MINNESOTA

Minnesota's Electric Transmission System

Annual Adequacy Report
January 15, 2019

Submitted by
The Minnesota Department of Commerce
in consultation with the Minnesota Public Utilities Commission

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Introduction

Minnesota Statute 216C.054[1] requires the Commissioner of Commerce, in consultation with the Minnesota Public Utilities Commission, to prepare and submit the Annual Transmission Adequacy Report to the Legislature to provide a nontechnical discussion of Minnesota's current electric transmission system. This law also requires a report on transmission planning and other actions taken or in process to maintain electric service reliability as well as comply with the requirements of the state's Renewable Energy Standard. [2]

Because transmission issues tend to involve numerous considerations and entities, this report provides a general discussion of transmission as a reference guide, similar to the discussion from previous reports. This report also provides an update on current transmission projects as identified in the most recent biennial transmission report from Minnesota transmission owners. In addition, the report notes that, while no new certificate of need processes started in 2018, the process for one transmission line that was started in Minnesota in 2017 continued in 2018 when the applicants filed their proposed project.

Why Transmission Matters: Overview

Generally, electricity is provided to consumers via three main steps: 1) electricity is produced at various generation facilities, 2) electricity is transmitted on an integrated system of large power lines and 3) electricity is delivered to consumers through a distribution system of smaller power lines. As the link between the production (generation) of electricity and delivery (distribution) to consumers, transmission plays a vital role in helping to ensure that consumers have low-cost, reliable energy. Further, as more generation facilities are added to the distribution system (also known as distributed generation), the dynamic and interconnected nature of the electricity system requires transmission to adapt to resulting changes in electricity flows on the system. The transmission system can be impacted by changes in either supply or demand for power.

While it is a critical component in providing electric service, transmission accounts for a much smaller percent of utility costs than either generation or distribution facilities. For example, transmission may account for 10 percent of the costs of providing electric service while generation and distribution would make up the other 90

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[1] The statute states:

The commissioner of commerce, in consultation with the Public Utilities Commission, shall annually by January 15 submit a written report to the chairs and the ranking minority members of the legislative committees with primary jurisdiction over energy policy that contains a narrative describing what electric transmission infrastructure is needed within the state over the next 15 years and what specific progress is being made to meet that need. To the extent possible, the report must contain a description of specific transmission needs and the current status of proposals to address that need. The report must identify any barriers to meeting transmission infrastructure needs and make recommendations, including any legislation, that are necessary to overcome those barriers. The report must be based on the best available information and must describe what assumptions are made as the basis for the report. If the commissioner determines that there are difficulties in accurately assessing future transmission infrastructure needs, the commissioner shall explain those difficulties as part of the report. The commissioner is not required to conduct original research to support the report. The commissioner may utilize information the commissioner, the commission, and the Office of Energy Security [now known as the Division of Energy Resources] possess and utilize in carrying out their existing statutory duties related to the state's transmission infrastructure. The report must be in easily understood, nontechnical terms

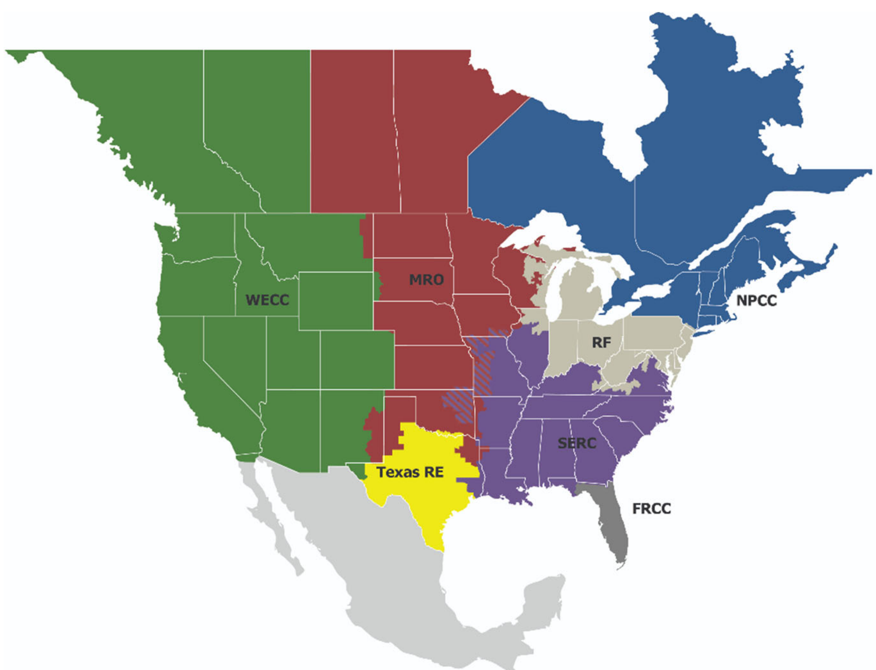
[2] See Minnesota Statute 216B.1691.

percent. Utilities that move large amounts of power over long distances tend to have relatively more transmission costs as a percent of total costs.

At the time many of the original transmission facilities in Minnesota were built, prior to the series of electric power blackouts in the 1960s, they were designed primarily to interconnect a utility's generation and distribution facilities, and secondarily to interconnect neighboring utilities to each other to provide additional backup power. Over time, the focus on interconnecting utilities has grown to include interconnecting broader regions, even as the need to connect a utility's generation and distribution systems remains. This evolving design enables utilities to access other generation or transmission systems if something goes wrong on that utility's system. This interconnection with other electric systems provides a more reliable system overall than isolated systems and allows utilities to access lower cost power from other suppliers, or purchase power on a temporary basis rather than building a generation facility that may be used only occasionally. More recently, there has been a need to adapt transmission systems to respond to changes in distribution systems. Transmission helps companies and states engage in a greater degree of specialization and thus allows the system of interconnected utilities to operate more efficiently and reliably than if each utility or state were operated on a stand-alone basis.

The interconnected transmission system is vast, covering the entire United States. Electrically, the nation's transmission grid is split into three sections: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). Reliability of the transmission grid in the Eastern Interconnection, in which Minnesota is located, is overseen by the Midwest Reliability Organization (MRO), as shown in Map 1[3] and as discussed below.

Map 1: Map of Regional Reliability Areas



[3] Source: North American Electric Reliability Corporation

Electricity follows the laws of physics: it follows the path of least resistance. Electricity placed onto the interconnected transmission grid could be withdrawn at any other place within the interconnection as long as there is no congestion on the transmission system. Moreover, the electrical system must be balanced in real time, meaning that the amount of electricity being produced at any given time must essentially equal the amount of electricity being used by consumers. Because electricity cannot currently be stored in a cost-effective manner with current technology, the transmission system helps maintain this balance at a lower cost by allowing electricity to flow through the broader electrical system where possible[4].

Transmission, Reliability and Power Costs

Adequate transmission is an essential component to ensure that Minnesotans have reliable electric service. When there are shortages in transmission capacity in certain areas, there are more frequent power outages and lower power quality (which can affect sensitive equipment such as computers). Since Minnesotans depend heavily on reliable power in their homes and businesses, it is critical to ensure that electric service is as reliable as reasonably possible to minimize the cost to Minnesota's economy in lost production time, disruption and potential harm to the myriad systems that depend on electricity. For example, electricity is needed to run the pumps that deliver natural gas, oil and other fuels to consumers. In addition, for most utilities the largest users of electricity are mining and manufacturing businesses that rely on electricity to produce and deliver their products.

Inadequate transmission capacity also increases the cost of power delivered on the system. The entire electric system starts by using the least-cost generators available and adds power from generators that are increasingly more expensive to operate. Electricity follows the path of least resistance, meaning it moves from more congested to less congested transmission lines. When there is not enough transmission capacity, certain paths on the system become congested, causing operators of the electric system to decrease the amount of electricity produced by the cheaper generators in congested areas and increase electricity produced by more expensive generators in areas free of congestion to make up for the generation that could not be delivered from the congested areas. As a result, when transmission congestion requires higher-cost generation facilities to produce power, the cost of power goes up.

In sum, inadequate transmission capacity can hurt Minnesota's economy. Lapses in power quality and reliability, along with higher costs, could potentially disrupt businesses, industries, hospitals, schools, public services and citizens who depend on computers and other electronics in their day-to-day lives and expect that their power costs will be reasonable.

[4] Technologies to store electricity for later use includes batteries, pumped hydro, compressed air, flywheels, and the transmission system itself. For example, "pumped storage hydro" in effect stores the electricity in the potential energy of water, by using electricity at times when little power is being used for other purposes to pump large amounts of water into a reservoir. Later, when electricity is needed, this reservoir water is sent through a hydro-power turbine, generating electricity. This technology's use is restricted due to the need for both a large amount of water to make it viable and large ponds to store the water and generate the hydro-power. Storage is discussed below

Roles of Entities Involved in Transmission

Numerous entities are involved in the design and cost of the transmission system that serves Minnesota. For example, because transmission lines located outside of the state serve Minnesota customers, the utilities that own those facilities and the states that regulate those utilities affect the cost and design of the transmission grid that serves Minnesotans. While Minnesota's electric utilities are certainly involved in these matters, so are other entities, including the following.

1. **The Federal Energy Regulatory Commission** (FERC) regulates the wholesale rates that utilities charge for transmission service and the type of transmission services provided.

2. **The Midcontinent Independent System Operator** (MISO) and Southwest Power Pool (SPP) do not own transmission or generation facilities, but work with utilities that choose to be their members to operate the regional transmission system reliably and in the least-cost manner through energy markets[5]. MISO and SPP help their members develop long-term transmission plans for the region. MISO currently covers all or part of 15 states plus the Canadian province of Manitoba[6]. MISO cannot require any of its members to build new resources and is not responsible for developing long-term generation plans. FERC regulates the rates and practices of MISO and SPP.

3. **The North American Electric Reliability Corporation** (NERC) develops and enforces certain electric reliability standards for what is known as the "Bulk Power System" or "the grid." There are seven NERC Reliability Regions covering the United States and Canada, as shown in Map 1 on page 3. Minnesota is in the "MRO" region, as noted above. NERC's other reliability organizations are the Western Electricity Coordinating Council, Inc. (WECC), Texas Reliability Entity (Texas RE), Northeast Power Coordinating Council, Inc. (NPPC), ReliabilityFirst (RF), SERC Reliability Council (SERC, the successor to the Southeast Electric Reliability Council), and Florida Reliability Coordinating Council, Inc. (FRCC). Because an outage in one part of the grid can affect other parts of the grid, NERC coordinates among these regions.

4. **The Midwest Reliability Organization** (MRO), with members in eight states (Minnesota, Wisconsin, Iowa, North Dakota, South Dakota, Nebraska, Montana and Illinois) and two Canadian Provinces (Manitoba and Saskatchewan), develops and ensures compliance with regional and interregional electric standards for the transmission system and performs assessments of the grid's ability to meet demands for electricity.

5. **The Organization of MISO States** (OMS) is a self-governing organization of representatives from each of the regulatory commissions in 15 states, the City of New Orleans and the Canadian province of Manitoba with authority over utilities or other entities participating in MISO. The OMS analyzes and makes recommendations to MISO, FERC and other relevant government agencies regarding matters that affect regional transmission issues. The Minnesota Public Utilities Commission represents Minnesota in OMS. In addition, the Department of Commerce represents Minnesota as an associate member in OMS and, along

[5] MISO and SPP are called Regional Transmission Organizations, which are responsible for moving electricity over large interstate areas. Despite this geographical definition, electric utilities can choose which Regional Transmission Organization to join and, if they meet the terms of the agreements, could switch to another Regional Transmission Organization.

[6] As shown in Map 2 on page 12, MISO covers some or all of the following states: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Manitoba, Michigan, Minnesota, Mississippi, Missouri, Montana, New Orleans, North Dakota, South Dakota, Texas and Wisconsin.

with other Public Consumer Advocates such as the Minnesota Office of Attorney General's Residential Utilities and Antitrust Division, participates in efforts by OMS and MISO.

6. **The Minnesota Public Utilities Commission** requires Minnesota utilities to develop sufficient transmission to serve load and regulates the rates that Minnesota's investor-owned utilities charge to their retail customers to recover transmission costs. In addition, while the Commission does not regulate the wholesale rates that Minnesota's investor-owned utilities charge to wholesale customers, it does ensure that these utilities allocate transmission costs and revenues appropriately at the retail level, considering facts pertaining to the various types or classes of retail customers.

7. **The Division of Energy Resources at the Minnesota Department of Commerce** investigates matters pending before the Commission and makes recommendations to address proposals by utilities and others.

Because it is so involved in the operations of Minnesota's electrical system, MISO warrants further discussion. As noted above, MISO is a Regional Transmission Organization created and regulated by FERC. It is involved in numerous matters that are critical to the reliable and low-cost operation of the bulk transmission system. These include: Planning for contingencies if large generation plants or transmission components retire or fail; conducting engineering analyses of the effects of changes in generation or transmission components on the system as a whole; planning for the transmission needs in the MISO region; coordinating with other areas of the Eastern Interconnection System; monitoring the day-to-day (and minute-to-minute) operations of the transmission system; telling utilities which generation facilities to operate (from lowest to highest cost); addressing the operational effects of congestion on the transmission system; and analyzing where the greatest congestion exists. Staff at the Department of Commerce and the Public Utilities Commission participate in various MISO and OMS committees.

As noted above, the geographical area of MISO's region spans 15 states and, for reliability purposes, a Canadian province. To focus its review of the reliability of the transmission system, MISO established resource "planning reserve zones." In its planning, MISO focuses on ensuring that there are adequate electric resources to meet the needs in each zone, and considers any limits on a region's ability to import or export power.

As shown in Map 2 on page 12, most of Minnesota is part of MISO's Planning Reserve Zone 1, along with the western half of Wisconsin, the portions of North Dakota with utilities belonging to MISO, and portions of Montana, South Dakota, and Illinois. The 13 utilities in Zone 1 include: Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Heartland Consumers Power District, Minnesota Municipal Power Agency, Minnesota Power, Missouri River Energy Services, Montana-Dakota Utilities, Northern States Power (Xcel Energy), Otter Tail Power, Rochester Public Utilities, the Southern Minnesota Municipal Power Agency, and Willmar Municipal Utilities.

How Much Transmission Is Enough

Minnesota's Transmission System

When the initial main components of Minnesota's transmission system were designed and built over 60 years ago, items such as home computers, video games, cable TV and cellphones were unheard of, few customers had air conditioners, and there were few plug-in appliances. Those transmission facilities were sized to meet the then-current electricity needs of the population and economy of the day plus some assumptions for growth based on what was known at that time.

While Minnesota's transmission system was previously built with more capacity than was needed for immediate economic and reliability purposes, Minnesota has been outgrowing its system both in terms of the quantity of electricity customers' demand and where the electricity is produced. In addition the system has been aging. In response to the changes in the amount and location of electricity supply and demand more transmission has been added recently and more may be needed in the future. Moreover, Minnesota residents and industry need not only electricity, but also acceptable power quality, meaning evenly delivered energy without power surges and other fluctuations that can affect computers and other sensitive electronic devices. Lack of sufficient space or capacity on the grid also means that there could be some locations in the state where power quality may become unacceptably poor. Further, in some Minnesota locations, too much electricity is trying to flow on the lines causing "grid lock," resulting in associated economic and reliability problems in making sure the power can be delivered where it is needed.

Determining the amount of transmission infrastructure needed to provide economic and reliable electric service in Minnesota requires balancing the risks of building too much transmission or too little. However, these risks are not symmetrical. If more transmission capacity is built than needed to provide delivery service for available generation resources, the system will be relatively free of transmission constraints, but will be higher cost than is necessary to provide adequate service. However, if too little capacity is built for delivery service from existing and new generation resources, the transmission cost component of providing electricity service may be lower, but the overall cost to Minnesota's economy of the less reliable power and use of higher cost generation resources that would result, may be far greater than the cost of building transmission. As noted above, costs of a less reliable electric system may include lost productivity, damage to security systems, damage to computer systems and increased cost of producing electricity.

While use of the transmission system varies with the overall demand for electricity and the location of the supply, transmission planning requires focus on the amount and timing of the highest needs to import electricity to a region and the highest needs to export electricity from a region. For example, in some regions the clearest need is to be able to export power from the region. Sometimes, the greatest need to export power is when demand for electricity is low, and the supply of electricity exceeds demand in an area. This imbalance typically occurs during overnight hours of the spring and fall when demand for power is low and generation from "must run" resources such as wind is high.

When planning for the requirement to import electricity, the highest demand for electricity (peak demand) is reviewed. While peak electricity use in the MISO region has typically occurred in the summer, MISO must also plan for meeting high winter loads. For example, temperatures in January and February of 2014 were exceedingly cold during the two "polar vortexes" experienced in that year. Further, cold weather and difficulties with generation facilities and demand resources in the southern part of MISO's region caused price spikes in the early part of January 2018.

The historic winter peak electric demand on MISO's system was set on January 6, 2014. At the same time, there were shortages of propane and natural gas, two primary fuels used to heat homes and water in Minnesota and surrounding areas. Because this event was significant, MISO issued a report on September 23, 2014, "MISO and Stakeholder Polar Vortex Experiences with Natural Gas Availability and Enhanced RTO/Pipeline Communication," in which MISO stated that the January 6, 2014, historic winter peak demand of 109,307 MW was nine percent higher than the prior winter peak demand[7]. MISO summarized its report as follows:

> *The January 2014 polar vortex brought extreme weather conditions to the MISO Region that introduced significant challenges to the reliable operation of the power grid. The [e]ffects were far-reaching, spanning from the Canadian province of Manitoba to the Gulf Coast. While the severity of the conditions was forecasted well in advance, this was nevertheless a rare weather event for which the full impact could not be precisely anticipated. Overall, however, MISO was able to effectively manage system assets to maintain the reliability of the Bulk Power System within its region, while also supporting and assisting neighboring entities in their efforts to do the same. MISO's market functions performed as expected during the event.*

In addition, well-designed transmission systems help facilitate more efficient use of generation resources. A transmission system or "grid" that covers a broader region and multiple utilities, with access to a larger portfolio of generation resources, permits strategic use of the most efficient resources available on the grid at any given moment. Since the grid uses least-cost generators first, having access to more generators can help reduce electricity prices. As indicated above, in its role as a regional transmission organization, MISO helps coordinate both regional transmission planning and operations. These functions help to mitigate potential inefficiencies that can result from a balkanized utility grid that is based on individual utilities planning and operating their systems solely to meet the needs of their own service territories. Being aware of the various costs of resources in its region, MISO can provide direction to its members on how to dispatch those resources more efficiently overall.

As a result, planning the transmission system means meeting not only the overall expected demand for power, typically in summer months, but also the demand for relatively high amounts of power during extreme weather and other circumstances. Moreover, when generation resources are higher than the demand for electricity in a region, the need to move electricity out of such a region increases.

This planning also needs to take into account expected changes in the economy. While excessive transmission facilities would result in costs and local environmental impacts being higher than necessary, too little transmission would also have a negative effect on the cost and reliability of electricity. Thus, the overall goal is to have a system that is sized just large enough to be ready to handle the demands to import and export power to allow for growth in the economy and expected changes in the generation fleet. For example, if the transmission system were planned assuming that the relatively low demand for power that occurs during a recessionary period would continue in the future, the transmission system would be unable to accommodate recovery and growth in the economy[8]. Or, if plans for transmission ignore potential growth in new technologies that rely on electricity, then the transmission system may not be adequate in the future.

The minimum time period that should be considered in planning for new facilities is the number of years that it takes to build new transmission lines (including assessing a need, conducting engineering analysis, working with local communities and landowners, obtaining needed permits and installing the lines). It can take a decade for a large transmission line to move from planning through permitting and construction to be placed in service. Thus,

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[7] On January 2, 2018, MISO's load was 104,700 MW

[8] The Minnesota Public Utilities Commission recognized these concepts in its May 22, 2009, Order in the certificate of need proceeding for the transmission capacity expansion project for 2020, or CapX 2020. The Minnesota Court of Appeals affirmed the Commission's decision on June 8, 2010.

as the economy grows in the future, it will be necessary to ensure that the transmission system is ready to meet the needs of the future.

Minnesota largely avoided serious problems with its transmission system due to having one of the strongest energy conservation programs in the country. Minnesota's Conservation Improvement Program has, since its inception, conserved enough energy to push back by many years the need for building multiple major electric generation plants by offering industry, business and residents various programs to save energy in their day-to-day operations. As a consequence, while power usage continued to increase, the rate of growth has declined significantly.

In addition, strategically placed generation and storage facilities could also help ensure reliable electric service, particularly when such resources are relatively low cost and located in areas where such resources can address congestion on the transmission system. For example, new generation should be sited where sufficient transmission capacity already exists. Storage resources placed in strategic areas may delay or prevent the need to build new transmission.

However, these programs should not be expected to put off needed changes to transmission indefinitely. Further, conservation might actually increase the need for new transmission if it occurs in an area where there are limits to the amount of generation that can be exported. For example, as more renewable energy has been added in and near Minnesota, there often is a greater need to build more transmission to export the power during off-peak hours when demand is low and renewable energy generation can be higher.

Federal and State Actions Related to Minnesota's Transmission Grid in 2018

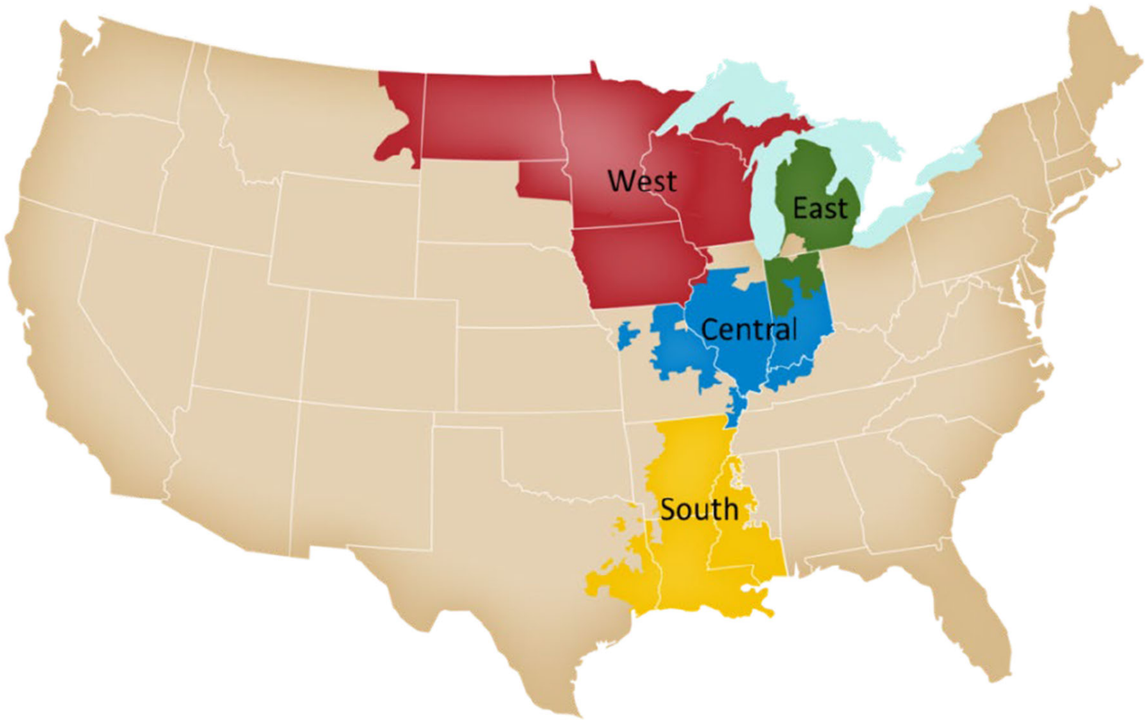
Additions to transmission are needed not only due to factors in Minnesota, but also due to federal and regional governmental actions directly affecting the use of Minnesota's transmission grid (as well as other states' grids). Issues that developed in 2018 with potential effects on Minnesota include:

MISO South Integration Update

As noted in prior reports, the Entergy Region of MISO [portions of Arkansas, Louisiana (including New Orleans), Mississippi, and Texas] referred to as "MISO South" started their energy market with MISO on December 19, 2013. As a result of this integration of MISO South, MISO's footprint added 16,000 miles of transmission lines (which was a 32 percent increase in transmission), 50,000 MW of generation (a 38 percent increase in generation), and 30,000 MW of load (a 31 percent increase in load). MISO South has been expected to create benefits for existing MISO members by reducing MISO administrative fees since they will be shared across a larger footprint. FERC approved a five-year transition period for MISO transmission planning and MISO cost allocation for the MISO South Region, with the end of the transition period being December 19, 2018.

Due to its wide swath and differences in certain areas, MISO divided its system into the following four geographical regions for transmission planning and ten geographical regions for resource adequacy: MISO East, MISO Central Region, MISO West Region, and MISO South Region.

Map 2: MISO Planning Subregions

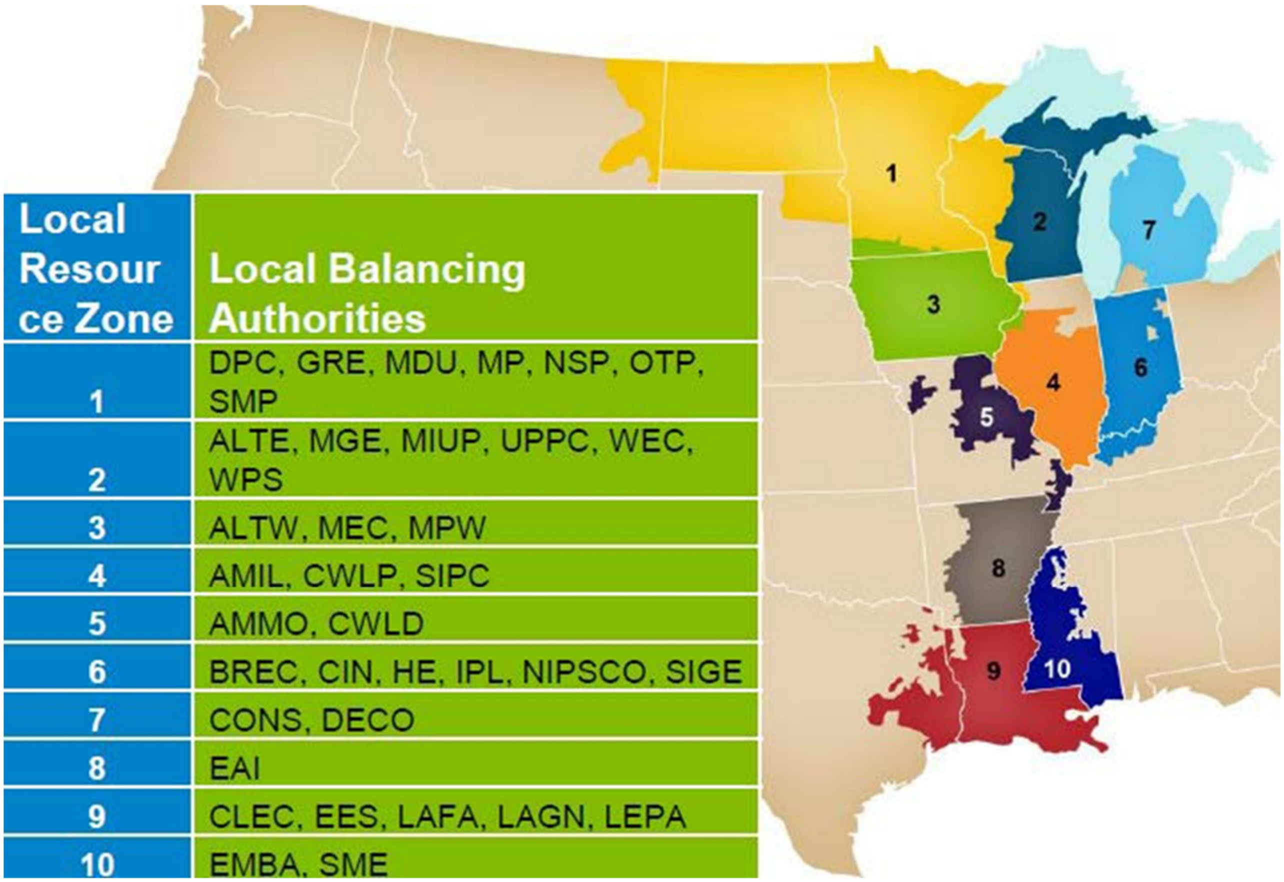


Map 2 above shows MISO's four geographical regions for transmission planning. In addition, MISO has 10 "planning reserve zones" to focus on each region and to help ensure that there are adequate electric resources to meet the needs in each zone (also known as "resource adequacy"). See Map 3 on page 11.

Minnesota is part of MISO's Planning Reserve Zone 1, along with the western half of Wisconsin, all of North Dakota and portions of Montana, South Dakota and Illinois. Utilities included in Zone 1 are Dairyland Power Cooperative, Great River Energy, Montana-Dakota Utilities, Minnesota Power, Northern States Power, Otter Tail Power and the Southern Minnesota Municipal Power Agency. The utility that serves Minnesota in Zone 3, in the southernmost part of Minnesota, is Interstate Power and Light, which sold its transmission resources to ITC Midwest, a transmission-only utility. Interstate also sold its distribution system to the Southern Minnesota Electric Cooperative.

Map 3: MISO'S Resource Planning Zones

Source: The Midcontinent Independent System Operator



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Constraints on Power Transfers within MISO

The amount of electricity that MISO North can export to and import from MISO South has been limited since shortly after MISO integrated the Entergy region in 2013. The Southwest Power Pool (SPP) filed a complaint with FERC, claiming that MISO should pay for certain transfers that exceed 1,000 MW. Under a settlement, MISO is currently paying SPP and Joint Parties more than it previously did to transfer power over 1,000 MW. The annual cost to maintain the settlement is estimated to be up to $38 million and is dependent on the capacity factor usage of the interface.

Late in 2016 MISO launched a study, called the Footprint Diversity Study, on addressing the 1,000 MW limit. Of the 35 transmission projects that were studied to solve the congestion, none passed the benefit-to-cost ratio of 1.25 that is used within the Market Congestion Planning study process to assess which projects might be cost-effective. While there are significant potential savings in settlement costs, the minimal amount of physical congestion on the interface between MISO North/Central and MISO South within MISO's models did not provide enough economic benefit to justify a project candidate for board approval. MISO continues to explore ways to increase the transfer limits between MISO South and MISO North.

MISO's Competitive Bid Process for Regional Transmission (Transmission Developer Qualification and Selection)

FERC requires MISO to have a Transmission Developer Qualification and Selection System and to eliminate federal (but not state) rights of first refusal on cost shared transmission projects. One of FERC's stated goals is to promote competition for the construction of transmission projects; Minnesota and other states agree with this goal. In fact, Minnesota's existing certificate of need (CN) law requires the Commission to consider alternatives to proposed facilities. Minnesota statutes also require a Minnesota utility ("incumbent electric transmission owner") to give notice as to whether or not it intends to build a high-voltage transmission facility that has been selected in a MISO planning process (passing MISO's various standards and engineering effects on the electrical grid). If the utility does not intend to build the facility, the Commission "may determine whether the incumbent transmission owner or another entity will build the electric transmission line, taking into consideration issues such as cost, efficiency, reliability, and other factors identified in [Minnesota law]."

One such project near Mankato, referred to as "Huntley-Wilmarth," was approved by MISO in December 2016. The project would build a transmission line to interconnect substations owned by Xcel Energy and ITC Transmission. Pre-filing procedural steps in the statutory Minnesota certificate of need process were started in 2017. The petition itself was filed by Xcel and ITC in 2018. The CN process is currently scheduled to reach a final Commission decision in the summer of 2019.

Minnesota has commented in FERC proceedings that reaching the overall goal of using competition to build new transmission resources -- obtaining the best projects at lowest costs -- depends critically on holding bidders accountable to their bids. If bidders are allowed to increase costs above bids or fail to meet the specifications in their bids with little or no accountability, then the federal process cannot be expected to result in low-cost, reliable resources.

Specifically, the Commerce Department and the Commission filed comments on August 27, 2015, raising concerns about a utility's proposal as to rates charged for transmission projects. FERC held a technical conference and took comments on how to hold bidders accountable for cost increases, but has not determined whether or how to do so as yet. Recently, MISO prioritized cost caps in their competitive bid process to encourage transmission entities to include caps for at least some of the costs in competitive bids.

MISO's Multi-Value Transmission Project Portfolio

In 2011, MISO approved a portfolio of 17 different transmission projects across the MISO North, Central and East footprint. The projects, referred to as multi-value projects or "MVP" projects, had a wide variety of goals across the footprint, including:

- Provide benefits in excess of costs under the scenarios studied. In this case the benefit-to-cost ratio for the MVP portfolio as a whole ranged from 1.8 to 3.0.
- Maintain system reliability by resolving various reliability violations defined by federal reliability standards. The MVPs addressed violations on approximately 650 transmission elements for more than 6,700 system conditions and mitigated 31 system instability conditions.
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million.

- Support a variety of generation policies by using a set of energy zones that support wind, natural gas and other fuel sources.

Two of the 17 MVP projects are located in Minnesota: the 345 kV line between Brookings, South Dakota, and the Southeast Twin Cities and the 345 kV line from Lakefield Junction to Winnebago, Iowa. The most recent cost estimates for these projects were at or below the cost estimates used by MISO. However, some of the MVP projects experienced cost overruns as high as 45 percent. This significant cost overrun highlights the importance of starting with a reasonable cost estimate and building adequate cost control measures into the transmission project approval process. The Minnesota Commission and the Commerce Department are participating in proceedings with OMS[9] and MISO to understand and address these concerns. MISO recently incorporated a method in their reporting process to FERC to compare the actual costs of transmission projects selected by MISO to estimated costs, escalated to current dollars as of the expected year in service. MISO provides this information to allow other entities to monitor cost overruns and attempt to hold transmission owners financially accountable.

In Minnesota, the Commerce Department and Public Utilities Commission hold investor-owned utilities accountable for the costs proposed in certificate of need proceedings by not only comparing actual costs (escalated to current dollars) to estimated costs, but also preventing rate-regulated transmission owners from charging cost overruns to ratepayers without a proper vetting process. Rate-regulated utilities may charge ratepayers for cost overruns only if: 1) there was no competitive process used to select the project, 2) utilities can justify why it is reasonable to charge such cost overruns to ratepayers, and 3) the utility files a general rate case (cost overruns are not charged to ratepayers through rider rates prior to the rate case).

MISO's most recent update from September 2018 indicated that all but one of the 17 MVP projects have completed the state regulatory process and construction is complete on 10 of the 17 MVP projects.

Complaint by Large Power Customers to FERC regarding MISO Transmission Owners' Return on Equity (ROE)

As discussed in prior reports, a group of industrial end-users filed a complaint at FERC in late 2013 seeking to reduce the allowed return on equity (ROE) of MISO Transmission Owners and limit capital structure ratios and incentive equity adders. At that time, MISO transmission owners had a base ROE of 12.38 percent, with transmission owners belonging to organizations such as MISO at 12.88 percent. The complaint sought to decrease the transmission owners' base ROE over 300 basis points below the then-current base ROE, to 9.15 percent.

In 2015, MISO's Public Consumer Group, of which the Commerce Department is a member, provided testimony identifying the basis for decreasing the ROE to a reasonable level. FERC's Trial Staff filed briefs that were supportive of consumer advocates' positions. Transmission customers and consumer advocates argued that FERC's high ROEs imposed undue costs on consumers and distorted decision-making by encouraging utilities to build transmission rather than generation or distribution resources. While transmission resources are needed, it would not be appropriate to build only transmission to meet the electric needs of society since there must be an appropriate balance of production and delivery of electricity.

[9] The Organization of MISO States is defined on page 5.

Because the Minnesota Commission requires utilities under its ratemaking authority to offset high ROE transmission costs with high ROE transmission revenues, Minnesotans taking service from such utilities have been spared from paying high ROEs without the revenue offset. While these ratemaking decisions have reduced the harm of paying for high ROEs for such ratepayers in Minnesota, such benefits will be returned to Minnesota retail ratepayers only if utilities choose to provide a credit to Minnesota retail ratepayers for higher revenues or – as with utilities subject to the Minnesota Commission's ratemaking – are required to do so. Even if Minnesota retail ratepayers receive the benefit of revenue offsets to reduce the high rates they pay for electric service, the distortion of utility decision-making remained an issue.

On December 22, 2015, Administrative Law Judge David H. Coffman issued his Initial Decision, determining that the allowed base ROE should be reduced by over 206 basis points (just over 2 percent), to 10.32 percent. On September 28, 2016, FERC approved Judge Coffman's Initial Decision, requiring MISO to refund the difference between the base ROEs of 12.38 percent and 10.32 percent, a reduction of over 200 basis points.

On July, 2017, MISO filed its compliance filing showing that the transmission owners provided sizable refunds to Minnesota utilities in February and June 2017 that were flowed back to Minnesota customers.

Also related to this proceeding is another complaint filed on February 12, 2015, regarding further reason to reduce the returns on equity for transmission assets in MISO. The Initial Decision by Administrative Law Judge David H. Coffman determined that the allowed base ROE should be further reduced from 10.32 percent to 9.7 percent. A final FERC decision in this case is expected soon.

In April 2017, the U.S. Court of Appeals-DC Circuit found that, in a case regarding transmission owners in New England, FERC did not adequately explain (1) why it found the previously approved ROE to be unjust and unreasonable and (2) the logic behind its adjustment for "anomalous market conditions." However, importantly, the Court also rejected the claim of the utility that the fact that the utility's existing ROE was within the zone of reasonableness produced by the analysis did not necessarily indicate that the ROE was just and reasonable.

On October 16, 2018, FERC issued two proposals in the New England case stemming from the DC Circuit Court decision: a method to determine whether existing ROEs are unjust and unreasonable, and a new method to determine ROEs.

First, FERC's proposal to test whether existing ROEs are reasonable is to see whether the ROE is in a "zone of reasonableness." FERC's zone would be an equal weighting of ROE estimates from different analytical methods: Discounted Cash Flow (DCF), Capital-Asset Pricing Model (CAPM), and Expected Earnings analyses, with the range then divided into sub-ranges for low-risk, average-risk and high-risk utilities. If an existing ROE falls within the appropriate sub-range, it is presumed to be reasonable, absent other convincing arguments. If it falls out of the range, it is unreasonable.

Second, to set a new ROE, FERC proposes to establish similar risk sub-ranges based on a zone of reasonableness determined by an equal weighting of ROE estimates produced by DCF, CAPM, Expected Earnings and Risk Premium analyses. FERC asked for briefs from parties about how to proceed in the four pending New England ISO dockets, which will be relevant for the pending MISO ROE dockets.

Because FERC's proposed methods regarding returns on equity are expected to affect transmission rates, the "MISO Complainant-Aligned Parties" are reviewing FERC's proposals[10].

Clean Power Plan/Affordable Clean Energy

The U.S. Environmental Protection Agency (EPA) issued its final rule for regulation of carbon emissions from existing power plants, called the "Clean Power Plan" (CPP). On February 9, 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review. On May 16, 2016, the full D.C. Circuit ordered, on its own motion, to reschedule a hearing before a three-judge panel to be heard instead by the D.C. Court en banc on September 27, 2016. On August 8, 2017, the D.C. Circuit ordered litigation be held in abeyance for an additional 60 days.

Meanwhile, on March 28, 2017 President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which called for a review of the Clean Power Plan. On October 25, 2017 the EPA issued a report on implementing the Executive Order. On October 10, 2017, EPA Administrator E. Scott Pruitt signed a Notice of Proposed Rulemaking proposing to repeal the CPP. The public comment period closed on December 15, 2017. While changes to federal rules could take several years, on October 9, 2018, the U.S. Supreme Court struck down any further challenges to repeal the Clean Power Plan. Instead, on August 21, 2018. the EPA issued proposed "Affordable Clean Energy" (ACE) rules, for which comments were due October 31, 2018.

Both the CPP and ACE target power plants rather than transmission facilities. However, the focus of the ACE is limited to small changes to coal generation plants, whereas the CPP was expected to have wider-reaching effects not only on generation but on transmission facilities. By encouraging more renewable facilities and discouraging non-renewable power, the CPP might have affected the configuration of the existing integrated electrical system, beyond those caused by market changes in the electrical industry. As a result, MISO worked with stakeholders to understand such possible effects. By contrast, given the limited focus of the ACE rules, little effect on power plants or the transmission system is expected if these rules are adopted.

Price Cap on Offers of Energy in the Regional Wholesale Electric Market

Because there were concerns about how MISO's energy market could affect costs ultimately charged to ratepayers, there has always been a cap on how high the charges for electric energy could rise. Since the beginning of the MISO wholesale energy market on April 1, 2005, MISO has had a cap of $1,000 per MWh for energy offers, plus a waiver to exceed this cap during winter emergency conditions ("soft cap").

However, balancing against concerns about prices is the worry, at least in deregulated states (which do not have jurisdiction over generation facilities), that there may not be sufficient resources to provide reliable service, unless electricity prices were higher. Thus, in 2016, largely in response to higher energy prices in East Coast states where electric generation is deregulated, FERC held rulemaking to consider increasing those price caps.

[10] Because decisions in the New England case could affect the MISO cases, on November 5, 2018, the Commerce Department joined with "MISO Complainant-Aligned Parties" to intervene out-of-time in the New England case. On November 14, 2018, FERC extended initial briefs to January 11, 2019, and reply briefs to March 8, 2019. On November 15, 2018, FERC allowed all parties in the MISO ROEs cases to participate in a paper hearing in the new FERC general ROE case. As a result, the MISO Complainant-Aligned Parties withdrew from the New England case and are focusing on FERC's general ROE proposals.

The concerns in Minnesota and other regulated states about higher prices were: 1) ensuring that bids were reasonably based on costs that could be verified and 2) whether resources that would ordinarily serve Minnesota would seek to provide service in other areas where prices were higher.

On November 17, 2016, FERC issued in its final rulemaking, which increased the “soft cap” for offers into the energy market at the higher of $1,000/MWh or that resource’s verified cost-based incremental energy offer and set a “hard cap” on the verified cost-based incremental energy offers used to calculate energy prices at $2,000/MWh. However, FERC allowed resources with verified energy offers above $2,000/MWh to be eligible for after-the-fact payments. The Independent Market Monitor must verify all energy offers above $1,000/MWh prior to any such offer being used to calculate energy prices, to ensure that a resource’s cost-based incremental energy offer reasonably reflects that resource’s actual or expected costs.

On November 9, 2017, FERC rejected MISO’s filing that attempted to comply with FERC’s price cap Order. On December 11, 2017, MISO requested that FERC rehear the order. Subsequently, on January 10, 2018, FERC issued an order giving itself more time to consider MISO's rehearing request.

On March 28, 2018, FERC concluded that MISO generally complied with the November Order’s directive to permit resources to submit incremental energy offers above $2,000/MWh. MISO’s revisions to MISO’s Tariffs, appropriately clarify that resources are allowed to submit cost-based incremental energy offers above $2,000/MWh and to be able to recover verified costs above $2,000/MWh through after-the-fact payments, but those higher costs would not be recognized in the market price for electric energy. On October 1, 2018, FERC also required MISO to apply these same offer caps to fast-start units, along with all other resources, by October 1, 2020.

Prorated Accumulated Deferred Income Taxes (ADIT)

Utility rates spread (depreciate) the costs of structures such as a transmission line over the expected life of the facility, charging those who use the structure over its life a fair share of the costs. Since the 1970s, Congress, through the Internal Revenue Service (IRS), has allowed utilities to assume accelerated depreciation for income tax purposes, which results in lower income taxes in the early years of the facility’s life and correspondingly higher taxes later in the life. Since ratemaking uses uniform rather than accelerated depreciation, utility rates overcharge for income taxes at the beginning of a facility’s life and undercharge for income taxes later in the life of the facility. To balance out the difference between uniform depreciation in utility rates and accelerated depreciation for income taxes, the utility maintains an accumulated deferred income tax (ADIT) account in its rate base, over the life of the facility. This account provides a credit to ratepayers (reduction in rates) for prepaying a utility’s income taxes at the beginning of the facility’s life. That is, ADIT offsets the overcharges to ratepayers for income taxes, prior to when those taxes are due. Each year, this account is adjusted to maintain the difference in imputed and actual income taxes. By the end of the facility’s life, the account should net out to zero.

In 2015, the Internal Revenue Service confirmed that, when utility rates are set based on a historical test year, this ratemaking should continue. However, the IRS determined that, when utility rates are implemented prior to the end of a forecasted rate period, the credit to ADIT should be reduced, for the portion of the year that has not yet occurred. For example, if a utility’s rates are forecasted and set for a calendar year, but the rates don’t go into effect until September of the year, the IRS determined that the full ADIT credit should be used (ratepayers should get the full credit) for the months of January through August, with the ADIT credit reduced (not fully given to ratepayers) for September through December.

In 2018, FERC fixed an ADIT issue in transmission rates, preventing transmission owners from inappropriately understating the ADIT credit by double averaging in calculating the ADIT proration. The Commerce Department participated with Joint Consumer Advocates in filing comments stating that utilities were double averaging ADIT proration and understating the credit that consumers should receive for prepaying federal income taxes. The comments pointed out that proration required by the IRS was already a form of averaging so an additional averaging using beginning and ending ADIT balances would be inappropriate. FERC ruled that transmission rates could no longer be based on double-averaging of ADIT. FERC's ruling reduced but did not eliminate the harm to ratepayers caused by prorating ADIT when rates are implemented prior to the end of the period used to set rates.

Incentive ROEs

Initially FERC granted ROE adders of 100 basis points to companies that were transmission-only companies, to encourage such structures. Previously, the Commerce Department participated with Joint Consumer Advocates to urge FERC to eliminate or reduce this ROE adder; FERC reduced the adder in half, to 50 basis points. The Commerce Department and other Consumer Advocates opposed FERC giving a bonus ROE of 50 basis points for ITC since changes in that utility's corporate structure called into question its independence from generation facilities. On Oct. 18, 2018, FERC reduced ITC's independence ROE adder from 50 to 25 basis points. FERC concluded that ITC is still "independent" following its acquisition by Fortis and GIC, but less independent than it was before, which means ITC is still eligible for an independence adder, but a smaller one.

Additionally, the Joint Consumer Advocates and the Organization of MISO States filed separate protest comments with FERC on January 5, 2018, to oppose Ameren Service's request for 100 basis point ROE incentive adder (on top their 10.32% base ROE), for Illinois River & Mark Twain components of Grand Rivers Project. Ameren did not support why this ROE incentive adder was needed, particularly since Ameren already has incentives for cost mitigation. On February 13, 2018, FERC denied Ameren's request for a 100 basis point adder. On March 30, 2018, the OMS and Joint Consumer Advocates filed a joint answer to FERC's rehearing request. On November 5, 2018, on rehearing FERC granted a 50 basis point ROE incentive adder (reduced from the 100 basis point adder requested by Ameren Service).

MISO and PJM Pseudo-Tie Requirements

A "pseudo-tie" allows electricity generating units that are physically located within MISO's boundaries to be operationally controlled and dispatched by a neighboring Regional Transmission Organization, such as PJM Interconnection, per neighboring RTO's market rule. However, MISO does not require pseudo-ties. On May 8, 2017, the Minnesota Public Utilities Commission joined OMS to ask FERC for a technical conference on how much a neighboring Regional Transmission Organization should be allowed to rely on resources in MISO.

Several parties also filed comments in this FERC docket during 2018, and there were court cases in 2018 regarding the standing of the entity that originally filed the complaint (the independent market monitor). The FERC Order is still pending.

Department of Energy (DOE) Notice of Proposed Rulemaking (NOPR) on Grid Resiliency

On September 29, 2017, the Department of Energy (DOE) requested FERC to issue a rule in 60 days to allow coal and nuclear plants (that maintain at least 90 days of fuel supply on site) to recover their full costs, even if those costs exceed prices in the energy market. This rule would have required all independent system operators and Regional Transmission Organizations, such as MISO, to file a tariff. This request appeared to address concerns about certain generation facilities in states that have no jurisdiction over generation resources, particularly expensive facilities such as coal, nuclear and pumped-storage facilities. In such deregulated states, capacity costs are not charged to state ratepayers, so the owners of the facilities have threatened to shut down the plants as not being financially viable in the deregulated market. By contrast, since Minnesota did not deregulate electric generation, all costs of such facilities (e.g., capital, property taxes, operation and maintenance) are included in utility rates. The DOE proposal would require all costs of the non-viable generation facilities to be charged throughout the MISO region, including to Minnesota in the MISO Energy Market.

On October 20, 2017, the Minnesota Public Utilities Commission and the Commerce Department joined OMS to file comments generally opposing this DOE/FERC proposal, which would likely increase energy prices in Minnesota due to subsidizing capacity costs of facilities in deregulated states. The OMS comments concluded that the FERC should respect the jurisdictional role of state and local regulators in setting retail rates and exempt the MISO region from the provisions of the DOE/FERC proposal. Further, any implementation of the proposal should hold harmless regions such as MISO that have addressed reliability and resiliency of the electric system on an ongoing and non-discriminatory basis.

On January 8, 2018, FERC terminated this DOE rulemaking in Docket No. RM18-1-000. However, FERC also issued an order that same day initiating a new proceeding to examine the resilience of the bulk power system. FERC recognized that it must remain vigilant with respect to resilience challenges, because affordable and reliable electricity is vital to the country's economic and national security. According to FERC the goals of this proceeding are to develop a common understanding among the Commission, industry and others of what resilience of the bulk power system means and requires; to understand how each regional transmission organization and independent system operator assesses resilience in its geographic footprint; and to use this information to evaluate whether additional FERC action regarding resilience is appropriate.

FERC required each regional market operator to submit the required information and invited other interested entities to respond to the market operators' comments. As of the end of 2018, FERC received several comments but has not yet issued its response or order on these comments.

Department of Energy (DOE) Defense-Critical Electric System Review

DOE may include transmission infrastructure in an on-going evaluation of electric power system assets that may be crucial to national security. DOE's review of defense-critical electric infrastructure can result in designations of electric system assets that are critical to national defense. DOE's review may also help identify and prioritize areas of the electric system that need additional investment and/or hardening against potential threats or disruptions. Transmission infrastructure in Minnesota that is deemed defense-critical may require increased security measures, additional investments and/or may be subject to emergency orders and rules issued by the Secretary of the DOE in an emergency.

Minnesota's Transmission System-Planning for the Future

Biennial Transmission Report

Minnesota Statute 216B.2425 requires utilities that own or operate electric transmission facilities in the state to report by November 1 of each odd-numbered year on the status of the transmission system, including present and foreseeable inadequacies and proposed solutions.

The last Biennial Transmission Report was filed on November 1, 2017, by the utilities listed below.

- American Transmission Company, LLC
- Dairyland Power Cooperative
- East River Electric Power Cooperative
- Great River Energy
- Hutchinson Utilities Commission
- ITC Midwest LLC
- L&O Power Cooperative
- Marshall Municipal Utilities
- Minnesota Power
- Minnkota Power Cooperative
- Missouri River Energy Services
- Northern States Power Company d/b/a Xcel Energy
- Otter Tail Power Company
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Willmar Municipal Utilities

These utilities also jointly maintain the following helpful website that provides information about transmission planning and projects: http://www.minnelectrans.com.

Detailed information (including maps) on all transmission actions is broken down into six geographic zones of the state: Northeast, Northwest, West Central, Twin Cities, Southwest and Southeast. The transmission-owning utilities operating in these six geographical zones work together to develop each zone's report. The six zones in the state are shown in the map below. The transmission-owning utilities in each zone are shown in Table 1.

Map 4: Geographic Zones for Transmission Reporting

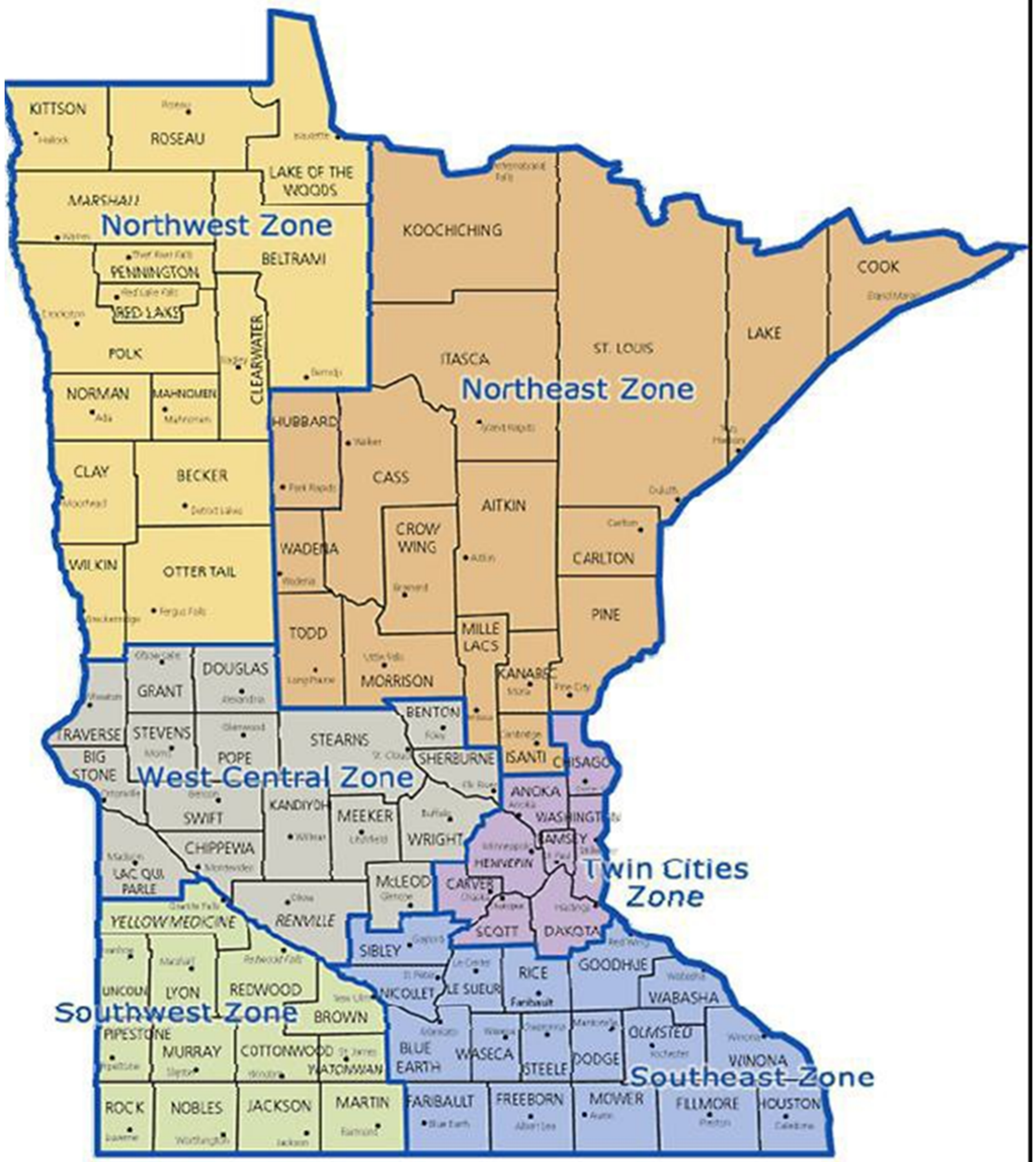


Table 1: Transmission-Owning Utilities in Each Minnesota Zone

Northwest Zone	• Great River Energy • Minnkota Power Cooperative • Missouri River Energy Services • Otter Tail Power Company • Xcel Energy
Northeast Zone	• American Transmission Company, LLC • Great River Energy • Minnesota Power • Xcel Energy
West Central Zone	• Great River Energy • Hutchinson Utilities Commission • Missouri River Energy Services • Otter Tail Power Company • Willmar Municipal Utilities • Xcel Energy
Twin Cities Zone	• Great River Energy • Xcel Energy
Southwest Zone	• ITC Midwest LLC • East River Electric Power Cooperative • Great River Energy • L&O Power Cooperative (headquartered in Iowa) • Marshall Municipal Utilities • Missouri River Energy Services • Otter Tail Power Company • Xcel Energy
Southeast Zone	• Dairyland Power Cooperative • Great River Energy • ITC Midwest LLC • Rochester Public Utilities • Southern Minnesota Municipal Power Agency • Xcel Energy

As shown in Table 2 below, the utilities' most recent Biennial Transmission Report, filed in 2017, stated that over 90 transmission inadequacies, 50 of which had been newly identified in that report, needed to be addressed to improve the transmission system. The 2017 Report identified projects in the Northeast Zone for Minnesota Power and Great River Energy; in the Southeast for Xcel Energy and ITC Midwest; and in the Northwest for Otter Tail Power. These utilities have already filed or will file certificate of need applications for new transmission lines in the near future.

Table 2: Expected Transmission Proposals

Name and Description of Proposed Transmission Project	Name of Utility
Great Northern Transmission Line 500 kV line between Winnipeg in Manitoba, Canada through numerous counties in Minnesota to the Blackberry Substation (225 to 300 miles), and a 345 kV double circuit line between Blackberry and the Arrowhead Substation near Hermantown in St. Louis County, Minnesota (approximately 50 to 70 miles)[11]. Impacted counties include Kittson, Roseau, Marshall, Pennington, Red Lake, Polk, Clearwater, Lake of the Woods, Beltrami, Koochiching, Itasca, and St. Louis. Commission granted a certificate of need in May, 2015 and approved a minor alteration in December, 2016. Minnesota Power began construction of the project in early 2017.	Minnesota Power
Palisade Pumping Station (X3A) - Construction of an approximately 13 mile 115 kV transmission line from Minnesota Power's 115 kV Line to the Enbridge Palisade Pumping Station. Project applied for a Certificate of need in MPUC Docket No. ET2/TL-15-423. On August 11, 2016, the Minnesota Public Utilities Commission issued an ORDER DEFERRING ACTION until such time that a decision is made on the Enbridge Line 3 certificate of need and route permit docket.	Great River Energy
Huntley to Wilmarth 345 kV Project – Construct new 345 kV circuit from the Wilmarth Substation to the Huntley Substation. Certificate of Need process begun in 2017, with initial petition filed in 2018. Proceeding is ongoing.	Xcel Energy and ITC Midwest
Winger-Thief River Falls 230 kV Project – Substation expansions for both Winger and Thief River Falls substations, construction of a new 47 mile 230 kV transmission line between Winger and Thief River Falls, and a new 230/115 kV transformer at Thief River Falls. Expected to file for a Certificate of Need.	Minnkota Power Cooperative and Otter Tail Power Company

[11] The Iron Range-Arrowhead 345 kV Project is not currently needed or economically justified at the current level of Manitoba Hydro export

Renewable Energy Standard Transmission Study

In addition to reporting on transmission in general, utilities are required to determine any transmission upgrades needed to meet an upcoming milestone of the Minnesota Renewable Energy Standard (RES). Ongoing progress by utilities toward the RES is monitored in several venues, including separate biennial reports to the Legislature on this issue. A separate report being filed by January 15, 2019, indicates that utilities are in compliance with present RES standards through 2017, the most recent data available, and expect to have enough renewable generation and transmission to meet increased future RES milestones. In the past year, several utilities added wind resources beyond the RES levels, based on the currently lower costs of such resources.

Challenges to Transmission Planning-Potential Impacts to Minnesota

New Transmission Projects Raise Concerns about Land Use and Land Rights

In recent years, a number of energy entities, including natural gas pipelines, electric utilities and crude oil pipelines, have sought approval to construct new energy projects in Minnesota. Since the siting process in Minnesota mandates a number of public meetings and hearings and other outreach efforts to potentially impacted residents, landowners and the general public, the legal framework and other issues regarding land rights and land use are also receiving close scrutiny. In addition to wanting to know what benefit their area of the state would derive from a project, landowners and other affected citizens naturally want to know what their rights are regarding such projects impacting their land so they may be assured that their rights are not infringed upon during the process.

To date, answers to affected citizens and landowners have been identified during the regulatory processes. The answer to "what benefit does this project have for my area or my State" is a key question that is addressed in the State's Certificate of Need process (Minnesota Statute 216B.243) and land rights questions are addressed in various parts of Minnesota's statutes.

To help stakeholders understand facility permitting proceedings before the Minnesota Public Utilities Commission that affect them and to help them have more productive input into those proceedings, the Commission created the specially designated position of Public Advisor. This position is responsible for designing and implementing a program to better inform stakeholders and to advise them on how to have a meaningful voice in the permitting process.

Cost Responsibility for Mitigations

As utilities build more energy infrastructure, state regulators must ensure that utilities use cost discipline as they construct new resources. To encourage cost discipline and prevent ratepayers from paying more than is reasonable for new utility infrastructure, at a minimum, a utility must justify any cost recovery above the amount the utility originally indicated that the project would cost. This focus is important since decisions to approve or deny a project are based in part on cost effectiveness of the proposed facility. Consequently, it is important to minimize errors in estimation to avoid ill-informed decisions from being made that would result in higher system costs than necessary. Minnesota has built such discipline into its transmission approval process.

When utilities install infrastructure in an area, there are always mitigation measures employed to address local concerns. Thus, it is important to ensure that decisions made by a utility on behalf of local governments or citizens reasonably consider the cost implications noted above. Further, it is important that costs of any significant upgrades are equitably allocated to ratepayers, based on ratemaking principles such as cost-causation, cost minimization and administrative feasibility. Discussions about such issues have occurred and are likely to continue in the future.

Federal versus State Jurisdiction Over Siting and Construction

The federal government "opened up" the interstate electric transmission grid in the 1990s. Certain eastern states challenged the federal government's jurisdiction over interstate electric transmission lines[12]. The challenge went to the U.S. Supreme Court, which upheld that FERC has legal and regulatory jurisdiction over electric lines used for interstate commerce. (States retain jurisdiction over small power lines that distribute power directly to retail electric customers.) After the Supreme Court reached its decision, FERC issued a policy statement saying that it would not "preempt" state regulation of transmission lines as long as transmission service is not detrimentally impacted by state actions. When the federal approach of one-size-fits-all has not worked for Minnesota, the Commerce Department and Public Utilities Commission have advocated before FERC for the interests of Minnesota.

Summary of Conclusions

In conclusion:

- Electricity continues to be an essential component in providing needed energy to Minnesota's homes and businesses.
- Minnesotans and the economy depend on reliable power every day.
- A Regional Transmission Organization (e.g., MISO) works with electric utilities to operate the electric transmission system in Minnesota and surrounding states to achieve regional coordination and efficiency.
- Even though we are using the transmission system in a highly efficient manner, our increased use of electricity and participation in the broader regional energy markets has strained the transmission grid, which was not designed for the purposes for which it is currently being used and expected to be used in the future.
- In some areas, we may have outgrown our aging transmission system and there have been and will continue to be significant changes in aging generation resources.
- Minnesota needs highly dependable electricity for computers and other sensitive equipment in our homes and businesses, so it is necessary to continue to upgrade and enhance our transmission infrastructure as needed to match expected use of the system and provide room for expansion in the future.

[12] See New York, et al. v. FERC, et al. and Enron Power Marketing, Inc. v. FERC for further details.

- The way that we build transmission is affected by state and federal policies, rules and laws facilitating the construction of certain types of generation and transmission and restricting other types of electricity generation and transmission in the state, region and across the United States.
- Minnesota has been and will continue to be involved in numerous regional and national efforts to ensure that electric transmission lines are planned and constructed in a reliable, cost-effective and environmentally responsible manner for the State's economic future and the needs of its businesses and citizens.