7.0 Critical Issues

7.1 Introduction

The Legislature directed the utilities to discuss in their Renewable Energy Standards Report critical issues that will have to be addressed in order to develop the transmission infrastructure that will be required to meet the upcoming RES milestones and ultimate standards. Assuredly, there are any number of significant issues that will influence the manner in which the utilities go about the task of obtaining renewable energy resources and transmitting that power to consumers, who will typically be located long distances from the renewable generation, particularly wind renewable generation.

The utilities have attempted in this section to describe some of the critical issues that will affect planning for purposes of achieving the Renewable Energy Standards. There are physical limitations, and regulatory controls, and competing priorities, and a whole litany of factors that will need to be taken into account. Not only would it be difficult to list all the factors that will come into play in this changing scenario, but indeed, it is highly likely that issues that are not even contemplated today will come to have a critical impact on the future ability of society to achieve renewable energy milestones. Planning for our energy future is a dynamic matter, with constantly changing assumptions and issues, and planning will be a continuing endeavor throughout the upcoming decade and beyond.

Nonetheless, the Minnesota electric utilities have attempted here to identify a number of issues that are presently known to have an impact on transmission planning to meet Renewable Energy Standards.

7.2 Unknown Location of Renewable Energy Sources

Transmission facilities are constructed to deliver electric generation to end use loads. One overriding issue is the fact that the eventual locations of the renewable generating resources necessary to achieve the RES are presently unknown. Location of the generation is a crucial factor in planning for transmission, and it is impossible today to predict exactly where renewable energy generation sources will be located. Good information is available to determine the general geographic location of future wind generation projects, but the specific locations and generating capacities are uncertain, and other types of renewable resources are also likely to be constructed in locations that are presently unknown.

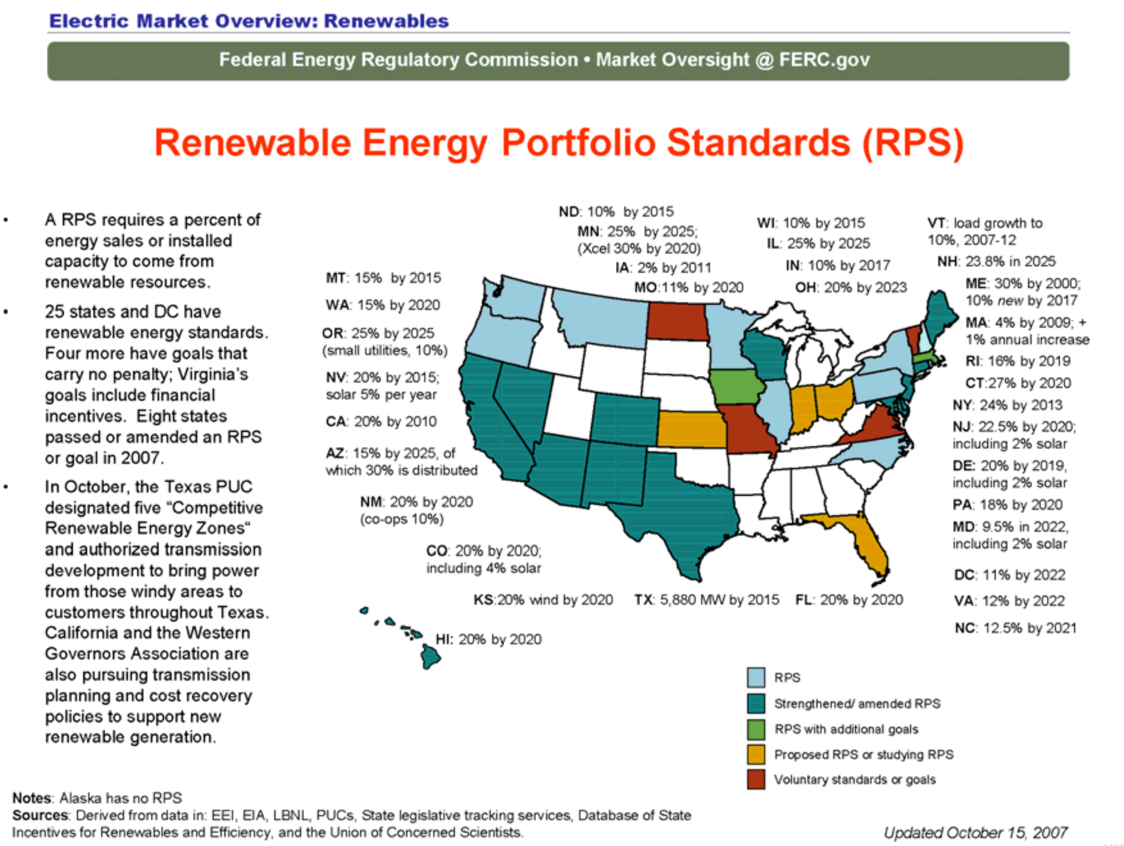
At the same time it is difficult to predict how much renewable generating capacity is going to be required. The utilities report in Section 2 (Gap Analysis) on their efforts to determine how much power will need to be generated from renewable resources to meet the RES milestones in future years, but those figures are only estimates. Moreover, it is uncertain what kind of capacity factors will be realized by future renewable generation facilities and how effective conservation and demand response measures will be five and ten years from now and even further into the future.

Not knowing specifics like location and performance of renewable resources requires the transmission planners to consider many possible scenarios to best identify potential transmission infrastructure. Planners must constantly update their models and their assumptions and inputs.

7.3 Renewable Energy Goals in Other States

Minnesota is not the only state in the country, or even in the upper Midwest region, to want to expand the amount of renewable energy used by electric utility customers in the state. Wisconsin and Iowa, for example, both have adopted renewable energy objectives, and federal renewable goals or standards are also a possibility. It is expected that out-of-state utilities will be looking to wind generation resources in Minnesota and the Dakotas – and relying on transmission in the state of Minnesota to deliver that wind energy – to satisfy their need for larger amounts of renewable energy. It is difficult to determine how much of Minnesota's wind resources and transmission capability will be used to respond to other states' renewable energy goals.

A map showing other states with renewable energy goals or standards is shown below.



7.4 Transmission Additions in Other States

Because of the interconnected nature of the transmission system, adding large amounts of renewable generation (or any type of generation for that matter) in one or more locations will have far reaching impacts. Electrons follow the laws of physics, and the installation of new generation or transmission facilities can have "loop flow" impacts on distant utilities. For example, the installation of a large generator in western Minnesota or the Dakotas might cause overload conditions on transmission facilities in Nebraska that must be resolved. Also, when large amounts of non-dispatchable generation are added to the transmission system, the transmission system needs to be robust (and there needs to be available dispatchable generation) to act as a "shock absorber" to move power into or out of the region depending upon the status of the non-dispatchable generation.

As a result, it is likely that major transmission facilities (and generation) will need to be constructed in areas outside of the state of Minnesota in order to accommodate the large amounts of wind generation anticipated to satisfy the RES requirements. To the extent that complying with the Minnesota RES is dependent on construction of transmission facilities in other states, it is necessary to take into account other states' regulatory policies and procedures for reviewing proposed new large energy facilities like high voltage transmission lines. A delay in a neighboring state will correspondingly result in a delay in constructing the transmission infrastructure necessary to achieve the RES.

At this point, it is too early to determine with great certainty whether meeting the Minnesota RES will require construction of transmission facilities in other states, but there are indicators that point to the possibility that this may be necessary. For example, the 2006 Wind Integration Study assumed over 3000 miles of new major high voltage transmission, some of which will occur outside the state of Minnesota. Also, MISO Pro-Mod study results are showing that transmission constraints outside the state of Minnesota will limit the amount of wind generation that can be added to the region. Conceptual plans reported in Section 5 suggest that out-of-state transmission lines are a possibility.

7.5 The MISO Generation Interconnection Queue

The MISO Large Generator Interconnection Procedure (LGIP) is one of many potential barriers standing in the way of Minnesota electric utilities from meeting the Minnesota Renewable Energy Standards. The MISO LGIP process was adopted in compliance with FERC Order No. 2003[1] and was primarily designed for interconnecting large, central station (*e.g.*, coal and natural gas fired) generating facilities. The MISO LGIP process initially worked acceptably well for

[1] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003); Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), 106 FERC ¶ 61,220 (March 5, 2004); Order 2003-B, 70 Fed. Reg. 265 (January 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2005); and Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), 111 FERC ¶ 61,401 (2005).

interconnecting traditional generators and for many of the early wind projects, but now is completely overwhelmed by projects seeking interconnection in the upper-Midwest.

MISO has received hundreds of interconnection requests for the upper-Midwest, totaling tens of thousands of MW. For example, MISO reported in October 2007 that there are approximately 14,000 MW of pending interconnection requests for new wind generation proposed to be located on the Buffalo Ridge. Under FERC Order No. 2003, each interconnection request is to be studied sequentially (e.g., first in, first out).

Each interconnection request can take close to two years to move from application to studies before the FERC-mandated Large Generation Interconnection Agreement (LGIA) is executed, and a project requesting interconnection today cannot expect to even begin required LGIP studies until 2011-2012 timeframe. The FERC Order No. 2003 process also provides a significant advantage to earlier projects, regardless of their commercial status. The barrier for entry into the queue is quite low: there are minimal costs to submit and process an interconnection request, and once a project developer executes an LGIA, it can suspend its project for up to three years without penalty. And if an individual project is suspended, and many have been, delays occur in MISO's processing of projects later in the queue. Thus, it is believed the MISO interconnection queue has a significant number of prospective project developers who simply want to use the interconnection queue as a means to gain competitive advantage.

The number of MISO-queued projects, and the amount of megawatts requested, are creating problems for all stakeholders, including MISO, the interconnecting generators, and the electric utilities. MISO recognizes that the LGIP process must be changed and has set up a stakeholder process to help develop an alternative LGIP process. The stakeholder process could be completed before the end of 2007; the alternative LGIP process would then need to be filed with and approved by FERC as a "regional difference" to Order No. 2003.

As an example of the ideas being discussed in the stakeholder process, Xcel Energy has developed and presented a proposal that provides an alternate MISO LGIP process to resolve some of the issues mentioned above. Xcel Energy is proposing a simplified process for interconnecting generators who plan to sign a power purchase agreement (PPA) to sell the output of the generator to a load serving entity (LSE), which Xcel Energy believes are the majority of the wind projects in the MISO queue. This proposal would let the interconnection process consider only the local issues pertaining to interconnecting the generation and allow the larger deliverability issues to be addressed in the Transmission Service Request (TSR) process. Xcel Energy believes this change could reduce the time needed to complete the interconnection process and reduce some of the uncertainty and risk created by the existing process.

Another proposal being considered by MISO is an "open season" process similar to that used successfully by interstate gas pipelines to identify market needs for new gas transmission capacity. The MISO open season proposal would provide advantages to interconnecting generators that complete all requirements and agree to be financially bound by the outcome, rather than based on the date of the interconnection request. The MISO open season proposal is also pending stakeholder comments. If approved by the MISO Board of Directors, the MISO open season proposal (or other alternatives) would be filed at FERC as change to the MISO tariff to respond to the unique "regional differences" within the MISO region.

7.6 NERC Reliability Standards/MISO Ancillary Services Market

On September 14, 2007, MISO submitted a filing to FERC to modify its tariff to establish an Ancillary Services Market (ASM) to provide certain transmission ancillary services — namely frequency regulation and contingency reserve services — as an enhancement of the "Day 2" wholesale energy market that began operations in 2005. The ASM proposal includes a provision to consolidate the 24 existing control areas — or "balancing authorities" — in the MISO footprint into a single balancing authority operated by MISO, with the existing balancing authorities operating as Local Balancing Authorities (LBAs) subject to MISO oversight.

A "balancing authority" (or BA) is responsible for complying with numerous NERC reliability requirements, including instantaneously balancing generation to load within the BA. For example, if the load in the BA increases 100 MW over the course of a few minutes during the morning or evening peak demand periods (called the "ramp" period), the BA must have generation online and available to respond to that change in demand. Similarly, if a 500 MW generator suddenly trips offline due to a forced outage (such as a tube leak), the BA must have alternative resources available to replace the 500 MW resource. Interstate Power and Light, Great River Energy, Minnesota Power, SMMPA, Otter Tail Power Company, Xcel Energy, and perhaps others, all operate balancing authorities today, and would operate LBAs under the MISO ASM proposal.

The ASM is a likely critical factor in meeting the RES because the intermittent nature of renewable wind generation makes balancing generation difficult. Since a BA must balance generation to loads on a second-by-second basis, a BA must have sufficient controllable generation available to respond to the loss of an intermittent resource. For example, assume the Xcel Energy BA has 5,000 MW of interconnected wind generation and 10,000 MW of interconnected load in its BA. Xcel Energy would need to have sufficient controllable generation (or load) to instantaneously respond to the loss of all or a portion of the 5,000 MW of wind generation in order to maintain reliable service to customers within the BA region. It would be extremely costly to customers to operate and maintain all of this reserve capability solely within the Xcel Energy BA region.

By creating a single BA for the entire MISO region, essentially all of the dispatchable generation in the MISO regional BA — approximately 135,000 MW — would be available to respond to changes in the 5,000 MW of intermittent wind generation. As more wind generation is added in the MISO and MAPP regions to respond to the Minnesota RES and other state renewable energy mandates, the ASM will provide greater regional operational flexibility to respond to the intermittent nature of renewable wind generation.

However, the ASM proposal is subject to FERC approval. MISO has requested an initial FERC order by December 31, 2007, and proposes to initiate the ASM by June 1, 2008. If the ASM is not approved by FERC, or is delayed by either regulatory or technical issues, it could make it more difficult for a MTO utility obligated to comply with the RES to manage the intermittent renewable generation within its BA sufficiently to maintain service reliability to customers without incurring high costs.

7.7 MISO/MAPP Seams Issues

MISO is a FERC-jurisdictional Regional Transmission Organization (RTO), but not all MTO utilities are members of MISO. Indeed, the state of Minnesota is on the "seams" between the MISO and the legacy MAPP region. For example, new wind generation on Buffalo Ridge in Minnesota is in the MISO region, but wind generation along Buffalo Ridge in eastern South Dakota — west of Brookings — would be in the MAPP region. This "seam" creates operational and cost issues, because transmission services are subject to two separate tariffs (the MISO tariff and MAPP Schedule F) using two separate transmission congestion procedures (the MISO Day Ahead and Real Time market and the MAPP Transmission Loading Relief procedures). The "seams" complicate the delivery of generation, and/or increase the costs of delivery, from one region to the other.

MISO and MAPP have been subject to a "seams agreement" — an operational arrangement to limit the impact of the seams — for several years. MISO has given notice to terminate the seams agreement with MAPP effective February 1, 2008, the end of the initial six year period of MISO operations. (MISO began "Day 1" operations on February 1, 2002.)

MISO and MAPP are discussing alternative arrangements to manage the seams between the two regions. Effective mechanisms for handling seams issues is important to ensure that there are not institutional barriers to installing generation in the area across the seam from the entity purchasing its output.

7.8 Cost Allocation

Historically, electric utilities have largely recovered the cost of new investments in high voltage transmission lines from the retail or wholesale electric rates paid by "native load" – the retail and wholesale "full requirements" customers of the utility. However, electrons follow the laws of physics, and the payments for transmission services may bear no resemblance to the transmission systems used.

In 2005 and 2006, MISO submitted filings, referred to as RECB I and RECB II, to modify its tariff to provide for partial "postage stamp" (or regionalized) pricing to help recover a portion (20%) of the cost of certain high voltage "reliability" and "economic" transmission projects. (RECB stands for Regional Expansion Criteria and Benefits, the name of the stakeholder task force established to develop proposals for the allocation of the cost of new transmission projects.) On August 1, 2007, transmission owning members of MISO were required to submit proposals for transmission pricing for existing and new transmission facilities for the "post transition" period starting February 1, 2008. Most vertically integrated utilities in MISO, including several Minnesota members, submitted a proposal to retain license plate rates for existing facilities and continue the RECB I and RECB II pricing for new facilities; other utilities in MISO, including some Minnesota utilities, submitted a proposal to retain license plate pricing for existing facilities but provide for 100% postage stamp pricing for all new facilities 345 kV and above. Other utilities support 100% postage stamp pricing for existing and new facilities. Various parties have suggested changes to transmission pricing, including provisions that would modify the RECB I & II methodologies for some types of projects. Lack of stability in transmission pricing makes it more challenging for potential project sponsors and regulators to assess the impacts and net benefits of projects.

In addition, Minnesota is located on the non-MISO/MISO seam, and there are several proposed transmission projects – *e.g.*, the initial CapX 2020 345 kV and 230 kV projects – that are intended to be owned by MISO and non-MISO transmission owners. The seam results in not having a single tariff to allocate costs. That causes some complexity in implementing mechanisms within both tariffs to appropriately recover the costs in each area and to avoid duplicative "pancaked" transmission charges for reciprocal use by the project owners. Resolving the cost allocation issue is an important element of assuring that the large extra-high voltage transmission upgrades needed to achieve the RES are constructed.

7.9 Landowner Concerns

Transmission line development and construction can be controversial and be subject to significant local opposition. Certainly, there are examples of specific projects that have moved through the process with relatively little controversy; however, there are also examples of projects that have been mired in controversy for many years. With the likely need to construct multiple major transmission facilities over the next eighteen years, there is the potential for significant public and landowner opposition. It is difficult to predict what effect landowner involvement in a proposed transmission line project will have on the timing and outcome of the regulatory process. The utilities are committed to outreach activities to landowners and other stakeholders involved in proposed projects, with the goal of identifying mutually agreeable solutions and minimizing controversy and delays.

7.10 Human Resource Limitations

With the expectation for construction of major generation and transmission facilities over the next two decades both regionally and nationally, and the expectation that up to half of the work force at utilities will be retiring over the next eight years, there is a concern over having adequate human resources to develop and construct these infrastructure projects. Utilities must assure that there are adequate professional and skilled trades' human resources available. In fact, due to a scarcity of experienced planning engineers, utilities' transmission planning departments are hard pressed to conduct all the transmission planning studies that are required and expected, particularly within tight timeframes. The 2007 NERC Assessment discussed earlier in Section 3.5 of the Biennial Report specifically identifies human resource needs as a potential barrier to reliable future electric service. Minnesota utilities are evaluating whether changes in human resource strategies are required to assure a sufficient workforce.