BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION FOR CERTIFICATES OF NEED FOR THREE 345 kV TRANSMISSION LINE PROJECTS WITH ASSOCIATED SYSTEM CONNECTIONS

Docket No. ET2,E002, et al./CN-06-1115

REBUTTAL TESTIMONY OF DR. STEVE RAKOW

ON BEHALF

OF THE MINNESOTA OFFICE OF ENERGY SECURITY

JUNE 16, 2008

REBUTTAL TESTIMONY OF DR. STEVE RAKOW
IN THE MATTER OF APPLICATION FOR CERTIFICATES OF NEED FOR THREE 345 KV TRANSMISSION LINE PROJECTS WITH ASSOCIATED SYSTEM CONNECTIONS

DOCKET NO. ET2,E002, et al./CN-06-1115

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name.

A. My name is Dr. Steve Rakow.

Q. Are you the same Dr. Rakow who previously submitted direct testimony on behalf of the Minnesota Office of Energy Security (OES) in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I am offering rebuttal testimony to the following parties' witnesses:

- Wind on the Wires, Fresh Energy, Izaak Walton League of America – Midwest Office, and Minnesota Center for Environmental Advocacy (jointly, Joint Intervenors) witnesses:
  - Mr. Larry L. Schedin; and
  - Mr. Christopher T. Ellison;
- Northern States Power Company, a Minnesota Corporation and wholly-owned subsidiary of Xcel Energy Inc. (Xcel) and Great River Energy, a Minnesota Cooperative Corporation (GRE) (jointly, the Applicants) witnesses:
  - Ms. Laura McCarten;
  - Mr. Kevin Lennon; and
  - Mr. Grant Stevenson;
- North American Water Office and Institute for Local Self-Reliance (jointly, NAWO-ILSR) witness:
  - Mr. Michael Michaud; and

- Citizens Energy Task Force (CETF) witness:
  - Dr. Arne C. Kildegaard.

II. REBUTTAL TESTIMONY

A. RESPONSE TO JOINT INTERVENORS

Q. What is the purpose of your offering rebuttal to the Joint Intervenors' direct testimony?

A. I wish to respond to the Joint Intervenors' proposed alternative to the Fargo, ND—Twin Cities line. I also wish to respond to the Joint Intervenors' proposed conditions.

1. Proposed Alternative to the Fargo, ND—Twin Cities Project

Q. What does Joint Intervenors' witness Mr. Schedin recommend regarding the Applicants' proposed Twin Cities—Fargo, ND 345 kV transmission line?

A. Regarding the Applicants' proposed Twin Cities—Fargo, ND 345 kV transmission line, the May 23, 2008 *Direct Testimony of Larry L. Schedin PE* states at page 6:

> I further recommend that this 345 KV line be constructed for double circuit 345 KV operation…

Q. What is your response to Mr. Schedin's recommendation?

A. While it is possible that a double-circuit alternative has merit, there is no cost or loss data regarding a 345 kV/345 kV double circuit alternative to the Fargo, ND—Twin Cities 345 kV single circuit transmission line. Therefore, it is not possible at this time to determine whether Mr. Schedin's recommendation represents an alternative with a lower cost than the alternative proposed by the Applicants.

As noted in my direct testimony, the Applicants' response to OES Information Request No. 40 provided line loss information regarding a 500 kV/345 kV option; I understand that this loss data is applicable to either two separate circuits or a double circuit transmission line. It is not clear if Mr. Schedin's recommendation for double circuit 345 kV transmission line would also apply to a 500 kV/345 kV double circuit transmission line. Therefore, it would be helpful for Mr. Schedin to offer an opinion in surrebuttal regarding a 500/345 kV double circuit.

The calculations in my direct testimony at pages 78 to 80 and in OES Exhibit No. ___ (SRR-16) demonstrate that a 500 kV/345 kV double circuit transmission line would be a cost-effective improvement on the Applicants' proposal (based solely on the energy conservation benefits) if the incremental capital cost (the cost above the Applicants' proposed 345 kV single circuit proposal) were less than $253.35 million (using the low values) or less than $522.81 million (using the high values).

In order to determine if a double circuit line would be preferred to a single circuit line, it would be necessary for the Applicants to provide cost data on the 500/345 kV double circuit alternative and, if possible, cost and loss data on a 345 kV double circuit alternative in surrebuttal. This information will allow a proper cost analysis. If the Applicants are able to provide such cost and lost data in a timely manner, I will review all of the options again. Potentially, a double circuit alternative may have a lower cost than the Applicants' proposal.

2. Proposed Conditions

Q. What does Joint Intervenors' witness Mr. Ellison recommend regarding the Applicants' proposed transmission lines?

A. The May 23, 2008 *Direct Testimony of Christopher T. Ellison* contains six conditions; the conditions are summarized on pages 13 to 15. Briefly, Mr. Ellison's conditions would require the Applicants to:

1. commit to obtaining renewable generation projects that use the capacity enabled by the new transmission lines and seek Minnesota Public Utilities Commission (Commission) approval of the generation;
2. provide details on how the Applicants propose to allocate the new transmission capacity among the Applicants;
3. sign power purchase agreements (PPAs) and/or commit to utility-owned renewable generation projects within the timeframe of the Minnesota RES milestones, or earlier depending on the proposed in-service dates of each segment of the three new transmission lines;
4. file transmission service requests with Midwest Independent Transmission System Operator (MISO) for the total amount of new capacity enabled by the three proposed transmission lines to deliver the output produced by renewable generators per condition number 1;
5. designate the new renewable resources as network resources; and
6. report to the Commission any proposed changes at the regional or federal level that could affect the conditions.

Q. Have you seen conditions similar to these in the past?

A. Yes, Joint Intervenors' witness Mr. Scott Hempling recommended five similar conditions in the April 17, 2008 *Direct Testimony of Scott Hempling* in the Matter of Xcel Energy's Four High Voltage Transmission Line Projects in Southwest Minnesota (Docket No. E002/CN-01-1958). The main difference between Mr. Hempling's conditions six years ago and those of Mr. Ellison today is that Mr. Ellison recommends a condition requiring the Applicants to explain how they allocate the new capacity created by the proposed facilities. No such condition was proposed six years ago (in the E002/CN-01-1958 docket) since there was only one Applicant—Xcel.

Q. What was your response to Mr. Hempling's conditions six years ago?

A. In the April 25, 2002 *Rebuttal Testimony of Steve Rakow* (Docket No. E002/CN-01-1958) I agreed with Mr. Hempling's conditions.

Q. Why did you agree with Mr. Hempling's conditions six years ago?

A. Basically, I concluded that, given the circumstances in that filing, such conditions were needed to support the proposed need for outlet capacity of wind energy in that region. As summarized in the April 25, 2002 *Rebuttal Testimony of Steve Rakow* Docket No. E002/CN-01-1958:

> The recommendation in my direct testimony was that the existence of a minimum of a total of 675 MW of signed PPAs be demonstrated to the Commission's satisfaction. My direct testimony left unresolved the issue of how to coordinate the timing of the availability of generation and transmission. Mr. Hempling's conditions address that difficulty by specifying dates by which certain actions must be taken.

Q. So, since you agreed with Mr. Hempling's conditions six years ago do you agree with Mr. Ellison's similar conditions today?

A. No. First, the scope of Mr. Ellison's conditions is flawed. If there are to be conditions, then Mr. Ellison's recommended conditions are inappropriate because they are too narrow and not in keeping with the purpose of this project as explained by the Applicants in the initial filing. The need case made by the Applicants in this docket is fundamentally different than the need case made by Xcel six years ago; Mr. Ellison's conditions do not reflect this fact nor tie with the purpose of the case currently before the Commission. Specifically, the April 11, 2002 *Direct Testimony and Exhibits of Steve Rakow* in Docket No. E002/CN-01-1958 stated, at page 6:

> Q. How does Xcel justify the need for the proposed LHVTL facilities?
>
> A. Xcel states that the four propose LHVTLs are needed because they are part of a larger plan to support development of renewable energy generation in southwestern Minnesota. Xcel states that the associated system improvements proposed in the Company's Petition are also necessary to increase transmission outlet capability in the Buffalo Ridge region. The transmission outlet capability will rise from about 260 MW to about 825 MW. Xcel states this increase will accommodate additional renewable electric energy generation in that region.

Thus, six years ago the need case was restricted to supporting development of renewable energy, and conditions furthering that end were necessary to satisfy that claimed need. By contrast, the May 23, 2008 *Direct Testimony of Dr. Steve Rakow* in this docket (E002, ET2, et al/CN-06-1115) at page 9 lists three main needs as purported by the Applicants in their initial filing:

- community service reliability: the lines are needed to meet reliability concerns in:
    - La Crosse, WI;
    - Rochester, MN;
    - St. Cloud, MN;
    - Alexandria, MN; and
    - the southern Red River Valley, (ND and MN);
- system-wide growth: the lines are needed to meet 4,500 to 6,300 MW of additional demand by 2020; and
- generation outlet: the lines are needed to support development of new generation.

It would be unreasonable to apply conditions that raise a subset (renewable generation outlet) of one of the need claims (generation outlet) above all of the other need claims.

Second, the timing of the conditions is in error; even if the conditions were ordered by the Commission today, it is already too late for Mr. Ellison's conditions to serve the intended purpose. The May 23, 2008 *Direct Testimony of Hwikwon Ham*, at page 16 states that:

> During September 2007 and October 2007, around the time of the Application filing, 25,032 MW of wind generation interconnection requests were filed at MISO. Most of the requested generator is located in the Minnesota, South Dakota, and North Dakota region. Further, many of the requested specific interconnection points are the substations along the proposed Project lines.

Thus, any activity ordered by the Commission would have a place in the MISO Queue behind many other requests to use the proposed transmission lines. The transmission system, in compliance with federal regulation, is used by generation owners that operate on a combined transmission grid open to all participants within a market system. In essence, the existence of market-based institutions forces generation owners to react much quicker to information than the Commission (and OES) can react through existing regulation-based institutions.

Third, the target of the conditions is in error; while GRE and Xcel are the Applicants, as explained in the *Application for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Connections* (Petition) the lines are intended to be owned by a much larger group of utilities. Further, even if the larger group of owners were subject to the conditions and it were deemed appropriate to raise renewable generation outlet above the other needs, the conditions' targeting still would be in error because not all current and potential project owners owning part of the transmission lines will be entirely or even potentially subject to Minnesota Statutes §216B.1691 (Renewable Energy Objectives). Further, targeting the conditions to owners would be too narrow because the lines are intended to support overall need to more generation to load, including the needs of all utilities subject to the Renewable Energy Objective (REO) and not all REO-subject utilities will own the proposed projects.

Fourth, an attempt to use transmission permitting to determine the issue of compliance with Minnesota Statutes §216B.1691 subd. 2b is inappropriate. The proper forum for determining whether any of the provisions for delaying implementation have been met is each individual utility's integrated resource plan (IRP). At this time it is appropriate to assume compliance since that is the current status of all utilities. Although I have no objection to the Applicants being put on notice by a party that this may be an issue in a future IRP, it is not appropriate to attempt to 'lock in' compliance at this time. Rather, the costs and benefits of compliance should be examined in IRP and a decision made based on such data at that time.

3. Miscellaneous Issues

Q. Do you have any other comments regarding issues in Mr. Ellison's direct testimony?

A. Mr. Ellison states, at page 12, that "the new transmission capacity could be used by nonrenewable sources, a result inconsistent with preferences established by the Minnesota legislature and the Commission." Again, on page 13 Mr. Ellison states "the Commission should condition the CONs on the Applicants taking a series of actions to minimize the risk of non-renewable generators using the available new transmission capacity in pace of renewable generators." In response, I note, first, at this time a reliable electric system depends upon both renewable and non-renewable generators unless one wishes to ignore issues of cost or reliability in the immediate timeframe. Second, the transmission lines at issue have been proposed so as to allow additional renewable and non-renewable generators to connect to the transmission system and deliver energy to customers. As such, that is the overall purported need that should be addressed rather than focusing on only one narrow aspect and ignoring the rest of the whole need "picture."

B. RESPONSE TO THE APPLICANTS

Q. What is the purpose of your offering rebuttal to the Applicants' direct testimony?

A. The Applicants' direct testimony proposes four significant changes to the certificates of need (CN) requested by the Applicants' original petition. My rebuttal testimony makes recommendations regarding these proposed changes to the CNs requested by the Applicants.

1. Proposed Changes for Brookings, SD—Twin Cities Project

Q. What is the first modification to the Brookings, SD—Twin Cities 345 kV transmission project proposed by the Applicants?

A. On page 17 lines 14 to 19 of the May 16, 2008 *Testimony of Laura McCarten* and page 8, lines 8 to 17 of the *Testimony of Kevin Lennon* the Applicants propose to accelerate the in-service date of the Brookings, SD—Twin Cities 345 kV transmission line. The proposed in-service date are now 2012 (Lyon County—Helena segment) and 2013 (Helena—Hampton Corner and Brookings County—Lyon County segments).

Q. What is your response to the modified in-service dates for the Brookings, SD—Twin Cities 345 kV transmission line proposed by Ms. McCarten and Mr. Lennon?

A. Sections 4.1.9 and 4.2.1 of the Petition make clear that the Brookings, SD—Twin Cities 345 kV transmission line is primarily being proposed to facilitate the development of additional renewable energy in southwestern Minnesota. Given the need for delivery of renewable energy shown by Mr. Ham and Ms. Peirce in their direct testimonies, the sooner the Brookings, SD—Twin Cities 345 kV transmission line can come on line the better. Therefore, I recommend that the Commission approve the Applicants' modified in-service dates of 2012 (Lyon County—Helena segment) and 2013 (Brookings County—Lyon County and Helena—Hampton Corner segments).

Q. What is the second modification to the Brookings, SD—Twin Cities 345 kV transmission project proposed by the Applicants?

A. On page 17 lines 20 to page 18 line 2 of *Testimony of Laura McCarten* and page 5 line 6 to page 6 line 2 of *Testimony of Kevin Lennon* the Applicants propose to change the voltage at which the Hazel Creek—Minnesota Valley transmission line is constructed from 230 kV to 345 kV. However, the Applicants propose to operate the line at 230 kV until other upgrades in the area are in place. My direct testimony (at pages seven to eight) noted that the proposed voltage of the Hazel Creek—Minnesota Valley transmission line needed to be updated. This information provides the requested update.

Q. What is your response to the modified construction voltage for the Hazel Creek—Minnesota Valley segment proposed by Ms. McCarten and Mr. Lennon?

A. The *Testimony of Kevin Lennon* states that the proposed change in construction voltage will cost about $3.7 million to $4.6 million. The proposed change in construction voltage will facilitate switching the Hazel Creek—Minnesota Valley transmission line to 345 kV operation if the Minnesota Valley—Panther—McLeod—Blue Lake (Minn Valley—Blue Lake) 230 kV line is later upgraded to 345 kV operation.

This is a situation where there are two possible options today (construct at 230 kV or construct at 345 kV). Further, each of today's options has 2 potential outcomes in the long run (operate at 230 kV or operate at 345 kV). To analyze this situation I used the following data:

- $724,000 per mile for single circuit 230 kV line;
- $1,109,000 per mile for single circuit bundled 345 kV lines;[1]
- 9 miles of transmission lines;[2]

[1] The unit costs per mile were provided by the Applicants in response to Joint Intervener Information Request No. 18; see OES Exhibit No.__ (SRR-R-1).

- assumed a five-year time period between construction of the line initially until the decision to operate at 230 kV or 345 kV in the long run is made;[3]
- a real discount rate of 4.0 percent;[4] and
- a 50 percent probability that the line would be operated at 345 kV and 50 percent probability that the line would be operated at 230 kV.

Using these assumptions I calculated the expected cost of the two options today (construct at 230 kV or 345 kV). Note that I am assuming that the line losses would be similar in each case and can be ignored for purposes of this analysis. The expected costs are shown in Table 1 below.

Table 1: Expected Values for Hazel Creek—Minnesota Valley (Million Dollars)

Build	Operate	Rebuild ?	Build Cost	Rebuild Cost	Discounted Total Cost	Probability	Expected Cost
230 kV	230 kV	No	$ 6.52	$ -	$ 6.52	50.0%	
230 kV	345 kV	Yes	$ 6.52	$ 9.98	$ 14.72	50.0%	$ 10.62
345 kV	230 kV	No	$ 9.98	$ -	$ 9.98	50.0%	
345 kV	345 kV	No	$ 9.98	$ -	$ 9.98	50.0%	$ 9.98

Table 1 demonstrates that the expected cost of constructing the line at 345 kV is lower (i.e., has a lower capital cost) than constructing the line at 230 kV. Also, I calculated that at a 57.76 percent probability of long run operation at 230 kV the two expected costs (construct at 230 kV and construct at 345 kV) are equal. Given the need for renewable energy confirmed by Mr. Ham and Ms. Peirce in their direct testimonies, I believe that the probability that the Minn Valley—Blue Lake line will be operated at 230 kV in the

[2] See the *Direct Testimony of Kevin Lennon* at page 6, line 19.
[3] I use a five-year estimate for when a 345 kV rebuild of an initial 230 kV build may occur because the *Renewable Energy Standards Report 2007*, dated November 1, 2007 in Docket No. E999/M-07-1028, indicates at page 302 that the underlying transmission study is anticipated to be completed by November, 2008. Thus, a petition for a CN could be filed by late 2009 and a Commission decision would occur in late 2010 or early 2011. Assuming two years to construct the line means that an assumption of a five-year delay to a decision regarding long run operation is reasonable.
[4] See page 53 of my direct testimony for further details regarding this input.

long run is much lower than 50 percent. Thus, I recommend that the Commission approve the Applicants' proposal to construct the Minn Valley—Blue Lake line at 345 kV but operating the line at 230 kV until other upgrades in the area occur.

2. Proposed Changes for Twin Cities—La Crosse, WI Project

Q. What is the first modification to the Twin Cities—La Crosse, WI 345 kV transmission project proposed by the Applicants?

A. On page 18 lines 3 to 13 of the *Testimony of Laura McCarten* and page 9, lines 13 to 19 of *Testimony of Grant Stevenson* the Applicants propose to make the timing of the Northern Hills—North Rochester 161 kV transmission line contingent upon the Commission's action regarding a future CN petition, expected to be filed by Xcel later this year. The Applicants explain that currently they propose that the Northern Hills—North Rochester 161 kV transmission line be in-service during 2011. However, if Xcel's future CN petition (for wind outlet; also known as 'RIGO') are approved soon enough, the Applicants propose that the Northern Hills—North Rochester 161 kV transmission line be in-service during 2012.

Q. What is your response to the flexible in-service date for the Northern Hills—North Rochester 161 kV transmission line proposed by Ms. McCarten and Mr. Stevenson?

A. It is good that the Applicants have made this contingency public knowledge in this proceeding. Further, I would not oppose a Commission Order approving the proposed flexible in-service date. However, there is another procedural option that the Commission may prefer. Based on this record in this case, the Commission could approve the Applicants' originally proposed in-service date of 2011. Additionally, in the Order, the Commission could note that if Xcel's RIGO forthcoming petition requests a modification of the in-service date for the Northern Hills—North Rochester 161 kV transmission line, the RIGO Order can also modify the in-service date for the Northern Hills—North Rochester 161 kV transmission line if the Commission's RIGO Order approves a 2011 in-service date for the RIGO lines. Using this option, no action need to be taken at this time regarding this potential modification at this time; it can be more adequately addressed in a separate proceeding at a later date when more information will be known.

Q. What is the second modification to the Twin Cities—La Crosse, WI 345 kV transmission project proposed by the Applicants?

A. On page 18 lines 14 to 24 of *Testimony of Laura McCarten* and page 8, lines 4 to 13 of the *Testimony of Grant Stevenson* the Applicants propose to make the implementation of the Northern Hills—Chester 161 kV transmission line contingent upon the Commission's action regarding the routing of the Twin Cities—La Crosse, WI 345 kV transmission line in the Rochester area. In essence, the Applicants propose that either the 345 kV transmission line or the 161 kV transmission line is needed to connect the Northern Hills and Chester substations but not both.

Q. What is your response to the contingent approval of the Northern Hills—Chester 161 kV transmission line CN proposed by Ms. McCarten and Mr. Stevenson?

A. The *Testimony of Grant Stevenson* explains that if the Commission orders the Applicants to use one of the southern river crossings (Winona or La Crescent), then the 345 kV line will more likely be routed to the south and east, potentially near or through the Chester substation. If that is the case, it would be more economically and operationally efficient to connect the two substations at 345 kV.

My direct testimony, at page 63, recommended that the Commission approve the La Crosse substation and associated La Crescent crossing as the southeast termination point for the proposed Twin Cities—La Crosse, WI 345 kV transmission line. Further, it is my understanding that the Applicants' proposal includes the LaCrosse substation (see pages 61 and 62 of my direct testimony). Therefore, I conclude that the 345 kV line will most likely be routed to the south and east. However, the exact route of the 345 kV line will not be determined in this docket. Thus, the question to be answered is 'what action is required at this time?'

Again, it is good that the Applicants have made this contingency public knowledge in this proceeding. At this time the Applicants have requested a CN for both the Twin Cities—La Crosse, WI 345 kV transmission line and the Northern Hills—Chester 161 kV transmission line. I recommend that the Commission allow both options to be examined in this record. Then, if the Commission approves both CN options in this docket in the subsequent routing proceeding for the 345 kV project, the Commission can either:

- route the 345 kV line so as to connect the Northern Hills and Chester substations and indicate in the routing order that an additional (161 kV) connection is not necessary; or

- not route the 345 kV line so as to connect the Northern Hills and Chester substations and indicate in the routing order that a 161 kV connection is necessary.

In summary, no action need to be taken regarding this potential modification as long as the original and modified proposals are both in the record and decided on by the Commission; it can be adequately addressed in a separate proceeding.

C. RESPONSE TO CETF

Q. What is the purpose of your offering rebuttal to CETF's direct testimony?

A. First, CETF's direct testimony indicates that CETF is unaware of the overall planning process for the electric industry established in Minnesota Statutes, Minnesota Rules, and implemented by the Commission. Thus, I provide background information clarifying how the Commission's generation and transmission planning processes work. Second, in the discussion supporting a DG alternative CETF makes certain statements which are incorrect. I correct these statements. Third, in the discussion supporting a DSM alternative CETF makes certain statements regarding DSM that are incorrect. I correct these statements regarding DSM. Also, I provide background data on current DSM activities in Minnesota.

1. Planning Background

Q. Does Dr. Kildegaard recommend a particular planning process?

A. Yes, at pages 4-7 the *Direct Testimony of Arne C. Kildegaard* explains his view that it is "economically irrational to separate generation from transmission." That is, Dr.

Kildegaard recommends that generation and transmission be planned in a single process rather than separately.

Q. Can you explain how the Commission's overall planning process works?

A. The Commission has two distinct planning processes. The first planning process is integrated resource planning (IRP) which is governed by Minnesota Statutes §216B.2422 and Minnesota Rules Chapter 7843. IRP establishes each utility's expansion plan for generation and is filed by each utility separately, typically every two to three years.[5] In IRP process, each utility proposes the supply-side and demand-side (DSM) resources necessary for a 15 year period. In the IRP process the optimal size, type, and timing of both supply and DSM resources are determined. For example, a utility's plan may require a 150 MW (size) peaking unit (type) be brought on line in 2015 (timing) along with 10 MW and 43,000 MWh of DSM annually.

Subsequently, DSM resources can be acquired in a variety of ways, but for investor-owned utilities are acquired, for the most part, through the Conservation Improvement Program (CIP) governed by the OES pursuant to Minnesota Statutes §216B.241 and Minnesota Rules Chapter 7690. One step in the analysis of a CIP is to compare the utility's proposed CIP goal to the goal determined in the most recent IRP. OES Witness Mr. Christopher Davis sponsors testimony regarding DSM and CIP, and any further information specifically on those two topics should be addressed to Mr. Davis.

Meanwhile, supply-side resources are also obtained in a variety of ways. The most common means of acquiring supply-side resources is through a Commission

[5] Under those rules, 10 utilities file (or soon will file) IRPs with the Commission every two to three years.

approved competitive bidding process (for power purchase agreements (PPAs)) or a CN (for a utility self-build).

The second planning process is the biennial transmission plan, which is governed by Minnesota Statutes §216B.2425 and Minnesota Rules Chapter 7848. The biennial transmission plan is filed by all jointly by multiple utilities every two years.[6] The biennial transmission plan provides a summary of the all the utilities' transmission planning activities, broken down into six different zones. At this time the biennial transmission plan serves to provide a forum for the utilities to make interested parties aware of developing transmission issues and for interested parties to influence how planning takes place. For example, in the most recent biennial transmission plan the OES recommended that the Commission require the use of the Commission's environmental externality values in all planning studies submitted to the Commission as part of a CN petition, and in the CN petitions themselves.

In summary, under Minnesota Statutes and Minnesota Rules the Commission has two separate planning processes, IRP and the biennial transmission plan.

Q. Is Dr. Kildegaard correct in asserting that an ideal planning process would encompass both transmission and generation?

A. Yes, Dr. Kildegaard is correct that location of transmission influences generation and location of generation influences transmission. There is a locational interaction between the two. Further, to some extent generation and transmission can act as substitutes for

[6] The most recent biennial transmission plan was submitted by 16 utilities as the Minnesota Transmission Owners in Docket No. E999/M-07-1028.

each other. Therefore, in an ideal world generation and transmission would be planned simultaneously in a single process/model.

Q. Then why does the Commission plan generation and transmission separately?

A. For two reasons. First, there is no electronic planning model tool available which can handle both expansion of the transmission system and expansion of the generation system. There are models, such as Strategist, that can optimize expansion of supply-side and DSM resources. However, I am not aware of any model which can do for transmission (select least-cost size, type, and timing based upon inputs from the user) what Strategist can do for generation. Further, there are no models which can simultaneously optimize the expansion of supply-side, DSM, and transmission resources.

Second, even if such a model were to exist, whether it should be used is highly questionable. The reason it is questionable is because a process designed to achieve an economically rational electrical system that cannot arrive at a conclusion within a reasonable duration is of no potential value. One example of this lesson can be found in Xcel's former bidding process for supply-side resources.[7] In the past, Xcel's Commission-approved bidding process essentially attempted to perform both the planning (IRP) and acquisition (PPA/CN) functions simultaneously. The goal was to use information from specific projects rather than generic resources to determine the optimal size, type, and timing (the planning function) and the select the best project (the resource acquisition function). The idea was that a superior identification of size, type, and timing could be made with real data on real projects as opposed to generic information on

[7] While Xcel still uses a bidding process for supply side resources, it has been redesigned to separate the planning and acquisition functions as discussed here.

generic projects. Unfortunately, the process failed to arrive at a conclusion in a reasonable time period and Xcel felt compelled to offer, as a practical alternative, a CN for a company build resource to maintain system reliability.[8] Third, I note that, as the region moves more toward a regionally planned transmission system, any given utility has less control over the transmission resources that are included in the regional plans.

Q. Please summarize your points here.

A. Dr. Kildegaard's contention that in an ideal world the Applicants would plan generation and transmission simultaneously does have a theoretical foundation. However, first, the tools that exist today are not capable of creating the planning process that Dr. Kildegaard envisions. Second, even if such tools did exist I would not recommend the Commission order their use since the likely result would be 'paralysis by analysis.' Unfortunately, in this case, the "theoretical ideal" cannot be carried out in a timely fashion that could lead to practical results.

Q. Are there other consequences of this separate approach besides the correct planning background?

A. Yes. As I state above, since no practical tools exist, to my knowledge, that can model simultaneous changes and results for both generation (G) and transmission (T), in order to identify and model changes in either (G) or (T), the other aspect (T or G) must be assumed as static or fixed. For example, one consequence of planning for generation separately from transmission is that, generally speaking, a transmission proposal

[8] See Docket No. E002/CN-04-76 for further details on this point.

generally takes as a given the overall generation mix.[9] Second, when valuing the societal impact of incremental transmission system losses, the avoided pollution impacts must come from a fixed estimate of the overall generation system rather than specific projects.[10] Third, this split means that we can focus on determining the size, type, and timing of transmission, as in this CN, without having to attempt to simultaneously analyze the generation that will be serving Minnesota. Fourth, in transmission CNs such as this, we are not charged by law to determine the ownership of the generation. At most we are determining potential general locations for the generation.

2. Proposed Alternative—DG

Q. Does Dr. Kildegaard appear to recommend a particular alternative?

A. Yes, at page 7 Dr. Kildegaard states that "if all costs are included, the CapX 2020 alternative may be more costly than alternatives including generation near load with a greater proportion of renewable energy." Thus, Dr. Kildegaard appears to recommend a DG alternative with more renewable energy in the mix. However, Dr. Kildegaard did not develop such an alternative to any significant degree and provides no cost basis for his conclusion that DG may be a lower cost choice.

Q. Given the discussion of the planning process above, is Dr. Kildegaard's observation about "a greater proportion of renewable energy" relevant?

---

[9] One exception is when the transmission line is to interconnect a particular generator, such as in the Big Stone 2 proceeding (Docket No. E017 et al/CN-05-619.

[10] An exception would be in an instance where the transmission is proposed specifically for the purpose of interconnecting a specifically identified generation project.

A. No, the preferred mix of renewable and non-renewable energy[11] (including consideration of environmental costs) is determined in the IRP process. The purpose of this proceeding is to determine the best transmission system expansion, if any, to transport the IRP-determined generation mix to the Minnesota load plus address overall transmission system reliability for Minnesota and the surrounding region pursuant to Minn. Stat. §216B.243, subd. 3(9) and Minnesota Rules 7849.0120A.

Q. Dr. Kildegaard discusses the benefits of various ownership structures for generation projects. Is that a relevant consideration in this proceeding?

A. In general, the specific ownership of the generation using the proposed transmission lines is not an item to be determined in this proceeding. Rather, this proceeding is to determine which transmission facilities are necessary to meet the needs claimed by the Applicants. Further, under federal rules, use of the transmission lines to transport and deliver power must be open to all types of generation projects. Also, as explained above, transmission and generation are planned on separate tracks. Therefore, the least cost generation mix, including questions of ownership, is not relevant at this time.

3. Proposed Alternative—DSM

Q. Does Dr. Kildegaard recommend that DSM be given further consideration as an alternative?

A Yes, Dr. Kildegaard recommends on page 9 that "potential savings through energy conservation should be analyzed and compared to costs of additional generation and

[11] Generally this is an issue concerning resource type since wind, the most cost effective form of renewable energy, is an intermittent resource distinctly different from typical fossil fuel generation resources.

transmission." Again, this approach (a comparison to G and T) represents a theoretical ideal but does not fit with how Minnesota Statutes and Minnesota Rules are established. However, the OES agrees that it is important to analyze energy savings, and OES has done so. First, Mr. Davis analyzes the impact of DSM in detail in this proceeding, both to serve load overall and as an alternative in local areas. Second, I note that the utilities in Minnesota have been pursuing demand control for many years. The OES regulates the investor-owned utilities' energy savings activities, also called the conservation improvement program (CIP). The Commission regulates all other activities of investor-owned utilities.

Q. Can you provide some background information on DSM activities related to demand control for Minnesota as a whole?

A. Yes. From my past experience working on CIP, rate design, and resource planning issues I can offer the following background information on DSM-related activities. As an overview, I provide a page from *Coordination of Retail Demand Response with Midwest ISO Wholesale Markets,* (dated May 2008) from the Ernest Orlando Lawrence Berkeley National Laboratory; See OES Exhibit No. ___ (SRR-R-2). This report shows that Minnesota MISO member utilities have about 1,245 MW of demand response; far more than the MISO member utilities of other states. Also, I can provide background data on the DSM-related activities of the two Applicants, GRE and Xcel. Lastly, I provide information from the other investor-owned utilities that are likely to be owners of CapX (MP and OTP) since their activities are approved by the Commission.

Q. Please provide some background information on DSM activities related to demand control for Xcel.

A. Xcel has substantial load management available through several different programs. I can provide a few examples. First, Xcel's customer-volunteered controlled air conditioning program (Saver's Switch) has over 328,000 residential and business customers with about 325 MW of load management available. The controlled air conditioning is available to be interrupted by the utility telemetrically based upon either market prices or reliability issues. Second, Xcel's Electric Reduction Savings program has 2,800 business customers with about 680 MW of load management available. These customers have committed to reduce electricity use to a contracted level of their own choosing during peak-use periods. See OES Exhibit No. ___ (SRR-R-3) for documentation.

Third, Xcel operates a customer buyback program for larger customers. In the buyback program the customers are paid market-based rates to interrupt their load and let the utility "buy it back." The buyback program currently has 16 industrial or commercial-class customers and 33 MW of load available to be interrupted.[12]

Fourth, the Commission investigated instituting time of use rates for residential customers through a pilot program in Docket No. E002/CI-01-1024. However, the Commission ultimately decided to not implement the pilot program.

Finally, considering the broader category of DSM efforts as a whole, Xcel's most recent IRP states, at page 9-1, that Xcel's efforts from 1990 to 2006 have saved about 2,100 MW of demand. Further, at page 9-7 of the IRP Xcel states that Xcel's preferred

[12] See Xcel's April 8, 2008 *Report on Customer Buyback Program and Petition to Extend the Pilot Program Period* in Docket No. E002/M-08-412.

plan will result in over 1,700 MW of demand reduction during the 2008 to 2022 planning period.

Q. Please provide some background information on DSM activities related to demand control for GRE.

A. GRE's most recent resource plan (Docket No. ET2/RP-05-1100) states, at page 55, that:

> Summer programs that reduce demand during peak periods include cycled air conditioning and air source heat pumps, controlled irrigation, and interruptible commercial and industrial programs. Through these efforts GRE has been successful in controlling demand the approximant [sic] equivalent of a 300 MW power plant.

GRE's IRP also states that the capacity savings of GRE's load management and energy conservation programs, including distribution losses, transmission losses, and the 15 percent reserve requirement are forecasted to be equal to about 404 MW for the summer of 2007 (see Figure 4-3 on page 56.

Q. Please provide some background information on DSM activities related to demand control for Minnesota Power.

A. Minnesota Power (MP) currently has substantial load management available through a program for MP's large power customers. However, MP's petition in MP's most recent resource plan (Docket No. E015/RP-07-1357) states at page 9

> By May 2010, two 15-year CID [certified interruptible demand] products of about 100 MW each will expire. Based on current indications from the industrial customers who have used these products that they are not interested in renewing or extending the term, Minnesota Power is planning on CID being reduced to zero as of May 2010. However, depending on future MISO market and planning

> reserve sharing pool requirements, Minnesota Power will explore alternative ways to utilize the interruption capability of these large customers as a future resource option.

Therefore, MP currently has about 200 MW of load management available from a few large customers. However, due to circumstances beyond MP's control, MP will be losing that resource. Given that MP's total load is about 1,750 MW and that large power customers account for about half of MP's energy sales, the most likely scenario is that MP's load management resources may decrease substantially in the near future absent further development in various MISO load management programs in which these large customers decide to participate.

Q. Please provide some background information on DSM activities related to demand control for Otter Tail Power.

A. Otter Tail Power's (OTP) petition in OTP's most recent resource plan (Docket No. E017/RP-05-968) states, at pages 6-14 and 6-15, that OTP:

> … has approximately 127,000 customers and 40,000+ of those customers have some type of load control. Normally, the system has the capability to control about 14% of unmanaged peak load during a winter cold spell.

Winter managed loads include water heaters, thermal storage, dual fuel, and others. Also, graphs 6-1 and 6-2 of OTP's IRP indicate that OTP has about 80 MW of load management available for the 2004-2005 winter season and 26 MW available for the 2004 summer season.

Q. After providing all of this background on Applicants' current DSM programs, how do you respond to Dr. Kierkegaard's statement that more DSM should be used as an alternative to this project.

A. The background I provide is to inform the record about the Applicants' current DSM activity. Also, as stated before, Dr. Kierkegaard does not develop or substantiate his statement that further DSM should be viewed as a reasonable option for the proposed project.

D. RESPONSE TO NAWO-ILSR

Q. What is the purpose of your offering rebuttal to NAWO-ILSR's direct testimony?

A. I wish to address the following errors or misleading statements in NAWO-ILSR's direct testimony. The statements are regarding:

- burden of proof;
- community-based energy development (CBED) use of the lines;
- a scenario of DG coupled with load management;
- renewable preference statute;
- protecting environmental quality; and
- assessment of alternatives.

1. Burden of Proof

Q. What issue do you have regarding burden of proof?

A. At page 12, line Mr. Michaud states "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 states renewable energy policy goals…" This statement may be true; however it is misleading. It is my understanding that, under Minnesota Rules 7849.0120 B, the burden of proof regarding alternatives is upon those persons proposing an alternative to the Applicants' proposed facilities. In essence, the Applicants' proposal becomes the yardstick against which all other alternatives are measured and an alternative proposed by another party (such as the OES's proposed 500 kV Fargo, ND—Twin Cities line) must be shown to be better than the Applicants' proposal. Thus, the Applicants do not need to prove "whether providing 700 MW of outlet capability from this geographic area with this particular line is the best option towards meeting the states renewable energy policy goals."

I note that interveners such as Mr. Michaud and myself do not have to show that a preferred alternative is the <u>best</u> option. Interveners only have to show that their preferred alternative is superior to the Applicants' proposal; OES has done so for the 500 kV alternative to the Applicants proposed Fargo, ND—Twin Cities 345 kV transmission line. NAWO-ILSR's Mr. Michaud has not attempted to provide information supporting his preferred alternative in a time and manner that is reviewable or can be tested by other parties.

2. CBED

Q. What issue do you have regarding CBED use of the lines?

A. At page 15 lines 3 to 6 Mr. Michaud states:

> The transmission resource identified using the Applicants' obsolete generation assumptions are biased in a manner that virtually ensures that state Community-Based Energy Development policy objectives will be stunted.

This statement and the supporting discussion on page 16 is without foundation as it is based upon the assumption that CBED projects will not be able to use the transmission capability created by construction of the proposed transmission facilities. First, Mr. Michaud provides no evidence to support his statement that CBED projects cannot be located in the areas where the transmission lines will be constructed.

Second, the Applicants merely located MW of generation resources in a transmission model. A 200 MW increment of generation at one node in the model can be assumed to be a single 200 MW project, it can be assumed to be 20 projects of 10 MW each or it can be assumed to be 200 projects of 1 MW each – any configuration of projects could provide the same 200 MW. Third, regardless of whether a single 200 MW project, 20 projects of 10 MW, or 200 single-MW each projects, the generation project ownership or ownership structure is not needed or determined in this proceeding. Rather, that will be determined by various utilities' resource acquisition processes.

3. Proposed Alternative—Load Management and DG

Q. What issue do you have regarding load management and DG as an alternative?

A. At page 9 Mr. Michaud states "load management strategies coupled with distributed generation resources is also a scenario they [the Applicants] should have examined." There is no requirement in Minnesota Statute or Minnesota Rules which requires a "DG plus load management" alternative to be explored. Further, the potential number of combinations of DG and load management would very large so would require a specific set of proposals in order to be considered in practical terms. Application of such a requirement would likely mean that no transmission would ever get built since the level of analysis would be too large to be completed in any reasonable duration. In this case, the burden is upon NAWO-ISLR to produce such an alternative and demonstrate that it is viable (passes a screening test) and that it is preferred to the Applicants' proposal. Mr. Michaud has not shown that he has taken any steps in producing such an alternative and providing it in a time and manner that is reviewable and can be tested by other parties.

4. Application of Renewable Preference Statute

Q. What issue do you have regarding application of the renewable preference statute?

A. At page 13 Mr. Michaud discusses the renewable preference statute. Mr. Michaud assumes the proposed transmission lines are proposed to interconnect base-load coal plants and points to a combination of "bio-fueled base load and peaking resources" as an alternative. However, I found no evidence in the initial petition stating a connection to coal plants and Mr. Michaud provides no other evidence to show that the Applicants intend to access any particular (renewable or nonrenewable) resource with the proposed transmission lines, much less a baseload coal plant. As discussed elsewhere in this rebuttal testimony, the Applicants claimed needs relate to both renewable and non-renewable types of generation. Moreover, Minnesota Statutes §216H.03 states:

> Unless preempted by federal law, until a comprehensive and enforceable state law or rule pertaining to greenhouse gases that directly limits and substantially reduces, over time, statewide power sector carbon dioxide emissions is enacted and in effect, and except as allowed in subdivisions 4 to 7, on and after August 1, 2009, no person shall:
>
> 1. construct within the state a new large energy facility that would contribute to statewide power sector carbon dioxide emissions;
> 2. 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

3. enter into a new long-term power purchase agreement that would increase statewide power sector carbon dioxide emissions.

Therefore, the only generation it is reasonable to assume will be interconnected and delivered by the proposed transmission lines is generation that does not emit CO_2. Additional exemptions are provided under Minnesota Statutes §216H.03 subdivision 7 for combustion turbines, and combined cycle units. Finally, the appropriate analysis of the renewable preference statute is contained in my direct testimony.

5. Protecting Environmental Quality

Q. Mr. Michaud claims the Applicants' proposed facilities do not adequately protect the environment. What is your response?

A. On pages 29-30 Mr. Michaud discusses greenhouse gases and the statutory requirement regarding environmental protection. First, I note that the statutory requirement regarding environmental protection is reflected in more detail in Minnesota Rules 7849.0120 B3. Second, as explained in response to CETF Witness Dr. Kildegaard earlier in this rebuttal testimony, the generation system is taken as a given in this proceeding—it is planned and permitted in separate proceedings. Third, as explained in my direct testimony, approval of the Applicants' proposed transmission lines and/or the OES's alternative would result in reduced line losses and thus reduced emissions of greenhouse gasses relative to a base case future without the proposed transmission lines. Thus, not approving the Applicants' proposal, as modified by my direct testimony will result in greater levels of pollution. In addition to offering no evidence regarding the cost of his preferred alternatives, Mr. Michaud offers no evidence regarding the environmental impact of his alternative.

Q. Mr. Michaud also discusses emissions from the construction process. What is your response?

A. On pages 31-32 Mr. Michaud discusses the assumed impact of construction on CO_2 emissions from construction of a transmission project in California. First, Mr. Michaud provides no reason to assume that the impacts in Minnesota will be similar to those of California. Even assuming the impacts are similar, they can be easily shown to not outweigh the avoided CO_2 benefits from the avoided line losses since the construction phase is so minimal compared to the life of the project. Using Mr. Michaud's data, 109,000 tons of CO_2 emitted for projects 150 miles (91 + 59) in length and assuming that the construction being discussed in the quote is construction of transmission (and not the associated generation), that equals about 727 tons of CO_2 per mile of construction. Assuming the total length of the facilities to be built is 700 miles the total construction CO_2 would be about 500,000 tons. That amount can be compared to the avoided CO_2 due to reduced line losses discussed in my direct testimony for the upgrade to 500 kV alone.[13] Under any future scenario, the 500,000 tons of CO_2 emissions would be made up in less than a decade. Thus, the proposed facilities still must provide a net reduction in overall CO_2 emissions.

Second, actually the issue is not whether there will be an impact from the Applicants' proposed facilities. Rather, the issue is what is the differential impact

[13] Of course the correct frame of reference is to the avoided line losses due to the entire proposal. However, the numbers in my direct testimony represent a subset of the entire project, are already in the record, and on their own make the point that CO_2 emissions from construction are relatively minor.

between the Applicants' proposal and the preferred alternative of other parties. The OES's preferred alternative has the same length of construction (the only basis provided by Mr. Michaud to determine construction-related emissions impacts), but has greater avoided line losses. Thus, the net emissions impact of the OES preferred alternative must be superior to that of the Applicants' preferred alternative.

6. Assessment of Alternatives

Q. Mr. Michaud discusses the quality of the Applicants' alternative's analysis. What is your response?

A. On page 33 Mr. Michaud states that the Applicants did not develop any of the information required by Minnesota Rules 7849.0260 C. First, to the extent Mr. Michaud is discussing the existence of the information, this is a completeness issue. The role of the completeness process is to ensure that a minimum level of information is present in any certificate of need petition. Since the Applicants' petition has been determined to be complete by the Commission, the next question is whether the information provided is sufficient to satisfy the stated requirement.

To address this next question, generally an alternatives analysis should be conducted in two phase. In the first phase the overall goals of the project are determined and compared to the list of alternatives provided in Commission rules. This is a screening analysis. The goal of a screening analysis is to reduce the broad universe of alternatives to a manageable subset of alternatives that could meet the proposed need.

In this case, the result of the Applicants' screening process was that no additional alternatives passed the screening test. This is not the first time this has occurred.[14] In my direct testimony I reviewed the Applicants' screening process and determined that the results, with the exception of higher voltage lines, were reasonable. Therefore, I proceeded to work with the Applicants to obtain the necessary information to analyze in detail higher voltage lines. Mr. Michaud has not even defined his preferred alternative to the point where it could be screened, much less provided a more detailed economic analysis. As such, the only developed alternative to the proposed project is mine. As stated at the beginning of this rebuttal testimony, Joint Intervenor Witness Mr. Larry Schedin recommends a project uprate as well but in a different way. Mr. Schedin recommends double-circuiting the project. However, it was not clear from his testimony whether this should also be considered an alternative. Further, cost and lost data will have to be provided, reviewed and tested of the viability of Mr. Schedin's recommendation as an alternative.

Q. Are there any further points you wish to make?

A. There is one more item. On the same day as this testimony is filed, it is my understanding that the Office of the (Acting) Reliability Administrator at OES will file with the Commission a report that will identify locations in the State that could potentially support the transmission of distributed renewable generation (DRG) projects using the existing transmission "grid" with little or no costs for additional facilities. As I understand it, this report will be filed pursuant to the 2007 Session Laws, Chapter 136.

[14] For example, see Otter Tail Power Company's petition in the Appleton—Canby 115 kV transmission line proceeding (Docket No. E017/CN-06-677).

The record developed in this docket (E002, ET2, et al/CN-06-1115) to date, especially by certain parties, makes it likely that one or more parties will be interested in having this study included in this (CapX) record. To that end, it is also my understanding that by the end of the day on Monday, June 16, 2008, the report will be filed with the Commission and available on edockets using Docket No. E999/DI-08-649. The information provided in the report during its development has been subject to a moratorium and disclosed only to the members of the DRG study group, of which no OES witness took part. Therefore, I have not been privy to the information prior to its filing so will be reviewing it at the same time as other Parties in this proceeding who were not involved in this study.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Elizabeth Goodpaster and Mary Marrow
Wind on the Wires, et al
Information Request No. 18
Date Received: April 3, 2008

Question:

Please provide a summary table showing right-of-way width and current typical per-mile construction costs for:

(a) single circuit 115 kV, 795 ACSS
(b) double circuit 115 kV, 795 ACSS
(c) single circuit 161 kV, 795 ACSS
(d) double circuit 161 kV, 795 ACSS
(e) single circuit 230 kV, 795 ACSS
(f) double circuit 230 kV, 795 ACSS
(g) single circuit bundled 345 kV, 954 ACSS
(h) double circuit bundled 345 kV, 954 ACSS
(i) single circuit tri-bundled 500 kV, 954 ACSS
(j) double circuit tri-bundled 500 kV, 954 ACSS
(k) single circuit quad bundled 765 kV, 954 ACSS
(l) double circuit quad bundled 765 kV, 954 ACSS

Response:

	Right-of-Way (feet)	**Unit Costs per Mile (1)**
(a) single circuit 115 kV, 795 ACSS	75	$ 458,000
(b) double circuit 115 kV, 795 ACSS	75	$ 852,000
(c) single circuit 161 kV, 795 ACSS	80	$ 595,000
(d) double circuit 161 kV, 795 ACSS	80	$ 946,000
(e) single circuit 230 kV, 795 ACSS	125	$ 724,000
(f) double circuit 230 kV, 795 ACSS	125	$ 1,082,000

	Right-of-Way (feet)	Unit Costs per Mile (1)
(g) single circuit bundled 345 kV, 954 ACSS	150	$ 1,109,000
(h) double circuit bundled 345 kV, 954 ACSS	150	$ 1,880,000
Single circuit tri-bundled 500 kV, 1192 ACSR (design of the Dorsey-Forbes-Chisago County 500 kV line)	180 & 200(2)	$ 1,611,000
(i) single circuit tri-bundled 500 kV, 954 ACSS	(3)	
(j) double circuit tri-bundled 500 kV, 954 ACSS		
(k) single circuit quad bundled 765 kV, 954 ACSS	(4)	
(l) double circuit quad bundled 765 kV, 954 ACSS		

Notes:

(1) These are indicative unit costs and are based on utility experience and judgment. Permitting, right-of way acquisition, and project and construction management are not included in these costs.

(2) The right-of-way on the existing 500 kV line varies depending on structure type. This estimate assumes the installation of multi-footed lattice structures similar to those used on the existing line.

(3) Only parameters for triple bundled 1,192 ACSR at 500 kV have been given as there is no experience with triple bundled 954 ACSS.

(4) None of the CapX2020 member utilities has experience with 765 kV and since it was not considered as an option for the CapX2020 series of projects, no detailed engineering has been performed for 765 kV designs.

Some utilities use an order of magnitude estimate of $3-4 million per mile for 765 kV with 6 – 795 ACSR bundled conductors per phase. Permitting, right-of-way acquisition, and project and construction management are not included in these costs.

The right-of-width would be greater than 200 feet and be dependent on final detailed design.

Preliminary calculations indicate that at 765 kV, quad bundled 954 ACSS will not meet the audible noise limits set by Minnesota State law. It appears that six bundled conductors per phase would be necessary to meet State standards.

Response By:	David K Olson
Title:	Principal Substation Engineer
Department:	Substation Engineering and Design
Company:	Xcel Energy
Telephone:	612-330-5909
Date:	April 24, 2008

2169271v1

LBNL-288E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Coordination of Retail Demand Response with Midwest ISO Wholesale Markets

Ranjit Bharvirkar and Charles Goldman
Lawrence Berkeley National Laboratory

Grayson Heffner, Global Energy Associates

Richard Sedano, Regulatory Assistance Project

Environmental Energy
Technologies Division

May 2008

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability, Permitting, Siting and Analysis of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

6. Survey Results: Overview of Existing DR Resources

Thirty-five utilities responded to the survey with information on 141 DR programs and dynamic pricing tariffs. Of these, four utilities (that reported information on 13 DR programs and 3 dynamic pricing tariffs) are not members of MISO but operate in states that belong to OMS. The analysis reported here includes all 141 programs.

The size of the DR resource is defined as the potential peak load reduction that the utility expects from the DR program or dynamic pricing tariff, which is consistent with the approach taken by FERC and EIA. The utilities reported retail DR resources totaling 4,727 MW, of which 757 MW are from MISO non-members (~16%).Response to the survey was quite good as MISO member utilities reported DR program resources of ~3,649 MW of DR resources, compared to the 4,099 MW reported in the latest FERC DR report (FERC 2007).

The distribution of DR resources by state is shown in Figure 4. States with the most DR resources include Minnesota (1,245 MW), Indiana (731 MW), and Michigan (822 MW). Note that OMS member states such as Illinois and Pennsylvania have large DR resources, although some utilities in these states were not sent or did not respond to the survey because they were not MISO members (e.g., Commonwealth Edison is a member of PJM).

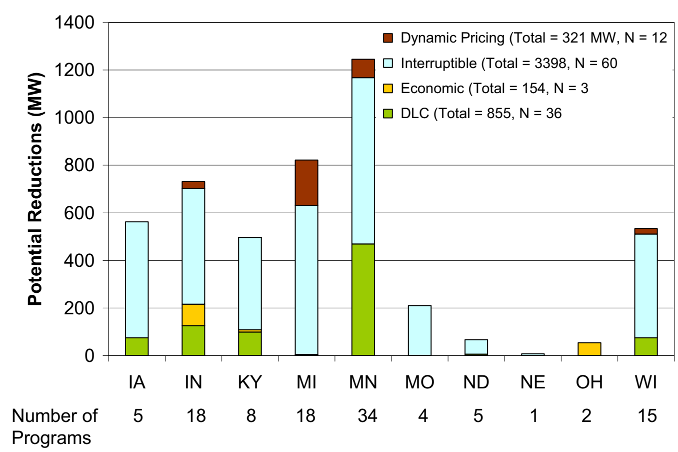
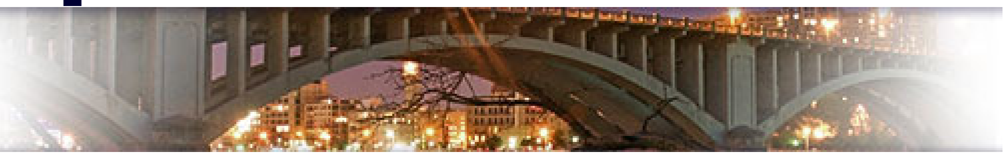


Figure 4: State-Level Distribution of DR Resources

Figure 5 shows how survey respondents characterized their retail demand response program offerings. Interruptible tariffs account for ~72% of the DR resource, while DLC programs account for ~18%, and economic programs account for ~3% of existing DR resources. Interruptible tariffs and DLC programs are offered in almost all OMS member states, however, economic programs were offered by LSEs only in Indiana and Ohio.

Privacy & Security FAQs Site Map Contact Us

Xcel Energy®



Company	Residential	Business	Energy Partners

Company > Newsroom > News Releases

55101 GO
Saint Paul, MN

- News Releases
- Media Contacts
- Executive Speeches
- Current Issues
- News Commentaries
- Utility Innovations
- Setting the Record Straight
- Logo Requests

QUICKTOOLS

- Bird Cam
- Safety
- Call Before You Dig
- View My Bill
- Pay My Bill
- How Are We Doing?
- Career Opportunities
- Contact Us

News Releases

06/21/2007

Xcel Energy customers help reduce peak electricity demand

More than 330,000 enrollees make approximately 1,000 megawatts of energy savings possible

MINNEAPOLIS - More than 330,000 Xcel Energy customers in the Upper Midwest have signed up to save energy and money on the hottest, stickiest days of the summer.

Customers enrolled in Xcel Energy's Saver's Switch and in Electric Reduction Savings programs help reduce electricity demand when temperatures and humidity levels are high. All together, the programs could reduce electricity demand by approximately 1,000 megawatts, almost as much as the capacity of the Prairie Island nuclear plant (1,100 megawatts) and enough power to serve approximately 1 million homes.

In Minnesota and nearby states – where Xcel Energy provides electricity to nearly 1.6 million households and businesses – approximately 328,000 residential and business electricity customers are enrolled in Saver's Switch and about 2,800 commercial and industrial customers are participating in Electric Reduction Savings programs.

Customers enrolled in the programs receive discounts on their electricity bills while helping Xce Energy delay building new power plants or avoid purchasing high-priced electricity from other utilities during peak-use periods.

"Customers deserve credit for helping us avoid energy shortages during peak-use periods, helping keep rates lower for everyone and helping preserve the environment," said Deb Sundin, director of business product marketing and Conservation Improvement Program/demand-side management for Xcel Energy. "During periods of hot, humid weather, the programs also reduce stress on distribution equipment that can cause power outages."

The Saver's Switch program allows Xcel Energy by remote control to cycle central air-conditioner compressor units on and off at 15- to 20-minute intervals. The approximately 315,000 residential and 13,000 business customers enrolled in the program in the Upper Midwest receive discounts on their electricity bills. Their participation will allow Xcel Energy to reduce electricity demand by approximately 315 megawatts, if needed.

Saver's Switch has been available in Xcel Energy's Upper Midwest service territory since 1990.

To enroll, residential customers should call Xcel Energy's 24-hour customer service line at (800) 895-4999. Business customers can enroll by calling Xcel Energy's business line at (800) 481-4700. Customers also can enroll on Xcel Energy's Web site at www.xcelenergy.com.

Commercial and industrial customers participating in Xcel Energy's Electric Reduction Savings programs also receive bill discounts. Their participation can help Xcel Energy reduce electricity demand in Minnesota and neighboring states this summer by nearly 680 megawatts.

Under the commercial/industrial programs, businesses, schools, government agencies and other large electricity users commit to reduce electricity use to a contracted level of their own choosing during peak-use periods. Program participants reduce their electricity use by shutting off lights, air conditioning or manufacturing processes. Some participants use backup generators. Under their agreements with Xcel Energy, participants who don't reduce electricity use at Xcel Energy's request pay a penalty.

"Generally, activation of the Saver's Switch and Electric Reduction Savings programs occurs or very hot, humid summer days -- especially consecutive days," Sundin said. "We expect to activate the programs when the temperature is more than 90 degrees. The programs also could be activated in emergencies when the integrity of the electricity system is in danger."

Xcel Energy's Saver's Switch Program At-A-Glance

- In Xcel Energy's service territory in the Upper Midwest, approximately 315,000 residential and 13,000 business customers are enrolled, for a potential electricity demand reduction of approximately 315 megawatts.
- Saver's Switch allows Xcel Energy by remote control to cycle central air-conditioner compressor units on and off at 15- to 20-minute intervals.
- Generally, activation occurs on hot, humid summer days -- especially consecutive days.
- Cycling generally occurs between late morning and early evening.
- The program is activated about 10 to 15 days in a typical summer, usually not on weekends or holidays. However, in extreme heat, Saver's Switch may be used for longer time periods and on weekends and holidays.
- Only customers with central air conditioning are eligible. Those customers also may enroll their electric water heaters.
- Residential customers in Minnesota, North Dakota and South Dakota who enroll their central air conditioners receive 15 percent discounts on their electric energy charges from June through September. In Wisconsin, participants receive $6 off their bills in each of the same four months. Customers who also enroll their electric water heaters receive a small additional discount on their electricity bill every month of the year. Business customers receive a discount based on the amount of air conditioning tonnage they enroll in Saver's Switch.
- To enroll, residential customers should call Xcel Energy's 24-hour customer service line at (800) 895-4999. Business customers can enroll by calling Xcel Energy's business line at (800) 481-4700. Customers also can enroll on Xcel Energy's Web site at www.xcelenergy.com.
- For daily updates on Saver's Switch control period times, call Xcel Energy's Saver's Switch hotline at (800) 835-6776.