Minnesota's Electric Transmission System

Annual Adequacy Report
January 15, 2022

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

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Executive Summary

Minnesota Statutes § 216C.054 requires the Commissioner of the Department of Commerce (Commerce), in consultation with the Minnesota Public Utilities Commission (PUC), to submit an Annual Transmission Adequacy Report to the Legislature. The report is to provide a nontechnical discussion of Minnesota's current electric transmission system and a summary of the transmission planned or in process that is intended to maintain electric service reliability as well as comply with the requirements of state policy goals.[1]

This report reviews why electric transmission is needed and its status in Minnesota—including an update on ongoing or planned transmission projects; how transmission lines are regulated at the state and federal level; provides updates for 2021; and summarizes ongoing long-term challenges and potential solutions. As requested by Minnesota Statute 3.197: This report cost approximately $2,000.00 to prepare, including staff time.

In 2021, the PUC issued permits for two high-voltage transmission projects: (1) a nine and one-half mile 115-kilovolt line in Becker and Otter Tail Counties, and (2) a 31-mile 345-kV line connecting a proposed 414-megawatt wind energy project to the grid in Redwood County. In addition, six more transmission line projects are currently at various stages of the state permitting process. Of these, five are single purpose lines proposed to connect wind-energy or solar projects to the grid,[2] and one is the Duluth-Loop Project intended to support the grid in that area due to recent coal plant retirements along the North Shore.

Since 2012, when the last CAPX project was approved in Minnesota, the PUC has issued three route permits for larger, high-voltage "backbone" transmission lines (345-kV or above). In 2015 the PUC approved the 50-mile 345-kV ITC-Midwest Minnesota to Iowa line, for which construction was completed in 2019. In June 2020 — following over eight years of planning, environmental review, permitting and construction—Minnesota Power energized a new 225-mile, 500-kilovolt line from the Canadian province of Manitoba to Grand Rapids, Minnesota (the Great Northern Transmission Project). Finally, in 2019 the PUC approved the 50-mile Huntley-Wilmarth 345 kilovolt (kV) transmission line in Southeast Minnesota near Mankato. Xcel Energy completed construction of that project in 2021 and was placed into service during the first week of December 2021.

Regarding other potential future projects, the most recent transmission owners Biennial Transmission Projects Report (2021) includes a list of 103 smaller transmission enhancements Minnesota utilities believe are needed to maintain system reliability over the next five to ten years.[3] While several of the projects listed may be large enough to trigger a state certificate-of-need and a route permit, the Minnesota transmission owners did not identify or propose any specific new large high-voltage 345-kV backbone projects.

The 2021 Biennial Report also shows that Minnesota electric utilities are exceeding the renewable energy standards (RES) in Minn. Stat. § 216B.1691. Some Minnesota utilities, however, now have more aggressive renewable energy goals than required by the RES statute.[4] Some utilities may be able to interconnect new wind and solar projects to the grid using available interconnection capacity at their existing or retiring coal or natural-gas plants. Longer term, meeting these company goals will require more transmission lines.[5]

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[1] Minnesota Statutes § 216C.054

[2] Despite recent high transmission network upgrade costs, many new wind and solar projects are currently requesting MISO approval to connect to the high voltage grid throughout the region, including in Minnesota and neighboring states MISO provides a helpful map of the current queue at https://giqueue.misoenergy.org/PublicGiQueueMap/index.html.

[3] https://www.minnelectrans.com/report-2021.html

[4] Clean Energy Goals Chapter 9.

[5] See, for example, CAPX2050 Vision Report, March 2020

Given the long lead time required to plan and build large transmission network upgrades, the PUC in August 2020 required the transmission owners in their 2021 biennial report to report on what transmission upgrades will be needed to meet these company goals.[6]

Rather than identify specific transmission upgrades, the 2021 Biennial Report describes the transmission owner's participation in ongoing Midcontinent Independent System Operator (MISO) planning processes.[7] Section 2.9 of the Biennial Report briefly summarizes the transmission owner's participation in MISO's regional transmission planning work. In addition, Section 9.4 of the Biennial Report summarizes MISO's ongoing Long-Range Transmission Planning (LRTP) effort. [8]

In addition to the LRTP effort, MISO has also started several other initiatives to address the future challenges of a changing generation resource mix over the last two years. For example, MISO is nearing completion of a Joint Targeted Interconnection Queue (JTIQ) Study with the Southwest Power Pool[9], reviews of enhanced transmission technology and battery storage planning. Along with the LRTP process, these efforts are intended to help evaluate approaches and tradeoffs on how best to deliver reliable, low cost, low-carbon energy to consumers in Minnesota and the entire MISO region over the next decade and beyond.

Finally, recognizing the general lack of progress on high-voltage transmission planning throughout the United States, the Federal Energy Regulatory Commission (FERC) started two new interstate transmission initiatives in 2021. The first is a potential federal rulemaking (Advanced Notice of Proposed Rulemaking) process to address transmission planning and generator interconnection issues[10] and the second is a new state/federal electric transmission task force.[11]

Why Transmission Matters: Introduction

Generally, electricity is delivered to consumers via three main steps: 1) electricity is produced at various generation facilities, 2) it is then transmitted on an integrated system of high voltage transmission lines, and 3) is delivered to consumers through a distribution system of lower voltage power lines.

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, and smaller 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 flows of electricity. The transmission system can be impacted by changes in either supply or demand for energy and power.

While transmission is a critical component in providing electric service, it accounts for a much smaller percentage of utility costs than either generation or distribution facilities. For example, transmission typically accounts for about 15 percent of the costs of providing electric service while generation and distribution account for the other 85 percent. Utilities that move large amounts of power over long distances tend to have relatively more transmission costs as a percentage of total costs due to the length of the transmission lines and the line losses experienced in the transport of electricity.

[6] Minnesota PUC Order Accepting Biennial Transmission Report, Docket No. E-999/M-19-205

[7] MISO has primary responsibility for planning and operating the high-voltage grid for our region.

[8] See, for example, Long Range Transmission Planning Update to MISO Board 12.7.2021

[9] Summarized in the following presentation: MISO SPP JTIQ Update 12.3.2021

[10] See Press Release at: FERC ANOPR Press Release

[11] https://www.ferc.gov/TFSOET

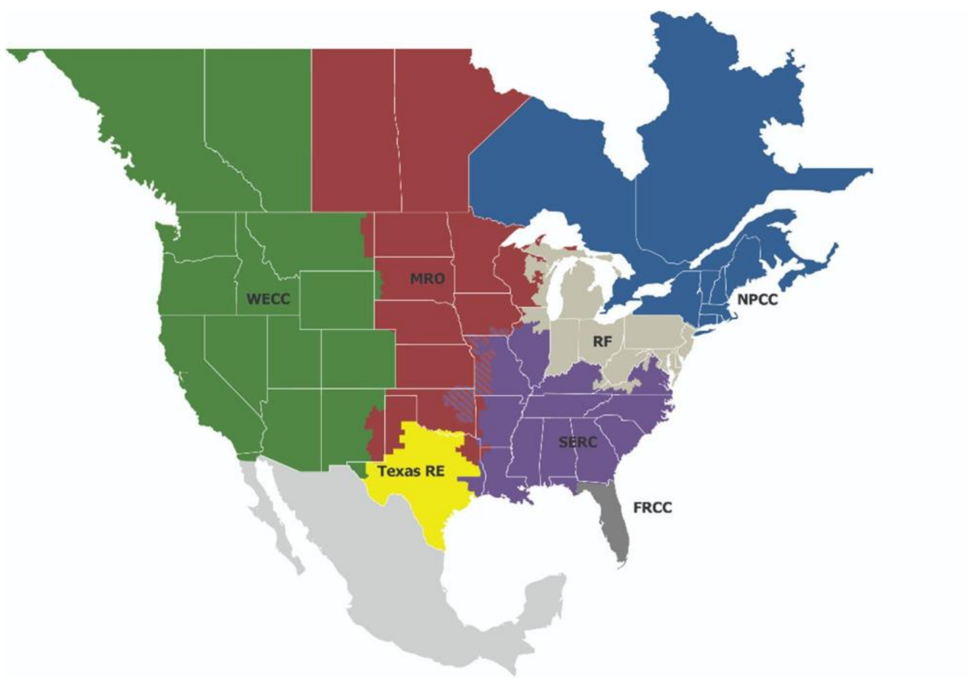
When the original transmission facilities in Minnesota were built in the 1960s, they were designed primarily to interconnect an individual utility's generation and distribution facilities, and secondarily to interconnect neighboring utilities to each other to provide additional backup power and reliability.

Over time, the focus on transmission planning and reliability 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 an individual utility's system. 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 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 and as discussed below.

Map 1: Map of Regional Reliability Areas



Electricity follows the laws of physics: it follows the path of least resistance. Electricity placed onto the interconnected transmission grid can be withdrawn at any other place within the interconnection if 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 in most cases electricity cannot yet be stored in a cost-effective manner, the transmission system helps maintain this balance at a lower cost by allowing electricity to flow through the broader electrical system where possible.[12]

Minnesota's Transmission System: Planning for the Future

Determining the amount of transmission infrastructure needed to provide economic and reliable electric service in Minnesota requires balancing the risk of building too much transmission with the risk of building too little. These risks are not symmetrical. If more transmission capacity is built than needed to deliver electric service from available generation resources, the system will be relatively free of transmission constraints, but will be higher cost than is necessary to provide adequate service.

If too little capacity is built for the delivery of electric service from existing and new generation resources, the transmission cost component of providing electricity service may be lower, but there could be a cost to Minnesota's overall economy. Economic costs could include less reliable power, curtailment of low-cost generation and the use of higher cost generation resources that would result in higher overall costs than the cost of building transmission.

2021 Transmission Projects

In 2021, the PUC issued permits for two high-voltage transmission projects: (1) the nine and one-half mile 115-kV Frazee to Erie line in Becker and Otter Tail Counties, and (2) a 31-mile 345-kV line connecting the proposed 414-megawatt Plum Creek wind energy project to the grid in Redwood County.

In addition, there are six (6) transmission line projects currently at various stages of the state permitting process. Of these, four are single purpose lines proposed by non-utility project developers to connect wind-energy or solar projects to the grid and one interconnection proposed by Xcel Energy: (1) a 161 kV line for Big Bend Wind, (2) a 345-kV line for Byron Solar, (3) a 161-kV line for Dodge County Wind (4) a 161-kV line for Three Waters Wind, and (5) two short (3.2 miles and 1.7 miles) 345-kV lines needed for Xcel's Sherco Solar Project. PUC docket numbers and more details are available in the annual Power Plant Siting Act update report.[13] The sixth transmission project is the Duluth-Loop project proposed by Minnesota Power. The purpose of that project is to support the grid in the Duluth area due to recent coal plant retirements along the North Shore, as described in more detail below.

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, 2021.

The sixteen (16) participating utilities also jointly maintain the following website that provides information

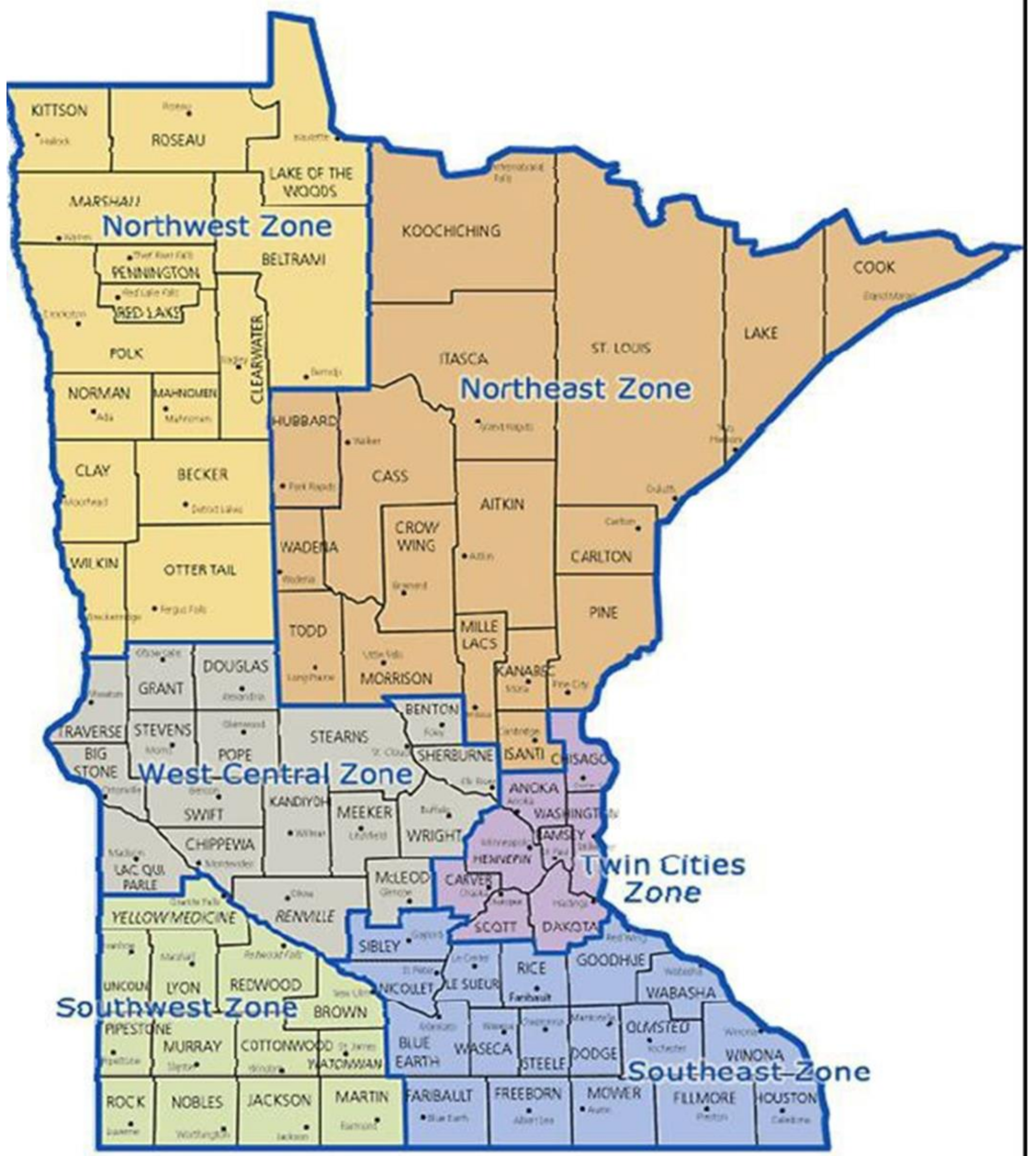
[12] Technologies to store electricity for later use includes batteries, pumped hydro, compressed air, flywheels, and the transmission system itself. For example, "pumped storage hydro" in effect stores the electricity in the potential energy of water, by using electricity at times when little power is being used for other purposes to pump large amounts of water into a reservoir. Later, when electricity is needed or more expensive, 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 hydropower. Storage is discussed further below.

[13] Department of Commerce PPSA Annual Summary 2021

about transmission planning and projects: http://www.minnelectrans.com.

Detailed information (including maps) on all transmission inadequacies 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 map 4 below.

Map 4: Geographic Zones for Transmission Reporting



The 2021 Biennial Transmission Projects Report identifies 103 separate, “reasonably foreseeable future inadequacies” in the transmission system across the state, including 58 new ones for this year’s report. The inadequacies identified fall into one or more of the following general categories: load interconnection, generator interconnection, thermal overloads, and voltage violations. Several of these projects may require a state certificate of need and a route permit. No specific, larger “backbone” transmission line projects are included in the 2021 Biennial Report. The report lists and describes each of the 103 identified future inadequacies and potential solutions by planning zone, including the underlying reasons for the project and the alternatives considered.

Northeast Zone Projects

The Northeast Zone has the largest number of inadequacies and potential future projects. The three largest potential projects in the Northeast Zone, each of which would require a state certificate of need, are summarized briefly below: (1) the Duluth Area 230 kV Project, (2) Iron Range-Arrowhead 345 kV Project and (3) the Duluth Loop Reliability Project. Minnesota Power has applied for permits for the Duluth Loop Project, but the others will likely not be needed for five years or more.

The Duluth Area 230 kV Project includes, among other things, an upgrade of an existing line from 115 kV to 230 kV between the Arrowhead and Hilltop substations. For a variety of reasons summarized in the report, the timing of the need for the upgrade is uncertain, and it may be delayed for five years or more.

The Iron Range – Arrowhead 345 kV line, would extend a double circuit 345 kV line from Grand Rapids to the existing Arrowhead 345 kV Substation near Duluth. This project was formerly coupled with the Great Northern Transmission Line, but the two projects were subsequently decoupled due to the lack of sufficient transmission service requests to justify the 345 kV connection to Arrowhead. Should the project become necessary in the future due to additional transmission service requests or other system reliability needs or regional transmission benefits, it will be advanced at that time.

The Duluth Loop Project, includes: (1) construction of about 14 miles of new 115 kV transmission line between the Ridgeview, Haines Road, and Hilltop Substations in the Duluth region; (2) construction of a new approximately one-mile extension connecting an existing 230 kV transmission line to the Arrowhead Substation; (3) upgrades to the Ridgeview, Hilltop, Haines Road, and Arrowhead substations; and (4) reconfiguration, rebuild, and upgrades to existing transmission lines and communications infrastructure in the Project area. The project has been proposed because since 2015, seven of the coal-fired generating units located in the Arrowhead have been idled, retired, or converted to natural gas. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to natural gas peaking units. Also, in 2015, Minnesota Power retired one of the units at Taconite Harbor. With PUC approval of its 2015 Integrated Resource Plan, Minnesota Power idled the other two Taconite Harbor units in the fall of 2016 with all coal-fired operations were retired by 2020. As a result, these transmission upgrades have been proposed to maintain reliability in the area.

Finally, Minnesota Power is also considering converting one of the existing units at the Boswell Energy Center into a synchronous condenser to provide voltage support in the Iron Range area as the existing coal plants are retired. The decision on whether to install a synchronous condenser is not planned until 2023 or beyond.

Projects in Other Zones

Although the Northeast Zone has the most potential future transmission projects listed, the 2021 report includes important new or upgraded projects in the other zones. For example, there are nine rebuild or upgrade projects and one new 115-kV line listed in the Northwest Zone as proposed by Otter Tail Power, GRE and Minnkota. The West-Central Zone has sixteen proposed projects, including one new 27-mile 115-V transmission line that would need a certificate of need and route permit: the Appleton-Benson project. The Appleton-Benson project has a planned in-service date of May 2025. In the Twin Cities Zone, the report lists eleven rebuild or equipment upgrade projects, none of which require state approval. The Southeast Zone has eleven rebuild or retirement projects listed, all rebuild, retirement or maintenance projects. Finally, in the Southeast Zone, there are eleven Xcel Energy and ITC Midwest projects described, including the Rochester-Wabaco 161 Rebuild Project, which has been a limiting transmission congestion point in the area for several years.

Renewable Energy Standard Compliance

The Minnesota transmission owners are required to report any transmission upgrades needed to meet upcoming milestones of the Minnesota Renewable Energy Standard (RES). The 2021 Biennial Transmission Projects Report, however, again illustrates that utilities already largely meet or exceed the present RES requirements through 2030 and expect to have enough renewable generation and transmission to meet future RES milestones. All utilities have satisfied their respective compliance requirements and expect to continue to achieve and maintain all compliance requirements into the future.

In part because of increasingly lower wind and solar energy generation costs and consumer demand, most Minnesota utilities now have more aggressive renewable energy goals than required by the RES statute.[14] Meeting these goals with large wind and solar projects located in more rural areas may require more transmission lines.[15] Given the long lead time required to plan and build large transmission network upgrades, the 2021 version of the report includes a description of ongoing long-range regional transmission studies and the transmission owner's involvement in these efforts.

CapX2050 Transmission Vision Study

The transmission lines built over the last decade as part of the CapX2020 initiative have already reached capacity,[16] so in March 2020, a consortium of 10 upper Midwest utilities (now called Grid North Partners[17]) issued a new report.[18] The CAPX 2050 report was not a transmission planning study but is intended to educate and inform Upper Midwest policymakers and other stakeholders of the implications of a future that is even more reliant on wind and solar resources.

The report discussed four critical findings related to dispatchable and non-dispatchable resources that are necessary to continue operating a safe, reliable, and affordable grid:

- Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot and therefore, some dispatchable resources will be necessary.

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[14] 2021 Biennial Transmission Owners Report Chapter 9.
[15] See, for example, CAPX2050 Vision Report, March 2020
[16] Sections of the CAPX projects are "double-circuit capable" with only one circuit currently constructed. See, e.g. Hampton to La Crosse Minnesota PUC route permit order, May 2012
[17] Grid North Partners - an evolution of CapX2020
[18] CAPX2050 Report, March 2020

- The ability for system operators to meet real-time operational demands will be more challenging and therefore, new tools will need to be developed and operating procedures created to address the challenges.

- More transmission system infrastructure will be needed in the upper Midwest to accommodate the transition of generation resources.

- Non-dispatchable resources alone will be incapable of meeting all consumer energy requirements and therefore, there will be a need to understand and promote a future electric grid that can continue to meet consumer energy requirements safely, reliably and affordably.

MISO Long-range Transmission Planning

MISO is primarily responsible for planning high-voltage transmission system in the region. Because of the evolving generation mix, emerging transmission constraint problems, and the long lead time required for new large transmission projects, regulatory and government leaders continue to advocate for MISO and other transmission operators to engage in long-range planning.

On June 13, 2019, for example, the Organization of MISO States (OMS) board approved a statement of principles for long-range transmission planning to help guide MISO away from reliability-based, short-term incremental transmission planning.[19] In addition, on September 17, 2019, the Governors of Minnesota, Iowa, Michigan, Arkansas, Wisconsin and the Premier of Manitoba submitted a letter to MISO requesting a new long-range study of the transmission system.[20] On September 8, 2020, on behalf of the Midwestern Governor's Association, Minnesota Governor Tim Walz and Iowa Governor Kim Reynolds sent an additional letter to each of the regional transmission system operators: MISO, Southwest Power Pool, Inc. (SPP) and PJM Interconnection L.L.C. (PJM) encouraging their on-going long-range transmission planning efforts.[21]

In May 2020, Grid North Partners (then CapX2020) sent a letter to the MISO requesting a comprehensive, long-term transmission planning analysis using an integrated approach to identify a plan to optimally meet the 2030 goals of utilities, their customers, and policymakers in the Upper Midwest. Grid North Partners' members, both individually and collectively, are engaged and participating in the MISO LRTP effort. In support of the MISO LRTP, Grid North Partners has commenced an informal technical study effort focused on more localized issues within the Grid North Partners footprint. All relevant potential options and findings have and will be supplied to MISO for potential inclusion in the LRTP.

MISO initiated their long-range planning effort in August 2020 and is in the process of developing a long-range study to better assess what upgrades over the next 20 years may be needed. Details on how the long-range "roadmap" will be used to evaluate specific potential transmission project reviews and approvals are still evolving.[22] Under its most recent schedule MISO intends to file a new regional cost allocation with FERC by mid-January 2022 and to propose an initial group of regional transmission projects for the northern part of MISO by May or June 2022.[23]

In addition, MISO and SPP have begun a related but separate process to evaluate potential joint transmission projects that would reduce transmission upgrade costs when proposed new generation projects affect both

[19] OMS Long-Range Planning Principles
[20] MGA Initial Letter to MISO Long-Range Planning, September 17, 2019
[21] September 8, 2020 MGA Letter to RTOs
[22] MISO Long-Range Planning Roadmap
[23] LRTP Update to MISO Board December 7, 2021, See Slide 8 for schedule

transmission networks. Initial planning for this joint MISO/SPP effort, started in December 2020.[24] A report is expected from this process in January 2022.

Transmission, Reliability and Power Costs

Adequate transmission is essential to ensure Minnesotans have reliable electric service. When there are areas with constraints or shortages in transmission capacity, 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, disruption and potential harm to systems that depend on electricity. For example, electricity is needed to run the pumps that deliver natural gas 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 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 as demand increases. 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 cheaper generators in congested areas and increase electricity produced by more expensive generators in areas free of congestion. As a result, when transmission congestion leads to the use of higher-cost generation facilities to produce electricity, the cost of power goes up.

Roles of Entities Involved in Transmission

Numerous entities can have an impact on the design and cost of the transmission system that serves Minnesota. Clearly determining responsibility and assigning authority for different aspects of transmission planning and reliability will be critical moving forward. For example, because transmission lines located outside of the state help serve Minnesota customers, utilities that own those facilities, and the states that regulate those utilities, can affect the design and cost of the transmission grid. While transmission owning utilities are involved in these matters, so are other federal and state nonutility organizations, 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. **MISO and SPP** do not own transmission or generation facilities, but work with utilities that voluntarily choose to be their members to operate the regional transmission system reliably and in the least-cost manner through energy and capacity markets.[25] MISO and SPP assist their members in developing long-term transmission plans for the region. MISO members currently operate in all or part of 15 states plus the Canadian province of Manitoba.[26] MISO cannot require its members to build new resources, nor is it

[24] MISO SPP JTIQ Update 12.3.2021, December 3, 2021

[25] 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.

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

responsible for the development of long-term plans for generation. 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. 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), Reliability First (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 the demands for electricity.

5. **The Organization of MISO States** (OMS) is a self-governing organization of representatives from the regulatory commissions of 15 states, the City of New Orleans and Manitoba. The regulatory commissions have certain authorities over transmission-owning utilities participating in MISO. The OMS examines various issues and makes recommendations to MISO, FERC and other relevant government agencies regarding matters that affect state jurisdiction and other regional transmission matters. PUC represents Minnesota in OMS. In addition, the Department of Commerce represents Minnesota as an associate member and, along with other Public Consumer Advocates such as the Minnesota Office of Attorney General's Residential Utilities and Antitrust Division, participates in the efforts and activities of OMS and MISO.

6. **The PUC** requires Minnesota utilities to develop enough transmission to reliably serve load. The Commission also regulates the retail rates of Minnesota's investor-owned utilities, including the amount of transmission costs that can be recovered from their retail customers. In addition, while the PUC does not regulate the wholesale rates charged by Minnesota's investor-owned utilities, it does ensure that these utilities allocate transmission costs and revenues appropriately at the retail level, considering factors such as the types or classes of retail customers and their usage.

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 heavily involved in Minnesota's electric transmission system, MISO warrants further discussion. As noted above, MISO is a Regional Transmission Organization (RTO) created and regulated by FERC. MISO is involved in numerous matters that are critical to the reliable and low-cost operation of the bulk transmission system. These activities include: planning for contingencies if large generation plants are retired or transmission components fail; conducting engineering analyses of the effects of various changes to the generation fleet or transmission components of the system as a whole; planning for transmission needs in the MISO region; coordinating with other RTOs in the Eastern Interconnection System; monitoring the day-to-day (and minute-to-minute) operations of the regional transmission system; determining which generation units will operate (from lowest to highest cost) in the energy market at any given time; addressing the operational effects of congestion on the transmission system; and analyzing where the greatest congestion exists. Staff of the Department of Commerce and Commission participate in various MISO workgroups and 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 electricity.

As shown in Map 3, below, most of Minnesota is part of Planning Reserve Zone 1, along with the western half of Wisconsin, portions of North Dakota, and certain parts 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[27], 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 transmission system was 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 few plug-in appliances had been invented or available. Those transmission facilities were sized and constructed to meet the electricity needs of the population and economy at the time with some assumptions for growth based on certain expectations at that time.

In response to the changing location of electric generation facilities, high-voltage transmission backbone projects were constructed in Minnesota between 2004 and 2012 and more may be needed in the future to cost effectively integrate new renewable energy technologies. Moreover, Minnesota residents and industry also need acceptable power quality, meaning evenly delivered energy without power surges and other fluctuations that can affect computers and other sensitive electronic devices. A lack of capacity on the grid could lead to some locations in the state where power quality would become unacceptably poor. Further, in some locations and times, too much electricity is trying to flow on the lines causing congestion or "grid lock," resulting in economic and reliability problems in making sure electricity can be delivered where it is needed.

While the use of the transmission system varies with the overall demand for electricity and location of the supply, transmission planning requires a focus on the amount and timing of the highest demand and need to import or export electricity between regions. In some regions the need is to be able to export power. However, sometimes, the need to export power is when the demand for electricity is low, and the supply of electricity exceeds demand in an area. This imbalance typically occurs during overnight hours in the spring and fall when the demand for power is low and the generation of electricity from certain resources, such as wind, is high.

When planning for the supply of electricity, the highest demand for electricity (peak demand) during the day and the season is reviewed. While peak demand for electricity 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 January 2018, in late January 2019 and in February 2021.

[27] Some of Missouri River Energy Services' members have joined MISO and some members joined SPP.

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, allows strategic use of the most efficient resources available on the grid at any given moment. Since the grid deploys 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 customers in 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 peak 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 capacity is higher than the demand for electricity in a region, the need to move or export electricity increases. Transmission planning also considers changes in technologies and the economy. While excess transmission capacity could result in additional costs and environmental impacts, a shortage in transmission capacity would have negative effects on the cost and reliability of electricity.

MISO’s stated guiding principles for transmission planning include:

1. Develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the region.
2. Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.
3. Support federal, state, and local energy policy and member goals by planning for access to a changing resource mix

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, it is necessary to plan at least ten years in the future to ensure that the transmission system is ready to meet future needs.

Battery Storage as a Transmission Asset

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, 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 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 2021

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 2021 with potential effects on Minnesota are described in this section of the report.

Federal Legislation: Infrastructure Investment and Jobs Act

On November 15, 2021, President Biden signed into law the $1.2 trillion Infrastructure Investment and Jobs Act (Act). The Act includes approximately $27 billion in new spending over five years on the nation's energy grid. Most of the funding targets updating and improving the existing grid, with some targeted towards new transmission lines. Some of its key provisions include:

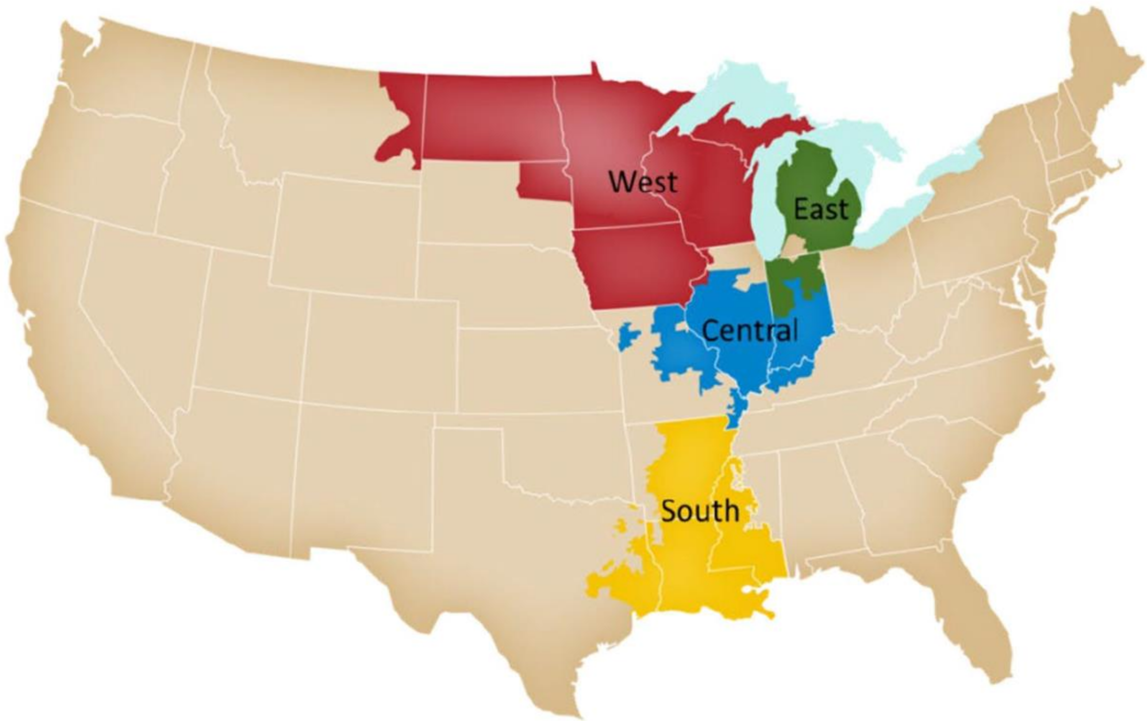
- Directing the U.S. Department of Energy (DOE) to establish a $5 billion grant program for grid hardening and weatherization to help reduce the impacts of extreme weather events on the grid.
- Authorizing $6 billion toward grid reliability and resilience research, development, and demonstration, including $1 billion specifically for rural areas. This new program includes innovative approaches to transmission, distribution and storage infrastructure that is implemented at the state level by publicly regulated entities on a cost-share basis.
- Authorizing $3 billion in the Smart Grid Investment Matching Grant Program to deploy technologies that enhance grid flexibility.
- Establishing a $2.5 billion Transmission Facilitation Fund and a Transmission Facilitation Program, positioning DOE to leverage federal funding to reduce the overall risks of transmission projects.
- Authorizing $500 million to the State Energy Program to support state transmission and distribution planning, among other activities.
- Authorizing $350 million to develop advanced cybersecurity technologies for the energy sector.
- In addition to these funds, the Act addresses some aspects of federal oversight of transmission siting and planning, summarized below in the federal and state jurisdiction section of this report.

Many of the details of these programs, and their specific applicability to Minnesota and the organizations with roles in the transmission system, will be determined by the Department of Energy over the coming months and years.

Federal Regulatory and Planning Developments

Federal and state actions regarding the high-voltage transmission system are often related to filings by MISO at the FERC, so an overview of MISO operations is provided below to help understand the underlying issues being addressed. 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 Region, MISO Central Region, MISO West Region, and MISO South Region. Map 2 below shows MISO's four geographical regions for transmission planning.

Map 2: MISO Planning Subregions



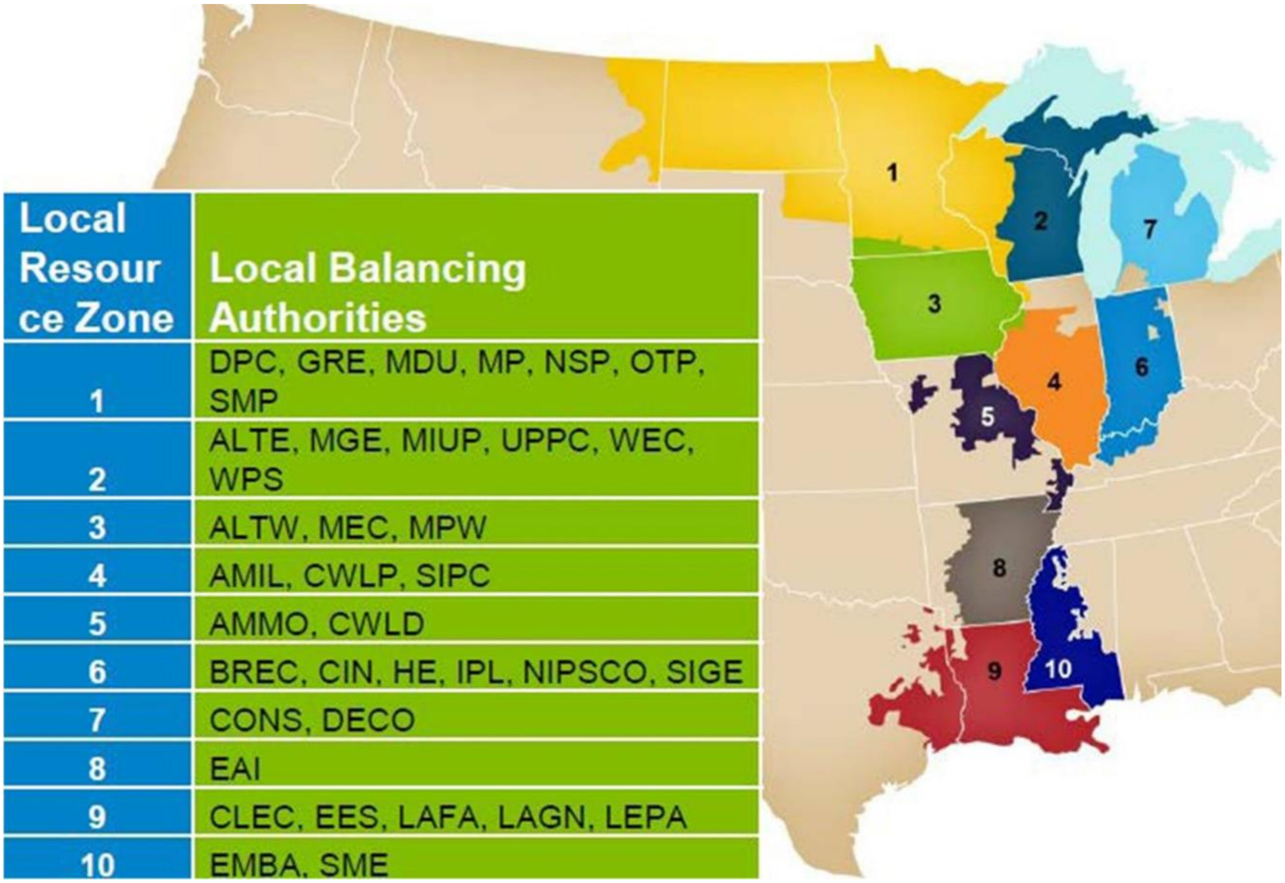
In addition, MISO has 10 "planning reserve zones" to focus on each region and to help ensure that there are adequate electric resources to meet the needs in each zone (also known as "resource adequacy"). See Map 3.

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[28], which sold its transmission resources to ITC Midwest, a transmission-only utility. Interstate also sold its distribution system to the Southern Minnesota Electric Cooperative.

[28] Noted in Map 3 as ALTW for Alliant Energy West.

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 (MISO South) in 2013. 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 the Footprint Diversity Study, to examine 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 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. MISO is generally planning to assess potential new projects for the North-South interface as part of its LRTP study in 2023 or 2024.

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

One of FERC's stated goals is to promote competition for the construction of transmission projects. FERC in Order 1000 eliminated a federal (but not state) right of first refusal on regionally cost shared transmission projects. Minnesota passed an incumbent utility "Right of First Refusal"—or ROFR—statute in 2012. This act provides in-state utilities with "the right to construct, own, and maintain an electric transmission line that has been approved for construction" by a FERC-regulated transmission planning process. The utility that owns the existing facilities that interconnect with the new line has 90 days following approval by the FERC-regulated process of the new line to notify the PUC of whether it intends to construct the line. If the utility does not intend to construct the line, the PUC may order it to do so. Otherwise, other entities may have the opportunity to construct the line. See Minn. Stat. § 216.246.

In November 2020, as part of on-going litigation, a non-utility transmission line developer petitioned the Supreme Court to review an U.S. Court of Appeals Eighth Circuit decision upholding Minnesota's ROFR law.[29] The United States Supreme Court declined to hear that case in March 2021.

Minnesota does promote transmission cost control and competition through other means. For example, existing certificate of need (CN) law does require the PUC to consider alternatives to proposed facilities. In addition, the Department, and the PUC typically approves, "soft" cost caps in CN proceedings. One such project near Mankato, referred to as "Huntley-Wilmarth," was approved by MISO in December 2016. The project establishes a transmission line to interconnect substations owned by Xcel Energy and ITC Transmission. The Commission granted the certificate of need and the route permit for the project on August 5, 2019.

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 costs of which were regionally shared across the MISO footprint at the time. The projects, referred to as multi-value projects or "MVP" projects,[30] had a wide variety of goals, including to:

- Provide benefits in excess of costs under the scenarios studied. In this case the benefit-to-cost ratio for the MVP portfolio 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 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. Overall, final construction costs for these projects were generally in line with cost estimates used by MISO when adjusted

[29] Summary of ROFR Petition to US Supreme Court

[30] MVP Report

for inflation, with some projects under budget and some over.

In Minnesota, Commerce and the PUC 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).

Planning for this MVP portfolio of transmission projects began in 2007. As of December 2021, all 17 MVP projects have been approved in state regulatory proceedings. Construction is now complete on 16 of the 17 projects. The last project to get regulatory approval, the Cardinal-Hickory Creek Project, is under construction and has an estimated in-service date of 2023 pending ongoing litigation.

Distributed Energy Aggregation in Interstate Markets: FERC Order 2222

On September 17, 2020 FERC issued a new final rule intended to enable aggregators of distributed energy resource (DER) like small generators, rooftop solar, behind-the-meter batteries and electric vehicles to compete in all regional organized wholesale electric markets.[31] The underlying purpose is to remove what FERC sees as existing barriers to distributed generation and to increase the competitiveness of wholesale markets. MISO's compliance filing is due April 2022, with implementation details to be worked out over the next several years. MISO held a series of DER Task Force meetings throughout 2021 that will continue into at least early 2022 that serve as a clearing house for discussions on MISO's Order 2222 compliance filing.

FERC Advanced Notice of Proposed Rulemaking (ANOPR) on Regional Transmission Planning and Cost Allocation and Generator Interconnection

On July 15, 2021 FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) that potentially sets in motion a new federal rulemaking process that may change the rules governing planning and expansion of the nation's electric transmission system.[32] The ANOPR expresses concern that the current rules for planning, cost allocation, and interconnection of generation, all of which were adopted a decade or more ago, are no longer resulting in economically efficient transmission expansion that reflects the need to add large amounts of renewable generation to the grid in the next two decades. The ANOPR received 376 initial comments totaling thousands of pages. Commerce filed initial comments in the docket in October 2021.[33]

[31] FERC Order 2222 Press Release, dated September 17, 2020

[32] FERC Transmission ANOPR

[33] Minnesota Department ANOPR Comments 10.12.21

FERC Proposed Rulemaking (NOPR) on Dynamic Line Ratings

There is increased industry interest in improving the operating capacity and efficient use of the existing high-voltage transmission system while longer range transmission capacity issues are addressed. These technologies are sometimes referred to generically as "Grid Enhancing Technologies." For example, transmission line ratings currently based on seasonal or static assumptions may allow less transmission system transfer capability than the transmission system can provide, leading to restricted flows and increased congestion costs. Conversely, static ratings can also lead to overloading a line under some conditions.

FERC released a draft line ratings notice of proposed rulemaking (NOPR) on November 19, 2020 that proposed to require transmission providers to implement ambient-adjusted ratings and seasonal line ratings on their lines, require RTOs to allow transmission owners to electronically update ratings at least hourly, and require TOs to share rating values and rating methodologies with the RTOs and the Independent Market Monitor. [34] OMS worked closely with MISO and the MISO transmission owners (TOs) for almost a year to better understand how line ratings work in MISO and is likely to submit extensive comments.

Ambient adjusted rating changes are based on temperature alone. More complicated, but potentially more valuable, Dynamic Line Ratings are based not only on forecasted ambient air temperature, but also on other weather conditions such as wind, cloud cover, solar irradiance intensity, precipitation, and/or on transmission line conditions such as tension or sag. The FERC NOPR provides extensive background on the technologies, potential benefits, and approaches to implementation.

On December 16, 2021, FERC issued a final rule on the use of ambient-adjusted ratings. This final rule requires all transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings as the basis for evaluating near-term transmission service to increase the accuracy of near-term line ratings. While the final rule does not mandate the adoption of dynamic line ratings – ratings that vary more frequently and account for other factors like wind speed – the rule does require that organized market operators establish and maintain systems and procedures necessary to allow transmission owners that would like to use dynamic line ratings the ability to do so. [35]

MISO Storage as a Transmission Only Asset Tariff (SATOA)

On August 10, 2020 FERC accepted MISO's proposal that allows energy storage resources to be selected as transmission-only assets as part of the grid operator's annual grid expansion plans. FERC accepted the proposal despite various objections to MISO restricting these assets only to storage owned by transmission owners.[36] DTE Electric Company and other parties recently appealed this FERC decision to the United States Court of Appeals for the District of Columbia. Oral argument at the DC Circuit was scheduled for December 2021.

[34] https://www.ferc.gov/media/rm20-16-000

[35] The initial FERC News Release is available here: https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs

[36] SATOA Joint Request for FERC Rehearing, September 9, 2020. The Minnesota Department of Commerce joined in these comments.

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. 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 Commerce 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.

Because the PUC 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 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 remains an issue.

On December 22, 2015, Administrative Law Judge David H. Coffman issued an 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. The final refund decision at FERC, however, is still under appeal.

More recently, following multiple rehearing requests, on November 19, 2020, FERC issued Opinion No. 569-B, in which it made minor modifications to the discussion in, but largely reaffirmed, its previously issued Opinion No. 569-A wherein FERC revised its return on equity (ROE) analysis and methodology.[37] This FERC decision is currently also under appeal at the Court of Appeals for the District of Columbia.

Incentive ROEs for Transmission

In another long-running issue, FERC originally granted ROE adders of 100 basis points to companies that were transmission-only companies to encourage such structures. Previously, Commerce 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. Commerce 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

[37] FERC ROE Order November 2020

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. In September 2019 ITC appealed this FERC decision to the DC circuit and OMS has intervened in support of FERC (19-1190).

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 of their 10.32% base ROE), for the Illinois River & Mark Twain components of the 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 Ameren'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).

In a FERC Order issued on March 21, 2019 in Docket No. PL19-3, FERC issued a Notice of Inquiry (RM20-10), seeking comments on the scope and implementation of its electric transmission incentives regulations and policy. The OMS (with Commerce and the PUC supporting) filed comments with FERC recommending the evaluation of granting ROE incentive adders on a case-by-case basis.[38] The comments recommended keeping benefits to consumers at the forefront of any analysis to determine whether to grant or eliminate ROE transmission incentives and supported non-ROE incentives first for mitigation of transmission project risks. A FERC decision on the issue is still pending.

U.S. Department of Energy Defense-Critical Electric System Review[39]

The United States Department of Energy (DOE) includes 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 identified as 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 Department of Energy in an emergency.

Challenges to Transmission Planning-Potential Impacts to Minnesota

New Transmission Projects Raise Concerns about Land Use and Land Rights

In recent years, 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 public meetings and hearings and other outreach efforts to potentially impacted residents, landowners and the general public,

[38] Joint Comments on FERC Incentive Adders, July 1, 2020

[39] 16 U.S. Code § 824o–1

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 established 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[40] and land rights questions are addressed in various parts of Minnesota's statutes.

To help stakeholders understand facility permitting proceedings before the PUC that affect them and to help them have more productive input into those proceedings, the PUC created the specially designated position of Public Advisor. This position is responsible for 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 Mitigation

As utilities build more 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 routing and permitting of interstate transmission lines been the province of the states (with limited exceptions) for virtually the entire history of the electricity industry in the United States. The grid formerly consisted of many localized transmission and distribution networks, so federal interest in siting of the transmission system was limited. In addition, state and local governments are well positioned to weigh the local factors that go into siting decisions, including environmental and scenery concerns, zoning issues, development plans, and safety.

However, the electricity transmission system in the 48 contiguous states has evolved into a complex continent-spanning network consisting of three major interconnections. Although the federal government has recently increased its authority over transmission reliability and in other areas, it has, for the most part, left transmission siting decisions in the hands of the states. However, as concerns over grid congestion and its impact in reliability have grown, the federal government has carved out a small role in transmission siting as a

[40] Minnesota Statute 216B.243

“backstop” siting authority in designated transmission corridors.

When the United States Congress passed the Energy Policy Act of 2005, one section of the Act authorized the U.S. Department of Energy (DOE) to designate “National Interest Electric Transmission Corridors” based on DOE’s findings after conducting a study of congestion. The 2005 Act then authorized FERC to permit the construction and operation of electricity transmission facilities within the boundaries of these DOE designated corridors. This authority, however, may not be exercised by FERC unless the state where the facility would be sited lacks the authority to issue the permit, the applicant does not qualify for the permit in the state, or the state has “withheld approval” of the permit for more than one year. Much debate and litigation occurred regarding whether “withheld approval” included rejecting a permit application. Partly as a result, FERC has to date never used this backstop permitting authority.

However, the federal Infrastructure Act of 2021 addresses this ambiguity by explicitly allowing FERC to overrule state objections whether the state “withheld approval” or denied approval within a DOE designated corridor. In addition, the 2021 Infrastructure Act, expands the scope of DOE’s review by providing additional factors that DOE may consider when designating a National Interest Corridor. Specifically, DOE may now review whether a designation will “enhance the ability” of electric generation facilities “to connect to the electric grid,” whether the designation will decrease electricity costs for consumers, and also whether the designation will enhance the United States’ energy security.

DOE is not required to issue a new transmission congestion study until 2023. Because there are currently no DOE-designated National Interest Corridors, FERC is unable to issue permits today. Nevertheless, the Infrastructure Act’s changes could affect the federal government’s future role in the siting of electricity transmission projects – a role that has historically been almost exclusively within the purview of the states.

Summary of Conclusions

- The high-voltage electric transmission system in Minnesota is part of a much larger regional system that is planned and operated by the Midcontinent Independent System Operator (MISO). MISO works with its utilities and member states to plan and operate the electric transmission system in Minnesota and surrounding states to achieve reliability, regional coordination, and efficiency.
- The existing high-voltage transmission system was largely not designed to accommodate the ongoing shift from a limited number of large conventional power plants towards many widely dispersed wind and solar projects. As a result, the existing high-voltage transmission system is increasingly constrained and has started to limit the amount of new large renewable generation projects that can be interconnected to the system.
- Because it can take eight years or more to plan, permit, and construct new large transmission lines, long-range transmission planning is needed to keep up with evolving electric generation technologies. The Minnesota Department of Commerce is working with other states and MISO to encourage and facilitate long-range transmission planning in the region, including how to efficiently and fairly allocate the costs and benefits of any new transmission lines.
- Over the short-term, Minnesota is also working with other states to encourage the potential use of new ways to use the existing high-voltage transmission system more efficiently.
- Over the longer term, the next five to ten years, MISO is working with member utilities, states (including Minnesota), and other stakeholders to develop a long-range transmission plan, the first iteration of which is scheduled to be completed in 2022. This long-range transmission plan is targeted at developing a coherent roadmap intended to maintain grid reliability, lower total delivered electricity costs over the long-run and enable future changes in the generation resource mix. Minnesota efforts also include participating in MISO coordination with the Southwest Power Pool (SPP) regarding the transmission upgrade requirements that can be triggered by new generation projects proposed in the others transmission network.
- 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 and to maintain the State's jurisdiction over the provision of essential services to ensure safe, adequate and efficient utility services at fair, reasonable rates.