

# Meeting Minnesota's Renewable Energy Standard Using The Existing Transmission System

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# Other Publications

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**Energy Self Reliant States: Homegrown Renewable Power**, by John Farrell and David Morris, November 2008

**Rural Power: Community-Scaled Renewable Energy and Rural Economic Development**, by John Farrell and David Morris, September 2008

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Since 1974, the Institute for Local Self-Reliance (ILSR) has worked with citizen groups, governments and private businesses to extract the maximum value from local resources.

A program of ILSR, the New Rules Project helps policy makers to design rules as if community matters.



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## Executive Summary

The recent request by 11 utilities that own transmission lines in Minnesota and the surrounding region (CapX 2020) to build 650 miles of new high voltage transmission lines (mostly in Minnesota) is the first major transmission proposal in the state in 30 years and probably the largest, most costly transmission proposal ever in the state.

During those three decades Minnesota has painstakingly developed a comprehensive process for state electricity planning. The least cost process requires that any new generation or transmission project over a certain size be compared to alternative ways of meeting future energy needs. In that examination, a priority is given to improving energy efficiency and expanding distributed generation and the use of renewable fuels. The state also requires that a priority be given to strategies that expand locally owned renewable energy plants.

The current regulatory proceeding in Minnesota covers the first phase of the CapX 2020 vision, a phase the utilities argue is to meet Minnesota needs. But when fully built out CapX will be a multi-state transmission network designed to serve largely regional needs. Despite its regional orientation, individual segments of CapX 2020 lines must be approved by individual states. In evaluating the Phase I proposal, Minnesota regulators must rely on the state's legislatively required need criteria and policy priorities.

One controversial issue related to the CapX proposal is whether new high voltage transmission lines are needed to meet Minnesota's ambitious Renewable Energy Standard (RES) that requires 25 percent of state electricity consumption to be generated from renewable resources by 2020. Two recent, unprecedented transmission studies conducted by the state's utilities provide empirical data that can be used to answer that question. These studies examined the potential for dispersed renewable electricity generation to be integrated into the existing transmission system. The data generated by that examination leads to the

conclusion that sufficient power transfer capability may be available on the existing grid or with relatively modest, strategic enhancements to the existing grid system to allow enough dispersed renewable electricity generation to meet the 2025 renewable energy goal without building major new 345 kV transmission facilities.

*By the early 2000s Minnesota had painstakingly created comprehensive legislative and regulatory rules governing electricity planning. The rules required planners to be guided by three goals: maximize efficiency, maximize the use of renewable energy and encourage the use of dispersed and locally owned generation.*

If completed as proposed, the CapX Phase I projects would provide an outlet for about 1,050 MW of additional capacity for renewable energy. The two utility-led studies suggest that this amount of renewable energy could be injected into the existing grid system with minimal transmission-related investments. With further study, we believe up to 3-5 times that amount of dispersed renewable energy projects can be connected to existing and any strategically-enhanced transmission/distribution lines at a cost less than would be incurred by continuing along the new transmission path envisioned by CapX.

Moreover, unless stringent conditions are tied to the approval of the new lines, the 1,050 MW of potential generation outlet is not guaranteed to be used for renewables; instead renewables will compete for transmission capacity with all types of non-renewable generation.

Vigorously pursuing a dispersed generation strategy for accomplishing our RES goals would allow the state to achieve several other legislated goals.

- **Least cost.** Since its cost could be a fraction of the cost of building a large, new network of high voltage transmission lines to achieve the RES goals, Minnesota ratepayers could save billions of dollars in avoided transmission line costs.

- **Greenhouse Gas Reductions.** By not establishing a potential energy delivery infrastructure, the dispersed and distributed generation strategy would significantly inhibit the construction of new large coal fired power plants that would deliver or pass carbon-based power through Minnesota, thereby helping Minnesota to achieve and remain firm in its greenhouse gas reduction goals.

- **Local ownership.** The dispersed generation strategy would enable a major expansion of locally owned wind turbines, an economic development goal the state legislature has formally adopted.

- **Meeting the Near Term RES.** Past practice has been that the regional transmission authority, the Midwest Independent Transmission System Operator (MISO), processed interconnection applications from power plant developers on a first come, first served basis. The result was a remarkably long queue in which locally owned and dispersed renewable electricity projects are near the back. All parties agreed that the queue process was broken. MISO proposed and is in the process of implementing changes to the queue process but the effectiveness and results will not be known for months or years. One near term strategy would be to

have the state assert authority over interconnection applications to existing subtransmission lines. By enabling the rapid interconnection of community based energy projects that can be shown not to cause grid reliability issues, this would achieve major in-state and community economic benefits and would

enable new renewable power plants to more quickly come on-line, thereby meeting the near term generation requirements of the state RES.

A major investment in transmission might be needed in the future if a policy decision is made to transmit tens of thousands of MW of wind energy from the Dakotas to Illinois or Ohio, but at this date Minnesota should remain focused on meeting our own state's aggressive state renewable energy goals. All of this renewable energy should and could be generated inside Minnesota, thereby keeping substantial economic benefits right here rather than sending them off to other states.

*Given the CapX projects' multi state regional characteristics is it reasonable for Minnesota's ratepayers to subsidize a transmission infrastructure investment that will be used by customers in other states?*

## Introduction

In the last 30 years, the electricity sector has experienced a policy and technological revolution.

The policy revolution began in 1978 when Congress passed the Public Utility Regulatory Policy Act (PURPA), ending the century-old monopoly of utilities on the production of electricity.<sup>1</sup> From that date forward<sup>2</sup>, utilities were required to purchase electricity generated by some independent power producers.<sup>3</sup>

The change in law, combined with the low price of natural gas in the 1980s, spurred the rapid growth of non-utility electricity generation. By 1990 the majority of all new power plants were built by independents.<sup>4</sup>

Independent power producers (IPPs) usually sold their electricity to local utilities. But as the independent power industry grew it lobbied Congress to allow it to sell to more distant utilities and to require utilities to give independently own power plants access to the utilities' transmission systems on the same terms as they offer to their own power plants. In 1992, Congress agreed. Utilities were required to provide open access to IPPs on demand, which in effect, also meant providing sufficient transmission capacity to meet IPPs' demand.

IPPs immediately began to lobby state legislatures to allow them to sell at retail rates to the final customer. Between 1996 and 2000, about half the states changed their electricity rules to permit this. Minnesota did not. The rush to retail electricity deregulation abruptly ended in 2001, with the near bankruptcy of the State of California, a result of electricity price manipulation by Enron and other energy marketers.

Congressional and state actions to deregulate wholesale and retail markets ran up against a key obstacle. The electric grid management system was not designed to handle large numbers of independent power producers selling electricity to distant markets. The electric grid has been designed to deliver power from utility owned generators largely located within a utility's service area to the utility's own customers. The transmission lines that delivered the electricity were also owned by the utility. In electric parlance, the electric grid system was designed to meet local load (demand). Bulk power transfers that crossed state

borders did occur, but they comprised a small portion of overall electricity flows.

A change is underway. An electrical grid that was traditionally designed to deliver power from a relatively nearby power plant to a local customer is now being utilized to deliver large amounts of power across much further distances and increasingly among multiple states. This puts an enormous strain on the system.

The physics of electricity leads it to flow to the path of least resistance. When you turn the light switch on, the electricity needed flows from the nearest power plant, regardless of any contract provisions between the owner of the power plant and the customer. An IPP can build a generator in Montana and sign a contract with a customer in Seattle, but the electricity could very well travel on different paths, to Los Angeles or Las Vegas for example on its way to Seattle. This is called a loop flow problem.

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Thus while transmission authorities are required by law to provide the capacity IPPs request, the physical fact that power flows could move along many lines means these authorities increasingly want to upgrade all parts of the high voltage transmission system. Indeed, today federal policy makers are aggressively pursuing the construction of a national electricity highway system to

accommodate the new rules governing wholesale electric markets. And to encourage that construction, Congress has given the Federal Energy Regulatory Commission (FERC) the authority to preempt state authority for transmission siting in certain circumstances. The first condition is there must be a finding that the line is in a "National Interest Electric Transmission Corridor" as determined by the U.S. Department of Energy (DOE). Although such a designation, according to the DOE, does not preempt state authority, the fact that the DOE's initial corridor designations have been fought so vigorously by states reflects the states' belief that it is the first step toward such preemption. The second trigger for federal siting is if the state jurisdiction considering the permit for the line in the corridor has taken more than 12 months to consider the completed application.

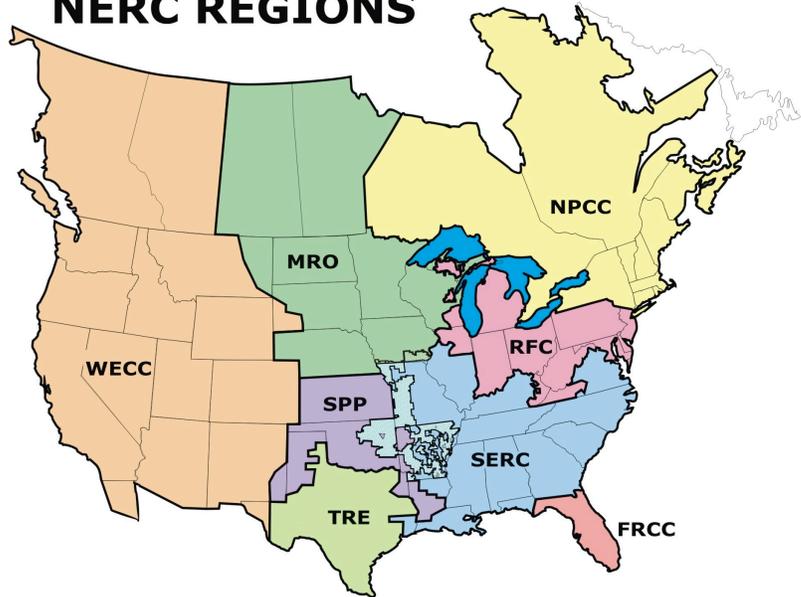
Over the last 15 years, FERC elaborated new rules to govern transmission access. Initially it required utilities to build a firewall between their generation and transmission departments to prevent the latter from discriminating in favor of the former. Eventually,

FERC decided that separation was necessary but not sufficient to prevent this kind of discrimination and strongly encouraged the creation of regional transmission entities to manage transmission lines.<sup>5</sup>

Regional transmission councils already existed, created to ensure the reliability of the grid system after a blackout struck New York and New England in 1965. The National Electric Reliability Council (NERC) was formed June 1, 1968, by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC focused on standards of reliability, not direct system management or regional planning. Nine regional reliability organizations were formalized under NERC. NERC was renamed the North American Reliability Council in 1981 to include Canada's participation and has recently dropped the moniker of Council in favor of Corporation.

Under the prodding of FERC, new entities called Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) have become a much more formal and integral part of the transmission planning, generation interconnection and operational processes.<sup>6</sup> These are charged by FERC to ensure reliable supplies of power, adequate transmission infrastructure and competitive and open markets for wholesale electricity. Eight regional entities now exist. New York and Texas, for example, have their own RTOs. Minnesota is part

## NERC REGIONS



Source: North American Electric Reliability Corporation. Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); ReliabilityFirst Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool, RE (SPP); Texas Regional Entity (TRE); Western Electricity Coordinating Council (WECC).

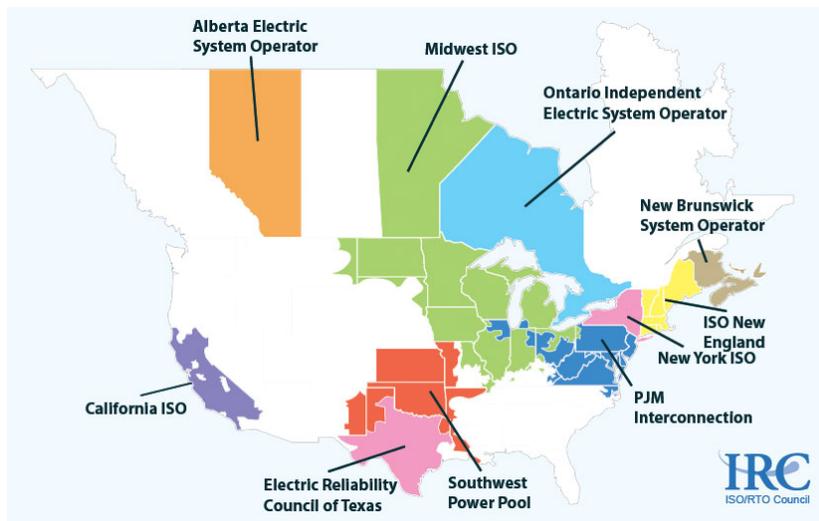
of the Midwest Independent Transmission System Operator (MISO) encompassing all or part of 15 states and the Canadian province of Manitoba.

These regional organizations view their multi-state jurisdictions as a single service territory. When they develop plans, they are regional plans, designed to serve regional needs, not necessarily the needs of any individual state within the region. In areas of the country that have not yet formed a regional ISO or RTO, transmission system expansion and energy transactions are still governed by FERC and state utility regulators, but planning and operations have a more localized focus.

While the political dynamic has encouraged a more centralized generation and regional transmission system, technological dynamics have been moving us in the other direction, toward a more localized grid system and more dispersed and smaller power plants.

The fastest growing parts of the electricity system are now decentralizing technologies like photovoltaics (PV), whose markets

## Regional Transmission Organizations and Independent System Operators (as of August 2008)



have been expanding worldwide 30-40 percent per year, and wind turbines, whose markets have been growing by 20-25 percent per year. These technologies, which barely existed 30 years ago, are now the basis for multi-billion dollar industries. On-site heat and power plants, which can achieve efficiencies more than twice that of conventional power plants, have also become increasingly attractive.

*The fastest growing parts of the electricity system are now decentralizing technologies.*

Meanwhile, public policies to reduce carbon dioxide emissions in order to mitigate global warming are strongly discouraging the use of coal, a fuel that currently accounts for 55 percent of the nation's electrical generation and a large proportion of U.S. greenhouse gas emissions. Nuclear power, another centralizing alternative, has its own set of undesirable characteristics. Thus we must aggressively pursue lower carbon emission natural gas technologies, wind and sunlight as our major new electricity sources. In combination, higher efficiency an increase in renewable energy, and natural gas power plants as a back-up enables a more localized electricity system where local power plants largely meet local loads.

## Minnesota Develops the Rules for a New Electricity System

Over the last 25 years, Minnesota has slowly elaborated new electricity rules. Before the 1980s, Minnesota and other states focused almost entirely on encouraging utilities to build new, increasingly large-scale power plants to meet what had become a relatively predictable increase in electricity demand. But in the 1980s, future demand became increasingly unpredictable; a result in part of the remarkable potential for improving energy efficiency and slowing economic growth. There was an increasing risk in building very large plants that could take a decade to bring on-line.

In Minnesota and other states, regulators began to more closely scrutinize applications for new power plants and devise new criteria to guide that scrutiny. Minnesota required utilities to submit Integrated Resource Plans that examined alternatives to new large-scale electric power plants or new high voltage transmission lines over a 15 year planning horizon.<sup>7</sup>

The state required utilities to apply for a Certificate of Need before they built new power plants over a certain size and new transmission lines over a certain voltage. In determining whether to grant the application, the Minnesota Public Utilities Commission (PUC) was

legislatively required to ensure that an evaluation was conducted of the need for the proposed project and of alternative ways of meeting or reducing future demand. In doing so, utilities were required by legislative

directive to give a priority to improved energy efficiency, conservation, renewable energy and distributed generation.<sup>8</sup> In the 1990s Minnesota required utilities and the PUC to take into account any pollution impacts by including a set of environmental cost values in the

analysis determining the "least cost" option, including a cost value for carbon dioxide. In 2007, as a result of another legislative directive, the PUC began ordering utilities to take the potential future costs of carbon dioxide into account as part of their decision making process.<sup>9</sup>

By the early 2000s Minnesota had painstakingly created comprehensive legislative and regulatory rules governing electricity planning. The rules required planners to be guided by three goals: maximize efficiency, maximize the use of renewable energy and encourage the use of dispersed and locally owned generation.<sup>10</sup>

## Decentralization and Local Ownership

Minnesota has also joined other states in designing rules to enable customers to become producers as well as consumers by evolving a two-way rather than one-way electrical grid.

In 1981, Minnesota adopted the nation's first net metering law. It required utilities to allow on-site producers with generators under a certain size to "turn the meter backwards" when more power was being produced than what was being used. Today at least 42 states and the District of Columbia have such laws. Some states require utilities to pay customers for any net excess electricity generated; others simply credit the next month's billing cycle.<sup>11</sup> Over 20,000 buildings across the U.S., most of them boasting rooftop solar cell arrays, are likely operating under this arrangement.<sup>12</sup>

In 2001 the legislature directed the PUC and the state's utilities to establish uniform, statewide interconnection technical standards and tariffs for clean, distributed generators of less than 10 MW. That process was completed for most utilities serving Minnesota by 2006.<sup>13</sup>

Minnesota has encouraged dispersed energy generation in part because of its positive economic impact on the state. Small and medium scale generation enable local ownership. Local ownership results in a far greater proportion of the electricity dollar staying in the state. Indeed, locally owned wind turbines, for example, can have a local and state economic impact 25-300 percent greater than if the same facility were absentee-owned.<sup>14</sup>

In 1997, to encourage local ownership, Minnesota enacted a 1-1.5 cent per kWh, ten-year producer payment to small, locally owned renewable energy projects. These later became known as Community Based Energy Development (C-BED) projects because of their ability to involve local landowners as owners

of the projects. In 2005, the state redesigned the incentive. The producer payment was capped at a certain number of MWs and utilities were required to develop a C-BED tariff (essentially a framework for a power purchase agreement) that is available to locally owned projects that satisfy the definition of C-BED (see accompanying text box).<sup>15</sup> In 2007, the state established a task force to design an even more effective C-BED tariff. Some 200 MW of small, locally-owned projects became operational between 1998 and 2006 prior to the formal definition of a C-BED project. Only about 57.3 MW of C-BED projects have become operational since then, as of June 30, 2008. As of October 2007 there were 778 MW of C-BED projects in some form of development or negotiation with Minnesota utilities.

### **Community Based Energy Development (C-BED) – Minn. Stat. §216B.1612**

In 2005 Minnesota lawmakers enacted legislation requiring all of the state's electric utilities to establish Community Based Energy Development (C-BED) tariffs. The key aspect of the C-BED tariff is a 20-year power purchase agreement that offers higher payments to project owners in the first 10 years of than in the last 10 years of the contact.

To be eligible the law defined what a C-BED qualifying owner as:

- (1) a Minnesota resident;
- (2) a limited liability company that is organized under the laws of this state and that is made up of members who are Minnesota residents;
- (3) a Minnesota nonprofit organization organized under chapter 317A;
- (4) a Minnesota cooperative association organized under chapter 308A or 308B, other than a rural electric cooperative association or a generation and transmission cooperative;
- (5) a Minnesota political subdivision or local government other than a municipal electric utility or municipal power agency, including, but not limited to, a county, statutory or home rule charter city, town, school district, or public or private higher education institution or any other local or regional governmental organization such as a board, commission, or association; or
- (6) a tribal council.

A C-BED project initially meant a new wind energy project that:

- (1) has no single qualifying owner owning more than 15 percent of a C-BED project that consists of more than two turbines; or
- (2) for C-BED projects of one or two turbines, is owned entirely by one or more qualifying owners, with at least 51 percent of the total financial benefits over the life of the project flowing to qualifying owners; and
- (3) has a resolution of support adopted by the county board of each county in which the project is to be located, or in the case of a project located within the boundaries of a reservation, the tribal council for that reservation.

In 2007, the original C-BED law saw several changes, including:

- C-BED projects can now use renewable technologies other than wind and have no size limitations.
- Utilities are now allowed to become ownership partners in C-BED projects.
- An advisory committee to be coordinated by the Legislative Electric Energy Task Force was formed to look into possible changes to the definition of what qualifies as a C-BED project.
- The tariff price cap for C-BED projects was eliminated (used to be 2.7 cents/kWh net present value over 20-year life of the project).
- Competitive resource acquisition requirements are relaxed for C-BED projects, and Xcel Energy was required to file a C-BED inclusive renewable energy plan with the PUC by March 2008. Xcel must also include C-BED acquisition discussions in its integrated resource plan.

## CapX 2020 and the Challenge of New Transmission Lines

Minnesota has largely been unaffected by the new rules governing high voltage transmission lines because it has not had to build a new base load<sup>16</sup> power plant in more than 20 years and almost a quarter of a century has passed since utilities last requested a major transmission expansion. The last major statewide transmission requests came in the 1970s and precipitated a famously widespread and sometimes violent response by rural Minnesotans.<sup>17</sup>

In 1994, Minnesota's legislature ordered its largest utility, Northern States Power (now Xcel Energy) to acquire a substantial quantity of renewable electricity, primarily wind generated, as part of a compromise over continued operation and generation of nuclear waste at the Prairie Island nuclear power plant (the 425 MW of wind power was later increased to 825 MW by the PUC, in accord with the 1994 legislative directive, along with 125 MW of biomass-fueled electricity).

The area of Minnesota with the highest speed winds, and therefore the lowest cost (at the bus bar) wind power, is along the Buffalo Ridge in the southwestern part of the state. Within a few years after wind development began, wind electric generation on Buffalo Ridge was beginning to approach the carrying capacity of its transmission system.

In 2003, Xcel Energy received permission from the PUC to build new high voltage transmission lines to increase the electricity export capacity from Buffalo Ridge. These new lines increased the existing 300 MW of export capacity to about 825 MW.<sup>18</sup> A subsequent transmission upgrade was also approved that will boost outlet capacity from Buffalo Ridge to 1,200 MW of wind energy by 2010.<sup>19</sup>

In 2007, Minnesota received another kind of transmission request, this time by 11 utilities that own transmission lines in Minnesota and the surrounding region. The CapX 2020 request is to build more than 600 miles of high voltage transmission lines at their initial estimates of a cost of between \$1.4 and \$1.7 billion. Minnesotans likely will pay about 80 percent of the costs of the new system. Construction is proposed to take place between 2011 and 2016.

This constitutes the first phase of what may eventually be the construction of thousands of miles of high voltage transmission lines not only in Minnesota but in

surrounding states as well.<sup>20</sup> A recent DOE study<sup>21</sup> on the potential transmission system needs to meet 20% of the nation's electricity needs by 2030 found that "12,000 miles of additional transmission" might be needed. Interestingly, the report also notes, "Much of that transmission would be required in later years after an initial period where generation is able to use the limited remaining capacity available on the existing transmission grid."

The CapX Phase I proposal initially included the following high voltage transmission segments:

- A 200-mile, 345-kV line between Brookings, SD, and the southeast Twin Cities, plus a related 30-mile, 345 kV line between Marshall, MN, and Granite Falls, MN;
- A 200-mile, 345 kV line between Fargo, ND and the St. Cloud/Monticello, MN, area;
- A 150-mile, 345 kV line between the Twin Cities, Rochester, MN, and La Crosse, WI
- A 70-mile, 230 kV line in the Bemidji and Grand Rapids area of north central Minnesota.

### CapX Initially Proposed Transmission Upgrade<sup>22</sup>

Line location	Line length	Cost estimate
Brookings, SD to Mpls-St. Paul	200 miles	\$600-665 million
Fargo, ND to Mpls-St. Paul	250 miles	\$390-560 million
Mpls-St. Paul to LaCrosse, WI	150 miles	\$330-360 million
		\$1.4 to 1.7 billion

As part of the ongoing Certificate of Need proceeding in Minnesota, the CapX proposal above was modified and now includes plans for "upsizing" and double circuiting some segments of the projects. Upsizing would mean that the 345kV lines would be built so that the poles could carry an additional 345kV line in the future. All three lines have upsized segments. The utilities proposed to double circuit (design and construct for double circuit operation with both circuits initially installed) portions of the Brookings line.

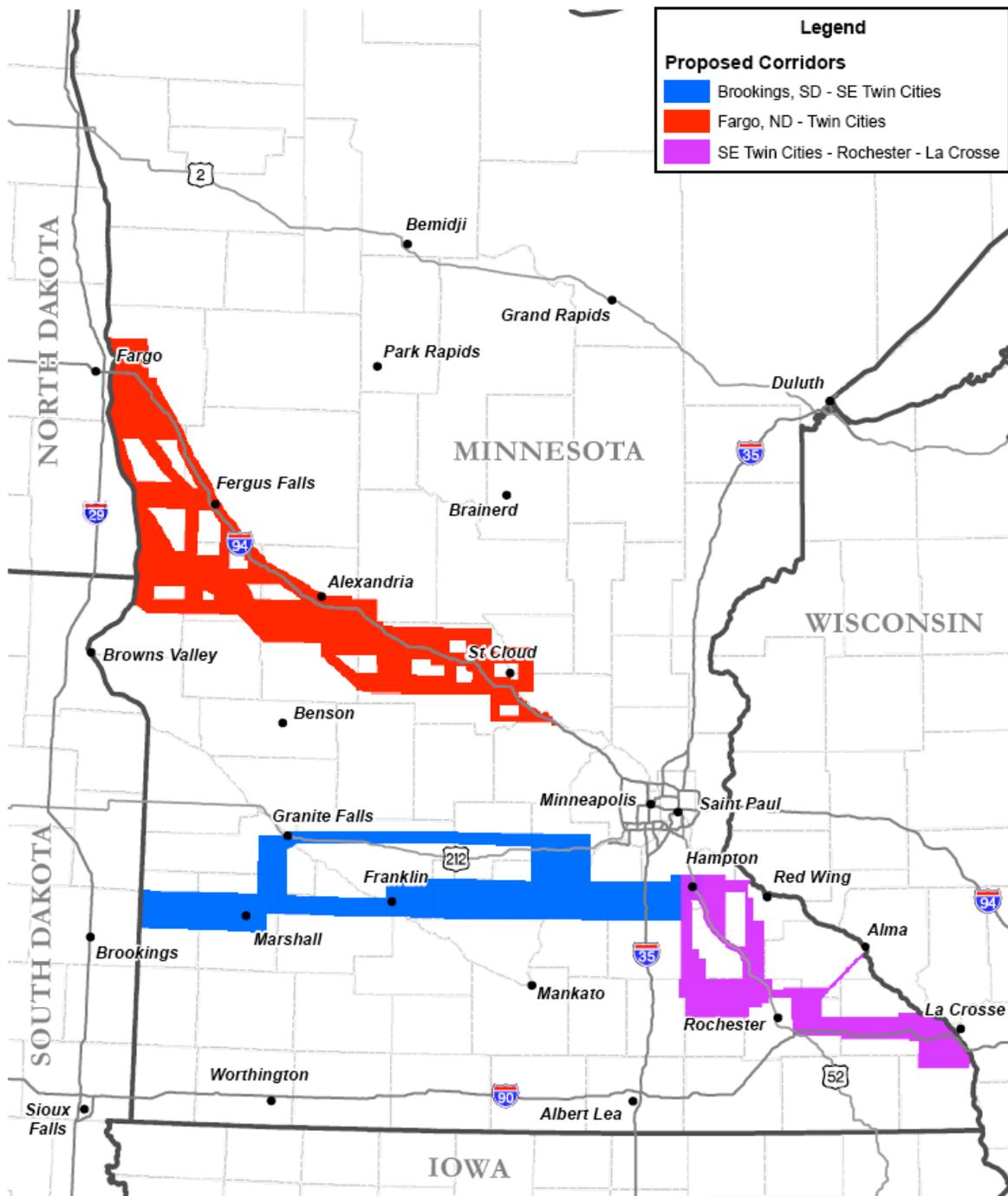
Much of the remainder of this report discusses the CapX 2020 proposal and the efforts by several Minnesota organizations to evaluate that application using the criteria mandated by the Minnesota legislature.

The CapX proposal must be approved by several states through which the transmission lines will pass. In Minnesota approval requires a Certificate of Need

(CON) and a Route Permit. Minnesota regulators are legally required to evaluate such a proposal based on statutory criteria that includes whether the lines are needed to meet Minnesota's future electricity needs as claimed in the Application and whether alternatives exist. The CapX application for regulatory approval in Minnesota did not propose or offer any comprehensive alternative that would fully meet the "need" claimed by the utilities.<sup>23</sup> While the Phase I CapX proposal has been framed by the utilities in a way that looks

Minnesota-centric, and if built is likely to be paid for largely by Minnesota ratepayers, this application combined with the long-term CapX vision plan can and is being viewed by many as intending to build a new transmission network largely to meet regional (e.g. Chicago) rather than state (e.g. Minnesota) electricity demands.<sup>24</sup> An issue for the state decision makers is not only whether the lines are needed to meet Minnesota electricity needs, but whether given the projects' multi state regional characteristics it is

### CapX Proposed Corridors in Minnesota



reasonable for Minnesota ratepayers to subsidize a transmission infrastructure investment that will be used by customers in other states.

A central question for the Minnesota PUC to answer is how much weight the environmental and economic needs of Minnesota and Minnesota ratepayers should receive compared to the regional criteria that the PUC is allowed to look at as part of their decision making process. The possible conflict between state and regional focus was illuminated by a May 2008 decision by two Minnesota Administrative Law Judges (ALJs) on a proposed \$250 million transmission line that would bring power into Minnesota from a South Dakota coal plant expansion – known as Big Stone II.<sup>25</sup> (This proposal is not part of the CapX proposal.)

The Big Stone II power plant expansion itself was quickly approved by South Dakota's utilities regulatory agency, as were the needed transmission lines in that state. For the Minnesota segment of the required transmission lines, however, the ALJs recommended that Minnesota deny the request because, when evaluated by Minnesota's electric planning criteria, the lines did not meet state standards. The Judges concluded the utilities had not met their burden to show they could not better serve their customers by investing in renewable energy and energy efficiency. The decision said in part, "The Applicants have failed to demonstrate that their demand for electricity cannot be met more cost effectively through energy conservation and load-management..." and they have "failed to demonstrate that they have explored the possibility of obtaining power from renewable energy sources and that Big Stone II is less expensive (considering environmental costs) than power generated by renewable energy sources..."

At this writing, the Minnesota PUC has received the ALJs recommendations but in their initial meeting to discuss the ALJ's findings, the PUC voted to delay a final decision on the Big Stone II transmission line proposal.

The CapX proposal was submitted to the PUC about the same time Minnesota added two important new electricity laws to the books. In 2007 the legislature enacted a Renewable Energy Standard (RES) that requires the addition of some thousands of MW of additional renewable electricity by 2025.

The exact amounts required depend on load energy growth and capacity factor assumptions. The RES does not require absolute amounts of renewable

*A central question for the Minnesota PUC is whether it will be guided by the environmental and economic criteria mandated by the state legislature or by the regional criteria used by CapX.*

electricity but rather an increasing percentage of electricity consumption. Thus if electricity consumption grows slower than historical levels, the amount required would grow more slowly. Based on historical growth levels, the cumulative

additions of renewable electricity over 2007 levels would be: 380 MW by 2010, 1,230 MW by 2012, 2,920 MW by 2016 and 4,260 MW by 2020 and a total of 5,640 MW by 2025. Since electricity growth is quite likely to slow in the future, these should be considered a high estimate and revised estimates that have been provided during the CapX 2020 regulatory proceeding in Minnesota have had estimates for required renewable energy by 2020 as low as 3,148 MW.

#### **Minnesota Renewable Energy Generation Estimates To Comply With Renewable Energy Standards by 2020**

	<b>Capacity Factor</b>	<b>2020 (MW)</b>
1% DSM	30%	4,911
1.5% DSM	30%	4,563
1% DSM	40%	3,404
1.5% DSM	40%	3,148

Source: Errata testimony of Hwikwon Ham, MN Office of Energy Security, PUC Docket No. CN-06-1115, June 13, 2008

Another legislative directive requires Minnesota utilities to reduce projected electricity demand by 1.5 percent per year.<sup>26</sup> Given historical levels of increased consumption, if this is achieved, a major stabilization of statewide electricity demand will take place and it will significantly affect the amount of renewable electricity that is needed to meet the RES.

Although the CapX transmission expansion was initially conceived four years before the Minnesota RES and new energy conservation targets became law, the CapX utilities still must demonstrate that their proposal and future forecast accurately reflect the forecasting requirements of Minnesota law.

Some intervenors in the proceeding have argued that the new transmission lines are needed to meet Minnesota's renewable energy standard and some insist that the renewable energy standard cannot be met in any other way.<sup>27</sup>

Fortunately, Minnesota has undertaken and largely completed two path breaking studies that empirically address the question of whether new interstate high

voltage transmission lines are needed to meet Minnesota's renewable energy requirements. Their findings argue that they may not be needed. Sufficient generation injection capacity is available on existing sub transmission lines to inject large quantities of dispersed renewable electricity.

The first phase of the distributed generation examination began in the Fall of 2005. The Community Based Energy Development Transmission Study is commonly known as the West Central C-BED study because its focus was on how allowing interconnection to the transmission system on lower voltage lines could enable local ownership and because the study examined a 17 county area in west central Minnesota.

In general, the cost of connecting single C-BED projects to high voltage lines is prohibitive for smaller locally owned projects. The cost of a substation connecting to a 345kV transmission line could be \$5-10 million while the cost of connecting to a 69kV line could be under \$1 million.<sup>28</sup>

The study was a result of negotiations between a utility consortium and the North American Water Office. The study area chosen was in west central Minnesota, a 17 county area encompassing more than 540,000 people, and nearly 11,300 square miles. The study area's boundaries encompass roughly a box that begins a little east of St. Cloud, Minnesota and whose borders are roughly 50 miles north and south of St. Cloud and west to the Dakotas



### Dispersed and Distributed Generation – What's the Difference?

The terms "dispersed" and "distributed" generation are often used interchangeably when talking about a future decentralized energy system. The term "distributed generation" tends to refer to small-scale power projects (Minnesota law defines it as 10 MW or below) built to meet on-site power needs at a particular location with net excess power flowing into the electric grid via an interconnection. In this paper we use the term "dispersed generation" as describing energy resources of no particular size limits (but generally smaller than central station power plants) that are located in geographically diverse locations along the existing transmission and distribution system. Dispersed generation can be located away from any particular power load at a specific location so that all power generated flows into the grid.

## 2005 West Central Minnesota C-BED Study

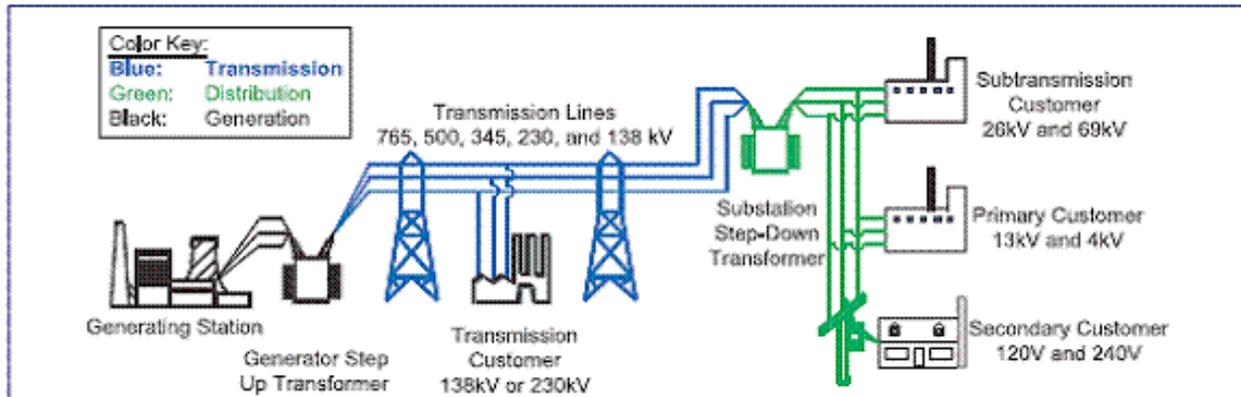
The West Central C-BED study was perhaps the first high level analysis in the nation of the impact of significant penetrations of dispersed and distributed power generation on an existing transmission system. The study, conducted by the state's utility engineers and using utility transmission models, essentially addressed two questions.<sup>29</sup>

- How much new C-BED generation capacity could be injected into the existing transmission system in the West Central Zone?
- What would be the cost for transmission upgrades to handle that new generation?

Before discussing the study, a discussion of how an electricity grid operates may be useful.

Electricity can be sent long distances relatively efficiently if the power is transmitted at high voltages. An electrical voltage might be likened to water pressure. The greater the pressure, the more water will travel through a given diameter pipe or, in the case of electricity, diameter wire.

Electricity may come out of a typical power plant generator at a force of up to 30,000 volts (30 kV). The voltage is then increased (stepped up) by an electric transformer at a substation to voltages from 115 kV to



Simplified Sketch of our Electricity System

Source: North American Electric Reliability Corporation (NERC)

765 kV for transmission over long distances to grid exit points, that is, substations with voltage step-down transformer equipment.

Substations sited along high-voltage transmission lines reduce voltages to what are called sub-transmission levels of 34 kV to 115 kV. More substations reduce the voltage to what are typically called distribution level voltages: 3.3 kV to 34 kV. Finally, the voltage is further reduced by a transformer that often sits on an electric pole outside an individual building to 240V and 120V.

Thus the substation is a critical component of the electrical grid. If customers reduce their consumption of electricity, less electricity flows through the substation from the central power plant. From the perspective of the substation, if customers generated some electricity, the substation power flow impact would be the same as if they simply reduced consumption. The distributed electricity generated would go to meet demand on the customer side of the substation transformer, thereby reducing the electricity flows from the central power plant into and through the substation. If more electricity was produced on the customer side of the substation than was being consumed by those customers, the electricity would go through the substation in the other direction, be stepped up by transformers and travel over the transmission system to other substations where it would be stepped down and delivered to more distant customers.

If electricity travels in the reverse direction, from customer to transmission system, then other generation on the transmission side of the substation must be backed out (reduced) to accommodate the new flows. The amount generated system wide must balance with the amount being used system wide. The West Central study assumed the power plants backed out would be natural gas fired plants in Minnesota. These plants are cheap to construct but because of the high price of

natural gas versus other electricity fuels, are costly to run. Thus they tend to more often serve as intermediate or peaking plants that run for only a few hundred or a few thousand hours a year.

An advantage to backing out natural gas plants is that these plants can easily be turned on and off. Moreover, they would remain readily available, and used to supply electricity when needed. Renewable energy sources are usually intermittent. In combination with a natural gas power plant they can become a firm power energy generation resource less expensive than a comparable stand-alone natural gas power plant and more reliable than a stand alone wind project.

The West Central study examined the possibility of adding dispersed generation on all of the high voltage substations (115kV or less) that serve customers in that region of Minnesota.

The study began with a “summer peak” model of the transmission system in west central Minnesota. The model looked at the performance and capacity of the electric lines and substations during the season of heaviest electricity demand in Minnesota. The modelers looked at available generation locations – where wind power could be produced in the 17-county west central area and interconnected to the existing transmission system. A total of 57 substation sites were identified with a total theoretical generation capacity of 3,500 MW.

Then a “transmission interchange limit analysis” activity was completed. This basically examines transmission line loading impacts and how new wind power would back out existing generation. Adding new wind generation of up to 1,907 MW would reduce the hours of operation of Minnesota’s natural gas-fired generation. If wind generation capacity above this level and up to 3,500 MW were added, the model indicated the new wind generation would begin to replace relatively inexpensive existing eastern

Wisconsin coal-fired power plants. The 3,500 MW was viewed as the upper limit for increased dispersed wind generation due to theoretical injection limits at existing load serving substations.

The analysis also estimated the incremental transmission network upgrade cost of additional MW of generation.

It identified various cost breakpoints, that is, points at which the cost increased sharply. The first cost breakpoint was at 800 MW of generation, where a new 115 kV line would be needed at a cost of \$10 million to \$15 million. Below that point the cost of upgrades was nominal and sometimes zero. A second breakpoint occurred at 1,000 MW when a transformer upgrade was required, raising total upgrade costs to \$25 million. Another breakpoint occurred at 1,400 MW when total costs climbed to about \$97 million.<sup>30</sup> This is the capacity level the study determined most likely to be achieved (considering line loading issues only) due to the increased costs for network upgrades beyond this level.

*The west central zone existing transmission and subtransmission system could integrate at least 1,400 MW of new generation capacity for a cost less than 8 percent that of integrating an equivalent amount of wind energy under the CapX 2020 proposal*

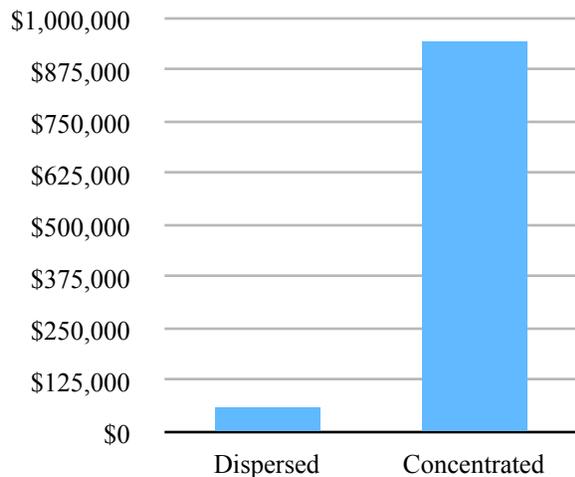
according to the latest estimates by the MN Office of Energy Security.

The final version of the West Central C-BED study, released in January 2007 concluded that under the study assumptions, during peak system conditions, the west central zone existing transmission and

subtransmission system could integrate at least 1,400 MW<sup>31</sup> of new generation capacity that could be delivered to the Twin Cities and points east for a cost of less than 8 percent that of integrating an equivalent amount of wind energy under the CapX 2020 proposal.<sup>32</sup>

We remind readers that the West Central C-BED study was only an “on peak” analysis. An “off peak” analysis and stability analysis were not completed as part of this study. This is important since there will be different impacts to the wider network of transmission and generation resources under an "off peak" situation and more study would be needed before the 1,400 MW of wind identified could be fully integrated into the grid.

**Infrastructure Needs for Dispersed Generation is Far Cheaper Than for Concentrated Generation (Cost per MW)**



It is important to note that if all 3,500 MW of the potential distributed generation capacity identified as technically possible came on line the cost of \$375 million would still be far less than the cost of the CapX proposal that in its first phase is supplying outlet capacity for only 1,050 MW. Moreover, 3,500 MW is between 70-100% of the total additional wind electricity required to meet Minnesota’s RES by 2020

The West Central C-BED Study work also examined other planning zones in the state to determine theoretically available generating capacity of substations for injection capability. The following table shows the total available generation MW, as calculated in the study, for the five planning zones examined.

**Potential for C-BED and Dispersed Energy Projects (wind and non-wind)**

Transmission Planning Zone	2020 (MW)
West Central Zone	3,585
Southwest Zone	1,182
Southeast Zone	4,000
Northwest Zone	2,602
Northeast Zone	2,383
<b>Total</b>	<b>13,752</b>

It is unlikely that all of this injection capability can be utilized. But if we assume that only 40% of the total can be developed in the other zones on lines below 115kV, as was found to be the empirical case in the West Central Zone, that still leaves some 5,300 MW of renewable generation that could be added to the existing Minnesota transmission network.

Some relatively modest investments in new transmission infrastructure would potentially be needed, but the key point is that Minnesota's RES for the year 2025 could be met without the need for a new network of large 345-kV high-voltage transmission lines like those proposed by CapX 2020.

Certainly more study is needed before a definitive statement can be made, but the West Central C-BED study results clearly show that dispersed and distributed generation of renewable energy can be integrated on a much larger scale than was previously thought.

*Minnesota's RES for the year 2025 could be met without the need for a new network of large 345-kV high-voltage transmission lines like those proposed by CapX 2020*

## The 2008 Dispersed Renewable Generation Study

The remarkable results from the West Central study led the legislature to order Minnesota's utilities to undertake an even more detailed statewide study of the impacts of adding up to 1,200 MW of dispersed generation around the state.<sup>33</sup> The first phase of that

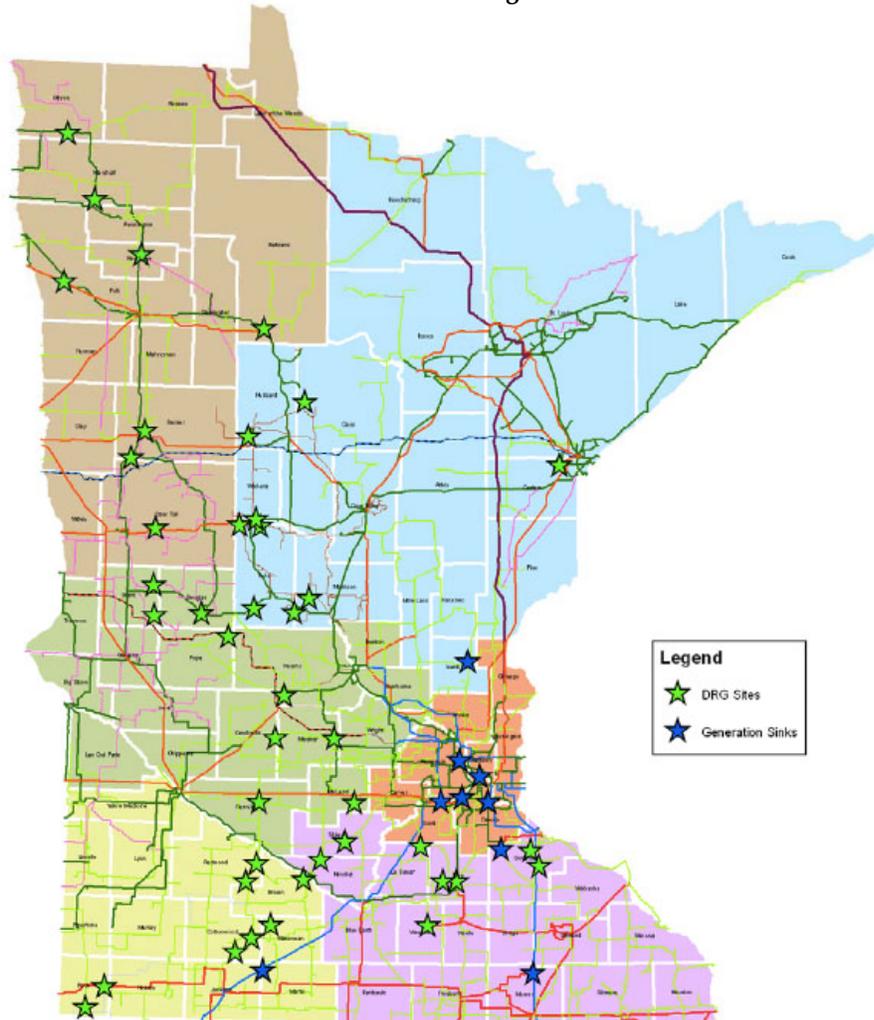
analysis was released in June 2008 and examined the integration of 600 MW of dispersed generation.<sup>34</sup> The second phase of the study will be completed in September 2009.

The results of Phase I of the Dispersed Renewable Generation Transmission Study (DRG Study) affirms, complements and supersedes the conclusions reached in the West Central study.

Perhaps the most important outcome of the DRG Study may be the development of a new utility transmission planning model that focuses on how we can more efficiently use our existing transmission infrastructure and our lower voltage lines. For the first time utilities will have the tools to integrate lower voltage distributed generation into their resource plans.

Before this study, the required transmission power-flow model to analyze the impact of decentralized generation did not exist. Neither the utility

**DRG Sites Selected After Initial Screening Process**



industry nor its regulators saw any value in creating it. Each electric utility serving Minnesota had its own lower voltage transmission power flow model that it used for its own system planning and load management purposes.

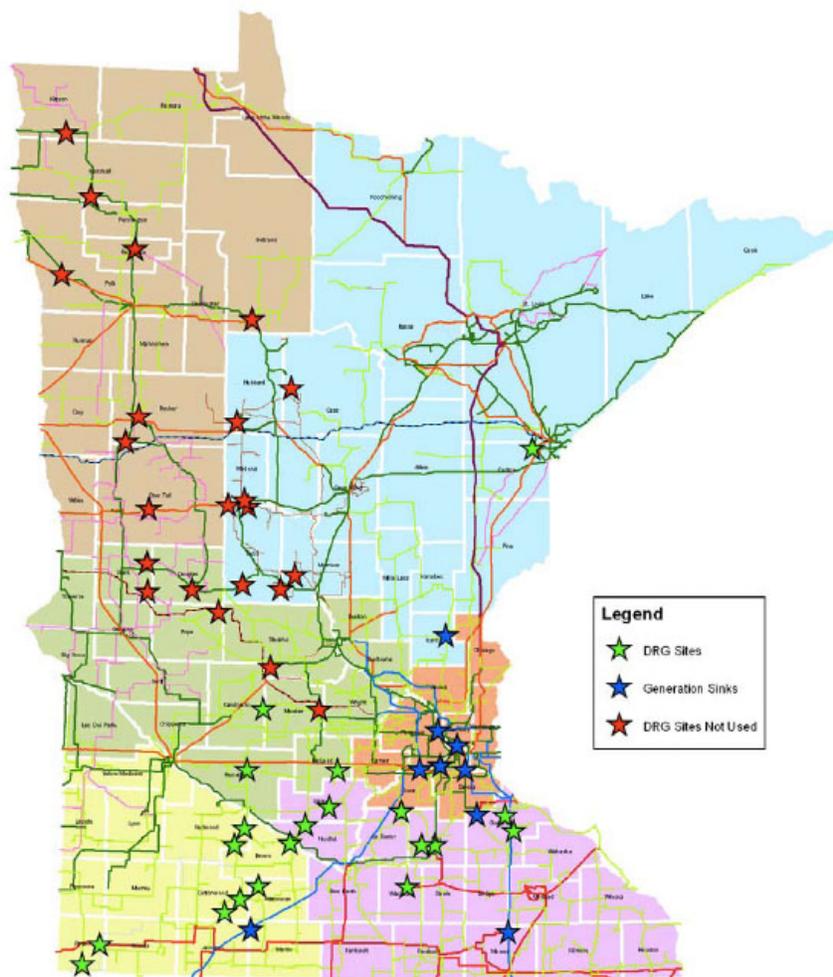
When system-wide, state, or regional planning were deemed necessary, each of these separate models would be integrated together but *only* at very high voltage levels. While useful for some macro analyses and planning exercises this is not useful for analyzing the impact of strategically sited dispersed generation.

Existing regional transmission models are essentially blind to any potential system-wide benefits or impacts of connecting strategically sized and located generation projects to the grid at lower voltage. In the real world, of course, the entire system is connected – from high voltage transmission to lower voltage distribution lines.

To shed light on lower voltage interconnection opportunities, the DRG Study needed each individual utility's model to be connected to other utilities' models down to the sub-transmission and distribution levels. All of the higher voltage aggregated loads in the system-wide models had to be disaggregated and appropriately reapportioned onto the lower voltage system, and all the 46 kV, 41.6 kV, 34.5 kV and 23 kV power lines had to be manually integrated into the system-wide model.

This was very tedious, time consuming and expensive work. However, it is critically important work for at least two reasons. One is that making better use of unused generation injection capacity in the lower voltage system can dramatically raise operating efficiencies for the overall transmission system and dramatically reduce, defer or avoid the need for new transmission.

### Final DRG Sites Selected



The other is that it can also enable locally owned power plants in a number of ways, as will be discussed in more detail below.

The DRG Study examined the electrical characteristics, and the available wind resource, for each of the 2,258 substations in Minnesota and selected 42 potential sites for further study. These sites were about evenly divided among the five greater Minnesota transmission planning zones: Northeast, Northwest, West Central, Southwest and Southeast.

The map shown above from the DRG Study illustrates the result of the screening process. The green-starred locations were selected to undergo further analysis to determine final DRG sites and the blue stars are the natural gas-fired generation sinks that were backed out as new generation was added in the analysis. The red stars indicate locations that were not selected for further analysis, a decision explained below.

The power flow model was then turned on and ran, using up to six computers, 24/7 for several weeks, compiling iteration after iteration, looking for transmission facilities that would need reinforcing. The study analyzed both summer peak and summer off-peak conditions. Each site was analyzed specifically for power transfer limits by ramping up energy production at each site in 5 MW increments until a limit was reached. Then transmission transfer capability was analyzed zone by zone to see when or whether limits were reached as generators at multiple sites ramped up production. Finally, the statewide system was analyzed to see how much of the power generated could be delivered to Minnesota natural gas peaking plants, which tended to be in the Twin Cities area. We hope this approach will be modified in Phase II to focus more on the impacts of local generation meeting local load and that other source/load sink combinations will be examined.

*Before this study, the required transmission power-flow model to analyze the impact of decentralized generation did not exist. Neither the utility industry nor its regulators saw any value in creating it.*

Once the power flow model was expanded and reconfigured so that it more accurately represented how electricity actually flows through the lower voltage system, under the study assumptions and modeling the results identified twenty dispersed locations in which 600 MW of new generation capacity could be sited and interconnected with no new transmission costs. This was a remarkable conclusion and provides evidence that supports a strategy of pursuing and maximizing the development of dispersed, renewable energy projects throughout the state.

It is important to note that the results of Phase I of the 2008 DRG Study are not represented as an upper limit for the potential for dispersed generation. The study scope did not investigate whether the system could accept distributed generation beyond 600 MW without incurring transmission upgrade costs. Similarly the scope did not include investigating the potential of dispersed generation if transmission network upgrade costs are included in the scope. And the DRG Study examined only dispersed projects 10-40 MW in size. Smaller scale projects could potentially be integrated into the distribution system in even more locations.

The specific parameters of the DRG Study were established by the legislative directive and the 600 MW found can certainly be seen as a minimum not a maximum to the extent that the six hundred MW level examined did not even begin to find out where the cost effective generation combined with transmission expansion point would be.

The legislature further constrained the analysis in the DRG Study by limiting it to the addition of just 1,200 MW of new, dispersed renewable electric generation capacity scattered among the five out-state transmission planning zones (600 MW in

the first phase, an additional 600 MW or more in the second phase).<sup>35</sup> We should recall that the West Central C-BED study, discussed above, had already identified at least 1,400 MW of dispersed capacity in just one section of the state that could be integrated, to the extent it was studied, with only modest transmission upgrades.

In brief, Phase I identified 600 MW of renewable capacity additions that would require no investments in the existing transmission system. It did not evaluate how much new dispersed generation could be interconnected at a network upgrade cost lower than that of the CapX proposal.

Another important limitation of the DRG Study was that the study team essentially eliminated the northern half to two-thirds of the state from its analysis. They did so when they encountered a well-known transmission system problem with the Dorsey substation near Winnipeg, Manitoba.<sup>36</sup> The DRG study team, with input from the study's Technical Review Committee (TRC) explored many approaches to resolving the Dorsey issue. Since there were time limits on Phase I of the study, and abundant locations to insert up to 600 MW of dispersed generation in the southern parts of the state, the final consensus was to shift the DRG sites from northern zone sites (red stars in the map below) to the zones in the south and east (green stars). Four possible solutions to the Dorsey problem were discussed by the TRC members:

- Install a third 1,200 MVA, 230/500 kV transformer at Dorsey (est. \$40 million)
- Install phase shifters on three northern 230 kV lines (est. \$60 million)
- Install a Special Protection Scheme to curtail Minnesota generation (est. cost unknown)
- Communicate and coordinate a resolution with Manitoba Hydro (est. cost unknown)

If approved by Minnesota regulators and built, the new 230 kV line from Grand Rapids to Bemidji will provide a parallel loop flow path and therefore also help to solve the problem.

## A Technical But Important Reflection on the DRG Study

One segment of the DRG Phase I study, the implications of which were not discussed in the DRG report, was the determination of an incremental transfer capability value for each of the 2,258 substations in the state. These results could prove invaluable to communities looking to identify locations where they can construct modest sized, locally owned energy generation projects that minimize interconnection costs by connecting to the existing lower voltage subtransmission system.<sup>37</sup>

This analysis was similar to the TLTG (transmission interchange limit analysis activity) process that was part of the West Central C-BED Study process. Here too the sink for the generation injection was the Minnesota natural gas plants. The DRG Study report says:

“Using DC (linear) analysis, the tool quickly and approximately calculates generation outlet capacity for all 2,258 buses for the summer peak and summer off-peak cases. The primary advantage of using the DC analysis is its efficiency and the relative ease with which an initial estimation can be attained. By comparison, AC analysis is much more time-consuming. Limiting the scope of the AC analysis made it possible to provide a much more robust finished product.”<sup>38</sup>

A similar DC type of contingency analysis is also done in the initial Feasibility Study portion of the MISO generator interconnection process. The results of this initial analysis provided the DRG study team with an evaluation of generator outlet capability for each of the 2258 substations studied.

The DC power injection capability for each substation as well as wind resource estimates and other substation data became part of the final report and are available in Appendix D of the study. This information can be used by C-BED and other renewable energy project developers as a preliminary screening tool to indicate a reasonable upper limit on a generation project size for a particular substation location. Going beyond the MW values listed in Appendix D will almost certainly require additional transmission network grades.

The DRG Study's screening process identified all the substation buses with some level of generation outlet

capability. For example, in Appendix D the Northwest Zone step 2 results listed 367 possible generation locations of project sizes ranging up to 325 MW at a single location.

*About 45% of the substation locations examined are possible locations for dispersed generation projects*

On a statewide basis a total of 1,033 substation locations demonstrated some positive amount of generation outlet capacity. The numbers demonstrated for each site are not necessarily additive with the other locations, and delivery of the maximum energy from multiple locations simultaneously cannot be

assumed. Nevertheless, about 45% of the substation locations examined can be considered possible locations for dispersed generation projects of various sizes. An interconnection study will be necessary to determine the actual system impacts of any individual project.

## Implications and Recommendations

The West Central Study and the first phase of the DRG Study have found that substantial quantities of renewable electricity in every section of the state could be injected into the existing grid system with appropriate transmission network upgrades. A small portion of this potential, 600 MW, has been shown to be developable with zero transmission costs. Perhaps up to five times that amount could be integrated with far lower transmission costs than a comparable amount of renewable electricity transmitted along the proposed CapX 2020 lines.

This conclusion should inform the Minnesota Public Utilities Commission's CapX Certificate of Need decision and future state electricity planning. Minnesota has a long history of preferring distributed and renewable electricity. These recent studies provide the foundation for building the right infrastructure to enable this preference.

A major investment in transmission might be needed in the future if a policy decision is made to transmit tens of thousands of MW of wind energy from the Dakotas to Illinois or Ohio, but at this date we should remain focused on meeting our own state's aggressive state renewable energy goals which, at the moment, likely require less than 4,000 MW of wind energy by 2020. All of this renewable energy should and could be generated inside Minnesota, thereby keeping substantial economic benefits right here rather than sending them off to other states.

The recent dispersed generation studies show that we can develop homegrown renewable energy projects interconnected to the existing transmission system at potentially much lower costs than would be the case under the CapX 2020 proposal. The CapX Phase I project, if completed as proposed, would provide a maximum of only about 1,050 MW of additional outlet capacity for renewable energy. However, there is a caveat to this assumption. Unless there are stringent conditions tied to the approval of the CapX lines, this 1,050 MW of potential generation outlet will not be reserved for renewable energy in general or renewable energy projects used to meet Minnesota's RES; instead renewables will compete for the capacity made available with all types of non-renewable generation.

While some argue there should be no delay in building a vast, new, large scale transmission infrastructure, we believe a delay in the construction of new high voltage transmission lines especially for RES goal purposes would allow Minnesota and surrounding states to better understand the political, technological and economic dynamics governing the new electricity system. It is likely, for example, that global warming initiatives will accelerate investments in conservation, energy efficiency and distributed, renewable energy technologies. Indeed, we are entering into a period of rapid technological advances in these areas. These advances, an example of which is Smart Grid technologies, would likely significantly reduce the system peak demand from currently projected values and certainly will affect future transmission planning needs. Smart Grid pilot projects are underway in Xcel Energy's service territory in Colorado that will surely demonstrate their effectiveness.

And looming in the near future may be the electrification of our transportation system. Rapid developments in large format batteries have spurred the announcement by major car companies that they will be offering plug-in hybrid electric vehicles (PHEVs) that can be powered primarily by electricity and all-electric cars (EVs) with driving ranges of over 100 miles. Major incentives for electrified vehicles have been embraced by both political parties as an important element in a strategy for reducing our dependence on oil.

We will know within five years whether electrified vehicles will play a significant role in our transportation future. A mass electrified vehicle market would mark the first time the electricity system would have a potentially large storage capacity. Several utilities already are seriously investigating such a possibility. One utility executive has called the introduction of large numbers of electrified vehicles a "game changer". Since EVs and PHEVs would likely utilize off-peak energy supplies for charging their

batteries when the electric system is least stressed and have stored energy to give back to the grid in times of peak energy demand, it is unclear what type of new transmission infrastructure, if any, an electric transportation system will require. Another reason to maximize the use of the existing system and make smart, strategic transmission investments if needed to enable a dispersed and distributed energy future.

Electricity storage can overcome the Achilles heel of renewable energy: intermittency. Which in turn could allow renewable electricity to comprise a much larger portion of the overall electricity on the system. A study of one California utility, for example, found that a significant penetration into the local market of plug-in hybrid electric vehicles would allow wind energy to constitute 50 percent of the utility's total electricity supply.<sup>39</sup>

Minnesota has a formal policy of aggressively pursuing efficiency and renewable energy.<sup>40</sup> It has also adopted a formal policy to reject the burning of additional quantities of coal unless absolutely necessary. If the CapX 2020 vision of transmission projects are built, a significant portion of the electricity carried likely will come from new coal fired power plants in the Dakotas.<sup>41</sup> This conflicts with Minnesota's goal of dramatically reducing carbon dioxide emissions.

Minnesota also has a formal policy of encouraging local ownership of renewable energy facilities.<sup>42</sup> New high voltage transmission lines tend to discourage local generation ownership. One reason, as noted above, is the very high investment required for wind turbines to connect to high voltage lines. That cost can be spread over the 100 turbines that may comprise a large wind farm but it would probably make a 5-10 turbine locally owned project uneconomical, even though there are hundreds of locations where such small and medium sized projects could be sited in Minnesota.

## A State Based Process for C-BED Interconnection Requests

State supervised lower voltage renewable generation interconnections to the existing grid system could prove advantageous for locally owned, C-BED projects by allowing them to avoid going through the burdensome MISO interconnection queue process.

At present all energy project developers seeking to interconnect to the high voltage transmission system must submit an application to MISO or another FERC

authorized transmission provider. Currently the queuing system, all parties agree, is broken. As of mid 2008, there appears to be an astounding 280,000 MW of projects in the queue throughout the MISO states.<sup>43</sup>

The queuing system initially operated on a first come, first served basis, which rewarded developers who put in an interconnection application far before they actually had a workable project. One result of so many applications is that recent C-BED projects were far down in the queue. In August 2008, FERC gave conditional approval to a MISO queue reform proposal.<sup>44</sup> Instead of the “first-come, first-served” approach the queue will now be organized as “first ready, first out.” The queue will be ordered based on whether a generation project is making real progress towards coming on-line. The proposed changes may help make the process more workable for large generation projects, but significant non technical milestones features may still create a disadvantage for smaller C-BED projects.

One way to overcome this situation is to give a priority to C-BED projects. It is doubtful that MISO would do this because they do not have the charge of encouraging local ownership. Minnesota does have a legislative mandate to encourage the expansion of locally owned renewable energy projects throughout the state, but doing so requires the wind energy proposals to have access to the transmission and distribution system.

The question then becomes: could Minnesota assert its authority over the lower voltage (subtransmission) parts of the grid system and create a new process for interconnections to the existing grid system? A 2007 paper by Michael Michaud lends support to the idea.<sup>45</sup> The paper reviewed the legal status of the limits of FERC interconnection jurisdiction.<sup>46</sup> In addition, MISO has issued a statement indicating that generation interconnections on lower voltage systems can be handled by the owner of the distribution system and should only involve MISO if “in the course of the distribution company’s evaluation it becomes apparent that there is a NERC Planning Criteria violation on the transmission system that is created or aggravated by the new interconnection.”

FERC governs the interstate movement of commerce (e.g. electricity sales crossing state lines), but FERC has also ruled that states have authority over electricity generation that serves local loads.

FERC had to establish boundaries between where its rules would be applicable and where they would not in generation interconnection proceedings. In the course of making those rules the states were very vocal in reminding FERC that it had no jurisdiction over the

distribution system or the retail provision of electric service. FERC (and MISO by extension) basically claimed the higher voltage interstate “transmission” grid as their jurisdiction. The local distribution system that is primarily a retail service function, would be under state jurisdiction for interconnections.<sup>47</sup>

In the same legislation calling for the DRG Study, the Minnesota legislature specifically requested information regarding interconnections at “locations on the electric grid where a generator interconnection would not be subject to the interconnection rules of the Federal Energy Regulatory Commission.”

FERC’s statements and orders about the application of its rules divide the power system, from an interconnection governance perspective, into three segments: transmission facilities, dual use facilities, and distribution facilities.

Because utilities that are MISO members have transferred operational control of facilities of 115 kV and above to MISO as part of their Open Access Transmission Tariffs (OATT) compliance choices, these could fit the category of transmission facilities used for interstate commerce. However, even here there is some ambiguity. FERC declared that qualified facility (QF) interconnections allowed under the Public Utility Regulatory Policy Act of 1978 (PURPA) remain under state authority. Thus we would need to investigate how QF connections at or above 115 kV would/should be managed.

In Minnesota, the power system includes lines that can be considered dual use facilities. Examples of these are in the voltage class of 41.6 kV and 69 kV. These lines are primarily used in network configurations but are not under MISO’s operational control. FERC has indicated that interconnections to these facilities may or may not be FERC jurisdictional depending on the type of transaction that the interconnecting entity intends to enter into. If the power purchase contract is for the wholesale power market, the FERC would assert jurisdiction over the interconnection. If the power is to be sold at retail, the interconnection is non-FERC jurisdictional and could be completed under a state authority if a process existed.

The state of Minnesota never specifically directed its utilities to send all interconnections on the 69 kV or 41.6 kV lines to the MISO queue. FERC specifically encouraged states in Order 2006 to develop interconnection rules for these retail power sales interconnections.

One might argue that by its very nature, electricity is part of interstate commerce. As demand for electricity changes on the transmission system, it results in

changes in power flows. But these variations in power flow on the transmission system also can take place within networked transmission service arrangements that are load serving. The transmission system effectively cannot distinguish whether the power flow was reduced for a given transmission service reservation because someone turned off a light or supplied power for the light from a local power source. To the extent that power flows from a distribution system-sited generator can be considered to occur inside the existing transmission service reservation for the local load serving utility, transmission system impacts should be minimal.

In its Order 2003, FERC noted that where power flows from a transaction do not enter the interstate power system it is not subject to the FERC's interconnection rules. If a generator is small enough that it never reduces power flow into the distribution system to zero, it cannot be said to have power enter the interstate power system.

On the local distribution system, the state would appear to have automatic jurisdiction over interconnection requests to meet intrastate demand or under a retail tariff, unless the particular facility has some prior existing wholesale power transaction or a new interconnecting entity wants to participate in the wholesale power market (e.g. their power would be transferred to the end use customer over transmission lines at or above 115 kV).

FERC also does not regulate electric power exchanges between retail utilities and their customers located within the utility's assigned service territory distribution system. Evidence of this is in the PURPA rules where FERC has recognized a state's right to set net energy billing rates above avoided cost values required by federal law, something that Minnesota does. Minnesota's C-BED tariffs that specify front-end loading pricing and 20-year time frames constitute a similar transaction between a retail load serving utility and its customers.

Thus an interconnection request for a C-BED project that interconnects to the distribution system would/ should not come under FERC's jurisdiction.

However, Minnesota statutes now grant C-BED projects a priority only for the power purchase agreement, not for interconnection.

The following observations and recommendations can be made about potential state jurisdiction of interconnection requests by C-BED projects.

1. Although the state has standard interconnection procedures in place governing onsite

*MN statutes now grant C-BED projects a priority only for the power purchase agreement, not for interconnection*

generation, the rules only cover projects up to 10 MW in size. These may not have sufficient project size scope to cover the interconnection of dispersed generation resources at the MW project size levels that are possible on "dual use" facilities.

2. C-BED contracts, are the result of state retail tariffs. Under FERC interconnection orders, projects with these retail tariff sales arrangements can be connected under state jurisdiction to dual use facilities. State level interconnection rules should be developed for these and other retail tariff-based transactions.
3. The state should set up a state level interconnection system for distribution interconnections that would operate in parallel with the transmission interconnection queue that MISO operates. The state level studies would "coordinate" with MISO as necessary.
4. The state process should be a two-tiered process where an initial request would be put in a preliminary queue where the feasibility of the interconnection would be analyzed. If an interconnection request passed the feasibility test it would stay in the preliminary queue until such time as the project completed a power purchase agreement. Then it would move to the final queue where the system impacts would be completely analyzed.
5. Since load serving utilities have in place transmission service reservations to serve load, they should insist that impacts to MISO from the power flow from a C-BED generator should be considered to be made under the umbrella of that prior existing approved usage of the transmission system. As a practical matter most always the power flows in those load-serving reservations would be altered by the addition of additional local generation. It would be rare that the power flow in these load serving reservations on the transmission system would actually zero out or reverse.

This is a complicated legal and regulatory subject. However, it appears Minnesota can expedite the review of C-BED interconnections selling their output to their local utility and connected to lower voltage lines by developing its own interconnection process.

## Notes

<sup>1</sup> For a more in-depth discussion of recent developments in the electricity industry, and their impact, see David Morris, *Seeing the Light: Regaining Control of our Electricity System*

<sup>2</sup> More precisely, after 1982, when the Supreme Court by a 5-4 decision, upheld the federal law. U.S. Supreme Court *FERC v. Mississippi* 456 U.S. 742(1982)

<sup>3</sup> Qualifying facilities had to be under 80 MW and if they used fossil fuels, had to capture a minimum amount of the waste heat produced when electricity is generated.

<sup>4</sup> *The Changing Structure of the Electric Power Industry: An Update*, EIA. December 1996

<sup>5</sup> As part of the deregulation process at the retail level, a number of states required utilities to sell off part or all of their generation capacity in order to avoid a conflict of interest when developing transmission access rules for IPPs.

<sup>6</sup> Independent System Operators grew out of FERC Orders Nos. 888/889 where the Commission suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada). Order No. 2000 delineated twelve characteristics and functions that an entity must satisfy in order to become a Regional Transmission Organization. See <http://www.ferc.gov/>

<sup>7</sup> The Minnesota Department of Commerce maintains that the Integrated Resource Planning process is strictly for generation planning, that the approval process for future transmission needs can and should be viewed separately from future generation needs although that seems a misreading of the intent and language of existing legislation.

<sup>8</sup> Minn. Stat. § 216B.243, subd. 3, states, in relevant part: "No proposed large energy facility shall be certified for construction unless the applicant can 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. "

Minn. Stat. § 216B.243, subd. 3(6) states that when assessing need, the PUC shall evaluate: "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation"

Minn. Stat. § 216B.243, subd. 3a. states: " The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or 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. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel."

<sup>9</sup> Minn. Stat. §216B.2422, Subd. 3. Environmental costs. (a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings. (b) The commission shall establish interim environmental cost values associated with each method of electricity generation by March 1, 1994. These values expire on the date the commission establishes environmental cost values under paragraph (a).

Minn. Stat. §216H.06 Greenhouse Gas Emissions Consideration in Resource Planning. By January 1, 2008, the Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate, which may be made in a commission order, must be used in all electricity generation resource acquisition proceedings. The estimates, and annual updates, must be made following informal proceedings conducted by the commissioners of commerce and pollution control that allow interested parties to submit comments.

Order on Future costs of Climate Regulation – PUC Order Order Establishing Estimate of Future Carbon Dioxide Regulation Costs (MPUC Docket No. E-999/CI-07-1199) On December 21, 2007, the Commission issued its order, which estimated that CO2 regulation of electricity generation will cost between \$4/ton and \$30/ton for CO2 emitted in 2012 and thereafter, and ordered that “electric utilities shall apply these estimates in all proceedings to acquire electricity generation resources to serve needs in Minnesota.”

<sup>10</sup> Minn. Stat. §216B.2426 Opportunities for Distributed Generation. The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243

Minn. Stat. §216B.1612 Community Based Energy Development (C-BED).

Minn. Stat. §216B.2422 Subd. 4, Resource Planning; Renewable Energy. Preference for renewable energy facility. The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.

<sup>11</sup> Minnesota's size limit is 40 kW. Each utility must compensate customers for customer net excess generation (NEG) at the "average retail utility energy rate," defined as "the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales." This rate is basically the same as a utility's retail rate.

<sup>12</sup> "Green Pricing and Net Metering Programs 2005." (Energy Information Administration, July 2007). Accessed 12/17/07 at <http://tinyurl.com/2husze>.

<sup>13</sup> For background see ILSR's archive at <http://www.newrules.org/dgtariff/>

<sup>14</sup> See Rural Power: Community-Scaled Renewable Energy and Rural Economic Development, by John Farrell and David Morris, Institute for Local Self-Reliance, August 2008

<sup>15</sup> The CBED tariff does not result in locally owned projects being paid more. Instead it front loads the payments to allow such projects to more easily repay the debt, which usually is in the form of ten year loans.

<sup>16</sup> A base load power plant runs constantly, interrupted only for maintenance and repairs. Recently, Xcel Energy has converted two coal fired power plants to natural gas and in the process has expanded their capacity. It has also raised the output of its nuclear plants and has increased the capacity of another coal fired power plant.

<sup>17</sup> For an in-depth examination of that era see, *Powerline: The First Battle of America's Energy War* (2003) by Paul Wellstone, Barry M. Casper, Tom Harkin.

<sup>18</sup> These lines will be completed in 2008 at a cost of \$160 million (or \$290 million). "Transmission Projects: At a Glance." (Edison Electric Institute, January 2008).

<sup>19</sup> At a cost of \$72.5 million. "Transmission Projects: At a Glance." (Edison Electric Institute, January 2008).

<sup>20</sup> See MISO 765 kV regional overlay system – [www.midwestiso.org](http://www.midwestiso.org); see "Transmission Projects: At a Glance." (Edison Electric Institute, January 2008)

<sup>21</sup> 20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply, U.S. Department of Energy, May 2008 – <http://www.20percentwind.org/>

<sup>22</sup> CapX 2020 utilities' Application to the Minnesota Public Utilities Commission for Certificates of Need, PUC Docket No. ET02, E-002/CN-06-1115

<sup>23</sup> The Capx utilities have claimed in their Certificate of Need application that these projects are needed for three primary reasons.

1. Community Service Reliability: To alleviate emerging community service reliability (growing demand for electricity) concerns in Rochester and other parts of southeastern MN, the LaCrosse, WI, area as well as St. Cloud, Alexandria and in the Red River Valley.
2. System Wide Growth: The three Phase I projects are part of a longer term plan to strengthen the transmission network to meet potential electricity demand forecasts in Minnesota and parts of surrounding states by 2020.
3. Generation Outlet and Renewable Energy Support: The proposed transmission lines will allow for about 1,050 MW of additional generation outlet support to be realized. The lines could support outlet for renewable energy generation in southwestern Minnesota and the surrounding region.

<sup>24</sup> The proposal also includes an expansion of the outlet capacity of Buffalo Ridge of about 700 MW at a cost of \$600-665 million. This will increase the Ridge's outlet capacity to 1,900 MW. "CapX 2020 Frequently Asked Questions," CapX 2020. Accessed 12/11/07 at <http://tinyurl.com/2d4wxq>; CapX 2020 utilities' Application to the Minnesota Public Utilities Commission for Certificates of Need, (PUC Docket No. ET02, E-002/CN-06-1115; 8/16/07), p. 1.17. Accessed 12/11/07 at <http://tinyurl.com/2483j9>; Wente, Scott. "Meetings coming up on high voltage lines." *The Republican Eagle*, 12/8/07. Accessed 12/11/07 at <http://tinyurl.com/27u5wy>.

<sup>25</sup> Supplemental Findings of Fact, Conclusions of Law and Recommendation In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota, May 9, 2008 (PUC Docket No. ET-9/CN-05-619)

<sup>26</sup> Minn. Stat. §216B.2401 "Energy Conservation Policy Goal. It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas..."

<sup>27</sup> "Minnesota's renewable electricity standard will not be met if expansions of the region's transmission infrastructure do not occur. Thus, all or almost all of the wind energy that will be added through the CapX plan would not be installed without the plan." Rebuttal Testimony by Robert E. Gramlich, on behalf of Fresh Energy, Izaak Walton League of America – Midwest Office, Wind on the Wires, Minnesota Center for Environmental Advocacy, June 16, 2008. OAH No. 15-2500-19350-2, PUC Docket No. CN-06-1115

<sup>28</sup> Total interconnection costs will vary widely depending on the scope of the project and the state of the surrounding distribution and transmission system infrastructure.

<sup>29</sup> The full study results are available at the utilities' website at [www.capx2020.com](http://www.capx2020.com) and on the website for community-based energy development at [www.c-bed.org](http://www.c-bed.org).

<sup>30</sup> "Community Based Energy Development Transmission Study." Performed by the CapX2020 Utilities with the concurrence of the Minnesota Department of Commerce and the North American Water Office. (1/18/07), 9-12. Accessed 12/11/07 at <http://tinyurl.com/3xy89o>.

<sup>31</sup> "Community Based Energy Development Transmission Study." Performed by the CapX2020 Utilities with the concurrence of the Minnesota Department of Commerce and the North American Water Office. (1/18/07). Accessed 12/11/07 at <http://tinyurl.com/3xy89o>.

<sup>32</sup> "CapX2020 Application to the Minnesota Public Utilities Commission for Certificates of Need." (MPUC Docket No. ET02, E-002/CN-06-1115; 8/16/07), p. 1.17. Accessed 12/11/07 at <http://tinyurl.com/2483j9>.

<sup>33</sup> Laws of Minnesota 2007, Chapter 136. The legislation leading to this study was spearheaded by the North American Water Office.

<sup>34</sup> Dispersed Renewable Generation Transmission Study Volume I - Prepared for the Minnesota Department of Commerce Office of Energy Security by the Minnesota Transmission Owners, June 16, 2008 (PUC Docket No. E999/DI-08-649). <http://www.commerce.state.mn.us>

<sup>35</sup> The directives provided by the 2007 Minnesota Legislature for this study can be found at Minn. Stat. § 136, Article 4, Section 17.

<sup>36</sup> For many years, there has been a "loop flow" problem at the substation. Dorsey converts the direct current electricity carried by the very big DC Powerline transmitting hydro power from the Churchill Nelsen River generators in Manitoba back to alternating current, which is then transmitted over the 500 kV line to the Forbes Substation in NE Minnesota and then on to the Chisago Substation north of the Twin Cities for consumption in the Minneapolis and St. Paul area. Several other 230 kV powerlines serving Northern Minnesota and North Dakota also connect at the Dorsey Substation. The loop flow problem occurs whenever power is injected into the system, essentially, anywhere north of Highway 12 going west out of Minneapolis and west of Highway 169 going toward Mille Lacs Lake and on north. The problem occurs because the 500 kV powerline is an electronic superhighway with very low impedance (resistance), which results in most power generated in that area for the Twin Cities market to first flow northward through Dorsey, and then onto the 500 kV line. The problem is that without "operating guidelines" that transmission operators use to guide power through the system, injecting too much power into this area would cause too much power to flow through the Dorsey transformers and overload them.

<sup>37</sup> To quote from the report, "The transmission substation screening process began by utilizing the Power System Simulator for Engineering Managing and Using System Transmission First Contingency Incremental Transfer Capability (PSSTME MUST FCITC) function. The purpose of the MUST FCITC function is to efficiently calculate the impact of transactions on key network elements during contingency conditions." See DRG Phase I study report, page 32.

<sup>38</sup> Ibid.

<sup>39</sup> Willett Kempton and Cliff Murley, Sacramento Municipal Utility District Modeling V2G for a Utility with a High Wind Generation Portfolio, Presentation to Zero Emission Vehicle (ZEV) Technology Symposium Session: "Electric Fueling Infrastructure" California Air Resources Board, Sacramento, California. September 26, 2006.

<sup>40</sup> Minn. Stat. §216C.05

<sup>41</sup> In North Dakota alone 2253 MW of coal plants are waiting in the MISO queue. See CapX hearing Kline Rebuttal Testimony schedule 2, Minnesota PUC Docket No. CN-06-1115, June 16, 2008.

<sup>42</sup> Minn. Stat. §216B.1612

<sup>43</sup> See current queue <http://www.midwestiso.org/page/Generator+Interconnection+Queue>

<sup>44</sup> FERC Order Conditionally Accepting Tariff Revisions Addressing Queue Reform, issued August 25, 2008. Docket No. ER08-1169-000

<sup>45</sup> *A White Paper on Untangling FERC & State Jurisdiction Interconnection Issues and Opportunities for Dispersed Generation*, by Michael Michaud, Matrix Energy Solutions, November 2007 [[http://www.c-bed.org/pdf/Jurisdiction\\_White\\_Paper\\_2007-11-16.pdf](http://www.c-bed.org/pdf/Jurisdiction_White_Paper_2007-11-16.pdf)]

<sup>46</sup> see MISO, <http://www.midwestmarket.org/>

<sup>47</sup> Order 888 (1997 and 1998) developed guidelines for transmission owners regarding access. It also required utilities to functionally separate their transmission and generation businesses. Order 889 (1997) created an on line system through which transmission owners could post available capacity so that companies wanting to use the system could observe the capacity. Order 2000 (1999 and 2000) encouraged transmission-owning utilities to form regional transmission organizations. Order 2003-A (2003) required transmission owners to interconnect new generators of larger than 20 MW under a standard set of terms and conditions. Order No. 2006-B (2006) that standardized small generator interconnection agreements and procedures. Order No. 890 (2007) that prevents undue discrimination and preference in transmission service. Order No. 697-B (2008) covering market-based rates for wholesale sales of electric energy, services by utilities. <http://www.ferc.gov/>