Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of Requests for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Interconnections

PUC Docket No. E-002/CN-06-1115,

OAH No. 15-2500-19350-2

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OF
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ON BEHALF OF
THE NORTH AMERICAN WATER OFFICE
AND
INSTITUTE FOR LOCAL SELF RELIANCE

May 23, 2008

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Michael Michaud. I am an independent energy consultant specializing in renewable community based energy development, transmission and interconnection issues, and renewable energy policy development. My business address is 802 North Pine Creek Road, Maiden Rock, WI. 54750.

Q. What is your educational and professional background?

A. I have experience and education in electrical engineering, wind energy project development, and energy policy analysis. I have a Bachelors Degree in Electrical engineering from the University of Minnesota, Institute of Technology and a Master of Science Degree from the University Of Minnesota Hubert Humphrey Institute Of Public Affairs in Science and Technology Policy. I have 13 years of policy analysis and Certificate of Need process experience working on staff of the Minnesota Public Utilities Commission, the Minnesota Department of Commerce, and the Minnesota Environmental Quality Board. I have been involved in transmission planning activities since the mid 1990's as a regulatory participant and as an independent consultant. I have attached a resume as Exhibit 1 to my testimony.

Q. What is the purpose of your testimony in this proceeding?

A. I will provide technical comments on behalf of the North American Water Office and the Institute for Local Self Reliance (NAWO & ILSR) to show that the Applicants have not met their burden of proof on specific statutory requirements necessary before a Certificate of Need can be issued for these lines under Minn. Stat. §216B.243, specifically subd 3 and 3a. I will address separately each of the three claimed categories of need as defined in the Application.

Q. Which particular items in the statutes will you address?

I will discuss problems with the Applicants 1) forecasting: 2) conservation and load management analysis, 3) inadequate planning for regional renewable energy development, 4) their legal requirement to consider the greenhouse gas emission impacts from the proposed project, 5) their inadequate analysis of renewable generation alternatives, and 6) an inadequate examination of the alternatives for the specific community service reliability issues as identified in the Application.

II. FORECASTING ISSUES & CONCERNS

Q. Why is the accuracy of the Applicants' forecast an issue?

A. The Application shows that their statement of need for these facilities is based on the projected system wide growth in energy consumption expected in the 2020 time frame. (App. P. 1.4). The core of the analysis they offer in support of this need is based on a forecast of future growth of energy consumption. Under Minn. Stat. § 216B.243, subd 3 item (1) the Applicants have the burden of showing that their forecast of long range energy demand is accurate.

Q. Where is the forecast of system wide growth found in the Application?

A. The technical analysis supporting the system wide growth claim regarding the need for these facilities is found in the Application in the CAPX 2020 Technical Update document, Appendix A-1, Table 1. It shows a load growth forecast for the CAPX utilities systems of 6300 MW by the year 2020.

Q. What are your concerns about the accuracy of this forecast?

A. This Technical Update study work is shown on page one of Appendix A-1 to have been completed in October 2005. That means that the forecast assumptions used in the analysis would have to have been made in 2004. Those forecasts are now four years old, and numerous economic and legislative forces have been at work since that time that affect the future forecast of energy. More recent Integrated Resource Plans have been filed by the CAPX utilities with updated forecasts for the year 2020. Significant changes made during the 2007 legislative session in Minnesota regarding an increased requirement for conservation and substantial renewable energy requirements have created a new paradigm that renders the forecasts used by the Applicants obsolete and inaccurate.

Q. What are the specific requirements of the 2007 legislation regarding increased conservation?

A. Minnesota Session Laws 2007, Ch 136 established a policy goal of conserving 1.5% of annual retail electric energy sales beginning in 2010. Prior to the passage of this new law, Minnesota did not have a specific performance-based conservation requirement. All of the forecasts used in the studies in Appendix A-1, and the data provided in Appendix C, were made without consideration of this new requirement.

Q. How can you be sure these new law changes are of significant magnitude to impact the accuracy of the Applicants' forecasts?

On July 20, 2007, Xcel Energy filed a “Notice of Changed Circumstances” in Docket E-

002/RP-04-752 indicating that "our preliminary analyses of the impacts of the 2007 legislation indicates substantial changes to system operations and suggest changed needs with respect to resource size, type, and timing." Transmission resource size, type, and timing, is the focus of this proceeding. Also, on September 17, 2007, Great River Energy issued a press release indicating it is withdrawing from an ownership position in the Big Stone II power plant. GRE cited one reason for their withdrawal being recent Minnesota legislation regarding renewables and conservation, stating, "the implications of the aggressive new state requirements on the Great River Energy's resource needs will be significant." These developments show that even the Applicants now recognize the magnitude and impact that new changes in the laws have on forecasting and future resource needs.

Q. What other information is available to support a different forecast scenario from the one used by the Applicants?

A. In response to an information request regarding updating forecasts submitted to the Applicants by NAWO & ILSR, the Applicants have provided new forecast information in a supplement to IR #7 dated May 1, 2008. That information is attached as Exhibit 2 to this testimony.

Q. What does this new forecast data show?

A. The supplemental data provide updated median and high Integrated Resource Plan forecasts that result in a median forecast load growth scenario for the CAPX utilities of 3919 MW and a high growth scenario of 4789 MW. The new median forecast is about 600 MW below the lower boundary forecast range used in the CAPX 2020 Technical Update Study provided in Appendix A-1. Even the new high-end forecast barely meets the lower boundary growth range of 4500 MW that was presented in the Applicants analysis. The magnitude of the error in their forecast assumptions can be seen by noticing that the 6300 MW of load growth assumed in the Application is 1510 MW, or about 31.5 % above the high-end Integrated Resource Plan forecast, and 60% above the median forecast of 3919 MW.

Q. Do you have any concerns about the accuracy of this new data?

A. Yes, the new data shows that Northern States Power (Xcel Energy) only assumed a 1.1 % conservation component in their forecast. This is contrary to what the law now directs them to achieve. The impact of understating the legal requirement for conservation is to overstate the MW of future energy demand. Thus the total MW that should be expected to occur in the area of concern by 2020 will be even less than stated in this new data.

Q. Can you explain in more detail the legal requirement to use a 1.5% conservation value in the forecast?

A. The 1.5% conservation policy goal was codified in statute as Minn. Stat. § 216B.2401. The legislature directed how this policy would be implemented by also modifying Minn. Stat. § 216B.241, subd 1c, clause (b). The new language in § 216B.241 states that each individual utility and association shall have an annual energy savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the Commissioner of the Department of Commerce in a specific petition requesting a variance. No variances have been granted as of yet, so all the CAPX utilities with Minnesota load now have a conservation goal of 1.5 % per year and this proceeding should be assuming they will comply with their legal requirement. This perspective was recently affirmed by the Administrative Law Judge in a Certificate of Need proceeding regarding the proposed Big Stone II power plant. In a supplemental order the ALJ stated:

> "The Applicants should not be excused from the 1.5 percent goal in this Certificate of Need proceeding. It provides an appropriate planning goal for energy conservation. It would be contrary to the statute to plan to not meet the goal established by the Legislature, particularly where, as here, new facilities are being built, and particularly where this is one of the very first cases to arise under the new goal. If any of the Applicants need relief from the goal in future years, that can be provided by the Commissioner of Commerce under the new statute. At the beginning of a trip, you plan to stay on the main road and to use "off ramps" only when necessary."[1]

Q. Why is this new data significant?

The high growth Integrated Resource Plan forecast represents the upper edge of the reasonable planning scenario range of growth. The lower limit of the forecast range used in the CAPX 2020 Technical Update Study barely coincides with the upper boundary of the range of scenarios used in resource planning proceedings. This indicates that all the forecast scenarios used in the Technical Update Study do not constitute a reasonable basis for determining the size, type, or timing of future resource acquisitions, including for transmission resources subject of this proceeding.

Q. Can you explain how this applies to transmission facilities?

A. The computer models of future years used in transmission analysis are created by building in assumptions of future load growth as a first step. The potential to reach operating limits on the grid system generally increases as you increase load. By overstating the amount of load growth in the input modeling assumptions, you are overstating the likelihood that new facilities will be needed to fix operational constraints.

[1] See OAH Docket. No. 12-2500-17037-2, MPUC Docket. No. ET-6131, ET-2, ET-6130, ET-10, ET-6444, E-017, ET-9/CN-05-619. ALJ Order dated May 9, 2008, page 7, finding #17.

The number and locations of constraints will be different depending on load growth assumptions, and therefore the size type and timing of necessary upgrades will be exaggerated.

Q. What do you conclude from this new forecast data?

A. The Applicants have not met their burden under Minn. Stat. § 216B.243 subd 3(1) to provide an accurate long range energy demand forecast of the projected system wide growth in energy consumption expected in the 2020 time frame on which the necessity for these facilities is based.

III. CONSERVATION AND LOAD MANAGEMENT

Q. Why is conservation and load management important to this proceeding?

A. One of the burdens placed on the Applicants by Minn. Stat. § 216B.243 is the burden to show that the demand for electricity cannot be met more cost effectively through energy conservation and load-management measures. The statute requires the Commission to consider "the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand."

Q. How should this requirement be interpreted in this proceeding?

A. The Applicants have declared a three-part argument for the need for these facilities: a generalized system wide load growth need, a local load serving based need and a renewables development need. The application of the Certificate of Need criteria identified in statute must be applied separately to each of the three components of their argument.

Q. Can you explain how conservation and load management applies to the system wide load growth portion of the stated need?

A. In my previous discussion of forecasting issues I have pointed out how the Applicants' Technical Update Study has failed to incorporate in their analysis the new requirement in state law to achieve 1.5 % annual energy savings beginning in 2010. This is a failure to properly consider conservation measures applied uniformly across the defined geographic need area. In addition, the Applicants have failed to study how targeted application of load management programs could relieve congestion points on the transmission grid, thus relieving the peak demand constraints that drive the alleged need for the specific transmission infrastructure enhancements they propose.

Q. Please explain what you mean by relieving peak demand constraints?

A. For most of the year the transmission system is relatively underutilized. During certain hours of the year, usually in July or August in Minnesota, the demand for electricity peaks and the utilization of the transmission system reaches its maximum usage state. Flows on all the transmission lines do not increase equally, so some lines reach their maximum rated capacity before others. These system constraints on power flow are on specific lines and totally definable. Targeted peak demand management programs focused on geographic areas "downstream" from the congestion point can relieve the power flow at the congestion point. Utilizing load management to relieve transmission constraints instead of building new transmission capacity is like encouraging drivers to shift their driving habits rather than building additional lanes on the highway.

Q. How should the Applicants have used the targeted application of load management analysis for system wide load growth?

A. Once the Applicants developed a reasonable forecast for the year 2020, the type of transmission system analysis used in the technical study of Appendix A-1 would identify constrained areas on the grid. At that point, the models could be tested for sensitivity to targeted load management efforts in relevant geographic areas. Even under the exaggerated forecast used in the study in Appendix A-1, they failed to investigate this requirement of the law.

Q. How would the legal requirement for the Applicant's consideration of conservation and load management be applied to local load serving needs?

A. The Application in section 4.1 lists several alleged specific local community service reliability areas. Minn. Stat. § 216B.243, subd 3(8) requires consideration of "any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically." The Applicants should have examined how targeted conservation and load management programs could have partially or completely resolved each of the 2020 year local reliability issues they have identified. These types of programs are readily available and are deployed routinely by utilities. Load management strategies coupled with distributed generation resources is also a scenario they should have examined.

Q. What is your assessment of the Applicant's analysis of conservation and load management as applied to local community reliability issues?

A. They have failed to comply with their statutory burden. The Applicants have not analyzed the potential for targeted load management or conservation strategies to replace all or part of the energy to be provided by these facilities to the communities alleged to have reliability needs. The Application consideration of Alternatives, provided in Chapter Seven, does not include any discussion of conservation or load management. None of the local area technical studies provided in Appendix A-2 through A-4 considered the potential for conservation or load management to impact the community reliability need component for the proposed facilities. In addition, all of the technical transmission studies were completed prior to the passage of the new conservation requirements to achieve 1.5% energy savings outlined in Minnesota Session Laws 2007, Ch 136, and so each of the local area peak demand forecasts used in the transmission studies fails to consider this important legal requirement in the local reliability analysis. These transmission needs analyses cannot be relied upon since these older forecasts used by the Applicants overstate the load growth and therefore predict the need for additional reliability support in a timeframe earlier than the most likely scenario.

Q. Does the Environmental Report prepared by the Department of Commerce adequately address this load management and conservation issue?

A. No. The Environmental Report limits its discussion of conservation and load management issues to only three short paragraphs, (see page 90) and does not consider the role of conservation or load management as a partial solution to be used in combination with other alternatives.

IV. RENEWABLES GENERATION SUPPORT

Q. What are your concerns regarding the Applicants claim that these facilities are needed for renewables generation support?

A. In their need summary on this issue, page 1.14 and 1.15 of the Application, the Applicants assert that these three lines are a "necessary step" toward meeting Minnesota's renewable energy policy goals and that "it is important to provide transmission support so that renewable development can continue." I concur with the general statement that transmission lines are necessary to support our electricity system and Minnesota's renewable energy policy goals, but the Applicants have not demonstrated that any of these three new 345 kV lines are a "necessary" precondition to being able to meet these goals.

Q. Can you explain your statement in relation to each of the three proposed lines in more detail?

A. The only specific renewables targeted transmission study evidence offered to by the Applicants is the analysis in Appendix A-4 related to the Twin Cities - Brookings 345 kV line. That analysis shows that this proposed segment will raise the generation outlet capability from the Buffalo Ridge area from 1200 MW to approximately 1900 MW. The generation in the interconnection queues, that are waiting to be connected in the Buffalo Ridge area, are almost exclusively wind. One can presume that if built, this line would perform as the study indicates. The problem is that the Applicants have not demonstrated in this record that unless we develop more outlet capability from the

Buffalo Ridge area, Minnesota utilities cannot meet their renewable energy mandates. In other words, the option of meeting our goals by developing renewable generation in other geographic areas and targeting existing transmission and distribution lines has not been analyzed in the Application. We cannot know whether providing 700 MW of outlet capability from this geographic area with this particular line is the best option towards meeting the state's renewable energy policy goals considering economic goals, power system, and community reliability needs. Ongoing transmission study work regarding Dispersed Generation siting strategies will likely help inform this issue.

Regarding the Twin Cities – Fargo 345 kV line the Applicants offer in their renewables support discussion on page 4.48, that this line by itself "will enable an additional 350 MW of generation to be transmitted on the electrical system to customers." The Analysis provided in Appendix A-3, Table 5.1.A, in support of this line shows that this 350 MW is actually an increase in transfer capability across the North Dakota export boundary that limits power transfer from North Dakota to Minnesota and points east. There is no guarantee that this increase in transfer capability will be utilized by wind. On the contrary there are entities trying to develop additional coal resources that could take up this additional transfer capability. So this claim that the Fargo line will enable renewables cannot be substantiated by this statement. Nothing in the supporting transmission study for this line, Appendix A-3, demonstrates any specific renewable development support.

The Twin Cities – La Crosse line is alleged to support renewables development, on page 4.47 of the Application, because "the ability of the electrical system to transfer power is currently constrained" and the new line relieves a 161 kV constraint on the grid during an outage when flow on the Byron - Adams 345 kV line exceeds 766 MW north to south. It is useful to know that the new proposed 345 kV line will enable increased flows out of the Twin Cities southward toward Iowa. This fact by itself does not demonstrate that the 779 MW, presumably wind, the Applicants have identified is in the queue in Mower County, will be able to move power northward to serve Twin Cities load if the line is built. Nothing in the supporting transmission study, Appendix A-2, for the Twin Cities - Lacrosse 345 kV line demonstrates any specific renewable generation development support.

Q. What are the ramifications of the Applicants not demonstrating all the lines will be used to transmit renewable generation?

A. For at least the Fargo 345 kV line and the La Crosse 345 kV line, it must be presumed that they will transmit electric power generated by non-renewable energy sources. This fact triggers a need for the Applicants to comply with Minn. Stat. § 216B.243, subd 3a, that prohibits the Commission from issuing a Certificate of need for a facility "that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source." The Applicants have made no attempt to comply with their burden of proof under this decision criterion. Arguments that you cannot substitute renewable generation sources for these transmission lines do not hold up if one assumes that the renewable generation is developed as dispersed facilities located reasonably close to the load to be served. Since bio-fueled base load and peaking plants are renewable resources, the argument that the intermittent nature of renewable resources requires transmission to reach base load coal plants does not apply here.

Q. What other observations do you have about the need to provide transmission to support our renewable energy policy goals?

A. I have two main concerns about the approach taken by the CAPX utilities leading up to this proceeding. The first is that all the analysis provided in Appendix A-1 was done almost four years ago, when the state only had a policy objective of obtaining 10% renewable energy as a long term goal. The decision to proceed with this application, utilizing obsolete assumptions for the level of renewables required by 2020, now a 20 % mandate, flies in the face of the requirement now in state statute to create a long term transmission plan to support the recently enacted Renewable Energy Standards (RES).

The second major concern is that the planning paradigm used in the Appendix A-1 analysis is based only on the obsolete assumption that new generation will be installed in large scale projects located remote from where the power is needed. This planning presumption virtually guarantees that you will come up with a need for additional high voltage transmission resources and runs contrary to state policy that desires an efficient use of existing transmission resources and corridors. Minnesota Stat. §216E.03 calls for the transmission determinations to be guided by the "state's goals to conserve resources, minimize environmental impacts, minimize human settlement and other land use conflicts, and ensure the state's electric energy security through efficient, cost-effective power supply and electric transmission infrastructure."

The high voltage transmission resources that are identified under these generation assumptions may be more expensive than necessary to meet customer requirements and renewable energy policy objectives. The transmission resources identified using the Applicants' obsolete generation assumptions are biased in a manner that virtually ensures that state Community-Based Energy Development (C-BED) policy objectives will be stunted. In enacting Minnesota Statutes §216B.1612 lawmakers established a preferential C-BED tariff to "optimize local, regional, and state benefits from renewable energy development and to facilitate widespread development of community-based renewable energy projects throughout Minnesota."

Q. What is the transmission planning requirement for renewables now in statute?

A. Minnesota Session Laws 2007 Ch. 3, sec 2, requires a comprehensive effort to study and develop plans for the transmission network enhancements necessary to support the renewable energy standards and milestones established in Minnesota Statutes. The Minnesota utilities were required to submit a report to the Minnesota Public Utilities Commission by November 1, 2007, describing the activities undertaken pursuant to this section. The filing contained a five year action plan that identifies with specificity the actions necessary to implement the specific proposals and to refine and further develop the transmission plans needed to support those standards and milestones.

Q. What are your concerns about that plan?

A. Rather than approach the question of what transmission do we need to support renewables at a level twice the previous standard with a fresh unbiased effort, the utilities simply assumed that the CAPX Phase I facilities, subject of this proceeding, were a done deal. They did not examine whether these proposed facilities were the appropriate match for a system designed to optimize delivery of that new renewable energy to Minnesota retail customers while maintaining system reliability**.**

Q. Please explain your concerns about the assumption that new generation will be installed in large scale projects located remote from where the power is needed?

A. For many decades the standard way to generate electricity was by utilizing large-scale central station plants. This assumption no longer holds true. Even small MW scale wind plants can compete on price of energy with large scale gas plants today. The "distributed" or "dispersed" construction of multiple small MW utility scale generation resources is now possible given present day technological development and economics. The problem is that utility planners are only now beginning to realize that this alternative paradigm has value, and they failed to consider that value when proposing these facilities as a solution to the alleged problem.

The CAPX utilities have asserted that the proposed facilities fit all likely generation development scenarios (see Application page 1.14.) However, in response to NAWO & ILSR's information request #12, provided as Exhibit 3**,** it is now known that generation alternative scenarios examined by the Applicants were biased overwhelmingly to large-scale generation facilities. The legislative directive to plan transmission to meet the RES goals requires the utilities to "incorporate and build upon the analyses that have previously been done or that are in progress, including, but not limited to, the 2006 Minnesota Wind Integration Study and ongoing work to address geographically dispersed development patterns." The legislature specifically required examination of dispersed generation development scenarios, building on the work started in the West Central CBED Study, as part of trying to find the optimal transmission network to deliver renewables to Minnesota customers but the transmission study provided by the Applicants in Appendix A-1 has not done so.

V. NEED FOR COMMUNITY RELIABILITY SUPPORT

Q. The Applicants have stated that a major part of the need for these lines is for community reliability support. What are your concerns about their examination of these issues?

A. The Application, in Chapter 4, identifies a future need for additional reliability support for the communities around and including Fargo, North Dakota, Alexandria, St. Cloud, Rochester, and the Winona and La Crosse, Wisconsin area. Each of those locations has unique circumstances that require an individual analysis of the validity of the claimed need and the range of alternatives available to mitigate any concerns. It is my opinion that the Applicants have generally overstated the urgency of the need for reliability enhancements, have ignored or undervalued various strategies for meeting the actual need for system enhancements in these areas, and as a consequence have not selected more cost effective and timely alternatives to resolve the problems while complying with Minnesota's renewable and energy efficiency public policy objectives.

A. Rochester Area

Q. Please outline your concerns about the stated need for reliability support for the Rochester Area.

A. There is little to dispute about the existing conditions regarding load serving resources available in the Rochester area. Some type of system reinforcement or dramatic reduction in energy usage is needed soon to mitigate the situation. However, the system reinforcements proposed by Applicants as a solution are substantively flawed. First, I'll note that there are deficiencies in the forecasted load growth that overstate the likely level of peak load to be expected in the 2020 timeframe. Second, even using the Applicant's erroneous forecast, there are more cost effective solutions to serving Rochester area load growth than the one proposed. Third, the Applicants have very recently revealed that they plan new 161 kV transmission facilities to connect to the Rochester system in the next few years, that further diminish the argument that a facility the size of the 345 kV line proposed here is the most cost effective way to enhance load service to the Rochester area.

Q. How do forecast deficiencies impact the need for system enhancements?

A. Transmission engineers examine projected peak load levels to determine at what level of Megawatts of demand the system reaches a reliability standard violation event. Differences in the rate of growth of load shift the point in time when the reliability event would be predicted to occur. Overstating the load growth forecast makes the reliability problem appear to occur sooner. A lower forecasted rate of growth would add additional time before a reliability problem would occur. In the case of Rochester, since there is an existing need for system enhancements, the question before us is what option most cost effectively relieves the problems, and for how long. The forecast assumptions impact the calculation of how long any option would reliably serve Rochester load.

Q. What leads you to conclude that the Applicants forecast overstates likely load growth?

A. As discussed above the requirements in Minnesota's new energy conservation laws affect likely forecasts of energy and demand growth. Even in the latest forecast data provided to NAWO & ILSR in Exhibit 2 to my testimony, the forecast for Rochester Public Utilities remains based on the MAPP 2006 Load and Capability report. These figures were developed prior to the passage of the 2007 Session Law and so the local Rochester area forecast used in the transmission studies is out of date and the changed public policy will change the load forecast for Rochester.

Q. What impact does this have on the analysis of solutions to the Rochester problem?

A. An overstated forecast results in understating the useful life of the various alternatives considered.

Q. What are the implications of the very recently revealed new 161 kV transmission facilities the Applicants plan to connect to the Rochester system in the next few years?

A. In Direct Testimony provided by Applicants witness Amanda King, (p.21) it has been disclosed that Xcel Energy plans to build three new 161 kV facilities in the Rochester area, and that Dairyland Power plans to upgrade a fourth 161 kV facility in the Rochester area. These are massive changes to the Rochester area transmission system that will provide additional load support out to at least 2018, according to Ms. Kings' testimony. Since this information was just recently made available, I have been unable as yet to discover the details of the assumptions behind her projection of 2018 as a date when the reliability issues are now projected to occur. Since the Applicants forecast data provided so far over states likely local load growth rates, the 2018 date offered by Ms. King may very well understate the time horizon when problems will begin to occur in the Rochester area after these new 161 kV reinforcements are operational.

Q. What do you conclude from these new planned reinforcements of the Rochester transmission system?

A. The Applicants have declared that the time frame of concern regarding the need for the 345 kV lines is the year 2020. Rochester will likely have a reliable transmission system until at least 2018 and likely longer than that if load management and conservation programs are aggressively pursued in the Rochester area. There is now no need for the new 345 kV line as proposed here for Rochester community reliability support purposes.

Q. What if the 2018 year forecast of reliability benefit to the scheduled 161 kV system upgrades turns out to be correct?

A. Even if this forecast of reliability support benefits is assumed to be true there are other system reinforcements available that would be more cost effective than the proposed 345 kV line.

Q. Can you be more specific?

A. Given that rapid technological advances are now occurring in the area of optimizing control of distributed generation and demand side resources, these types of system efficiency enhancement and peak load management tools will likely be well developed within the ten year time frame before the problems occur.

Also, in response to NAWO & ILSR information request #18, the option of just building the new North Rochester 345/161 kV substation and the two proposed new 161 kV lines also provides increased additional load support to the Rochester area. According to the response to NAWO & ILSR IR #18, the addition of just these facilities by themselves raises the critical load level in the Rochester area to 620 MW. See Exhibit #4 attached. The cost of this option as described in Appendix A-2 is $10.8 million for the 161 kV lines (p. 143) and $6.8 Million (p.148) for the 345 kV substation. This $17.6 million investment buys additional reliable load service, well beyond the 2020 time frame.

B. La Crosse Area

Q. Please outline your concerns about the stated need for reliability support for the La Crosse area.

A. For the need assessment transmission studies that analyzed the La Crosse/Winona region, Applicants have here again used forecasts for load growth for the La Crosse/Winona area that predate the passage of the 2007 Minnesota conservation law. While load in La Crosse is not a target for application of Minnesota law, Winona load forecasts will be impacted. The original La Crosse 161 kV Load Serving Study, found on page 64 of Appendix A-2, was completed in 2005, about three years ago. The study work was performed on a 2003 MISO Model issued in January 2003 that simulated a 2009 model year. (See page 67 of App. A-2). In responses to the supplemental response to information request #16 from NAWO & ILSR (See Exhibit #6 attached) it became obvious that numerous system upgrades have been implemented in the La Crosse area that were not in the initial modeling work. The Applicants responded to the request using a different updated model, the 2011 Summer Peak from the 2006 MAPP Series. The response to the information request contains a list of seven major system and La Crosse area upgrades that were not in the original study model. (See Exhibit #5 attached). The supplemental response shows revised critical load levels under worst case planning criteria conditions, a NERC Category C contingency. The impact of these seven new upgrades significantly changes the need for local reliability support in the La Crosse area from that determined in the initial study work.

Q. What are your concerns about the results of the analysis provided in the response using the newer system models?

A. Part of my concern about the proposed 345 kV solution to the alleged La Crosse area problems is that the 345 kV line stops in Lacrosse. The Applicants have made it clear in their response that they do not intend to build any of the eastbound 345 kV lines out of La Crosse that were a part of the regional analysis done in Appendix A-2. When a radial 345 kV line is proposed to terminate in a lower voltage 230 kV system for load support, a natural engineering concern is how the La Crosse load will be served when the 345 kV line is out of service. The response to IR #16 provides critical load level information in a scenario where the proposed 345 kV line is out of service and a second system element outage also takes place. This N-2 contingency is roughly analogous to a scenario where the line is not built and an N-1 contingency occurs. The only difference is there are some lower voltage facilities added to support the 345 kV line that would otherwise not be in the model.

The IR response shows that in the event of a combined outage of the John P. Madgett ("JPM") generator and an outage of the North-Rochester – North La Crosse 345 kV line, the capability of the electrical system was 800 MW.

Also, in the event of a combined outage of the Genoa 3 generator and the North Rochester – North La Crosse 345 kV line, the capability of the electrical system was 700 MW. If a new transformer were added, the critical load level in this scenario reached 750 MW.

These scenarios, roughly equivalent to N-1 contingencies without the proposed line, can be compared to the N-1 critical load level of 470 MW shown in Figure 4-8 of the Application. Both of these new modeling N-1 critical load levels are significantly above the 602 MW of expected load growth in 2020 for the La Crosse/Winona area.

Q. What do you conclude from this observation?

A. It appears as if the actively occurring system upgrades contained in the modeling, and the underlying facilities added as part of the proposed project, by themselves, have provided enough additional local support to provide reliable service to the area through the 2020 time frame. Additional detailed modeling work would answer this conclusion more fully. They have not shown that the proposed 345 kV line to La Crosse is needed for community reliability load serving purposes. Instead, the alternative of adding just the 161 kV system upgrades, which appear to be those shown on p. 144 of Appendix A-2 for a cost of $32 million, may be a cost effective solution to the 2020 time frame load serving issues.

C. Fargo Area

Q. Please outline your concerns about the stated need for reliability support for the Fargo area.

A. The reliability analysis supporting the claimed need for reliability enhancements to the Fargo North Dakota area are contained in Appendix A-3. Like the Rochester Study the load growth forecasts used in the analysis were developed prior to the passage of the 2007 conservation laws, so the local area forecasts used in the study overstate load growth compared to compliance with the new law. The analysis in this Red River Valley/Northwest Minnesota Load Serving Transmission Study is divided into a discussion of reliability issues in the northern portion and the southern portions of the Red River Valley region. The analysis of the value of alternatives considered is different for the two regions and also depends on the alternative considered. The two major transmission alternatives examined include the 65 mile Boswell to Bemidji 230 kV line and the 250 mile Fargo to St. Cloud 345 kV line. If you unbundle these two regions in terms of analyzing the benefits of the two options you find that the Bemidji to Boswell 230 kV line essentially fixes the problems identified for the northern region. If you assume that the 230 kV line is built and then look at the residual reliability needs in the southern region different alternatives, other than the 345 kV line become evident.

Q. Explain how you conclude that the Bemidji – Boswell 230 kV line solves the northern region reliability issues.

A. Appendix A-3, section 5.0.4, identifies two important north zone needs, the need for another source into the Bemidji sub zone of the northern area and the need for another source into the north zone as a whole. Regarding this 230 kV alternative, this section concludes “The Bemidji-Boswell 230 kV line is the most effective transmission option studied with respect to satisfying these two needs.” Section 5.0.3 states that, for the combined north and south study zones, the 230 kV option provides 300 MW of load growth improvements considering N-2 conditions. The 345 kV option only provides an incremental 100 MW more performance in this regard, for a lot more money. Lastly, the conclusions section (7.0) states that “the Fargo-St. Cloud 345 kV transmission option is not particularly effective at providing load serving support to the northern RRV sub area because the Maple River-Winger 230 kV outage isolates this new transmission source from the northern RV load center.” So only the 230 kV Bemidji - Boswell option, of those presented in the report effectively resolves these northern region issues.

Q. What problems remain to be analyzed if one assumes the 230 kV line is built?

A. Figure 5.3A in appendix A-3 identifies the load benefit area from the 230 kV line, primarily the northern area. The Application, Chapter 4, specifically identifies Alexandria as a southern zone reliability concern load center. Additionally, the St. Cloud area is identified.

D. Alexandria Area

Q. Please outline your concerns about the stated need for reliability support for the Alexandria area.

A. The application indicates a critical load level for the Alexandria area at 171 MW of load without local generation support (See Fig 4-16). In response to NAWO & ILSR information request #13 (See Exhibit #5 attached) the Applicants have stated that if the Bemidji to Boswell 230 kV line is constructed the critical load level in the Alexandria area rises to 190 MW. Using the Applicants forecast they conclude in their response that this would occur in about 2017 for the Alexandria area. The incremental load growth between 190 MW and the year 2020 shown in Figure 4-16 is about 8 MW. This corresponds to an additional growth above the 190 MW critical load level of only 4.2 %. Given that the Applicants have not applied the conservation requirements of the 2007 conservation laws to the local area forecast used in the Appendix A-3 analysis, this additional 8 MW is likely in the error range of their load growth forecast. Since the Alexandria area is a winter peaking locality, peak demand load management programs such as dual fuel heating systems targeted to the area beginning now should eliminate 8 MW of peak load by 2017.

Q. What are your conclusions about the Alexandria area need for reliability support?

A. If the Bemidji to Boswell 230 kV line is built to enhance the northern Red River Valley region reliability issues, there likely will not be a reliability problem to solve in the Alexandria area in the 2020 timeframe of concern as outlined in the Application. The Applicants have not shown that the Fargo to Twin Cities 345 kV line is the most cost effective way to manage 2020 year load growth issues for the Alexandria area.

E. St. Cloud Area

Q. Please outline your concerns about stated need for reliability support for the St. Cloud area.

A. St. Cloud, like Rochester has a fairly well defined existing system deficiency requiring system reinforcements or a substantial reduction in local load. The discussion in the Application, Ch 4.1.6 identifies reliability issues related to the outage of the Benton County 115 kV double circuit line, and the outage of the Crossroads – Granite City 115 kV line. The Applicants propose to tap the Fargo to Monticello 345 kV line at a point at or near the Sauk River substation or the West St. Cloud substation to reinforce the local St. Cloud power system. My concern is that the complete story regarding the solution to the St. Cloud reliability is not easily gathered from the discussion in section 4.1.6 or the Appendix A-3 transmission Study.

Q. What part of the story needs clarification?

A. The discussion in section 4.1.6 regarding the outage of the Benton County double circuit 115 kV line includes a discussion of the operating procedure that trips the 115 kV line going to the St. Regis substation at the same time the double circuit line is tripped. The reason for this is because of the physical arrangement of the St. Regis line "between the line terminals for the Benton County – Granite City double circuit 115 kV line." The point that needs clarifying is that the Applicants' proposed solution likely will not solve the problem of the need to trip the St. Regis substation when the double circuit 115 kV line is tripped**.**

Q**. What other issues need to be clarified?**

A. The discussion of the schedule for the line contained in section 4.1.7 indicates that the Applicants would construct the Monticello to St. Cloud portion of the proposed 345 kV line as soon as possible to bring "additional transmission capacity to the area where the need is most immediate." The point that needs clarification is how long this short extension of a 345 kV line would serve as a solution by itself to the local load serving problems in the St. Cloud region.

Q. How can you clarify the value in building just this segment as a solution to reliability issues in the area?

A. The transmission study contained in Appendix A-3 did not directly examine this option. However there is some information in the report that sheds light on the question. One way to examine the value of this 345 kV radial option is to look for information about the performance of the longer proposed 345 kV line to Fargo under scenarios where the portion of the proposed line from St. Cloud to Alexandria would be out of service. The examination of the termination point options for the Fargo line in the St. Cloud 345 kV Sensitivity found in Appendix A of the Red River Valley/Northwest Minnesota Study offered in Application section A-3 contains some information in this regard.

Q. How is this discussion helpful?

A. The discussion in this section shows that by adding double transformers in various locations the amount of support to the local area provided by the Applicants' proposed project can be up to 343 MW of incremental St. Cloud load serving capability.

Since the need for additional support to St. Cloud even in the year 2020 is identified to be an incremental 230 MW as shown in Figure 4-19 of the Application, the Applicants' solution provides significant margin above 230 MW. What can be gleaned from the data in this analysis regarding the radial 345 kV option I described above is contained in the discussion of the specific double contingency limitation that results in the 343 MW limit. On page 3 of Appendix A to Section A-3 it states "The Monticello option is limited to 343 MW by the outage of the Sherco-Monticello 345 kV line in conjunction with outage of one Benton Co 345/230 kV transformer." What is significant about this is that the outage of the section of the proposed 345 kV line between St Cloud and Alexandria is not part of this system limiting double contingency. This means that in the radial scenario, for an N-1 outage analysis, equivalent to simulating the outage of the Alexandria to St. Cloud section of the 345 kV line and any other contingency event will have incremental load serving limit higher than 343 MW. This is significantly above the existing system's N-1 critical load level of 228 MW as identified in the Application in Figure 4-19.

Q. What do you conclude from this observation?

A. It appears that the St. Cloud area N-1 reliability issues can be resolved beyond the year 2020 with the radial 345 kV option from Monticello and the portion of the 345 kV line west of St Cloud is not needed to resolve this level of reliability of service to the St Cloud area.

Q. Are there other options for resolving the St. Cloud reliability issues?

A. Yes, even though the existing MW at risk level is stated to be 140-175 MW, a combination of peak demand management and strategic distributed generation deployment could be targeted to the St. Cloud area and probably Rochester as well, using "Smart Grid" technologies. I will speak to this opportunity later in my testimony.

VI. GREENHOUSE GAS EMISSION IMPACTS

A. Climate Change Statute Requirements

Q. Why is the issue of greenhouse gas emissions relevant to this proceeding?

A. There is a reference in Minn. Stat. § 216B.243, subd 3 (5) that requires consideration of the benefits of this facility, including its uses to protect or enhance environmental quality. It follows that, to the extent a project degrades environmental quality, that should also be a factor in the decision to be made here.

The Minnesota Environmental Policy Act, found in Minn. Stat. § 116D.02, Subd. 2(16), places a responsibility on state agencies to "reduce the deleterious impact on air and water quality from all sources." Minnesota Environmental Law, as stated in Minn. Stat. § 116D.04, Subd. 6, provides that no state action which is likely to cause impairment of the environment shall be allowed if there is a feasible and prudent alternative.

There is also statute language in the newly created Minn. Stat. § 216H regarding greenhouse gas reduction policy that also must be considered in this proceeding.

Q. How does the 216B.243 requirement regarding enhancing environmental quality apply here?

A. As I have demonstrated above, the Applicants have failed to show that there is any specific renewable energy transport benefit for at least two of the three 345 kV lines they propose. Since the power that would flow on these lines is quite likely to be non-renewable sourced energy, in fact the location and size of the generators on the list of generation sources modeled in the Analysis in Appendix A-1, used to justify the need for these projects, likely shows fossil fueled sources now in interconnection queues. To the extent that these lines enable those proposed generation sources there would be an adverse effect on environmental quality, thus an environmental cost, rather than a benefit is associated with operation of these proposed facilities.

Q. In what ways are the new Chapter 216H laws applicable here?

A. First, per Minn. Stat. 216H.02, subd 1, it is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

Second, there is a specific directive in Minn. Stat. 216H.03 subd 3, that on and after August 1, 2009, no person shall "construct within the state a new large energy facility that would contribute to statewide power sector carbon dioxide emissions" and no person shall "import or commit to import from outside the state power from a new large energy facility that would contribute to statewide power sector carbon dioxide emissions; or enter into a new long-term power purchase agreement that would increase statewide power sector carbon dioxide emissions."

Q. How do these requirements apply here?

A. Enabling the importation of fossil fueled power from outside the state by construction of the proposed facilities would contribute to statewide power sector carbon dioxide emissions. There is also evidence available in this record that the carbon dioxide contribution from the mere construction of these transmission lines would significantly contribute to an increase in statewide power sector emissions.

B. Impacts from Power Line Construction

Q. What kind of evidence is available regarding construction impacts?

A. There is evidence in this record already, in the form of Environmental Report Scoping comments from the Sierra Club, that indicate that transmission line construction CO2 impacts can be greater than any operational CO2 benefits that may accrue over time. The

Sierra Club cites an Environmental Review document developed by California Public Utilities Commission and U.S. Bureau of Land Management in a proceeding regarding the Sunrise Powerlink transmission project. This project consists of 91 miles of 500 kV single circuit overhead line, a new substation, and a 59 mile segment at 230 kV line intended to help deliver power from a solar, a geothermal, and a wind facility. The California PUC Draft Environmental Impact Report concluded:

> "Assuming long-term avoided GHG emissions of 1,650 tons of CO2 annually, based on the CAISO forecast for 2015, during every year of transmission line operation would provide 66,000 tons over 40 years. This quantity of avoided GHG emissions would not fully offset the two years of GHG emission increases caused by construction (approximately 109,000 tons). Because total construction GHG emissions exceed the GHG reductions achieved due to avoided power plant emissions over 40 years of transmission line operation, the Proposed Project would cause an overall net increase in GHG emissions and a significant climate change impact."[2]

Since these lines similar in class to the lines proposed here, utilizing similar right of way requirements and construction techniques the construction CO2 impacts on a per mile basis should be similar.

C. Impacts from Enabled Coal Generation

Q. How will these lines enable import of fossil fuel from other states?

A. At a minimum the Fargo line could enable importation of at least 350 MW of fossil fueled, likely coal fired energy from North Dakota. The transmission line Certificate of Need proceeding regarding Big Stone II transmission lines contains voluminous data on CO2 emission levels from coal plants. This environmental impact and the CO2 impact

[2] See Sunrise Powerlink DEIR, January 2008: http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/deir/D11%20Air%20Quality.pdf, page D.11-55.

from construction should be a part of the Environmental Report developed for this proceeding.

VII. ALTERNATIVES ANALYSIS

Q. What is your assessment of alternatives provided in the Application and in the Environmental Report?

A. Both efforts have failed in the first instance to make any showing in this regard because they have failed to offer any comprehensive alternative that would meet the combined needs that the proposed project is intended to satisfy. Nowhere in Chapter 7 of the application, the Alternatives Chapter, do the Applicants develop any of the information required by Minn. Rule 7849.0260(C) that would enable a reasoned comparison of cost and performance data of any alternative to the project's cost and performance. Similarly the Environmental Report fails to develop any comprehensive alternative, not even one based on considering the possibility of a combination of various strategies.

Q. What is your assessment of the need for the analysis of Alternatives at this time?

A. As I just mentioned, a complete and comprehensive alternative would address all of the three categories of need identified by the Applicants, 1) Minnesota area system wide needs for future load growth, 2) Community reliability needs for the specific communities identified in the Application, and 3) Renewables development support. Additionally, since there are three major 345 kV lines being proposed for three different geographic regions of the state, the alternatives should be focused on satisfying the needs on a line by line basis. The Applicants have predominantly examined finding only a set of transmission solutions to the individual problems they have alleged. A one size fits all transmission only approach to alternatives isn't a realistic way of solving problems that occur 20 years out.

However, as I have just shown in my testimony the three categories of need as stated in the Application to do not hold up to the evidence available given the new state renewable energy standard and conservation law requirements. The actual need for system enhancements is substantially different for all three categories of need from those alleged in the Application. Since the assumptions in the Application on which the need for the proposed project are based are shown to be in error, the Applicants have failed in the first instance to demonstrate the need for their projects. It is technically not necessary to reach the examination of alternatives in this proceeding unless there is a verifiable demonstration of need around which alternatives can be constructed and examined.

A. System Wide Needs

Q. Please explain your position regarding the evidence for or against the claimed need to Support Minnesota area load growth.

A. In the case of the claimed need for Minnesota area system wide load growth support, the projections of future load growth used by the Applicants for the year 2020, between 4500 and 6300 MW of load growth has been shown to be obsolete and exaggerated given the latest forecasts being used in Integrated Resource plans. The actual projections of future Minnesota area load growth now offered by the Applicants fall into the median to high forecast range of 3,919- 4,789 MW. A new low load growth forecast, which is just as probable as the high growth scenario, was not even offered by the Applicants. The transmission study offered in support of the proposed lines didn't even examine the forecast range that is used by Minnesota regulators to determine resource acquisition requirements. The claimed need for these facilities for Minnesota area system wide load growth fails to pass the burden of proof hurdle since the applicability of the proposed transmission project has not been studied for suitability to the load growth projections now offered by the Applicants.

Q. Couldn't we just assume we would "grow into" these new facilities over time?

A. The Applicants have claimed a need that needs to be satisfied in a 2020 time frame. The question of what is the least cost option to meet the 2020 year system load growth need has not been adequately analyzed by the Applicants. Beyond this 15 year time frame the industry cannot create believable system models to even test various options to meet any claimed need. It is important to recognize that the Applicants have created this set of proposed lines using an "old paradigm strategy" set of study assumptions that is no longer a likely set of assumptions about the future to plan around. A realistic approach would acknowledge Minnesota's GHG reduction goals and how that policy will drive the state towards dramatic absolute reductions in electricity consumption or towards an even more dramatic switch to renewable energy technologies. The applicants have not demonstrated that their proposed lines fit well in to meeting these future requirements.

Power System Design Strategies

Q. What do you mean by an old paradigm strategy?

A. Earlier in my testimony I referenced the fact that the Vision Study offered in Appendix A-1 of the Application had presumed a set of generation that would be developed that was almost exclusively of the large scale variety, sized in the hundreds of megawatt range. The locations selected to be analyzed included many locations in the

Dakotas, Manitoba, Iowa, and Wisconsin. Even the wind plants were modeled as single injections of plants with 100 – 400 MW units. This bias in the assumptions used in planning, reflective of the way power plants were sized and located in the past, no longer is indicative of where the technologic innovation in generation technology economics, and public policy are driving generation patterns now and on into the future.

Q. What would be a new paradigm then?

Power generation technologies are evolving into smaller plant sizes, and new technology types that can be located close to the point of end use of the energy. Open Access policies at the federal level and the passage of Community Based Energy Development laws in Minnesota have enabled local communities to capture the economic development benefits associated with owning these types of generation resources. The Minnesota legislature in 2007, recognizing this trend, required utilities to study how to integrate 1200 MW of Dispersed Generation into Minnesota's power grid. The report on the first phase of that study, integrating 600 MW, is due to be released in just a few weeks on June 16th. The results of that study will further inform the value of these types of resources. At this time, I am limited in what I can say about the study results because of signed confidentiality agreements for those advising the process.

Additionally, new technology options utilizing Internet based communication strategies, and new legal requirements to implement these technologies to control demand on the power system will significantly affect the need to plan for what historically been uncontrollable customer system peak demands. This is especially relevant to transmission planning since the transmission system generally must be sized to service the maximum peak power flow event. Since transmission planners have to plan out to a fifteen year time frame, the scenarios they create of the power system as they expect it to be in the future must consider these important trends in technology innovation in their planning assumptions. The study work presented by the Applicants in this proceeding has not done so. The future trend in tools that are and will be available to transmission planner's impact both what assumptions should go into the future models and what options can be used for mitigation strategies.

Dispersed Generation Studies

Q. How has the concept of Dispersed Generation been integrated into transmission planning to date?

A. Except for responding to Interconnection Queue requests, modeling for integration of dispersed technologies has generally not been a part of transmission planning assumptions. One exception has been right here in Minnesota when, the Minnesota utilities, as a result of negotiations with NAWO, undertook a study of integrating Dispersed Generation into the West Central transmission planning zone in the state. This West Central CBED Study has been made part of this record as part of direct testimony of Tim Rogelstad. That study showed that it is possible to integrate 1400 MW of dispersed resources into the existing grid for less than $100 million in system improvements. The improvements were upgrades of existing facilities that would not require Certificate of Need process to implement.

Q. What did that study show in regard to transmission planning?

A. The conclusion section of the CBED Study Report states "this study has pointed out that future generation scenarios based on dispersed resources can have an impact on the type of system reinforcements that may be necessary to accommodate these smaller dispersed resources." This statement verifies that if you include dispersed generation as part of your transmission planning assumptions, you will discover they will impact the type of system reinforcements that may be necessary. If smaller dispersed generators become the predominant generation type in the ten to fifteen year planning horizon the nature of transmission reinforcements that are necessary will likely be significantly different than the ones that the Visioning Study offered in Appendix A-1 produced that used an old paradigm future of large scale facilities located far from load.

Q. What happened as a result of the West Central CBED Study?

A. The showing in the study that during summer on peak time that up to 1400 MW of dispersed generation could be used to offset expensive gas peaking generation in Minnesota for the relatively small investment of about $100 million in transmission enhancements led to passage of the legislation in the Next Generation Energy Act of 2007 requiring further exploration of Dispersed Generation strategies applied throughout the state.

Q. Are there other attributes of Dispersed Generation resources that need to be recognized?

A. Since smaller generators generally can be installed on lower voltage facilities they offer the potential for their interconnection to be managed under state authority rather than having to enter the FERC jurisdiction MISO Queue. The MISO Queue is a well known barrier to interconnection because of the long lead times to get through the process. The recent Minnesota State legislature CBED Advisory Taskforce committee investigated this interconnection jurisdiction process and recommended that "The work group noted the MISO queue process is overwhelmed with a backlog of generator interconnection requests and recommended the state should exercise its authority to implement state interconnections as a tool to facilitate C-BED project installation."[3] These smaller resources could be integrated into the system through an expedited state review process.

B. Community Reliability

Q. Please explain your position regarding the evidence for or against the claimed need for Community Reliability Support.

A. For the claimed need category of community reliability support, I have examined each of the local communities identified in the Application intended to be served by either the Fargo to Twin Cities 345 kV line or the Twin Cities to La Crosse 345 kV line and found that given that the CAPX utilities are applying for a permit to build the Bemidji to Boswell 230 kV line, and because significant system reinforcements are either in service or committed to be built for Rochester and La Crosse, and because a radial 345 kV option is available for St. Cloud, the need for these two 345 kV lines for community reliability support does not hold up under scrutiny. In addition to these transmission related problem mitigation strategies there are other options such as the "Smart Grid" that could be applied to the identified issues.

The Smart Grid

Q. What do you mean by the term Smart Grid?

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[3] See: Legislative Electric Energy Task Force Legislative Coordinating Commission Minnesota Legislature Community-Based Energy Development (C-BED) Advisory Task Force Report, March 28, 2008.

A. The Smart Grid term is one of several labels that are used to refer to using communication and control technology to add intelligence and efficiency to the power transmission and distribution system. The technology is used in a real time mode to monitor and manage power flow on the grid through interactions with storage systems, and both demand and supply side distributed resources. Technology is also provided to electricity customers that allow them to actively participate in lowering their energy consumption and lessening of their impact the rest of the grid system.

Q. Are utilities using this technology now?

A. The concept is being implemented across the country in various degrees and manifestations. One of the Applicants, Xcel Energy has committed to install a comprehensive Smart Grid system in the City of Boulder Colorado. They have published a Smart Grid White Paper to explain the technology. I have attached a copy to my testimony as Exhibit #7.

Q. Do you have more detail on the Xcel Energy Boulder Project?

A. The Smart Grid White Paper indicates that the Boulder Smart Grid project is phase II of a three phase project that would lead in the third phase to an Xcel wide deployment of proven technologies after the results of the "Smart Grid City" Boulder project results are available.

Q. What system benefits are available using this technology that are relevant to this proceeding?

A. One of the benefits of the Smart Grid listed in the White Paper are expected deferral of capital expenditures for transmission projects based on improved load estimates and reduction in peak load from enhanced demand management. The Community Reliability support need identified by the Applicant is caused by peak demands on the system. This new tool can therefore be utilized as a peak demand management device to mitigate these transmission bottlenecks.

Q. What are the cost and timing parameters of the Boulder project?

A. Xcel indicates in the White paper that total investment among the project partners will be about $100 Million. In a supplemental response to NAWO & ILSR information request #15, copy attached as Exhibit #8, Xcel indicates that the system is being built this year and will be fully operational by the end of 2009. This is an extremely short lead time to install a system that has so much potential for a wide variety of system and customer benefits. One can easily expect that costs will come down dramatically as Xcel Energy and other utilities gain experience in implementing Boulder's Smart Grid.

Q. In their response to your IR # 15, Xcel indicates that this Smart Grid concept is just developing, and very little exists in the way of quantifiable results or judgments about the project. Why do you think this Smart Grid concept has value to this proceeding?

A. First, this technology is more than a concept; previous applications of this strategy have shown significant positive results. In particular I will point to a test of the technology performed through Pacific Northwest National Laboratories (PNL). Their “GridWise” Demonstration Project has a number of reports available. A “Fast Facts” paper on the project from PNL is attached as Exhibit #9. PNL has come to some more definitive conclusions about the usefulness of this concept than offered by Xcel in their IR response. In particular in the paper I mentioned, PNL concludes “The project demonstrated that utility-dispatched demand response can alleviate the need to build expensive new infrastructure to address constraints on the distribution or transmission system during times of peak demand." Not only do they offer this general statement, but their study demonstrated that "an Internet-based network coordinating demand response can save consumers money on power, and reduce peak load on the grid by 15 percent over the course of one year." When the technology is used in combination with distributed generation they found "A combination of demand response and distributed generation reduced peak distribution loads by 50 percent for days." The power of this technology has been demonstrated already, the investment of $100 million being made by Xcel energy and its partners in Boulder is an investment whose magnitude is such that the parties making such an investment won't do it unless they are relatively certain of its outcome.

Q. What do you see as the long term potential impact of this technology for transmission planners?

A. The demonstration of a 50 % reduction in peak load demand for days at a time by PNL when supply and demand side resources are simultaneously managed collectively could dramatically change the shape of load duration curves for the grid system as a whole. This would increase overall utilization of the existing grid system, getting more energy delivered from our sunken investment in infrastructure, and greatly impacting the timing and nature of new infrastructure enhancements. Xcel Energy's CEO Dick Kelly seems to concur with the potential of the Smart Grid. He has stated that the Boulder

Smart Grid technology "is a forward-thinking project that will transform the way we do business."[4]

C. Renewables Support

Q. Please explain your position regarding the evidence for or against the claimed need for Renewables Support.

A. The third category of claimed need, regarding providing renewables support, also has problems. The Applicants have not tried to make any showing that the Twin Cities – Rochester – La Crosse 345 kV line will help Minnesota meet its renewable energy goals. Regarding the Fargo – Twin Cities 345 kV line the Applicants have offered that 350 MW of increased generation outlet is evidence of this line having renewables support attributes. They offer no guarantee that the 350 MW made available will not be scooped up by fossil fueled generation resources. Regarding the Brookings – Twin Cities 345 kV line the Applicants have made a showing that 700 MW of outlet capacity from the Buffalo Ridge area will be created by this system addition, evidence offered that it will be utilized by renewables is the magnitude of wind generation now in the MISO queue for this area. However, they have made no showing that building this $600 + million dollar line is either the least cost next step to reduce the MW of need for renewables calculated in the Gap analysis by 700 MW or a necessary prerequisite to achieving the Minnesota RES goals.

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[4] See Press Release provided to NAWO & ILSR as part of response to IR # 15.

Focus on Delivered Cost of Energy

Q. Isn't it obvious that the high wind resource region in southwest Minnesota and eastern North and South Dakota would be the least cost next step to achieving the Minnesota RES goal?

A. No. From a societal policy perspective what is the determinant of what would be the least cost way to get 700 MW of renewables for Minnesota goals would be to look at the total cost of delivering the energy to Minnesota load, not the cost of power out where it is injected into the grid should be the proper comparison between alternatives. A comparison between the cost of energy from 700 MW on the Buffalo Ridge, including the $600 million cost of building the Brookings – Twin Cities 345 kV line, with the delivered cost of energy from another area including the infrastructure necessary to deliver energy from that location would be the way to examine alternative strategies to meet the RES Goals.

Q. Are the Applicants doing this kind of analysis?

A. The utilities responsible for doing RES related transmission planning have initiated a "G & T Study" to examine this issue. Information about results is not yet available from this effort. Proper decisions about the nature of least cost new transmission infrastructure investments for renewables cannot be made without this type of data.

D. Ratepayer Economic Impact

Q. Why are socio-economic issues relevant to this proceeding?

A. There are provisions in both the Certificate of Need statutes and in Minnesota Environmental Policy Act that requires an evaluation of the direct and indirect economics of the proposed project and the alternatives.

Q. What do the Certificate of Need Laws require?

A. Under Minn. Stat. § 216B.243, subd 3, "the applicant must show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need." Even more detail regarding this issue is developed in Minn. Rules Ch. 7849.120 subp B(3), which states "a certificate cannot be granted unless a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering: the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives." Both of these legal requirements force an examination of cost issues related to the project and its alternatives.

Q. What does the Minnesota Environmental Policy Act require?

A. In Minn. Stat. § 116D.04, subd 6, it requires that:

> "No state action significantly affecting the quality of the environment shall be allowed, nor shall any permit for natural resources management and development be granted, where such action or permit has caused or is likely to cause pollution, impairment, or destruction of the air, water, land or other natural resources located within the state, so long as there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare and the state's paramount concern for the protection of its air, water, land and other natural resources from pollution, impairment, or destruction. Economic considerations alone shall not justify such conduct."

That statement bounds the value of consideration of economic parameters and shows that environmental concerns override economic considerations.

Q. What other socioeconomic factors are relevant here?

A. The state has a policy that encourages local economic development through the deployment of Community Based Energy Development projects as outlined in Minn. Stat. § 216B. 1612. These renewable energy project ownership structures are to be given priority consideration for contracts by utilities that have an obligation under the Renewable Energy Standard law.

Community Based Energy Development

Q. How do these CBED socioeconomics fit into the decision to be made here?

A. Since part of the claimed need is for renewables development, a comparison of the Applicants' proposed project's renewable attributes with other renewable development alternatives, such as Dispersed CBED Generation development throughout the state should be considered when evaluating whether a Certificate of Need should be granted.

Cost allocation and Ownership

Q. How do ratepayers fit into this analysis?

A. Rate payers are part of the socioeconomic environment required to be evaluated under Minn. Rules Ch. 7849.

Q. How will the proposed projects costs be allocated to Minnesota ratepayers?

A. The Applicants, after being ordered to do so by the commission, provided information in Appendix D-5 of the Application. This section provides part of the picture regarding ratepayer impacts.

Q. Why is this only a part of the picture?

A. The data in Appendix D-5 show how much money MISO will collect from the various Minnesota loads using the lines (Table 5) to get the money needed to pay for the lines. The money that MISO collects to pay for the lines will be distributed to the eventual owners of the proposed facilities if they are built. The Applicants have failed to make any demonstration regarding who will actually own what part of these lines so we cannot know for sure who will get this money. The Applicants have provided a surrogate example of how much money each of them would receive from owning these lines in Table 2 of Appendix D-5. This Table is built upon a premise that they all commit to invest at their maximum agreed upon percentages.

Q. Why is the ownership question so important here?

A. For the investor owned utilities, the investments these utilities make in owning these lines are capital expenditures that would typically become part of a rate case proceeding. The investment would become part of the rate base consideration of appropriate charges to Minnesota ratepayers. For Municipal and Cooperative utilities, rate cases are not before the Commission, but the costs or profits from the investment in these lines will be borne 100% by the ratepayers of each entity. Any net revenues from ownership would presumably help offset the costs that are charged to them by MISO under Table 5.

Q. Are there other reasons why ownership is important here?

A. The CAPX utilities have openly admitted that they would consider other as yet unidentified third party entities to become owners of these lines. When Interstate Power & Light sold its transmission assets to Interstate Transmission Company, the Minnesota Commission transferred jurisdiction on a number if transmission related items to FERC. If a Certificate of Need is granted in this proceeding with no proof of ownership requirement attached to the Certificate as a condition, it is not clear that the Commission would have any say in who ends up owning these lines. The Commission may have given up future jurisdiction over these facilities without knowing it.

VIII. SUMMARY AND RECOMMENDATIONS

Q. What is your overall assessment of the alleged need for these facilities?

A. The Applicants claimed three categories of need do not stand up to the evidence available. The need for system wide load growth support need has been grossly overstated by the Applicants, to the point that recent projections of load growth developed by the Applicants themselves fall outside and below the range of forecast scenarios examined in the CAPX Vision Study offered in support of this claimed need.

The need for community reliability support has been shown to be based on overstated forecasts for the local area of concerns. Even if these forecasts were accurate there are other more cost effective options available for resolving all of the community reliability issues identified in the Application.

The need for renewables support that each of the three lines is purported to offer does not hold up under scrutiny. No specific identified renewable benefit is offered for the Twin Cities to La Crosse 345 kV line, the Fargo to Twin Cities line's alleged 350 MW of North Dakota export capacity has not been shown to be guaranteed to be used by renewables, and the Brookings to Twin Cities line, while likely shown to provide renewable generation outlet capability, has not been shown to be the least cost way of adding 700 MW of renewables to the system to reduce the gap in achieving Minnesota's RES Goals.

Q. What is your recommendation regarding what action the Commission should take regarding the Certificate of Need permit Application?

A. The Commission should determine that based on the needs identified in the Application, the Applicants have not met there burden of proof to show that this proposal is the least cost way to meet the actual need for system enhancements in each of the three categories of claimed need. The Commission should deny the permit request.