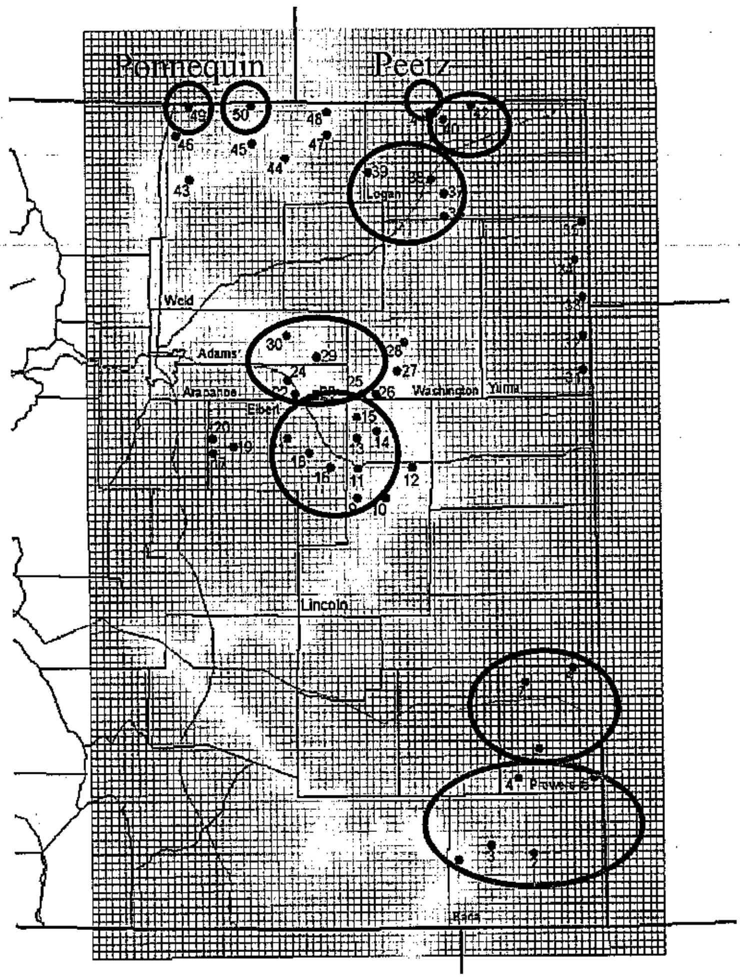


Figure 7. Region for wind plants in Xcel Energy West study

Table 1. Results from Xcel Energy West integration study

Penetration Level	10%	15%	20%[2]
Hourly Analysis	$2.26/MWh	$3.32/MWh	$6.57/MWh
Regulation	$0.20/MWh	$0.20/MWh	$0.20/MWh
Gas Supply (1)	$1.26/MWh	$1.45/MWh	$2.10/MWh
Total	**$3.72/MWh**	**$4.97/MWh**	**$8.87/MWh[2]**

Table Notes:
(1) Costs include the benefit of additional gas storage
(2) Rough results obtained from scaling wind from the 15% case

The Xcel Energy West study provides additional useful insights relative to natural gas supply and management. The additional gas storage required to accommodate wind's variability and uncertainty would provide a winter-summer seasonal hedging benefit to the system of about $1.00/MWh of wind energy at 15% penetration. And in a much more extensive assessment of wind's role in hedging against swings and spikes in natural gas prices, researchers at Lawrence Berkeley National Laboratory find wind energy hedge values of about $5.00/MWh of wind [11].

Results Summary and Discussion

Key results from these and other studies are summarized in Table 2:

Table 2. Wind impacts on system operating costs

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commit-ment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May 03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep 04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
July 04	CA RPS Phase III	4	0.46 (1)	na	Na	na	na
June 03	We Energies	4	1.12	0.09	0.69	na	1.90
June 03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.6
April 06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April 06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
April 06	Xcel-PSCo (2)	20	0.20	na	6.57	2.10	8.87

Table Notes:
(1) Represents maximum regulation cost for all wind resource areas
(2) Preliminary results based on scaling wind generation from the 15% case, therefore likely overestimates cost impacts

The results in Table 2 show that the ancillary service impacts of wind from the recent studies are in line with studies that we have previously examined [6]. The Xcel studies represent significant steps forward in the analysis, by using detailed wind profiles developed to represent the wind behavior coincident with load. The Xcel Energy West study illustrates that there is not a one-size-fits-all answer to the wind integration question, and applies a method to analyze the impacts on a gas-constrained system where gas purchases are made in advance. The California multiyear study applies the methods to three years of data that were collected by the ISO and utilities that purchase the wind output. All this recent work points to the desirability of using multiple years of time-synchronized wind and load data to obtain more robust results.

Capturing the spatial variations of wind—both within an individual wind plant and across the entire region considered—is also important, since these variations significantly mitigate impacts.

Conclusions and Insights

Given the work that has been done, several conclusions are emerging. Although wind imposes additional operating costs on the system, these costs are moderate at penetrations expected over the next 5–10 years. These results are expected to apply as additional wind generation is developed in the next few years in response to state government RPSs, although wind integration costs will increase with penetration.

Large, diverse balancing areas with robust transmission tend to reduce wind's impact and ancillary service cost. At current U.S. levels, the impact on regulation and load following appear to be modest, and the unit commitment time scale appears to be more important. In this time scale wind forecasts can play a more prominent role, and improvements in forecasting technology will certainly mitigate wind's integration costs. As wind penetration increases in the United States, better forecasting is expected to play a more important role. To be effective, forecasts do not need to be perfect, although increasing accuracy tends to reduce costs. It is possible that at some point the incremental cost of forecast improvements will outweigh the incremental benefits that accrue from increased accuracy.

Aside from large balancing areas, other factors can mitigate wind impacts. If several adjacent balancing areas can develop cooperative arrangements or markets for ancillary services, larger quantities of wind could be absorbed because of the greater load and wind diversity that would be expected across broader regions. This could be captured by larger balancing areas, but other means of tapping this potential can be used. This is discussed further by Kirby and Milligan [7].

There is also some evidence that system operators will become more familiar with wind after working with it. For example, The Western Farmers Electric Cooperative (WFEC) in Oklahoma recently performed an analysis with the National Renewable Energy Laboratory of the operational impact of wind on its system. WFEC has a peak load of 1,400 MW and installed wind capacity of 74 MW. Initially the system operators could not maintain the CPS-1 frequency standard at its pre-wind level. With experience they became familiar with the wind system and brought CPS-1 into its pre-wind range [13].

Emerging Best Practices and Methods

Although there are differences between studies, there appears to be some convergence on techniques and methods used to analyze wind's ancillary service impacts. A key point is to recognize that the entire system—not individual loads or generators—need to be balanced. In the United States, this balance does not need to be perfect, but is required to fall within the statistical limits defined by CPS-1 and CPS-2. The implication for wind integration is profound: not every movement in wind generation needs to be matched one-to-one by another conventional generator.

The approaches used in recent studies generally capture the important system characteristics through detailed modeling of the relevant grid and operational practices. These representations of the system can then be simulated in a chronological environment that can observe the detailed constraints on the system that are imposed by loads and generators.

Because wind impacts occur throughout the time domain, the coincidence of loads and wind generation must be captured. Because wind speed and wind generation data are often difficult or impossible to obtain for desired time periods, an emerging approach is to construct the wind data from detailed time-calibrated mesoscale meteorological modeling for the desired time period. Normally this is accomplished by selecting load data for the study period based on recent historical data. Wind data sets can then be constructed to match the historical load period. And because wind impacts on some longer time scales may differ from year to year, the best approach is to extract multiple years of wind data that correspond to the loads in a multiyear study period, and complete several years of detailed simulations. This picks up any correlation (which may be highly nonlinear with significant phase shifts) between wind and load, and improves confidence that the results are meaningful.

Detailed meteorological modeling also allows the geographic impacts of wind to be represented as the turbines are spread over small areas (within a wind plant) or large areas (several wind plants) and picks up the impact of prevailing weather patterns that drive the wind generation and influences load.

The short-term behavior of wind power plants has been quantified by Wan [8]. The data sets indicate that wind power variability is quite low at fast time frames, and increases at progressively longer time frames. As a practical matter, this implies that wind's impacts will be relatively small in the regulation time scale, increase at the load following time scale, and become even more significant at the unit commitment/scheduling time scale. The U.S. studies broadly support this conclusion, and as more wind operating data become available, a more realistic representation of wind in the analytic models can be captured so the results are more accurate.

Within the modeling frameworks used in the U.S. studies, the variability of wind generation is added to the already considerable variation in load. The analytic tools approximate the view of the system as seen by the operator. This implies that the statistical treatment of the wind and load time series is important and provides a realistic representation of wind's impact on the regulation and load following time frames.

To better understand the role of forecasting, some studies have constructed wind forecasts and run the analysis with and without the forecasts. Clearly forecasting can play an important role in mitigating wind's impacts on system operations and costs, but only if the forecast is used appropriately in the control room.

Remaining Questions and Future/Ongoing Work

In spite of significant progress in understanding wind's impact on the grid, questions remain. Current systems can apparently handle wind penetrations up to 10%–20% based on capacity, but the costs appear to increase with penetration. Models, analytic tools, and practices have generally not been adapted to extensive experience with large quantities of wind. As wind penetration increases over the next several years in the United States, this increasing cost will provide an increasing economic incentive to investigate cost-mitigation approaches.

Several possibilities for these strategies appear promising, but all require further quantification:

- Dynamic scheduling
- Consolidation of balancing areas
- New operational practices and economic curtailment
- Better use of flexible resources, including dispatchable hydro and pumped storage
- Plug-hybrid electric vehicles with smart-charge controllers that can provide demand and supply to the grid
- Hydrogen and other forms of energy storage
- Aero derivative gas (jet) engines with quick start capability and good heat rates
- Price-responsive load
- Integration of wind forecasting into the control room
- Learning how to best operate the system with large wind power plants

This list is not exhaustive, nor are the items on the list mutually exclusive. Some combination of these items may significantly increase the ability of the grid to absorb increasing quantities of wind generation.

Future and Ongoing Work in the United States

In Minnesota a project to evaluate the grid impacts of 20% wind by energy (5 GW of wind) has recently begun. This project resulted from legislation, and is on behalf of the Minnesota Public Utilities Commission. EnerNex is the contractor; WindLogics provides the meteorological data foundation. The study will also examine the new MISO market structure, examine transmission and mitigation strategies, and compare market and reliability rules. Anticipated completion date is November 2006.

In response to the 2004 Xcel Renewable Development Fund solicitation in Minnesota, a team led by WindLogics, including EnerNex, AREVA T&D, and the Utility Wind Integration Group, was awarded a grant of nearly $1 million to research and demonstrate a utility-scale wind power forecasting system for the Xcel North system. The goal of this project is to define, design, build, and demonstrate a complete wind power forecasting system for use by Xcel system operators. This project will begin in 2006 and builds on other studies that the development team has performed for Xcel to quantify the cost of ancillary services for wind plants on the Xcel system.

Key objectives will be to optimize the way wind forecast information is integrated into the control room environment (for both load-following and unit commitment time scales) and to evaluate the impact of the wind forecast on control room operations. A critical part of the process will be to define the types of wind forecasts, delivery mechanisms, and method of control room integration that will be most useful in day-to-day activity.

In California the Intermittency Analysis Project is evaluating the system impacts of 5 GW wind by 2010, possibly up to 15% (rated capacity to peak) or greater by 2020. Some items to evaluate include periods of high wind and low load, and the study may develop a scenario that aggressively pushes the amount of wind on the system to higher levels. The study primary contractors are Davis Power Consultants, GE Energy and AWS Truewind. The study will be completed by the end of 2006.

There are also several projects that involve smaller systems. The Sacramento Municipal Utility District is embarking on a study of high wind penetration and will investigate the role of hydro pumped storage. The analysis framework will be the Areva Dispatch Training Simulator (DTS), a software platform that mimics the control room environment of the system operator. Another project that will use the DTS is at the Public Service Company of New Mexico, which has a wind plant that is built along a ridge top. The limited import/export capabilities, the relatively high and increasing wind penetration, and ramping impacts provide an interesting look at mitigation strategies, particularly during minimum load/maximum wind time periods. Idaho Power and Grant County Public Utilities Department also have projects to evaluate wind integration in systems with constrained hydro resources.

Other larger scale studies are also underway in the United States. Because of limited transmission interconnections in parts of the Midwest and West, several transmission organizations have begun to analyze wind scenarios in the framework of subregional and regional reliability areas. These studies generally collaborate with the utilities and load-serving entities in the region, and with other stakeholders. Example studies are underway at the Seams Steering Group of the Western Interconnection (in process of transferring to the Western Electricity Coordinating Council), Northwest Transmission Assessment Committee, Southwest Area Transmission, and MISO. The Rocky Mountain Area Transmission Study (RMATS) completed Phase I of a similar project in 2005. There has also been a high level of interest in examining transmission tariffs to assess the role of tariff reform, partly growing from the RMATS work, and partly from interest in the Northwest by PacifiCorp, Bonneville Power Administration, and the Renewable Northwest Project. The FERC has indicated interest in this topic, and we expect further activity in the near future.

References

Most of the studies discussed in this article are available on the Utility Wind Integration Group website, www.uwig.org.

1. DeMeo E, Grant W, Milligan M, Schuerger M. *Wind Plant Integration*. IEEE Power & Energy, Nov/Dec 2005.
2. Parsons B, Milligan M, Zavadil R, Brooks D, Kirby B, Dragoon K, Caldwell J. *Grid Impacts of Wind Power: A Summary of Recent Studies in the United States*. European Wind Energy Conference, June 2003. Available at www.nrel.gov/docs/fy03osti/34318.pdf. Accessed Feb 24, 2006.
3. Smith J, DeMeo E, Parsons B, Milligan M. *Wind Power Impacts on Electric-Power-System Operating Costs: Summary and Perspective on Work to Date*. American Wind Energy Conference, March 2004. Available at www.nrel.gov/docs/fy04osti/35946.pdf. Accessed Feb 24, 2006.
4. Zavadil R, Miller N, Ellis A, Muljadi E, *Making Connections*, IEEE Power & Energy, Nov/Dec 2005.
5. Federal Energy Regulatory Commission. Docket No. RM05-4-001; Order No. 661-A. www.ferc.gov
6. Smith J, DeMeo E, Parsons B, Milligan M. *Wind Power Impacts on Electric-Power-System Operating Costs: Summary and Perspective on Work to Date*. American Wind Energy Conference, March 2004. Available at www.nrel.gov/docs/fy04osti/35946.pdf. Accessed Feb 24, 2006.
7. Kirby B, Milligan M. A method and case study for estimating the ramping capability of a control area or balancing authority and implications for moderate or high wind penetration. American Wind Energy Conference, May 2005. Available at www.nrel.gov/docs/fy05osti/38153.pdf. Accessed Feb 24, 2006.
8. Wan Y. *Wind Power Plant Behaviors: Analysis of Long-Term Wind Power Data;* National Renewable Energy Laboratory Report NREL/TP-500-36651, 2004. Available at www.nrel.gov/docs/fy04osti/36551.pdf. Accessed Feb 24, 2006.
9. Zavadil R, King J, Xiadong L, Ahlstrom, M, Lee B, Moon D, Finley C, Alnes L, Jones L, Hudry F, Monstream M, Lai S, Smith J. *Xcel Energy and the Minnesota Department of Commerce, Wind Integration Study - Final Report*. EnerNex Corporation and Wind Logics, Inc., September 2004.

10. GE Energy. *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations: Report on Phase 2.* Prepared for The New York State Energy Research and Development Authority, March 2005.
11. Bolinger M, Wiser R, Golove W. Quantifying the value that wind power provides as a hedge against volatile natural gas prices, Proceedings of WindPower 2002, June 2002.
12. California RPS Integration Cost reports (Phases I-III) available at http://www.energy.ca.gov/reports/reports_500.html. Accessed Feb 24, 2006..
13. Wan, Y, Liao, J, Analyses of Wind Energy Impact on WFEC System Operations; National Renewable Energy Laboratory Report NREL/TP-500-37851, June 2005.

Acknowledgments

Thanks to Kevin Porter, Exeter Associates, Henry Shiu, California Wind Energy Collaborative/University of California at Davis, Nick Miller and Richard Piwko, GE Energy for their assistance with and comments on this report.