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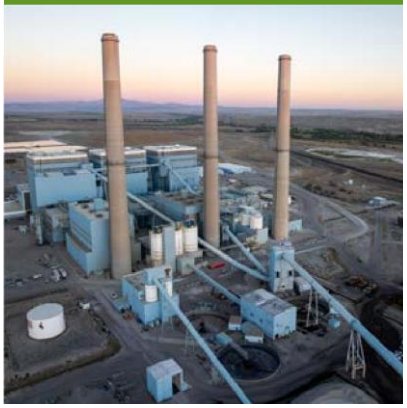

RESILIENCE OF TH ELECTRIC GRID IN NORTH DAKOTA

NORTH DAKOTA
TRANSMISSION AUTHORITY

The North Dakota Transmission Authority is required by statute to provide an annual Grid Resiliency Plan and Report. This report was prepared for the North Dakota Transmission Authority by EERC staff, Daisy Selvaraj, Bradley Stevens, and Sina Ahmed. Funding for the report was secured through the State Energy Research Center. This report also serves as a grid resiliency plan and complements the North Dakota State Energy Security Plan.

17-05-13*. Reporting requirements.*

1. The authority shall deliver a written report on its activities to the legislative council each biennium. The authority shall provide an annual report to the industrial commission detailing activities and expenditures incurred during the preceding year.

2. The authority shall deliver a written report on the status of the resilience of the electric grid to the legislative council and the industrial commission by September 1, 2022, and annually thereafter. The report must be forwarded by the industrial commission to the regional transmission operators in the state. a. The information for the report should be collected from publicly available information to the extent possible. If public information is unavailable, the authority shall request a generation facility and a transmission owner to provide the information needed to complete the report. b. The report may be a short-term and long-term projection of the following: (1) The adequacy of the state's electric grid to meet the demands of load within the state and to continue to export electricity from the state; (2) The resilience of the state's electric grid, including local resilience; and (3) The plans of generation owners, developers, or operators to add or remove generation assets connected to an independent system or regional transmission operator in excess of an aggregate of twenty-five megawatts.

This report provides an overview of the electric grid, specific to North Dakota, describing the key players and processes for generation (resource adequacy) development, transmission planning, and electric load forecasting. The report provides a grid resilience assessment along with threat identification. Those threats are categorized as natural threats, technological threats as well as man-made threats. Man-made threats include energy policy, supply chain disruptions, physical and cyberattacks.

The final pages of the report emphasize the need for short-term and long-term risk mitigation for generation resource adequacy and mitigation of other identified risks. While we can't control the weather, we can mitigate risks from those events, and be diligent in mitigating other risks from cyber and physical security to supply chain management. Finally, **energy policy** that supports generation resource adequacy, and transmission expansion is vital for grid reliability and resilience in this era of unprecedented demand growth.

Claire Vigesaa, Executive Director

North Dakota Transmission Authority

NORTH DAKOTA GRID RESILIENCY PLAN

Final Report

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NOMENCLATURE

AIFG	Aging Infrastructure Focus Group
AOER	Always on Energy Research
BEPC	Basin Electric Power Cooperative
BES	bulk electric system
CCR	coal combustion residual
CCUS	carbon capture, utilization, and sequestration
CSAPR	Cross-State Air Pollution Rule
CSGs	Community solar gardens
CIP	Critical Infrastructure Protection
CITAP	Coordinate Interagency Transmission Authorization and Permits
CPEC	Central Power Electric Cooperative
CO_2	carbon dioxide
DC	direct current
DER	distributed energy resources
DOE	U.S. Department of Energy
DPP	detailed project proposal
EEA	energy emergency alert
EERC	Energy & Environmental Research Center
EIA	U.S. Energy Information Administration
EIC	Eastern Interconnection
ELCC	effective load-carrying capacity
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric reliability organization
EV	electric vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
G&T	generation and transmission
GI	generation interconnection
GW	gigawatt
HCD	highest-certainty deliverability
IBR	inverter-based resources
IDDs	intrusion detection systems
IoT	Internet of Things
IPSs	intrusion prevention systems
IOU	investor-owned utility
ITP	integrated transmission plan
kV	kilovolt
lb	pound
LMP	locational marginal price
LOL	loss of load
LOLE	loss of load expectation

NOMENCLATURE (continued)

LRE	load responsible entity
LRTP	long-range transmission planning
LRZ	load resource zone
LSE	load-serving entity
LTRA	long-term reliability assessment
MATS	Mercury and Air Toxics Standards
MCC	marginal congestion cost
MDU	Montana–Dakota Utilities Co.
MEC	marginal energy component
MISO	Midcontinent Independent System Operator
MLC	marginal loss cost
MPC	Minnkota Power Cooperative
MRO	Midwest Reliability Organization
MRES	Missouri River Energy Services
MRV	monitoring, reporting, and verification
MTEP	MISO transmission expansion plan
MW	megawatt
MWh	million megawatt-hours
MWEC	Montrail Williams Electric Cooperative
NAAQS	National Ambient Air Quality Standards
NDDEQ	North Dakota Department of Environmental Quality
NDTA	North Dakota Transmission Authority
NERC	North American Electric Reliability Corporation
NEPA	National Environmental Protection Agency
NESC	National Electric Safety Code
NFPA	National Fire Protection Agency
NMPA	Northern Municipal Power Agency
NREL	National Renewable Energy Laboratory
NO_x	nitrogen oxide
NRI	National Risk Index
NSPS	New Source Performance Standards
NTEC	Nemadji Trail Energy Center
NWS	National Weather Service
OTCPO	Otter Tail Power Company
OTR	Ozone Transport Rule
PRM	planning reserve margin
RC	reliability coordinator
REC	Rainbow Energy Center
RTO	regional transmission organizations
SCADA	supervisory control and data acquisition
SCRIPT	Strategic and Creative Re-Engineering of Integrated Planning Team
SESP	State Energy Security Plan

NOMENCLATURE (continued)

SPP	Southwest Power Pool
STEP	SPP transmission expansion plan
TBtu	trillion British thermal unit
TOP	transmission operator
WAPA	Western Area Power Administration
WIC	Western Internconnection

NORTH DAKOTA GRID RESILIENCY PLAN

EXECUTIVE SUMMARY

Threats such as extreme weather events, changing fuel mix, resource inadequacy, supply chain interruptions, aging infrastructure, and physical and cyberattacks impact grid reliability and resiliency. Ensuring that the grid infrastructure is more resilient is critical so communities can thrive in the face of catastrophic weather events and adapt to changing conditions including technological developments, policy-driven transitions, and grid transformation.

North Dakota's electric grid is managed by regional transmission organizations (RTOs) Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP). As part of a complex regional grid and located in the frequently harsh climate of the upper Midwest, the North Dakota grid is not exempt from problems arising from weather-related events and other issues affecting grid reliability and resiliency. Therefore, the goal of this study is to develop a grid resiliency plan for North Dakota by assessing the risks that various threats pose to the North Dakota electric grid and devising mitigation strategies to address the risks specific to the state's electric grid. This report serves as a grid resiliency plan and complements the North Dakota state energy security plan (SESP).

In this study, historical weather event data, Federal Emergency Management Agency (FEMA) risk profiles, utility data/partner surveys, Midwest Reliability Organization's (MRO's) regional risk assessments, reliability reports from MISO, and SPP and North American Electric Reliability Corporation (NERC) assessments are used to identify potential threats to the state's electric grid resilience, evaluate their impacts and consequences, and rank the resilience risks to the North Dakota electric grid.

Key findings of the risk assessment include the following:

1. **Major Risks Identified**: Ice and snowstorms, resource adequacy issues, supply chain interruptions, and cyberattacks pose the most significant threats to North Dakota grid resilience.

2. **Impact of Extreme Weather**: Always vulnerable to extreme weather, FEMA data and the utility survey confirmed that ice and snowstorms are the most severe weather threat facing utilities in North Dakota. These storms can cause widespread generator outages, limiting energy supply at the same time demand surges because of cold weather.

3. **Resource Adequacy Issues:** Changing resource mix, primarily the result of state mandates and national energy policy, is challenging grid resilience. The high penetration of variable renewable resources into the grid and the growing number of traditional baseload plants being prematurely retired are leading to increased uncertainty and reduced planning reserve margins.

4. **Supply Chain Interruptions:** Ongoing high demand for electrical equipment to support the expansion of generation interconnections and transmission systems has strained manufacturers' production capacity, resulting in longer delivery times for many components, especially transformers. During a storm recovery operation, substantial replacement of storm-damaged transmission and distribution system parts is required immediately. The stressed supply chain is challenged to respond in a timely manner, inventories are low, and production has already surged to meet normal demand.

5. **Cybersecurity Threats:** The Internet of Things (IoT) has significantly improved the sensing and communication capabilities of systems, but this also exposes grid infrastructure to cybersecurity vulnerabilities and attacks. Cyberattacks are a constant threat, as evidenced by successful attacks on critical facilities elsewhere in the country.

6. **Aging Infrastructure:** Although aging infrastructure risks appear to be moderate, when combined with other common-mode risks, they can have a significant impact on bulk power system resiliency. The age and condition of the grid can increase the likelihood of weather-induced outages, and supply chain issues can delay the repair of damaged equipment. Depending on the severity of the initial threat, this combination can propagate across large regions of the grid, as happened with Winter Storm Uri.

This study recommends various mitigation strategies that will allow generation, transmission, and distribution utilities to use risk profiles and mitigation strategies for recurring resilience assessments. Some recommendations are specifically targeted at the group or entity responsible for leading the mitigation action, while others are more general and can apply to different entities, including utilities, regional grid operators, policymakers, and regulators. This study did not analyze the resource requirements for mitigation actions. The following are the recommendations of this study:

1. **Strengthen Resource Adequacy**: North Dakota electric utility stakeholders must engage in the RTO, NERC, and Federal Energy Regulatory Commission (FERC) processes to raise the bar on generation accreditation requirements to ensure the trend of decreasing reserve margins is reversed.

2. **Enhance Infrastructure Resilience**: Local electric utilities must invest in modernizing transmission and distribution systems to improve reliability and resiliency.

3. **Centralize Supply Chain Management**: North Dakota should consider creating a centralized depot for essential electric transmission and distribution materials/components that could be accessed by state electric utilities to expedite storm damage repairs. Establishing such depots would help mitigate the risks posed by supply chain disruptions and ensure faster grid service restoration during severe weather.

4. **Implement Cybersecurity Measures**: Utilities must implement comprehensive strategies, including real-time intrusion detection systems (IDSs), intrusion prevention systems (IPSs), and multilayered defense strategies to protect against cyberthreats targeting grid infrastructure.

5. **Prioritize Maintenance of Aging Infrastructure**: Utilities must focus on proactive maintenance and timely repairs to reduce vulnerabilities associated with aging grid infrastructure.

6. **Establish Continuous Resilience Assessment**: North Dakota must develop a robust framework for continuous resilience assessments and implementation of resilience strategies, ensuring collaboration among electric utilities, generation and transmission owners, regional grid operators, policymakers, and regulators.

NORTH DAKOTA GRID RESILIENCY PLAN

INTRODUCTION

Emerging technologies, aging infrastructure, rising electricity demand, changing energy mix, inverter-based renewable energy sources, climate change, weather-related outages, and a growing trend toward transportation electrification and hyperscale data centers are posing unprecedented challenges to U.S. power grid planning and operations and raising questions about the reliability and resiliency of the grid. A grid system that was once largely designed around baseload plants is now changing, primarily because of increased use of natural gas caused by the shale revolution, growing emphasis on improving sustainability, and the effort to combat climate change, which includes increased use of renewable energy sources and an emerging trend in transportation electrification. Several factors, including decreasing renewable energy costs, favorable federal tax credits, and state renewable portfolio mandates and sustainability goals, have contributed to this shift toward renewables and the early retirement of dispatchable thermal generation. Despite significant investments by the electric sector to meet customer expectations amid the rapid evolution of the electric grid, the reliability of electrical transmission and distribution networks is still an issue for the reasons listed above. Substantial changes in both supply and demand of electricity, combined with transmission system constraints, necessitate a reassessment of operational and planning strategies to ensure grid reliability and resiliency.

North Dakota is a significant producer and exporter of electricity. The state's 65,000 miles of transmission and distribution lines transport roughly twice as much electricity as it typically consumes.[1] While North Dakota coal-fired power plants continue to generate most of the electricity (57% in 2021), wind energy has recently contributed significantly to the market, making up 34% of total generation.[2] Electric generation and transmission (G&T) owners (generation-owning utilities and the utilities that own networked, connected high-voltage transmission facilities) in North Dakota are members of either the Midcontinent Independent System Operator (MISO) or the Southwest Power Pool (SPP)—regional transmission organizations (RTOs)—and participate in interstate electricity markets. Regulatory constructs and public policies that govern the RTOs are often outside of the control of decisions made solely within the state. These dynamics are especially impactful in North Dakota, given the economic importance of the state's electric generation sector relative to the state's overall economy. Moreover, the North Dakota grid as part of the regional grid is not exempt from problems arising from weather-related events and other issues affecting grid reliability and resiliency. Therefore, the goal of this study was to develop a grid resiliency plan for North Dakota by assessing the risks that various threats pose to the North Dakota electric grid and addressing gaps in grid resiliency. This report serves as the grid resilience plan, presenting a comprehensive overview of the current state of the North Dakota electric grid, identifying its vulnerabilities and threats, and outlining actionable steps to mitigate risks and enhance grid resilience at both local and regional levels. The following specific tasks were carried out for this study:

[1] North Dakota Official State Website, 2023, www.ndstudies.gov/energy/level2/module-3-coal/transmission-and-distribution (accessed October 2024).
[2] U.S. Energy Information Administration, 2024, www.eia.gov/state/analysis.php?sid=ND (accessed November 2024).

- Evaluating North Dakota electricity infrastructure, operational conditions, bulk and wholesale energy markets, reliability, resource adequacy, MISO and SPP planning efforts, and other factors that have an impact on North Dakota grid resiliency.

- Identifying potential threats to North Dakota electric grid resilience.

- Defining the impacts and consequences of these threats.

- Assessing electric grid vulnerabilities.

- Evaluating grid resilience risks based on the likelihood and consequence of threats.

- Identifying gaps and opportunities for improving grid resiliency.

- Providing recommendations for risk mitigation.

GRID RELIABILITY AND RESILIENCY

Grid reliability can be defined as the ability of the power system to deliver the electrical power required by users while minimizing any loss of electrical service. During any power disruption, utilities are responsible to respond and restore service as soon as possible. On the other hand, grid resiliency means “the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions.” Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.[3] Both concepts are interrelated. Table 1 provides a comparison of the attributes of grid reliability and resiliency.[4]

The Long-Term Reliability Assessment (LTRA) is published annually by the North American Electric Reliability Corporation (NERC), an organization that evaluates the overall health of the bulk power system and ensures reliability by minimizing reliability and security risks. This report identified several assessment areas with reliability risks because of changes in the resource mix, which is reducing the amount of dispatchable generation in favor of variable renewable energy resources; extreme weather events; transmission lines out of service, impacting interregional power transfers; growing demand; and more.[5] Power system planning is becoming more crucial because of increased reliability and resiliency risks.

[3] Pierre, B.J., 2021, www.osti.gov/servlets/purl/1863870 (accessed October 2024).
[4] Murphy, C., Hotchkiss, E.L., Anderson, K.H., Barrows, C.P., Cohen, S.M., Dalvi, S., Laws, N.D., Maguire, J.B., Stephen, G.W., and Wilson, E.J., 2020, Adapting existing energy planning, simulation, and operational models for resilience analysis: https://doi.org/10.2172/1602705 (accessed October 2024).
[5] North American Electric Reliability Corporation, 2023, www.nerc.com/pa/RAPA/ra/ Reliability%20Assessments %20DL/NERC_LTRA_2023.pdf (accessed October 2024).

Table 1. Comparison of Grid Resiliency and Reliability Attributes[6]

Attribute	Grid Resiliency	Grid Reliability
Event Characteristics	High-consequence, less frequent events, typically represent black sky operating conditions	High-frequency, low-consequence events often representing local outages under normal operating conditions
Outage Duration	Days to months	Seconds to hours
Geographical Extent	Large geographical area	Concentrated area
Economic Losses	Losses because of power outages and cascading impacts[1]	Losses limited to subset of customers with unserved load
State of Metrics	No structured or widely adopted metrics	Well-defined and industry-standard metrics
Entities Responsible for Standards	None	NERC, FERC, Public Utility Commissions, Institute of Electrical and Electronics Engineers
Relevant Information	Insights from historical events to model and simulate future events	Aggregate of historical (small-scale) event records over a certain period

[1] Cascading impact can include business losses and interrupted natural gas and water delivery to customers because of power outages.

National Renewable Energy Laboratory (NREL) researchers define grid reliability using three Rs: resource adequacy, operational reliability, and resilience.[6] All of the Rs are required for secure and reliable grid operation. According to NERC, the U.S. electricity grid is at higher risk from various natural and man-made threats. Therefore, power system planning and operations must prioritize a thorough assessment of resource adequacy, operational reliability, and resilience to effectively mitigate risks and ensure a stable electricity supply.

Resource adequacy is the adequate supply of electricity to meet the load-serving needs of the grid at all times and conditions. Generation resources need to be available to cover the variability in demand and supply. Demand variability is a result of sudden load changes, peak and minimum load periods, and weather events. The variability in supply results from scheduled maintenance-based outages of power plants, unexpected outages, changes in renewable generation output, and transmission congestion curtailing generation. Renewable generation, such as solar and wind, is a major component of supply-based uncertainty. Generation resources held in reserve can mitigate generation outage impacts and is referred to as the planning reserve margin (PRM). Upgrades of the transmission system or interregional transmission coordination can improve resource adequacy by increasing the ability to import power from other areas of the system and by reducing congestion that could otherwise curtail generation output. Because of an increasing

[6] National Renewable Energy Laboratory, 2022, www.nrel.gov/news/program/2022/assessing-power-system-reliability-in-a-changing-grid-environment.html (accessed October 2024).

number of renewables, storage technology can also contribute to the overall improvement of resource adequacy.

Operational reliability focuses on the power system's ability to manage supply and demand in real time. Generation stochasticity, ramping constraints, and transmission failure can lead to unacceptable system conditions, and the power system must respond to address these unexpected events by adjusting the generation or reducing end-user consumption. Operating reserves are a key aspect of operational reliability, as they respond to any unexpected event to maintain stable frequency. Grid inertia allows time for the system to respond to generation loss or demand rise. Traditionally, coal, natural gas, and nuclear or hydroelectric plants are the main source of grid inertia. Wind, solar photovoltaics, and batteries use power electronic inverters to provide grid-compatible inertia performance. However, power system planners are concerned that large additions of inverter-based resources may impact system stability.

According to FERC, grid resilience is the ability of a power system to recover from disruptive events by anticipating, adapting, or rapidly recovering from the event. Resiliency overlaps with grid resource adequacy and operational reliability from the operational reserve or the supply adequacy point of view.

Grid resiliency deals with extreme events that are longer than typical outages and focuses on the ability of the grid to reenergize after disruption within the shortest possible time. Extreme weather and renewable generation variation have been an increasing strain on grid reliability.

Today the U.S. grid is increasingly vulnerable to risks from natural disasters, supply chain issues, and malicious attacks. The U.S. economy presently suffers tens of billions of dollars in losses annually because of long-lasting, widespread grid disruptions brought on by severe weather alone, and this hazard is only one of many that are becoming more significant and likely.[7] As part of a complex regional grid and located in the frequently harsh climate of the upper Midwest, North Dakota is also subject to these threats and vulnerabilities. This report primarily focuses on identifying potential threats and vulnerabilities that affect the North Dakota electric grid as well as gaps and opportunities for improving grid resiliency.

OVERVIEW OF NORTH DAKOTA ELECTRIC GRID, KEY PLAYERS, AND PROCESSES

The U.S. Energy Information Administration (EIA)-860 survey dataset shows that North Dakota has 99 generating units, with a cumulative nameplate summer and winter generation capacity of approximately 9875, 9409, and 9478 megawatts (MW), respectively. In 2022, the state's electricity consumption was 25 million megawatt-hours (MWh) out of the 44 million MWh of net electricity generated.[8] The industrial sector consumed roughly 11.7 million MWh, accounting for 46% of the total electricity consumption. This was followed by the commercial sector, which used 8.4 million MWh, accounting for 33%, and the residential sector, with the consumption of 5.3 million MWh, representing 21%.

[7] Rocky Mountain Institute, 2020, https://rmi.org/insight/reimagining-grid-resilience/ (accessed October 2024).
[8] U.S. Energy Information Administration, 2022, www.eia.gov/electricity/state/northdakota/ (accessed October 2024).

North Dakota’s high-voltage transmission network was originally built to deliver power generated at minemouth coal-fired generation plants to customers throughout the upper Great Plains. Then, in the early 2000s, changes in energy policy encouraged installation of wind generation in eastern North Dakota (mainly to meet state mandates in Minnesota) and Bakken oil development caused a huge increase in electrical load within North Dakota. To meet these challenges, aggressive transmission expansion was undertaken to strengthen the North Dakota-to-Minnesota interconnection as well as the transmission system in western North Dakota. This development continues to this day.

This section discusses the general makeup of the North Dakota grid and provides high-level information that will help frame the diversity of the North Dakota electricity sector. It gives an overview of the operational conditions and planning efforts of grid operators in North Dakota and various factors that impact how well the grid can serve customers in North Dakota.

U.S. Transmission System Interconnections

The power system in the United States is split into three major grids: Eastern Interconnection (EIC), Western Interconnection (WIC), and Texas Interconnected System (managed by the Electric Reliability Council of Texas [ERCOT]), as shown in Figure 1. The interconnections operate independently from each other, with interarea power transfers limited to a small number of back-to-back direct current (DC) ties. North Dakota resides within EIC, which covers a diverse landscape ranging from Florida in the south to Saskatchewan in the north (Figure 1).

As a result of FERC Order 2000 in 1999,[9] several RTOs were formed within EIC. An RTO’s purpose is to independently manage a power market and oversee the planning and operation of the bulk power transmission system within its footprint. RTOs also perform reliability studies and direct the construction of transmission system improvements. Access to the electricity market allows participants to buy and sell electricity efficiently and for the lowest cost. As a single entity with visibility and control of its entire footprint, the RTO ensures reliable operation across the regional transmission system. However, local transmission system operators still maintain control of their systems but receive guidance and/or direction from the RTO when necessary.

[9] Pennsylvania–New Jersey–Maryland Interconnection, 2016, https://www.pjm.com/-/media/committees-groups/task-forces/trpstf/20160620/20160620-item-04-ferc-major-orders-related-to-open-access-and-transmission-investment.ashx (accessed October 2024).

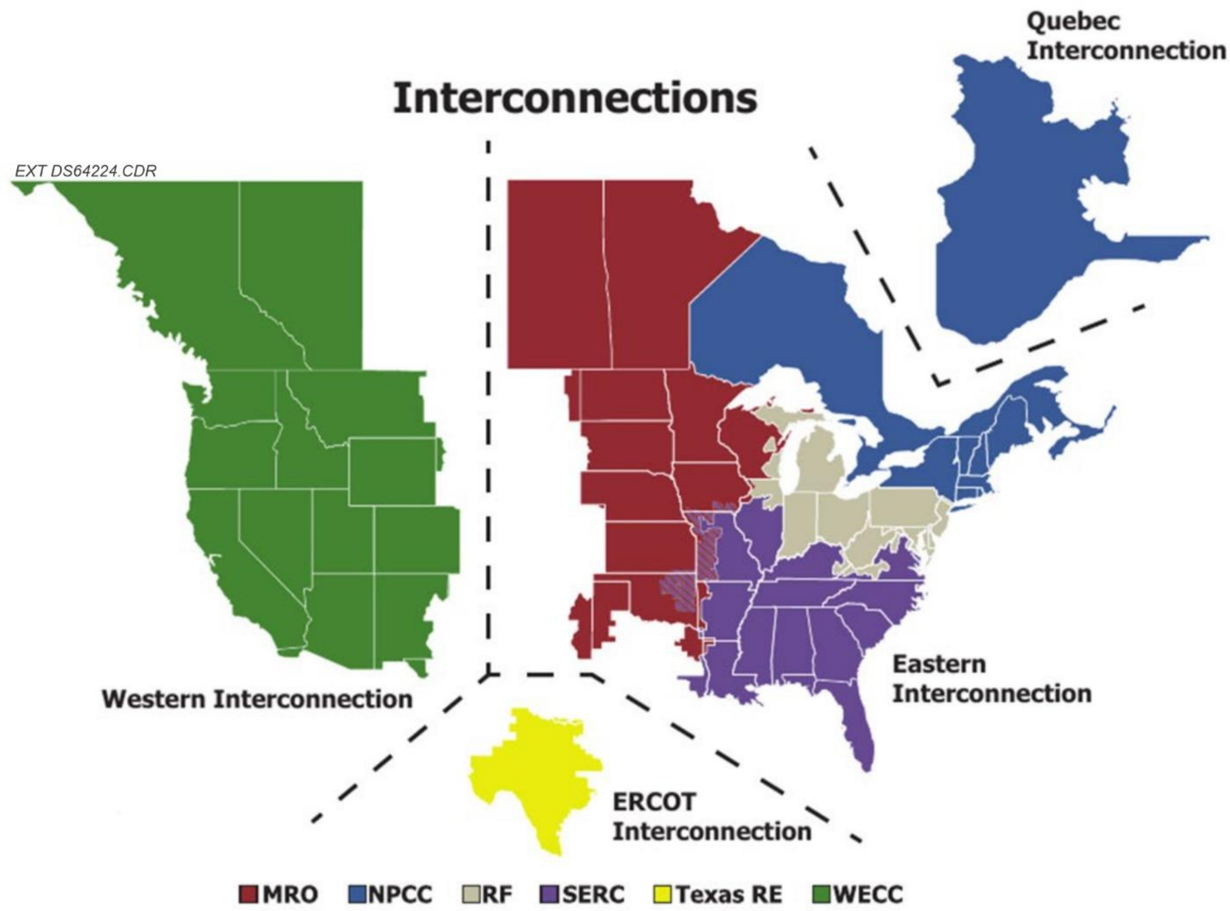

Figure 1. U.S. transmission system interconnections.[10]

North Dakota transmission system owners participate in either the MISO or SPP RTO (Figure 2). Basin Electric Power Cooperative (BEPC) (along with several of its member cooperatives) and the Western Area Power Administration (WAPA) belong to SPP. Northern States Power Company (Xcel Energy), Otter Tail Power Company (OTPCO), and Montana–Dakota Utilities Co. (MDU) are members of MISO. Minnkota Power Cooperative (MPC) is a MISO market participant and has its own transmission tariff, which is managed by MISO.

[10] North American Electric Reliability Corporation, 2024, www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf (accessed October 2024).

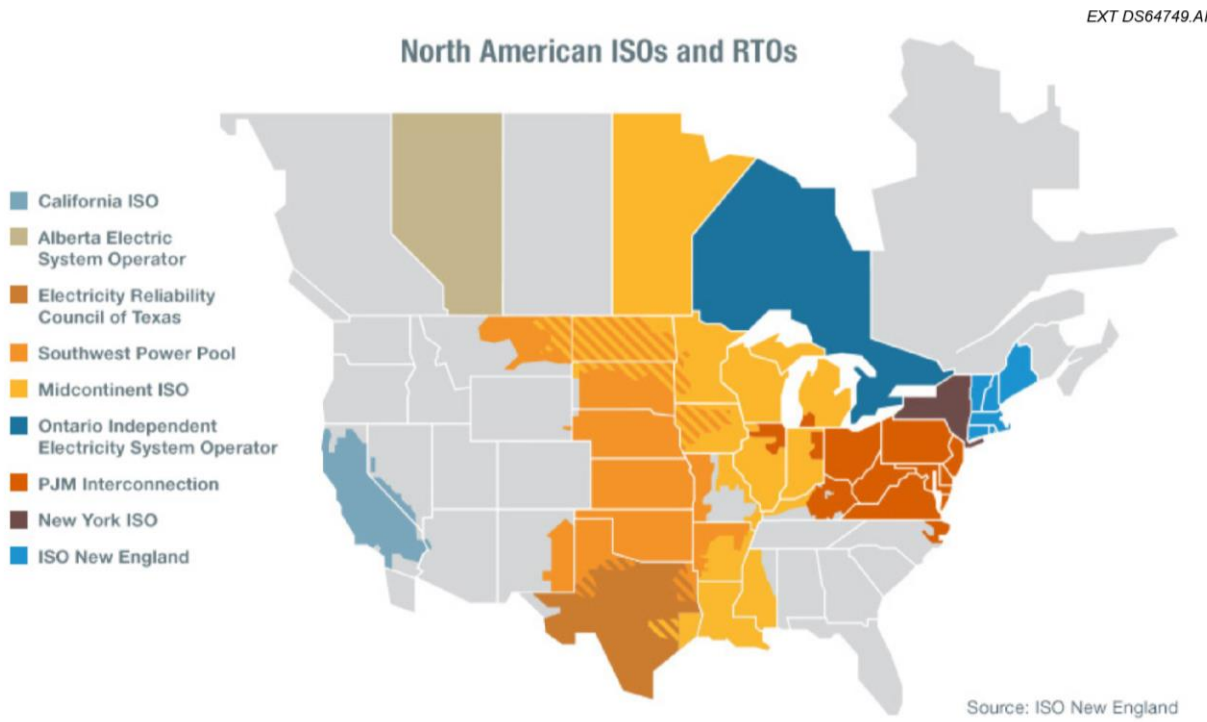

Figure 2. U.S. RTO coverage.[11]

Electric transmission system owners, users, and operators abide by an extensive list of mandatory reliability standards. Violation of these standards can result in financial penalties. Development and enforcement of the standards are managed by NERC at the direction of FERC because of the Energy Policy Act of 2005. To manage this effort more effectively, NERC delegates standard compliance management to six regional entities that each cover a portion of North America. North Dakota lies within the Midwest Reliability Organization (MRO) area that includes both SPP and MISO.

MISO and SPP RTOs

As an RTO, MISO manages the transmission grid across 15 midcontinent states in the United States. MISO regulates one of the largest energy markets in the world and consists of over 500 market participants, serving approximately 45 million customers. MISO has a total market capacity of 191 gigawatts (GW),[12] with around 42% natural gas, 25% coal, 24% renewables, 7% nuclear, and 2% other sources (Figure 3) and a summer peak load of 127 GW.

[11] ISO New England, 2023, www.iso-ne.com/about/key-stats/maps-and-diagrams#isos-rtos (accessed October 2024).
[12] Midcontinent Independent System Operator, 2024, www.misoenergy.org/meet-miso/media-center/2024/corporate-fact-sheet/ (accessed October 2024)

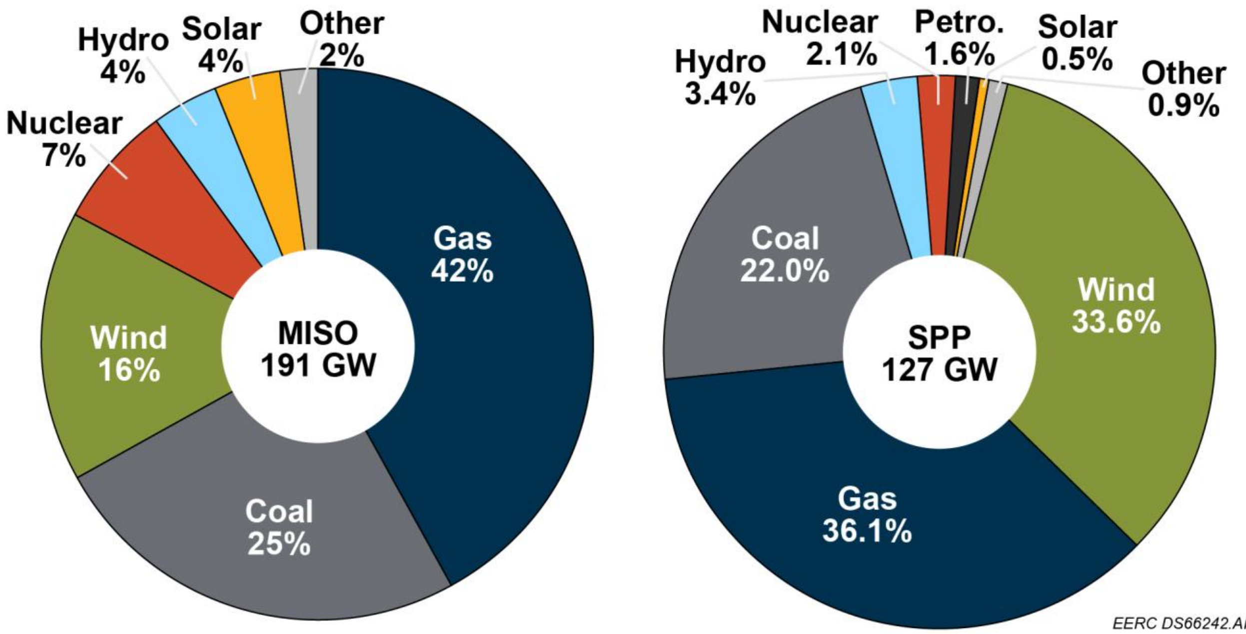

Figure 3. MISO and SPP resource mix at the end of 2023.

Just like MISO, SPP is a large regional transmission operator that covers a service territory of 552,885 square miles and is responsible to ensure the reliability of the power grid in 15 U.S. states. SPP serves more than 18 million people and has over 72,820 miles of transmission lines. It has a total nameplate generating capacity of 100.4 GW, with 36.1% natural gas, 22.0% coal, 33.6% wind, 3.4% hydro, 2.1% nuclear, 1.6% fuel oil, 0.5% solar, and 0.9% other fuel sources.[13] (Figure 3). SPP set a record coincident peak load of 56 GW in August 2023.[14] and is in the process of expansion into WIC. It presently operates in the Western Energy Imbalance Service market, serves as the WIC reliability coordinator (RC), and is developing an RTO with several WIC transmission owners.

Generation Resource Adequacy

Resource adequacy is a critical component of grid reliability. This was demonstrated most recently in February 2021 during Winter Storm Uri when a lack of generation resources in SPP resulted in directed load sheds across the SPP footprint, including North Dakota.

Resource adequacy is a measure of the ability of an RTO to provide enough generation to cover its peak load plus losses over a forecast time period. Laws of physics dictate that consumption of electrical energy must match the production of electrical energy on a continuous basis to maintain constant electrical frequency and other essential system operating parameters. System operation must account for the unexpected and scheduled loss of generation units or

[13] Southwest Power Pool, 2023, www.spp.org/documents/71645/2023%20annual%20state%20of%20the%20market%20report%20v2.pdf (accessed October 2024).
[14] Southwest Power Pool, 2023, https://storymaps.arcgis.com/stories/79884f30428b4b4a9469765f3ecfc652 (accessed October 2024).

transmission elements, variation in loads (including demand response), and variation in weather-based generation resources while ensuring the balance of generation and load. Therefore, resource adequacy study is very complex.

It is the responsibility of each load responsible entity (LRE), also known as load-serving entity (LSE), in an RTO to ensure arrangements have been made to obtain sufficient accredited generation capacity to meet peak load needs. The capacity can be owned by the LRE or obtained through power purchase agreements or a demand response action. Therefore, if each LRE in an RTO acquires sufficient generation resources, then the RTO in total will have sufficient resources. An LRE or LSE is typically a local utility. For example, MDU and OTPCO are MISO LSEs, while BEPC is a SPP LRE.

Accredited capacity differs from nameplate capacity. Accredited capacity is the capacity of a generation facility that can be counted on to meet an LRE's peak load requirement. Nameplate capacity is the maximum megawatts a facility is designed to produce. Thus, depending on the type of facility and the fuel source, the accredited capacity is a fraction of the nameplate capacity. Several methods are used to calculate accreditation. SPP is implementing a method called effective load-carrying capability (ELCC), a probabilistic measure of how much load can be added when also adding the generator in question without degrading reliability. Thermal generation typically has a high accreditation rating. However, nondispatchable resources are lower. According to the SPP 2024 ELCC Wind and Solar Study Report,[15] wind accreditation is 15.4% in the summer and 25.1% in the winter. Typical solar generation accreditation is 61% in the summer and 33% to 41% in the winter. But, in practice, each generator will receive an individual accreditation value based on its characteristics.

MISO Resource Adequacy and PRM

MISO is struggling with resource adequacy. NERC issued a warning in its 2024 summer reliability assessment:[16] "Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."

MISO maximum generation emergency declarations have increased over the 13 years, from 2009 to 2021, but have declined in the last 3 years. Table 2 shows the data from the MISO maximum generation emergency declarations report through June 2024 (updated August 30, 2024).[17]

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[15] Southwest Power Pool, 2024, www.spp.org/documents/72346/2024%20spp%20elcc%20wind%20solar%20&%20esr%20report.pdf (accessed October 2024).
[16] North American Electric Reliability Corporation, 2024, www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf (accessed October 2024)
[17] Midcontinent Independent System Operator, 2024, www.oasis.oati.com/woa/docs/MISO/ MISOdocs/Capacity_Emergency_Historical_Information.pdf (accessed October 2024).

Table 2. MISO Maximum Generation Emergency Declarations, 2009–2024

Year	Maximum Generation Emergency Declarations
2009	1
2010	1
2011	5
2012	9
2013	1
2014	6
2015	0
2016	10
2017	13
2018	21
2019	17
2020	7
2021	32
2022	18
2023	11
2024	1

The MISO 2023 regional resource assessment[18] describes the challenges of decreasing accredited capacity combined with increasing loads, putting pressure on sufficient reserve margins, as shown in Figure 4. Figure 4 shows a large number of variable energy resource facilities with relatively low accredited capacity being added while large amounts of thermal generation with higher relative accredited capacity are being retired. Thus the total amount of installed capacity is forecast to increase while the total accredited capacity decreases.

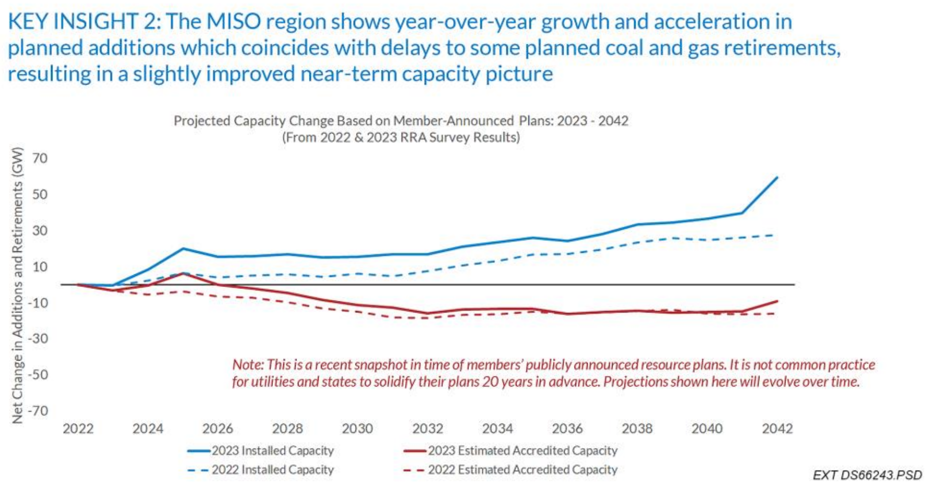

Figure 4. MISO projected capacity changes.[19]

[18] Midcontinent Independent System Operator, 2023, https://cdn.misoenergy.org/2023%20Regional%20Resource%20Assessment%20Report630736.pdf (accessed October 2024).
[19] Midcontinent Independent System Operator, 2023, https://cdn.misoenergy.org/2023%20Regional%20Resource%20Assessment%20Report630736.pdf (accessed October 2024).

The lack of MISO-accredited capacity is reflected in the graph in Figure 5, a graph of MISO Future 2A that corresponds to a load growth of 0.8%. The required load plus reserve is plotted with the black line. The existing accredited resources are represented by the dark blue bars. The planned resources are represented by the light blue bar sections. The light gray bar components are defined as "model-built resources." The reliance on model-built resources is a concern. As defined by MISO, "the gray 'model-built resources' are not included in MISO members' current publicly available resource plans; rather, they are added during an analysis step of the RRA called the Resource Assessment. Because members do not produce detailed resource plans 20 years in advance, the Resource Assessment uses computer modeling to select additional resources—informed by capital cost, emissions profiles, and other assumptions—members may choose to build to achieve their decarbonization goals and reserve margin in a reliable manner."

Therefore, it appears MISO is not certain it will have enough accredited capacity and is relying on its membership having confidential resource addition plans to meet its resource adequacy needs.

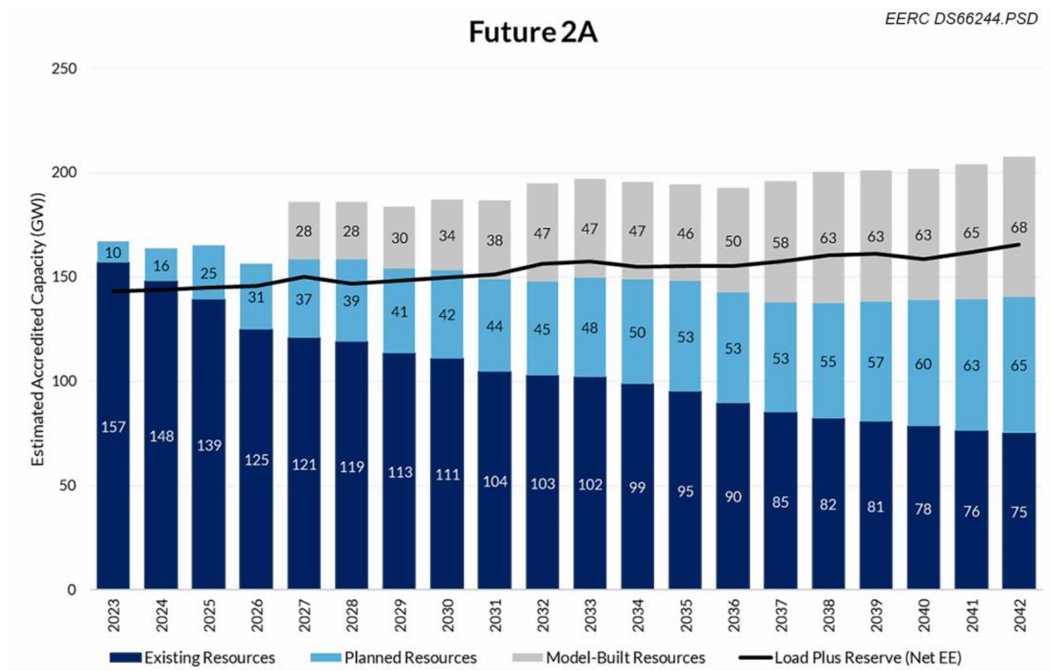

Figure 5. MISO Future 2A-projected resource, load, and reserves forecast.[20]

MISO states in the 2023 regional resource assessment,[21] "The region's capacity picture improved slightly since 2022, but because retirements continue to outpace additions in terms of estimated accredited capacity, reliability risks remain."

[20] Midcontinent Independent System Operator, 2023, https://cdn.misoenergy.org/20231002%20LRTP%20Workshop%20-%20Draft%20Series1A%20Futures%20Report630365.pdf (accessed October 2024).
[21] Midcontinent Independent System Operator, 2023, https://cdn.misoenergy.org/2023%20Regional%20Resource%20Assessment%20Report630736.pdf (accessed October 2024).

MISO covers a large geographic area and divides its system into ten local resource zones (LRZs). These zones are designed so that the loads and resources within the LRZ are connected by sufficient transmission to allow loads to access generation. North Dakota is located within MISO LRZ01, as shown in Figure 6. A plot of the LRZ01 resource and load gap forecast is provided in Figure 7. LRZ01 trends are similar to the overall MISO trends in Figure 5, and North Dakota being part of MISO's LRZ01 is not isolated from the near-term capacity risk of MISO.

Figure 6. MISO LRZ01 footprint.[19]

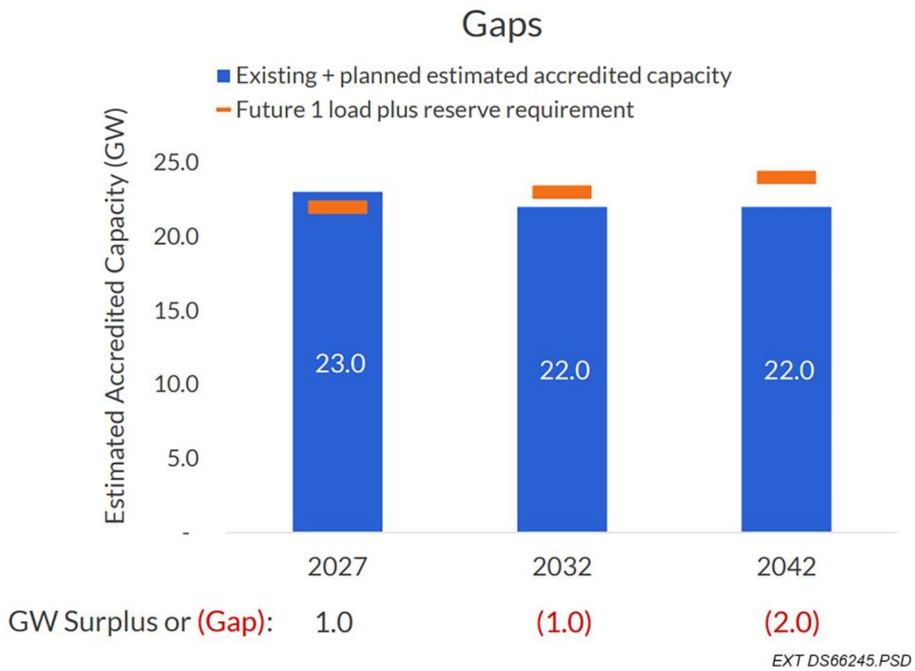

Figure 7. MISO LRZ01 projected resource and load gap forecast.[19]

SPP Resource Adequacy and PRM

According to the NERC 2024 summer reliability assessment, SPP is at low risk of inadequate resources: "Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios." The main threat NERC identified is the possibility of low wind generation during an above-normal summer peak load period.

SPP performs an annual resource adequacy study and a biennial loss of load expectation (LOLE) analysis. SPP published the results of its most recent resource adequacy study in its 2024 SPP resource adequacy report dated June 14, 2024. The report is a compilation of SPP LREs' individual resource adequacy status and is posted each year in June. In order to ensure that SPP has sufficient overall adequacy, each of its participating LREs must demonstrate annually sufficient generation capacity to cover its peak load plus the required PRM. If an LRE has insufficient capacity, then it can be subject to a deficiency payment.

The methodology that determines the adequacy status for each LRE is to add up its firm, accredited network resources and purchases to determine its total capacity, then add up its forecast peak demand and firm power sales and subtract demand response load to find the LRE's total net peak demand. Then the net peak demand is increased by the PRM criteria to calculate the LRE's resource adequacy requirement. The difference between the total capacity and the resource adequacy requirement is the excess capacity. The LRE's actual PRM is found by dividing the total capacity by the net peak demand; this value must be in excess of the SPP PRM criteria.

BEPC and WAPA are the load-responsible entities (LREs) under SPP in North Dakota. BEPC provides the LRE function as part of its "all requirement" power supply obligation to its member cooperatives. The WAPA LRE obligation covers its allocation of federal hydropower energy to its preference customers. A summary of results from the SPP 2024 resource adequacy report[22] is provided for BEPC and WAPA in Figures 8 and 9, respectively. According to this report, all LREs in SPP met their resource adequacy requirements.[22] The SPP criterion was 15% for most LREs, including BEPC. However, LREs with primarily (>75%) hydro-based resources (such as WAPA) had a 9.89% PRM criterion. BEPC's PRM was 21.1% for 2024, and WAPA's PRM was 12.3%.[22]

While the 2024 results met criteria, the 2024 SPP resource adequacy report forecasted a steady decline in PRM. By the summer of 2027, SPP as a whole will be deficient 2587 MW and not meet its 15% PRM criterion. By 2029, SPP will be deficient 5950 MW. SPP states the reason for the deficiency is a 10% increase in load and a 3% reduction in generation capacity. This forecast is provided in the graph in Figure 10 and the table in Figure 11.

BASIN ELECTRIC POWER COOPERATIVE

Capacity Summary	
Capacity Resources (MW)	3,231.3
Firm Capacity Purchases (MW)	893.1
Deliverable Capacity Purchases (MW)	91.6
Firm Capacity Sales (MW)	0.0
Deliverable Capacity Sales (MW)	0.0
External Firm Power Purchases (MW)	0.0
External Firm Power Sales (MW)	0.0
Confirmed Retirements (MW)	0.0
Total Capacity (MW)	4,216.0
Demand Summary	
Forecasted Peak Demand (MW)	3,724.1
Internal Firm Power Sales (MW)	0.0
Internal Firm Power Purchases (MW)	3.7
Controllable and Dispatchable DR (MW)	238.0
Net Peak Demand (MW)	3,482.4
Requirements Summary	
Resource Adequacy Requirement (MW)	4,004.7
Excess Capacity (MW)	211.3
Deficient Capacity (MW)	0.0
LRE planning reserve margin (%)	21.1
Planning Reserve Margin (%)	15.0

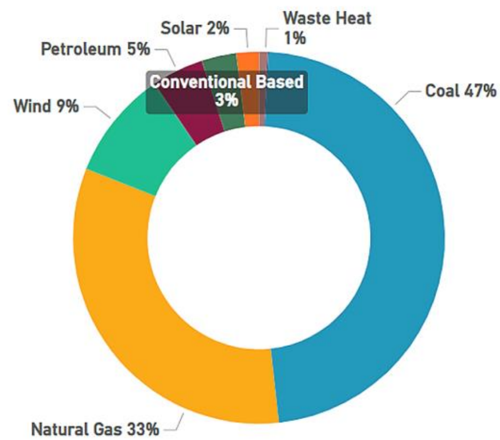

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Figure 8. BEPC resource adequacy results.[22]

[22] Southwest Power Pool, 2024, www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf (accessed October 2024).

WESTERN AREA POWER ADMINISTRATION – UGP

Capacity Summary	
Capacity Resources (MW)	2,307.6
Firm Capacity Purchases (MW)	3.0
Deliverable Capacity Purchases (MW)	0.0
Firm Capacity Sales (MW)	440.9
Deliverable Capacity Sales (MW)	0.0
External Firm Power Purchases (MW)	0.0
External Firm Power Sales (MW)	0.0
Confirmed Retirements (MW)	0.0
Total Capacity (MW)	1,691.7
Demand Summary	
Forecasted Peak Demand (MW)	760.2
Internal Firm Power Sales (MW)	745.6
Internal Firm Power Purchases (MW)	0.0
Controllable and Dispatchable DR (MW)	0.0
Net Peak Demand (MW)	1,505.8
Requirements Summary	
Resource Adequacy Requirement (MW)	1,654.8
Excess Capacity (MW)	37.0
Deficient Capacity (MW)	0.0
LRE planning reserve margin (%)	12.3
Planning Reserve Margin (%)	9.9

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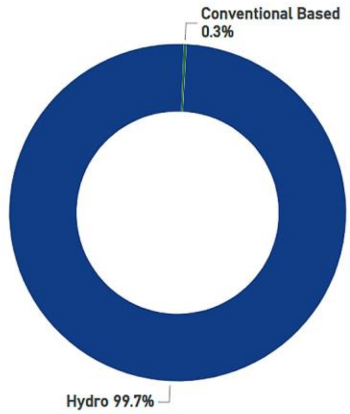

Figure 9. WAPA resource adequacy results.[22]

Figure 10. SPP PRM forecast.[22]

In power systems, LOLE is defined as the probability that a transmission system will not have enough generation capacity to meet its load requirements over a defined time period. The industry-standard criteria are a LOLE of 1 day in 10 years, or 0.1 day per year.

The results of the SPP 2021 LOLE indicated that a 12% PRM was not adequate to meet the 1-day-in-10-years LOLE criterion. Therefore, in 2022, SPP reviewed the results of the 2021 LOLE study and investigated adjusting the PRM. SPP determined the cause of the declining PRM was the replacement of thermal generation with variable energy resources. SPP is concerned about the

Demand Summary *(Units – MW)*	2024	2025	2026	2027	2028	2029
Total LRE Forecasted Net Peak Demand [7]	54,987	56,415	57,417	59,061	59,754	60,569
Forecasted LRE Peak Demand (Non-Coincident Peak)	56,202	57,881	59,188	61,118	61,878	62,741
Controllable and Dispatchable Demand Response[8]	1,215	1,465	1,771	2,057	2,124	2,172
Energy Efficiency and Conservation	266	325	426	529	631	729
Stand–by Load Under Contract	1.8	8.2	6.4	6.4	6.4	6.4
Capacity Summary *(Units – MW)*	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Total Capacity[9]	65,975	66,514	66,441	65,227	64,140	63,598
Existing Resources	65,474	64,959	64,669	64,226	64,187	63,975
Retirements[10]	186	281	294	1,006	2,059	2,389
New Resource Additions[11]	0	910	1,120	1,120	1,120	1,120
Other Capacity Adjustments – Reductions	303	128	128	128	128	128
External Firm Capacity Purchases	301	296	316	316	321	321
External Firm Capacity Sales	699	629	629	629	629	629
External Firm Power Purchases	1,388	1,388	1,388	1,328	1,328	1,328
External Firm Power Sales	0	0	0	0	0	0
SPP BA Area Planning Reserve[12]	20.0%	17.9%	15.8%	10.5%	7.4%	5.0%
Planning Reserve Margin *(As specified in SPP Planning Criteria)*	15%	15%	15%	15%	15%	15%
Total LRE Resource Adequacy Requirement	63,158	64,771	65,923	67,814	68,610	69,548
Total LRE Excess Capacity	2,741	1,391	186	-3,554	-5,438	-7,256
Total Generator Owner Excess Capacity *(Excludes Generator Owner uncommitted Deliverable Capacity of wind resources)*	76	352	332	967	967	1,306
Total Excess Capacity *(SPP BA Area)*[13]	2,817	1,743	518	-2,587	-4,470	-5,950

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Figure 11. SPP PRM forecast data[22].[22]

accuracy of load forecasts, demand response, fuel supply limitations, wind forecasts, and other issues. SPP is also concerned that the LOLE 0.1-day-per-year criterion may not suffice and supplemental measures, such as expected unserved energy, should be considered. As a result of this analysis, SPP increased the PRM to 15% starting in the summer of 2023.[23]

Subsequently, the 2023 SPP LOLE report (posted on June 28, 2024) added a winter PRM analysis; previously, only the summer season was examined. In addition, the 2023 LOLE study increased the historical weather record to 43 years from 9 years in the 2021 study and added cold weather-related outage history and other more detailed modeling assumptions.[24] As a result of these changes, the SPP 2023 LOLE study recommended a 2026 summer PRM of 17% and a winter PRM of 45% and a 2029 summer PRM of 21% and winter PRM of 51%.[24] These changes were reviewed and adjusted by multiple SPP work groups, and at their August 5–6, 2024, meeting, the SPP board approved a 16% summer PRM and a 36% winter PRM effective summer 2026 and winter 2026–27.[25]

Generation Interconnection Process Delays

As the reserve margins are decreasing, the ability of RTOs to process new generation interconnections (GIs) in a timely manner is an issue that needs to be addressed. All generation additions are managed by the RTOs through their GI process. The GI requests are placed in a

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[23] Southwest Power Pool, 2021, www.spp.org/documents/67465/2021%20spp%20lole%20study%20report.pdf (accessed October 2024).

[24] Southwest Power Pool, 2023, www.spp.org/documents/71904/2023%20spp%20lole%20study%20report.pdf (accessed October 2024).

[25] Southwest Power Pool, 2024, https://spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/ (accessed October 2024).

queue and studied in the order they are received or through measures of their project in service progress. There is typically an open season, and all requests received in the open season are studied in a cluster. The GI study provides a portfolio of transmission additions required to accommodate the GI requests. The cost of the transmission additions is allocated to each of the GI requesters based on their individual impact contribution. Unfortunately, this process is unwieldy, inefficient, and prone to delays.

Because of FERC separation of function rules, local transmission planners are not allowed to communicate with generation developers. Therefore, GI requests are typically made by out-of-state entities with little knowledge of local transmission performance or issues. For example, two large wind farms were connected to the grid via 30-mile-long 345-kilovolt (kV) lines in North Dakota when the adjacent 115-kV system had sufficient capacity with much less expensive upgrades. System support from the wind farms could have benefited the load-serving 115-kV system area; instead, the wind power was connected to the 345-kV system, which was intended to provide an import path into the region.

Typically, the first pass of the GI cluster study transmission solution is extremely expensive. Renewable energy projects have little appetite to pay for transmission. A large percentage will drop out of the cluster study. The loss of a portion of the generation in the cluster invalidates the study, and the process must start over. This process repeats multiple times until the remaining GI requests accept the cost of the resulting transmission additions. The result is the GI study process is 3 to 6 years behind schedule. For example, the MISO 2017 study was completed in 2023.[26]

This issue also affects how local transmission owners plan and operate their systems. For example, in the SPP GI queue, there is a request by the Mountrail Williams Electric Cooperative (MWEC) Strandahl Substation for a 255-MW wind generation facility. This request is part of the 2018-002 GI queue; thus, it is 6 years old. Preliminary results have assigned the GI customer responsibility for a new 115-kV line and rebuilding of another. This request has undergone many restudies and was assigned another with a scheduled completion of October 25, 2024.[27] Until this study is completed and the interconnection agreements are signed, MWEC will not know if the facility upgrades associated with the GI request will be completed. These are major upgrades in the middle of the MWEC service area. The years of uncertainty of these additions complicates the MWEC transmission planning process and introduces the risk of either overbuilding or underbuilding other reliability-based projects.

RTOs are attempting to speed up the process by increasing deposits and other fees and establishing a first-ready, first-served type of process. FERC has also adjusted its rules.[28] Unfortunately, one component of the new FERC rules financially penalizes RTOs for missing study deadlines. By rushing the study effort, engineers will have less time to optimize their transmission solutions. Therefore, they will simply provide overbuilt solutions or, worse, in their

[26] Southwest Power Pool, 2023, https://opsportal.spp.org/documents/studies/sppgistudyupdate_weekly.pdf (accessed October 2024).
[27] Southwest Power Pool, 2024, https://opsportal.spp.org/documents/studies/sppgistudyupdate_weekly.pdf (accessed October 2024).
[28] VanNess Feldman LLP, 2023, www.vnf.com/ViewMailing.aspx?MailingId=45061&MailKey=6066091 (accessed October 2024).

haste, miss mistakes and provide incorrect solutions. Neither effort will eliminate the cluster process, which will inherently result in a repetitive restudy delay issue.

U.S. Environmental Protection Agency (EPA) Rules – Impacts to Generation Resource Adequacy

EPA is rolling out new rules that may impact resource adequacy in the SPP and MISO areas, the Ozone Transport Rule (OTR), coal combustion residuals (CCRs), New Source Performance Standards (NSPS) for greenhouse gas emissions, and Mercury and Air Toxics Standards (MATS).

OTR

The 2015 Ozone National Ambient Air Quality Standard (NAAQS) (OTR) will add the requirement to install NO_x (nitrogen oxide) controls to many coal and natural gas fuel generators by 2026. This is a tremendous burden for owners of these generators and operators of the transmission system. For example, catalytic reduction equipment was installed by BEPC at its Laramie River Station. The project cost $250 million and took 5 years from planning to completion. While OTR does not affect generation located in North Dakota, thousands of megawatts of accredited generation are at risk in the MISO and SPP areas. Since RTOs dispatch their generation in a consolidated fashion, shortages of generation outside of North Dakota can result in prorated curtailments of load within North Dakota, as happened during Winter Storm Uri in February 2021.[29]

SPP wrote a letter to EPA dated August 17, 2022, that stated, "What this means for the SPP region is that, due to the SCR retrofit requirement alone, we can expect the premature retirement of 1500 Megawatts of gas-fired generation and 8184 Megawatts of coal-fired generation (37% of the SPP coal fleet) in the next four years."[30] This is a total of 9684 MW of dispatchable generation at risk. Figure 11 shows a total SPP generator owner capacity deficiency of 2587 MW in 2027. A reduction of 9684 MW would leave SPP –12,271-MW-deficient.

MISO provided comments on the EPA rule on June 21, 2022,[31] including a section on resource adequacy. MISO performed an economic analysis of three scenarios: a base case, retirement + retrofit, and retire all affected units. The retire-all-affected-units scenario assumes generator owners would not make the investment of emission retrofits for units with less than 20 years of life expectancy. A summary of results is provided in Table 3 that shows the 2026 projected number of hours of insufficient generation resources for each scenario. The maximum impact is 477 hours in 2026, which is approximately 20 days.

Thus, based on SPP and MISO feedback, OTR will severely impact resource adequacy across the region. It will be expensive at $250 million per generator, and it will be impossible to

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[29] Federal Energy Regulatory Commission, 2021, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (accessed October 2024).
[30] Southwest Power Pool, 2015, https://spp.org/documents/67328/20220621_spp%20comments_epa-hq-oar-2021-0668.pdf (accessed October 2024).
[31] Midcontinent Independent System Operator, 2015, www.federalregister.gov/documents/2022/04/06/2022-04551/federal-implementation-plan-addressing-regional-ozone-transport-for-the-2015-ozone-national-ambient (accessed October 2024).

meet EPA's 2026 deadline assuming a 5-year project schedule. In June 2024, the U.S. Supreme Court issued an emergency stay of the rule until the lawsuit challenging the rule is resolved.[32]

Subsequently in October 2024, EPA issued a third interim final rule responding to the Supreme Court's order. From the EPA press release,[33] "On October 29, the Agency issued a third interim final rule responding to the Supreme Court's order by further temporarily amending the good neighbor plan to administratively stay the effectiveness of its requirements for covered facilities in the remaining 11 states for which an administrative stay was not already implemented under the two previous interim final rules starting with the 2024 ozone season: California, Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. In addition, the D.C. Circuit has granted EPA a voluntary partial remand of the record of the good neighbor plan to enable EPA to more fully respond to certain comments identified by the Supreme Court. The three interim final rules include provisions designed to ensure that states' obligations to address interstate ozone pollution with respect to the 2008 ozone NAAQS under two prior rules, the CSAPR [Cross-State Air Pollution Rule] update and the revised CSAPR update, continue to be met while the effectiveness of the good neighbor plan's requirements is stayed."

Table 3. MISO Ozone Transport Rule Resource Adequacy, MISO Comments to EPA

Y2026	Impacted Generation, MW	Hours of Insufficient Generation	Change from Base Case
Base Case	–	6	–
Retirement + Retrofits	12,438	99	16.5 times greater
Retire All Affected Units	12,438 + 11,514 = 23,952	477	79.5 times greater

Legacy CCR Rule

Another EPA rule is the disposal of CCRs, also known as fly ash. Coal-fired power plants are required to improve their fly ash disposal sites to meet the new EPA rule.[34] In North Dakota, this rule could impact Coal Creek Station, owned by Rainbow Energy Center (REC). This 1.1-GW generation station is connected to the MISO transmission system in LRZ01. EPA has provided notice that it intends to deny Coal Creek Station's compliance plan application. 4.7 GW of generation connected elsewhere in the MISO system may also be impacted, for a total of 5.8 GW including Coal Creek Station. As shown in the data previously presented in this report, the loss of 1.1 GW of capacity in MISO LRZ01 and 5.8 GW in the total MISO area will be devastating to MISO resource adequacy. However, EPA has left room to consider grid reliability as a reason to grant an extension to compliance, and MISO provided comments to EPA addressing that issue. No

[32] National Mining Association, 2024, https://nma.org/2024/06/27/nma-applauds-supreme-court-stay-of-epa-ozone-transport-rule/ (accessed October 2024).
[33] EPA Response to Judicial Stay Orders, 2024, www.epa.gov/Cross-State-Air-Pollution/epa-response-judicial-stay-orders (accessed October 2024).
[34] U.S. Environmental Protection Agency, 2023, www.epa.gov/coalash/coal-combustion-residuals-ccr-part-b-implementation (accessed October 2024).

SPP-connected generation is affected by the CCR rule. EPA posted its final legacy CCR surface impoundment rule on November 8, 2024.[35]

Regional Haze Rule

OTPCO and MDU are concerned about this rule's impact on the Coyote Station. In its 2022 proposed revision to the state implementation plan to address regional haze, the North Dakota Department of Environmental Quality (NDDEQ) determined for the second implementation period that Coyote Station does not require emission reductions to comply with the regional haze rule. However, if EPA does not accept this conclusion, Coyote Station may require significant upgrades. In its "Application for Supplemental Resource Plan Approval 2023–2037" to the Minnesota Public Utilities Commission, OTPCO is requesting the ability to withdraw from Coyote Station ownership if it is faced with "nonroutine capital investments," which will likely include the cost of complying with EPA's regional haze regulations.[36] In the submittal, OTPCO recognizes that if it cannot find an entity to replace its Coyote Station ownership participation, the station will likely be closed. The MDU 2024 Integrated Resource Plan estimates the cost to install new flue gas desulfurization equipment at $243 million, with a $20.6-million-per-year operating cost.[37] NDDEQ submitted a state implementation plan to EPA in August 2022. EPA is expected to give a decision by the end of November 2024. If EPA disapproves or partially disapproves, a federal implementation plan may require MDU to establish different pollution controls at Coyote Station.[37]

In July 2024, EPA posted its expectations and guidance memorandum regarding the second planning period state implementation plan progress reports.[38]

NSPS for Greenhouse Gas Emissions

EPA posted a new rule regarding NSPS for greenhouse gas emissions (111b and d) on May 9, 2024, that became effective July 8, 2024. This proposed rule requires coal-fired power plants that are scheduled to operate after 2039 to capture at least 90% of their CO_2 emissions.[39]

At least two North Dakota utilities are developing carbon capture and storage (CCS) projects that would capture 90% of CO_2 emissions and inject the CO_2 into geologic formations permitted for permanent CO_2 storage.

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[35] U.S. Environmental Protection Agency, 2024, www.epa.gov/coalash/final-rule-legacy-coal-combustion-residuals-surface-impoundments-and-ccr-management-units (accessed October 2024).
[36] Otter Tail Power Company, 2024, www.otpco.com/about-us/energy-generation/resource-plan (accessed October 2024).
[37] Montana–Dakota Utilities Co., 2024, www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/2021-ND-IRP-Volume-1-non-print.pdf (accessed October 2024).
[38] U.S. Environmental Protection Agency, 2024, www.epa.gov/visibility/second-planning-period-progress-reports (accessed October 2024).
[39] U.S. Environmental Protection Agency, 2023, www.federalregister.gov/documents/2023/05/23/2023-10141/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed (accessed October 2024).

Developing and deploying these projects require visionary strategic planning and are technically, logistically, and economically challenging, especially when considering that the techno-economic viability of utility-scale 90% CO_2 capture has not yet been demonstrated . The North Dakota Transmission Authority (NDTA) May 17, 2024, report analyzing the impact of the EPA 2023 GHG Emissions Rule on North Dakota fossil fuel power plants describes the challenges of deploying CCS/carbon capture, utilization, and storage (CCUS) technologies. .[40]. Only one large-scale CCUS project is presently in service (Boundary Dam in Saskatchewan, Canada), and it is not currently meeting the EPA 90% capture criteria. CCS and CCUS projects come with high capital cost (in the range of $1.5 billion per site depending on site-specific conditions and objectives) and operating cost (due to significant electricity consumption). Adding to the challenges, EPA is calling for CCS or CCUS deployment by January 2032 while—as described in the NDTA report—permitting and construction would likely take at least 10 years.

The NDTA report also included an analysis of potential impacts of the 2023 GHG Emission Rule on SPP resource adequacy. The analysis used EPA model-generated data in the context of SPP generation accreditation rules. Figures 12 and 13 compare forecasted peak demand with accredited generation and PRM for summer and winter, respectively

The NDTA analysis shows a large deficiency of generation starting with inadequate PRMs in 2028 and inadequate capacity after 2030.

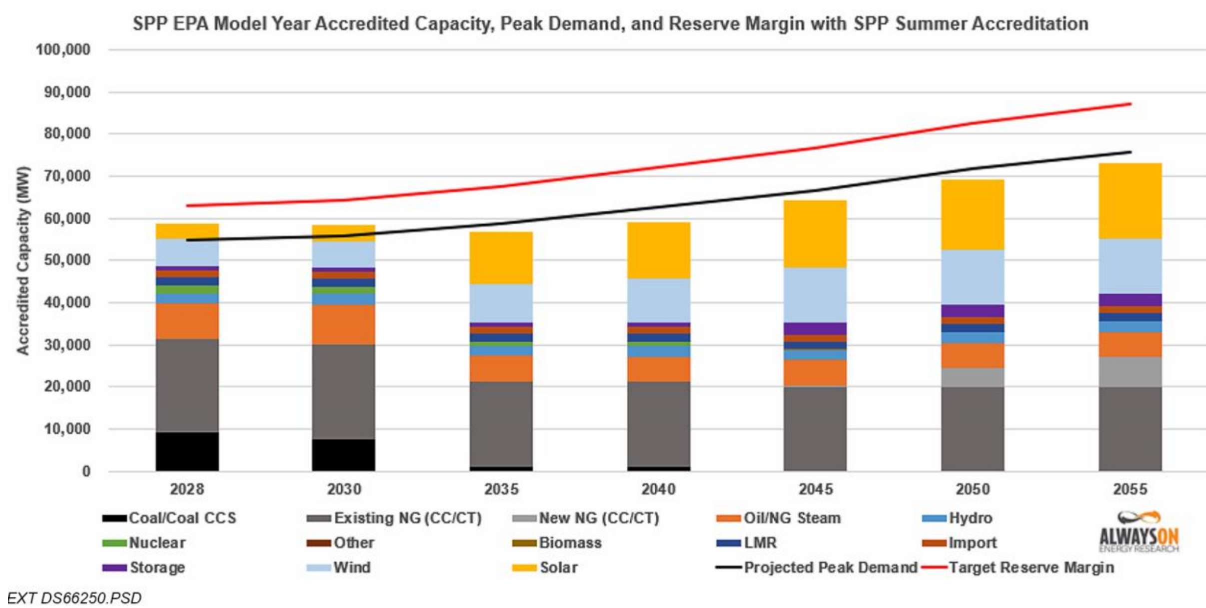

Figure 12. SPP summer generation accredited capacity versus peak demand with margin.

[40] North Dakota Transmission Authority, 2024, www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/AlwaysOnEnergyResearchGreenhouseGasReport5172024.pdf (accessed October 2024).

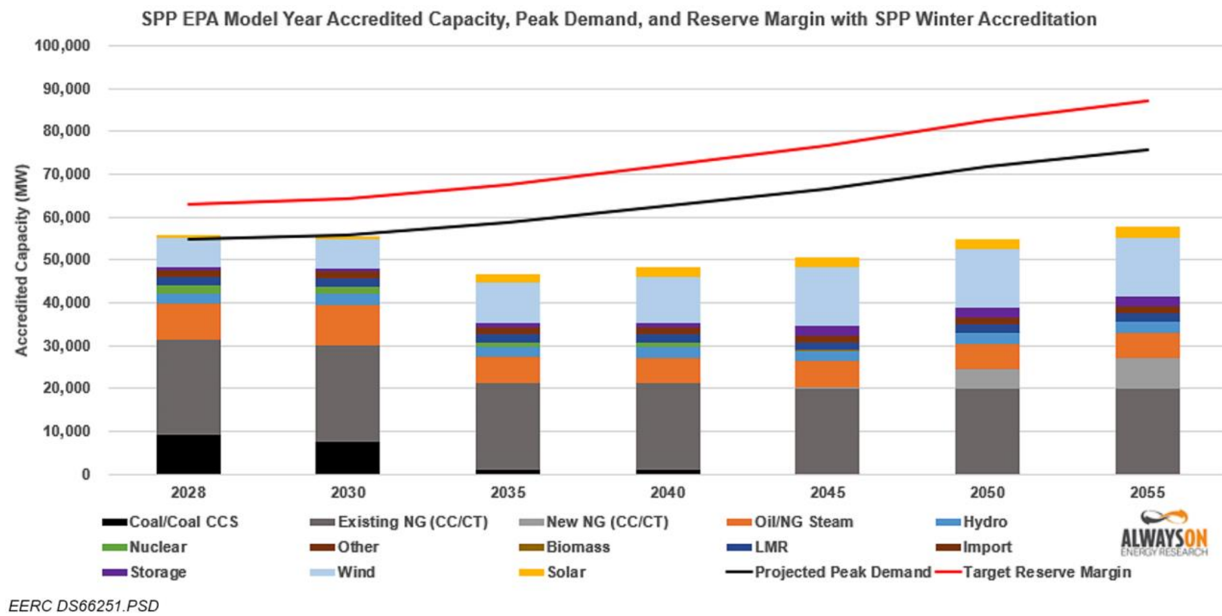

Figure 13. SPP winter generation accredited capacity versus peak demand with margin.

The NDTA study also analyzed the impacts of the proposed EPA carbon rules on resource adequacy in the MISO region. This analysis incorporated EPA's projected 2035 generation portfolio and utilizes 2020 weather data to model renewable energy output. The results showed a lack of generation resources due to wind generation operating lower than EPA's assumptions. The worst shortfall was 25,900 MW in July 2035, as shown in Figure 14. These data confirm the MISO data provided in Table 3.

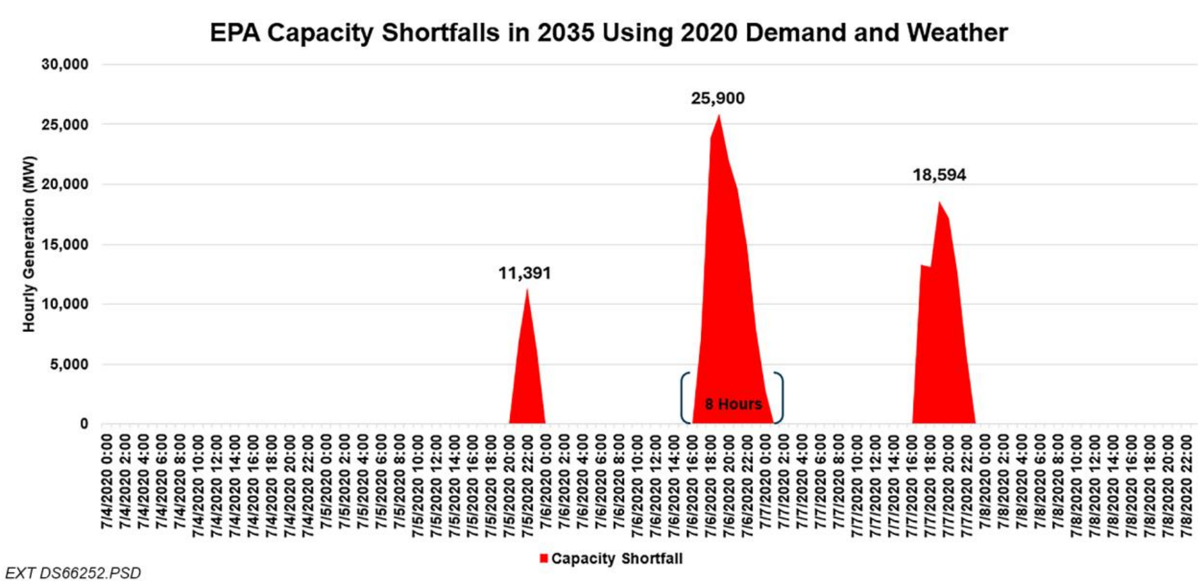

Figure 14. July 4–8, 2035, MISO capacity shortfall with EPA portfolio.

The authors have also found data errors in the EPA greenhouse gas regulation study. In EPA's resource adequacy analysis technical support document,[41] Table A-3, a 16% planning reserve margin is considered. However, SPP has changed its winter planning reserve criteria to 33%. This could be a loss up to 8 GW of generation, assuming 17% additional reserves to meet 50 GW of load obligation. Therefore, the EPA analysis overstates how much generation capacity is available to serve load. In Table 3-26 of the regional net internal demand in the EPA reference case,[42] the peak demand for SPP is understated. For example, EPA is using 55 GW of peak demand, but in the 2024 SPP FERC 714 form submittal, SPP is forecasting 62.5 GW of peak demand by 2029. EPA is short 7.5 GW of peak demand in its model. Therefore, EPA is short 8 GW of generation and 7.5 GW of peak demand for a total error of 15.5 GW in just SPP.

EPA also overstates the hydro capacity factor in SPP. In its power system operation assumptions document,[43] EPA uses a hydro capacity factor of 40%–45%. However, the WAPA hydro capacity factor is 37%.[44] WAPA is the only significant source of hydro power in SPP.

It is also noted that the EPA report overestimates the transmission capacity available between the WAPA system within SPP and the MISO Minnesota–Wisconsin system. In Table 3-5 of the power system operation assumption document,[43] EPA claims this capacity to be 3000 MW. However, based on historical data, the actual available transmission capacity between WAPA and MISO is significantly lower—often close to 0 MW at times. This discrepancy will likely lead to the EPA model inaccurately simulating energy transfers between SPP and MISO, transfers that would not occur in real-world operations. As a result, this error could obscure congestion and resource shortages within the SPP and MISO systems.

If CCUS technology performs as expected, it will enable dispatchable, reliable baseload generation to continue operating while meeting low-CO_2-emission standards. Additionally, income streams may be available from 45Q direct payments or enhanced oil recovery to offset the costs associated with CCUS equipment. The economics of CCUS are critical, as all coal-fired generation in North Dakota is bid into the SPP or MISO energy markets, where it competes with other sources of power. To achieve the necessary yearly run time hours and generate the income needed for high-capital projects with long payback periods, low bid prices will be essential.

MPC is developing CCUS through its Project Tundra at the Milton R. Young generation station site in Oliver County. It has received EPA monitoring, reporting, and verification (MRV) plan approval and is working on air permits. The estimated construction cost is $1.4 billion.

REC is also investigating CCUS at its Coal Creek Station near Washburn, North Dakota. In partnership with the Energy & Environmental Research Center (EERC), REC received a $38

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[41] U.S. Environmental Protection Agency, 2024, www.epa.gov/system/files/documents/2024-04/tsd-resource-adequacy-analysis_final.pdf (accessed October 2024).
[42] U.S. Environmental Protection Agency, 2023, www.epa.gov/power-sector-modeling/documentation-2023-reference-case (accessed October 2024).
[43] U.S. Environmental Protection Agency, 2024, www.epa.gov/system/files/documents/2024-04/chapter-3-power-system-operation-assumptions.pdf (accessed October 2024).
[44] U.S. Department of Energy, 2021, www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf (accessed October 2024).

million award from the U.S. Department of Energy (DOE) to investigate CCUS solutions at Coal Creek Station.[45]

MATS

On April 25, 2024, EPA announced final revisions to strengthen the MATS rule for existing coal-fired power plants.[46] These rules were published in the Federal Register on May 7, 2024, and were effective July 8, 2024. A request to block the rule while challenges were litigated was blocked by the U.S. Supreme Court on October 4, 2024,[47] so the rule remains in effect. The rule targets lignite fuel power plants. Under the previous rule, the mercury emission limit was 4 lb/TBtu, while a bituminous and subbituminous fuel plant was 1.2 lb/TBtu. The rule sets the lignite emission limit to the same as the bituminous and subbituminous limit. This new standard will apply to the entire fleet of North Dakotas lignite coal-fired power plants.

Transmission Adequacy

North Dakota utilities and transmission developers are a part of an incredibly complicated system that manages the transmission of over 200,000 MW of electricity through 100,000 miles of transmission lines and delivers power to customers in 20 states.[48] Figure 15 shows the North Dakota transmission lines. Within North Dakota, management of the transmission system and its reliability operation is a function of SPP and MISO RTOs. However, actual physical control is performed by the local utilities as transmission operators (TOPs) to meet their own operation and maintenance needs or at the direction of the RTO should a more regional issue require action. The RTOs perform this role as part of their NERC-defined responsibility as a RC. The RC, through a real-time computer simulator called a “state estimator,” monitors the health of the transmission system. Should the state estimator detect an operating criterion violation during a simulated outage, the RC can direct real-time redispatch, flow gate activation, or the local TOP to mitigate the potential impact of the outage.

Determination of future transmission adequacy is performed by a process called transmission planning. Both SPP and MISO RTOs have similar transmission-planning processes. NERC standards dictate the requirements of this process. The process has a time frame anywhere from the present to 20 years in the future, based on the goals and requirements of the particular study.

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[45] Hoeven, J., 2023, www.hoeven.senate.gov/news/news-releases/hoeven-helps-secure-more-than-38-million-award-to-support-implementation-of-ccus-at-coal-creek-station (accessed October 2024).
[46] U.S. Environmental Protection Agency, 2024, www.epa.gov/system/files/documents/2024-04/presentation_mats_final-2024-4-24-2024.pdf (accessed October 2024).
[47] Scotus News, 2024, www.scotusblog.com/2024/10/supreme-court-declines-to-block-epa-methane-mercury-rules/ (accessed October 2024).
[48] North Dakota Transmission Authority, 2022, www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-22.pdf (accessed October 2024).

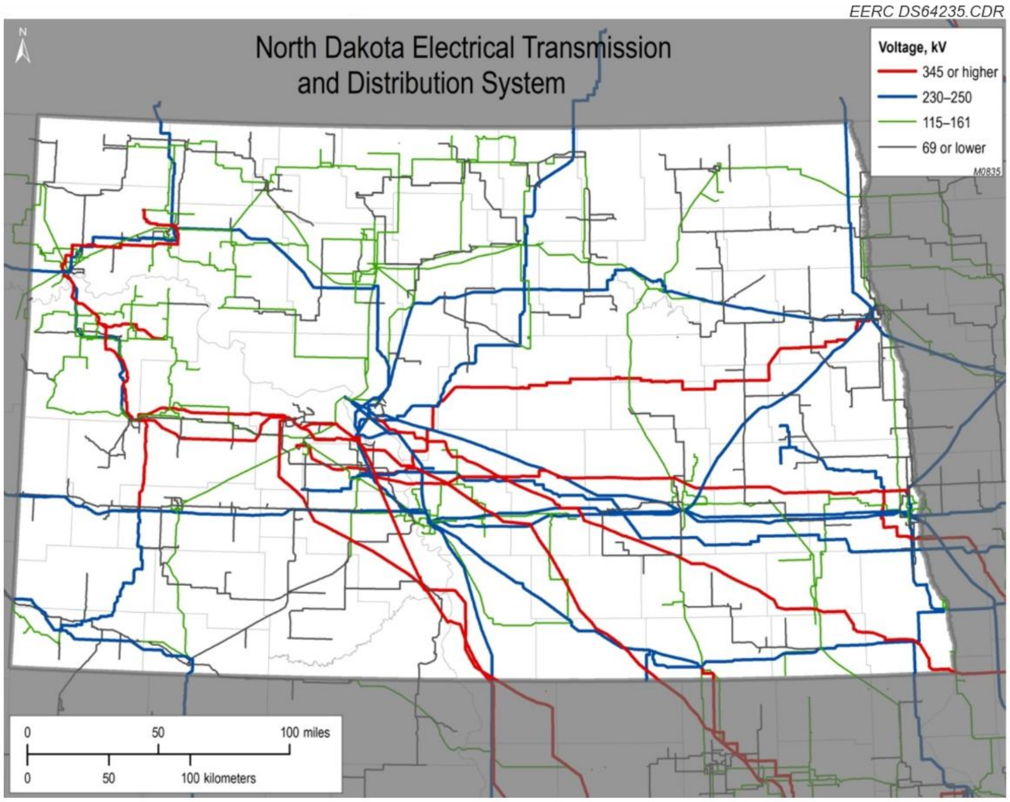

Figure 15. Transmission lines in North Dakota.

The transmission-planning process is a collection of studies that will create a list of projects to meet the following needs:

Reliability: The study will identify facility additions required to ensure NERC operating and planning criteria are met to ensure the system operates reliably over the identified time frame.

Congestion Relief or Economic: Transmission congestion can curtail the production of economic resources and increase overall energy prices. Targeted additions of new transmission can relieve congestion. The resulting energy price cost savings can result in the transmission project having a benefit–cost ratio higher than 1.0.

Generation Interconnection: New generation projects may inject more power than the transmission system can accommodate. Analysis is required to determine the required transmission upgrades to accommodate generation requests. These studies are done in a grouped manner based on interconnection request date or project readiness.

Transmission Service Request: These requests are for new point-to-point schedules of power. Depending on the source and sink of the request, new transmission upgrades may be required.

New Load Requests: Normally, systemwide load growth is approximately 1%–2%. This impact is accommodated in the reliability study process. However, for large spot loads that are requested with short notice, special load addition studies may be required to determine the need for transmission upgrades.

SPP Transmission-Planning Process

The primary SPP transmission-planning process is called the integrated transmission plan (ITP). This is performed yearly and results in a portfolio of new projects based on reliability needs and/or economic benefit. The ITP covers a gamut of scenarios, near-term, 5-year, and 10-year forecasts. It includes baseline and high-renewable-generation assumptions for each case. Reliability and economic analysis are performed in a separate but coordinated manner. The initial analysis results in a list of deficiencies, which are outages that cause a violation of SPP planning criteria. These deficiencies are posted for a 2-week period. Stakeholders have an opportunity to provide detailed project proposals (DPPs) to cure each deficiency. SPP collects all the DPPs and runs them through a screening process. SPP then picks a family of DPPs that will address all the deficiencies, which becomes the ITP project portfolio. This portfolio is reviewed by stakeholders as well as several SPP work groups and then is submitted to the SPP board for approval. After board approval, the reliability projects are assigned to affected transmission owners via a notice to construct.

Separate processes accommodate generation interconnection, short-notice load interconnection, and transmission service requests. Projects derived from these processes are consolidated into the SPP transmission expansion plan (STEP). A recent example of the process, the 2021 ITP study,[49] resulted in the Leland Olds–Tande 345-kV transmission project, which includes a new delivery substation near New Town, North Dakota; the Kummer Ridge–Roundup 345-kV transmission line project; a new 345-kV delivery substation near Williston, North Dakota; and a voltage control facility (Static Var) at New Town. These projects are derived from the reliability analysis portion of the 2021 ITP study and are needed to accommodate load growth in the Bakken oil production area of western North Dakota. The 2021 ITP study also identified the need for two 230-kV transmission lines from northwestern North Dakota to Saskatchewan, Canada. These transmission lines are required to accommodate a 600-MW transmission service request from SPP to Saskatchewan. This represents 210 miles of 345-kV and 110 miles of 230-kV transmission line construction (Figure 16). The total cost estimate of these projects is $725 million.

The 2024 ITP final portfolio includes major transmission upgrades in North Dakota.[50] These projects include a $740 million 345-kV line connecting the Laramie River Station near Wheatland, Wyoming, to Belfield, North Dakota. Also included is a $240 million project that consists of upgrading an existing 230-kV line from Leland Olds generation station to Logan Substation (near Minot, North Dakota) and a new 345-KV line from Logan Substation to a new substation in the New Town North Dakota, area; a $70 million 345-kV line from the Watford City North Dakota,

[49] Southwest Power Pool, 2021, https://spp.org/documents/64632/2021%20itp%20scope_v1.1.pdf (accessed October 2024).
[50] Southwest Power Pool, 2024, www.spp.org/documents/68855/2024%20itp%20assessment%20scope%20v1.3.pdf (accessed October 2024).

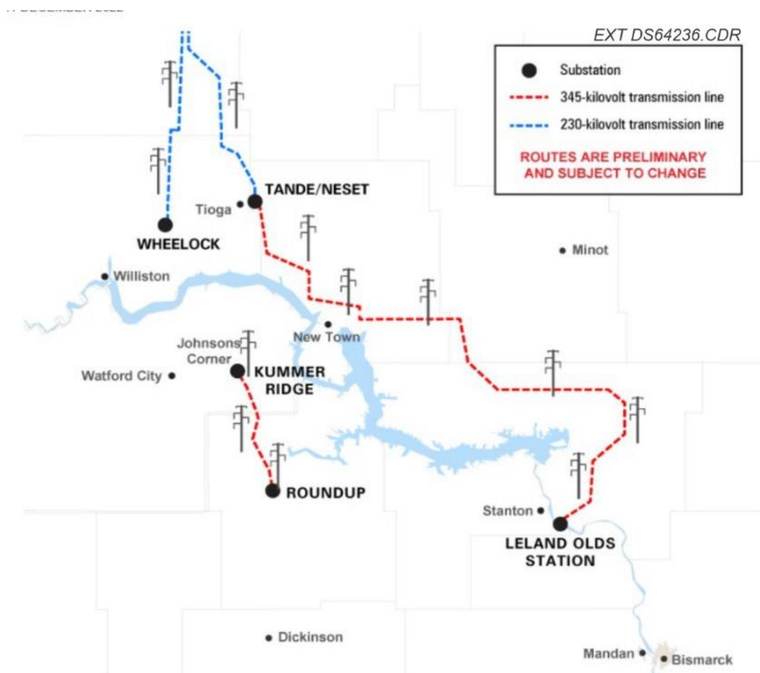

Figure 16. BEPC proposed transmission projects.[51]

area to Williston, North Dakota; and several other projects. The 2024 ITP portfolio will be submitted to the SPP board of directors in October 2024. The portfolio of all projects in the SPP footprint is estimated to be up to $7.7 billion. Table 4 outlines the transmission projects scheduled for completion within the next 5 years in SPP and North Dakota.

Table 4. SPP Transmission Projects in North Dakota[52]

G&T Utilities	Transmission Line Project
BEPC	a. Kummer Ridge to Roundup 345-kV line (35 miles) b. Leland Olds–Finstad–Tande 345-kV line (170 miles) c. Tande-to-Saskatchewan and Wheelock-to-Saskatchewan 230-kV transmission line project d. Springbrook 345/115-kV substation and 12-mile 345-kV line e. Belfield, North Dakota, to Laramie River Station 345-kV line f. Judson–Pioneer 345-kV line g. Finstad–Logan–Leland Olds 345-kV line
WAPA	a. Dawson County, Montana, to Williston, North Dakota, 230-kV line
MWEC	a. Finstad–Satterwaite 115-kV line b. Ellisville–Simpson 115-kV line c. Pioneer–Sanderson 115-kV line

[51] Basin Electric Power Cooperative, 2022, https://www.basinelectric.com/news-center/news-briefs/Basin-Electric-board-approves-nearly-a-half-billion-dollars-in-new-transmission-construction-in-western-North-Dakota (accessed October 2024).
[52] Basin Electric Power Cooperative, 2024, https://apps.psc.nd.gov/webapps/cases/ psdocketdetail?getId=24&getId2=259&getId3=1#, (accessed October 2024).

MISO Transmission-Planning Process

The primary MISO transmission-planning process is the MISO transmission expansion plan (MTEP). This annual assessment is performed in a similar manner to the SPP ITP process. MISO also performs a long-range transmission-planning (LRTP) study as needed that covers a 20-year horizon and a multivalued project process that incorporates high-level policy, regulation, and economic considerations.

The 2021 LRTP[53] considers three scenarios called futures. These futures are a base case assuming utility resource plans proceed as announced, a future assuming 60% carbon reduction and energy consumption increase of 30% by 2024, and a future assuming 80% carbon reduction and energy consumption increase of 50% by 2024. For each reliability need, several solutions are identified. These reliability solutions are tested with an economic analysis using a production cost analysis to determine the benefit–cost ratio. The projects that meet the reliability needs with the best economic benefit are added to the LRTP portfolio.

The LRTP performed as part of the 2021 MTEP resulted in the Jamestown–Ellendale 345-kV project (Figure 17). The project is being developed by OTPCO and MDU. It will be an 85-mile-long, 345-kV transmission line connecting OTPCO's Jamestown substation with MDU's Ellendale substation. The in-service date is 2028, and the estimated cost is $439 million. This project's purpose is to relieve transmission congestion on the 230-kV transmission system in southeastern North Dakota and thereby facilitate export of North Dakota wind energy to Minnesota. The LRTP also identified the need for 17 other projects elsewhere in MISO with a total cost of $10 billion. These projects are referred to as the Tranche 1 portfolio and have a benefit–

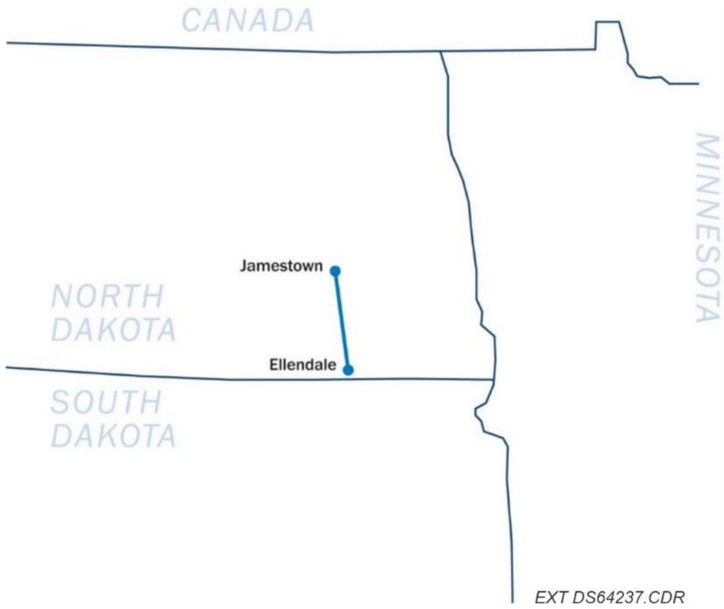

Figure 17. Jamestown–Ellendale 345-kV transmission line.

[53] Midcontinent Independent System Operator, 2022, https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf (accessed October 2024).

cost ratio between 2.6 and 3.8. Tranche 1 focused on the northwestern part of the MISO footprint and included North Dakota.

MISO's present study effort, MTEP23, has moved into the central and southern regions of the MISO footprint and is referred to as Tranche 2. While there are $9 billion worth of projects proposed, only $69 million are in North Dakota.[54] These projects include a $25 million Nelson Lake Substation to be built by Great River Energy and Minnesota Power Inc. and a $18 million rebuild of the MDU Wishek Substation.[55] Table 5 outlines the transmission projects scheduled by G&T utilities in the next 5 years within the MISO footprint in North Dakota.

Transmission Line Construction-Permitting Challenges

Acquiring the necessary permits from the various regulatory entities is a major component of a transmission line construction schedule. However, often that effort is a major roadblock to project completion. For example, Nebraska Public Power District's R-Project, a $400 million, 345-kV transmission line, has been stuck in the National Environmental Policy Act (NEPA) process since 2013.[56]

Table 5. MISO Transmission Projects in North Dakota[57–58]

G&T Utility Company	Project
Minnesota Power Inc.	Nelson Lake 230-kV substation Square Butte DC line upgrade
MPC	Buxton–Taft–Caledonia 69-kV line rebuild
MDU	Wishek Substation rebuild Ellendale Load 2 addition
Northern States Power Company	Prairie to OTPCO connection rebuild
OTPCO	Wilton 41.6-kV breaker addition Gackle–Jamestown 41.6 kV Pickert–McVille 41.6 kV Wabek–Parshall 41.6 kV Cooperstown 41.6 kV Devils Lake 115-kV delivery Fordville–Fordville Junction 41.6 kV Michigan–Mapes 41.6 kV
MDU and Otter Tail Power	Jamestown–Ellendale 345-kV line

[54] Midcontinent Independent System Operator, 2023, https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf (accessed October 2024).
[55] Midcontinent Independent System Operator, 2024, www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd= (accessed October 2024).
[56] Nebraska Public Power District, 2024, https://rproject.nppd.com/project-status/ (accessed October 2024).
[57] Montana–Dakota Utilities Co., 2024, https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=264# (accessed August 2024)
[58] Otter Tail Power Company, 2024, https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=285# (accessed August 2024).

In order to expedite the permitting process, on April 25, 2024, DOE announced a Coordinate Interagency Transmission Authorization and Permits (CITAP) Program.[59] The CITAP Program will coordinate government review and approval by streamlining the permitting process. The goal is to ensure that federal permitting is completed in 2 years. Fortunately, North Dakota has not experienced the issues with permitting that have severely delayed projects in other states.

Load Forecast

RTOs perform a yearly reliability study. SPP's process is the ITP, while MISO's process is the MTEP. Each plan requires approximately 1 year of load forecast and other data-gathering to prepare the power flow base cases used for the reliability studies before the actual reliability study can start. Internally to the RTO members, additional time is required to prepare the load forecasts for submittal to the RTOs. Therefore, in any given reliability study, the actual load forecast can be 2 to 3 years old by the time the study is completed. This time lag introduces a probability that the forecast will be inaccurate because of changing of the parameters of the original forecast over time. An example is the impact of the Bakken oil and gas area. The oil and gas industry responds to market conditions faster than the reliability study process can accommodate. Therefore, its power needs are highly variable. In the case of the Bakken, the rapid increase in load exceeds the load-serving capacity of the local transmission system. Short-term mitigation is the addition of undervoltage load-shedding relays, out-of-merit-order operation of generation, and establishment of special operating guides. New projects under construction identified by the SPP reliability study process will restore required transmission capacity. RTOs have processes to account for the addition of individual new loads that appear with little notice, but these studies have a narrow focus that does not account for regional impact which is covered by the annual reliability studies. Figure 18 illustrates projected growth in systemwide peak demand for LSEs in North Dakota. It should be noted that "systemwide" encompasses a utility's total (North Dakota and beyond) service territory. BEPC is expected to see the largest systemwide growth, driven by oil and gas (including hydrogen) activities, crypto mining, and data centers. Xcel Energy's annual systemwide demand growth is projected at 2%–4%. Other LSEs in North Dakota are expected to experience modest systemwide demand growth over the next 10 years.

Data centers have long been pivotal in facilitating traditional Internet-based services. In recent years, the demand for data centers has grown significantly globally, driven by the rapid advancement and adoption of artificial intelligence (AI) technologies. AI applications demand significant computational power and storage, driving the increased need for data centers. Each ChatGPT request consumes approximately 2.9 watt-hours (Wh) of electricity, about ten times the energy required for a traditional Google query (about 0.3 Wh).[60] Other major contributors to increasing electricity demand include the ongoing expansion of cryptocurrency mining, cloud services, and the growing dependence on digital infrastructure across various industries.

By March 2024, the number of data centers worldwide had reached around 10,655, with the United States hosting 5381 of them. This marks a significant increase from January 2021, when there were about 8000 data centers globally, roughly one-third of which were located in the United

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[59] U.S. Department of Energy Grid Deployment Office, 2024, www.energy.gov/articles/biden-harris-administration-announces-final-transmission-permitting-rule-and-latest (accessed October 2024).

[60] Vries, A.D., 2023, The growing energy footprint of artificial intelligence: Joule, v. 7, no. 1, p. 2191–2194.

States. In 2023, 15 states (including North Dakota) accounted for 80% of the U.S. data center load.**Error! Bookmark not defined.** North Dakota's significant tax incentives, low cost of o perations, low-cost reliable electricity, and natural cold weather have made it a preferred location for data centers.

The Electric Power Research Institute (EPRI) projects that by 2030, data centers will account for 9.1%, 6.8%, 5.0%, and 4.6% of total U.S. electricity consumption under higher-, high-, moderate-, and low-growth scenarios, respectively, assuming all other loads increase by 1% annually.[61] It is projected that major independent system operators (ISOs) including SPP and MISO will see more than 100% growth within 2027.[62] Table 6 compares EPRI-estimated 2023 North Dakota data center electricity consumption (in MWh and as a percentage of total North Dakota electricity demand) to projected 2030 values based on four different growth scenarios. As shown in Table 6, data centers are anticipated to be a major driver of North Dakota electricity demand.

Table 6. EPRI-Projected Power Consumption by North Dakota Data Centers (2023–2030)[61]

Data Center (cumulative) Load	MWh/year	% of Total State Electricity Consumed
2023 Load	2,975,815	15.4
2030 Load Estimates Based on Increasing Levels of Data Center Growth		
Low Growth, 3.71%	3,840,169	18.0
Moderate Growth, 5%	4,187,271	19.3
High Growth, 10%	5,799,022	24.8
Higher Growth, 15%	7,901,284	31.1

There is a growing trend toward transportation electrification, with electric vehicles (EVs) becoming increasingly prevalent. However, from a load-forecasting perspective, EV adoption presents significant challenges due to its unpredictable nature. . It is likely that retail rates will discourage charging during system peak load periods, limiting charging to off-peak periods. Therefore, EVs may not increase peak demand significantly. Another uncertainty is EVs could discharge during peak demands if proper incentives are available. This would have the net effect of reducing peak demand. MISO performed a study in 2021 on the impact of EVs on its transmission system operations.[63] MISO investigated two scenarios looking at the year 2039, assuming a high EV fleet percentage, up to 30%. The first scenario was charging times responding to market price signals; the second added a discharge into the grid option as well. With low market prices occurring in off-peak times, there was no increase in peak system usage. All charging occurred in off-peak times. Adding the discharge ability, the system peak loads were curtailed as the EVs acted as a negative load, providing power in response to high market price signals.

[61] Electric Power Research Institute, 2024, Powering intelligence—analyzing artificial intelligence and data center energy consumption: 2024 White Paper.
[62] Wilson, J.D., and Zimmerman, Z., 2023, The era of flat power demand is over: Grid Strategies.
[63] Greenblatt, J., McCall, M., and Prabhakar, A.J., 2021, https://cdn.misoenergy.org/20210505%20MISO%20 Electrification%20Studies%20Workshop%20Item%2003%20Vehicle%20Impact%20Assessment546340.pdf (accessed October 2024).

Therefore, given the ability to respond to the proper price signals, EVs were found to be a positive impact to the high-voltage transmission grid. However, this is dependent upon EV charging only occurring during off-peak load time periods which may not be realistic as commuters may want to charge their vehicles while at work. Also, the MISO study did not consider the effect on lower-voltage distribution systems which may have difficulty accommodating the electrical needs of EV chargers.

RTO Market Function

The purpose of an RTO market is to match resources and loads and establish prices for wholesale electric energy. In MISO and SPP, there are two markets: the day ahead and real time. The day ahead allows generators and customers to establish binding schedules and commitments for the next day. As the name suggests, the real-time market functions in real time, with pricing solutions calculated every 5 minutes. The real-time market trues up the day-ahead market commitments with the actual real-time use of the system. For example, if an entity forecasts a need for 10 MW during a particular hour in the day-ahead market but the actual need was 11 MW, the entity would acquire the extra 1 MW in the real-time market.

The market-clearing price is the marginal price to serve the next 1-MW increment of electric load. The market participants submit their load forecasts and generation offers. The RTO stacks the generation bids from lowest to highest. Based on the load at the time of calculation (hourly for day ahead and 5 minutes for real time), the highest-offered generation price required to serve the next 1 MW becomes the RTO marginal price. For example, if the load is 100 MW and there are generation bids of 75 MW at $50/MWh and 75 MW at $100/MWh, the marginal price is $100/MWh. In this example, the second generator is dispatched at 25 MW. Absent losses and congestion, this price applies to the entire RTO footprint. This price is defined as the marginal energy component (MEC).

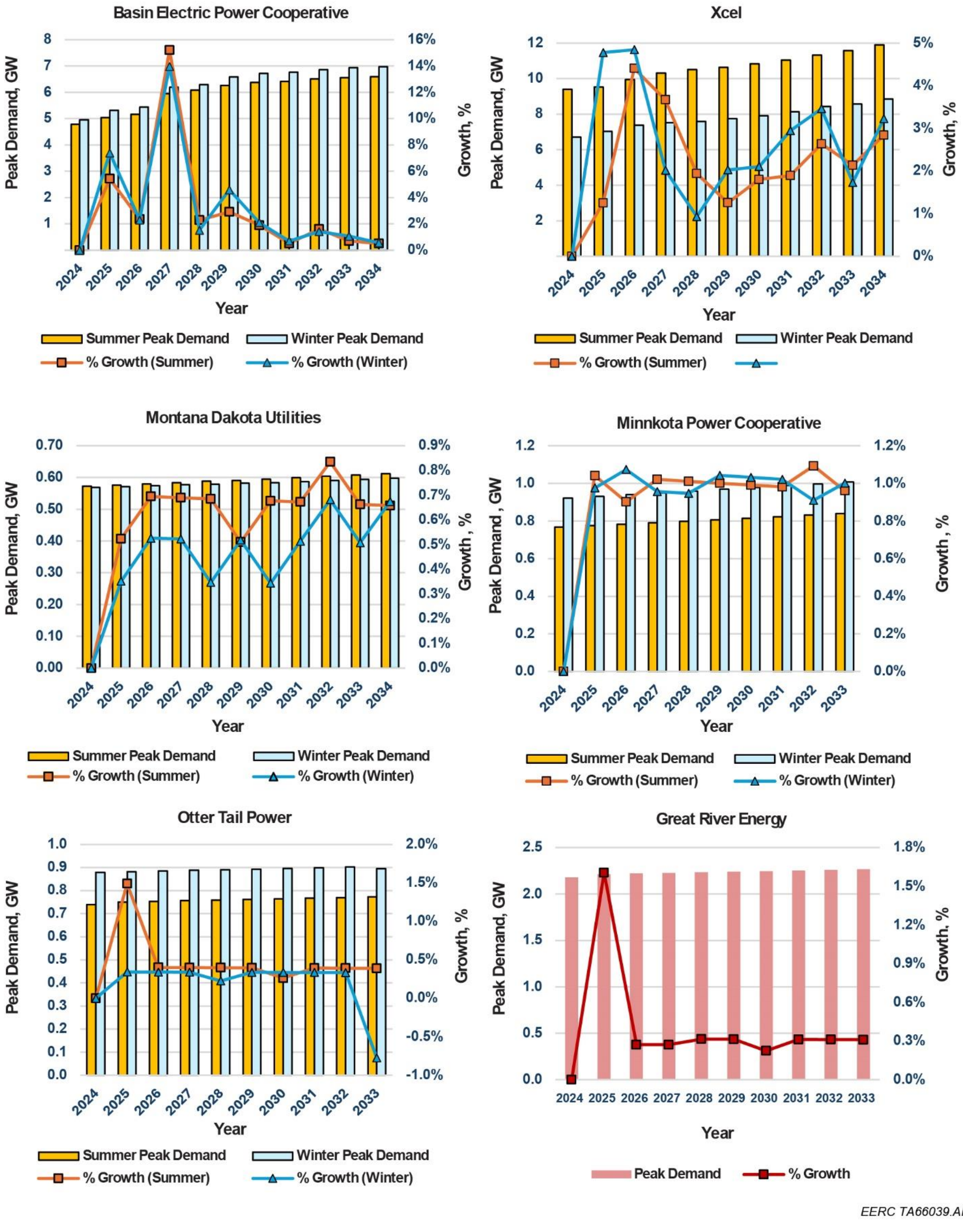

Figure 18. Forecast of systemwide seasonal peak demand and annual demand growth of North Dakota utilities.

However, because of losses and congestion, the net marginal price will vary by its location on the transmission network. Thus the clearing price at a particular location is referred to as the locational marginal price (LMP) (Figure 19). Losses are the energy wasted by the electrical friction of current traveling through a conductor. Depending on the location of a particular generator, a schedule can either increase or decrease system losses. These losses are calculated and defined as the marginal loss cost (MLC). Congestion can constrain generation schedules to load. Similar to losses, the location of the generator can either increase or decrease congestion. The congestion costs are defined as marginal congestion cost (MCC). Congestion is the amount of megawatts that flow across a particular path on the transmission system that exceeds the amount of megawatt capacity that path can accommodate without violating system operating criteria, such as thermal overload or voltage excursions.

LMP at any location is the summation of the MEC, MLC, and MCC. The MLC and MCC can have positive or negative adjustments to MEC. The variability of LMP across the geographical footprint of the RTO can distort the normal stacking of generation bids. If a generator is contributing to transmission system losses and/or congestion, its MLC and/or MCC costs will decrease its LMP and put that generator at a market disadvantage, perhaps to the point of it dropping out of the stack. Conversely, a more expensively bid generator may gain an advantage if its operation lowers losses and/or congestion and incentivizes it to run. The result is the generator with the negative impact on congestion will be reduced, and the generator that relieves congestion will be increased. In this way, price signals control of the dispatch of generation to manage transmission losses and congestion. A good example of this process is a transmission flow gate in western North Dakota that is frequently flagged on SPP’s LMP heat map.

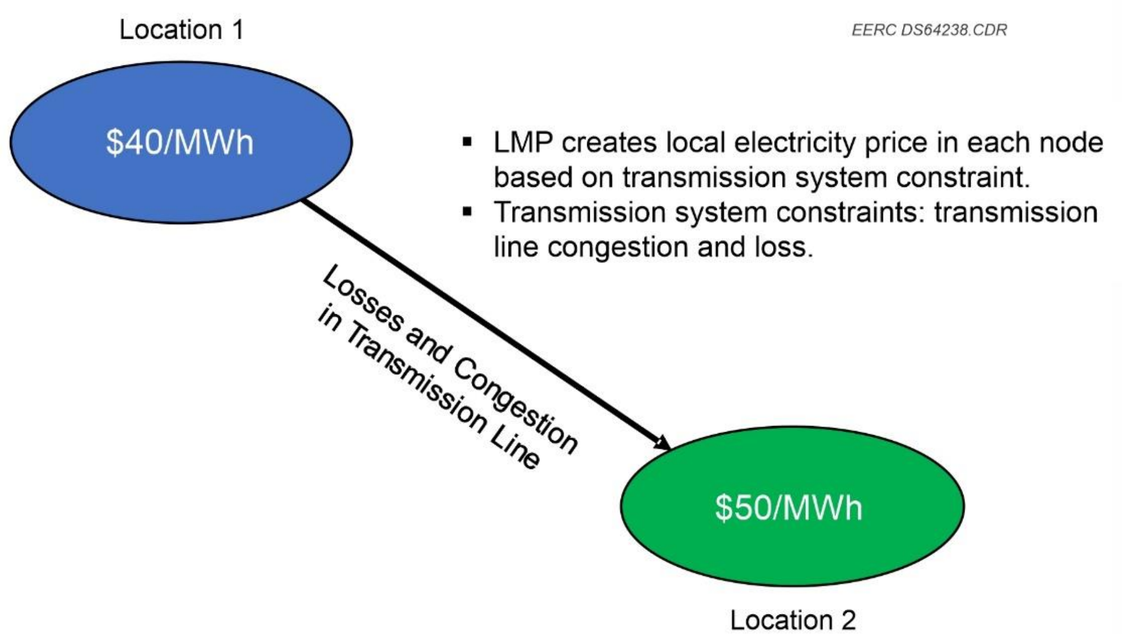

Figure 19. LMP.

When Bakken area loads are high and area generation is out of service, LMP prices rise because of congestion on the western North Dakota flow gate. This provides an incentive for the operation of peaking generation in the area to run to take advantage of the high prices. The power injection of the peaking generation backs off the power flow across the transmission flow gate and congestion is relieved.

Figure 20 shows an actual LMP map of SPP. LMP prices are defined by color along the left side of the map, and actual prices are plotted over a map of the SPP region. This format is referred to as heat map. In Kansas, there is a large differentiation in prices. This represents a transmission congestion situation. LMP prices in western Kansas are negative, as shown by the dark purple color. Prices in eastern Kansas are relatively high, as shown by the light blue color representing LMP of around $40/MWh. These price differences will force a redispatch, as the generators in the negative area will curtail and the negative prices will force them to pay into the market to operate. Meanwhile, the generation in the $40/MWh region will be incentivized to operate. The resulting change in power injections into the transmission system will reduce power flow across the congested element and relieve transmission congestion.

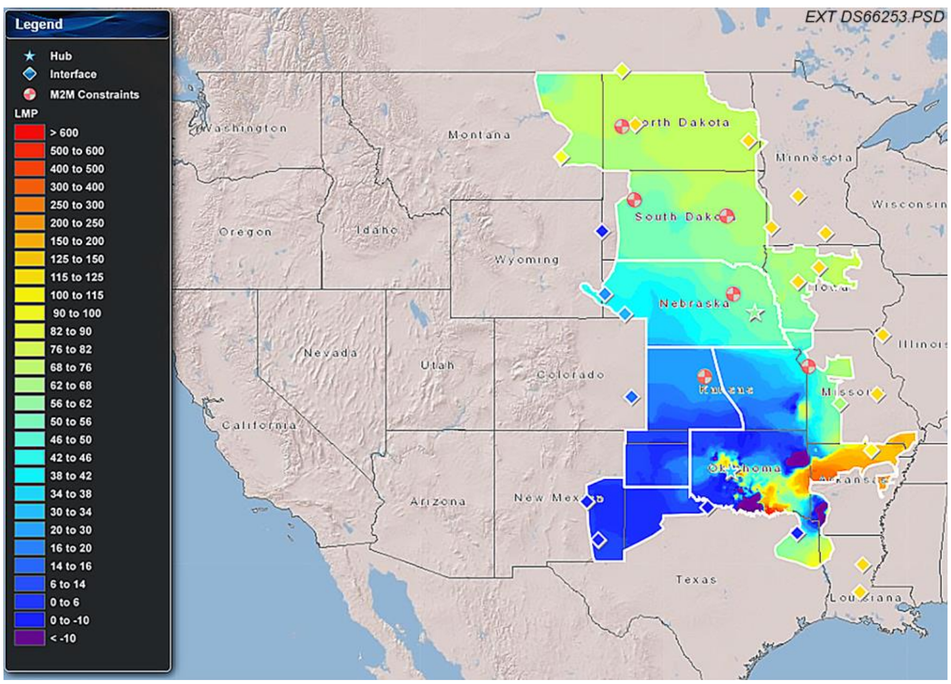

Figure 20. Example SPP LMP map.[64]

MDU has recently faced higher energy costs due to transmission congestion in western North Dakota. This congestion puts a strain on the transmission infrastructure and violates transmission constraints. Although SPP has confirmed that data center load growth in western North Dakota has contributed to the increased congestion, it also noted that transmission congestion existed prior

[64] Southwest Power Pool, 2024, https://pricecontourmap.spp.org/pricecontourmap/ (accessed October 2024).

to the establishment of Atlas Power.[65] During the fall of 2023, the most congested transmission constraint in the SPP region was Flow Gate 5717 at Charlie Creek–Watford City 230 kV [WAUE] for the loss of Charlie Creek–Patent Gate 345 kV [WAUE]. SPP attributed this congestion to transmission and generation outages, along with increased loads and the impact of wind generation. Figure 21 illustrates the real-time off-peak and on-peak LMP prices within the SPP footprint during the fall of 2023, showing that the highest LMP prices for both off-peak and on-peak periods occurred in the SPP territory in North Dakota.

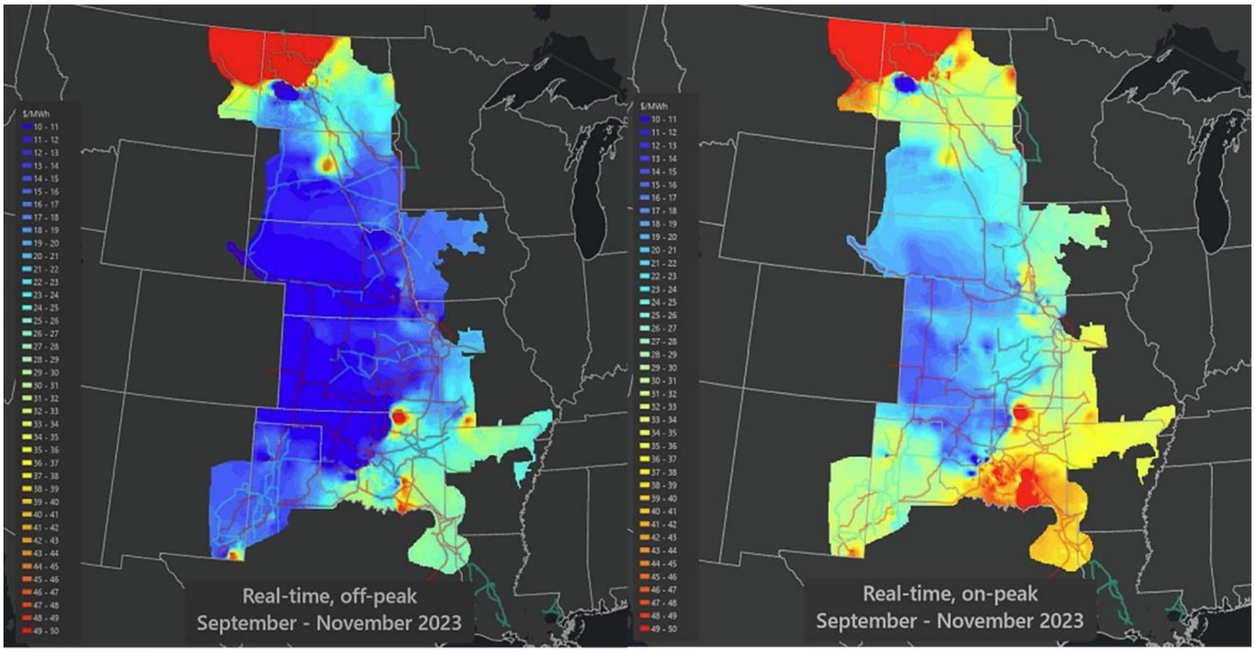

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Figure 21. Real-time off-peak and on-peak price in SPP territory.

The market impact of a transmission constraint is typically measured by the shadow price, which indicates the degree of congestion on a specific flow gate. The shadow price represents the marginal value of alleviating congestion on a constrained path and its effect on reducing total production costs. This value is reflected in the marginal congestion component of the energy price. Figure 22 illustrates congestion by shadow price for the rolling 12-month period ending in November 2023. The Charlie Creek–Watford City 230-kV (WAUE) flow gate had the highest average shadow price in both day-ahead and real-time markets during this period.[66]

[65] Southwest Power Pool, 2024, www.spp.org/documents/71108/20240212_spp%20answer%20-%20montana-dakota%20utilities%20complaint_el24-61-000.pdf (accessed October 2024)
[66] Southwest Power Pool, 2023, www.spp.org/documents/71103/spp%20mmu%20qsom%20fall%202023%20v2.pdf (accessed October 2024).

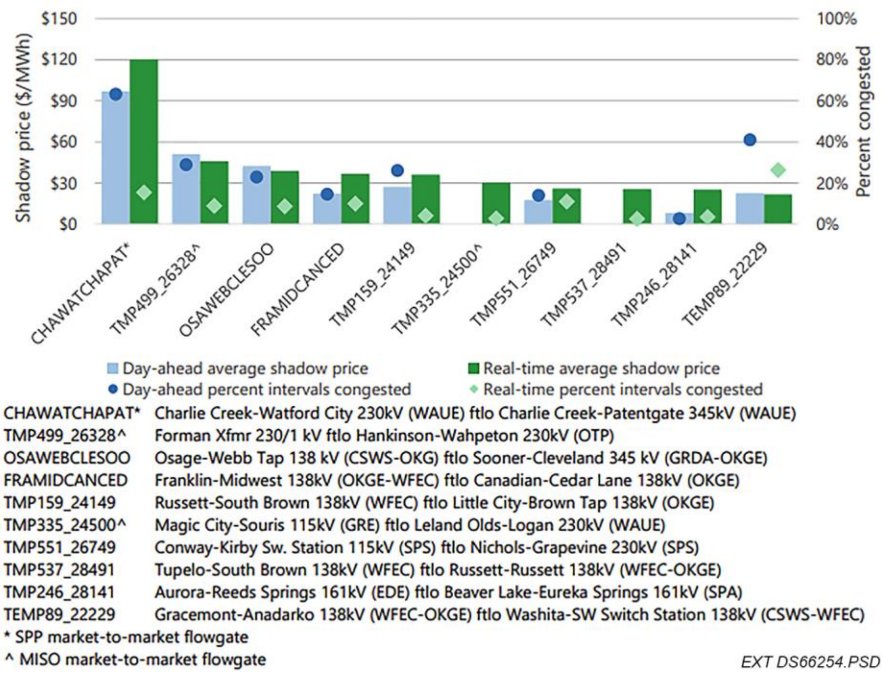

Figure 22. Shadow prices for the top 10 most congested flow gates in SPP over the rolling 12-month period.

MDU has filed a protest with FERC against SPP regarding the congestion charges. The situation is complex because MDU is a MISO member and the flow gate is managed by SPP. MDU asserts that SPP applied the congestion fees inappropriately resulting in duplicative congestion charges. SPP disagrees and believes it followed its tariff and the SPP–MISO joint operating agreement appropriately. On September 11, 2024, FERC dismissed the MDU complaint against SPP.[67]

Transmission congestion was relieved significantly in 2024. BEPC installed a remedial action scheme that trips the Atlas Power load in the event of the limiting transmission line outage and dynamic line rating measuring devices were placed on WAPA's Charlie Creek–Watford City 230-kV line. The dynamic line rating allows real-time calculation of transmission line rating instead of using conservative design-rating assumptions. Meanwhile BEPC's Round Up–Patent Gate 345-kV line is expected to be placed in service by the end of 2024, and the BEPC Leland Olds–Tande 345-kV line expected in service by the end of 2026.[68] BEPC's Pioneer Phase IV 600-MW generation additions are expected to be placed in service in 2025. These projects will add a significant amount of transmission capacity to the Bakken area.

[67] RTO Insider LLC, 2024, www.rtoinsider.com/87067-ferc-refuses-miso-mdu-complaints-flowgate/ (accessed October 2024).

[68] Basin Electric Power Cooperative, 2024, www.basinelectric.com/about-us/transmission/Leland-Olds-to-Tande-transmission-project (accessed October 2024).

Electric Power G&T Providers in North Dakota

North Dakota's electric providers can be classified into three categories: rural electric G&T cooperatives, investor-owned utilities (IOUs), and municipal utilities. These entities are either members of SPP and/or MISO. BEPC, Central Power Electric Cooperative (CPEC), Upper Missouri G&T, and MPC are the rural G&T cooperatives in North Dakota (Figure 23). OTPCO, MDU, and Xcel Energy are the IOUs currently operating in North Dakota (Figure 24). Missouri River Energy Services and the Northern Municipal Power Agency (NMPA) provide electric energy to North Dakota's municipal power utilities.

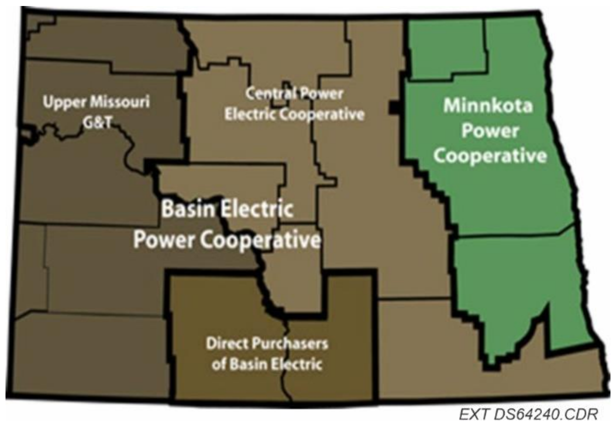

Figure 23. North Dakota rural G&T cooperatives.[69]

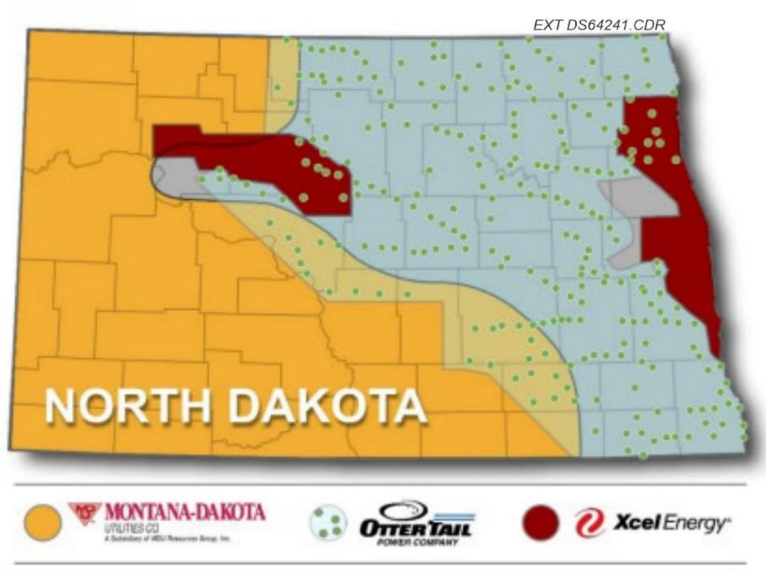

Figure 24. North Dakota IOU service territories.[70]

[69] North Dakota Association of Rural Electric Cooperatives, 2024, www.ndarec.com/content/generation-transmission-cooperatives (accessed October 2024).
[70] Clark, T., and Erickson, T., 2022, https://www.wbklaw.com/wp-content/uploads/2022/03/Resource-Adequacy-in-North-Dakota-Feb2022-00B.pdf (accessed October 2024).

Rural Electric G&T Cooperatives

BEPC

BEPC and its member cooperatives have a generation capacity of over 3000 MW in North Dakota. It also has power plants in South Dakota, Wyoming, and Iowa. Combining the generation capacity of all the power plants, BEPC has a maximum nameplate capacity of 8112 MW at the end of 2023. Figure 25 shows a breakdown of BEPC's generation mix.[71]

BEPC's member systems are located in both EIC and WIC. To enable power transfers between EIC and WIC, BEPC either owns or has obtained rights in three back-to-back DC ties (Miles City, Rapid City, and Stegall) for a total capacity of approximately 300 MW.

BEPC has load in both the SPP and MISO RTOs. BEPC is a transmission owner, generation owner, and market participant in SPP, while in MISO, they are only a market participant.

According to SPP's 2024 resource adequacy report, BEPC has a net accredited capacity of 4216 MW in the SPP region in 2024. It has a net peak demand of 3482 MW, which makes its resource adequacy requirement 4004 MW. Currently, its PRM is 21.1%, which is 6.1% above the SPP's PRM requirement of 15%.[72]

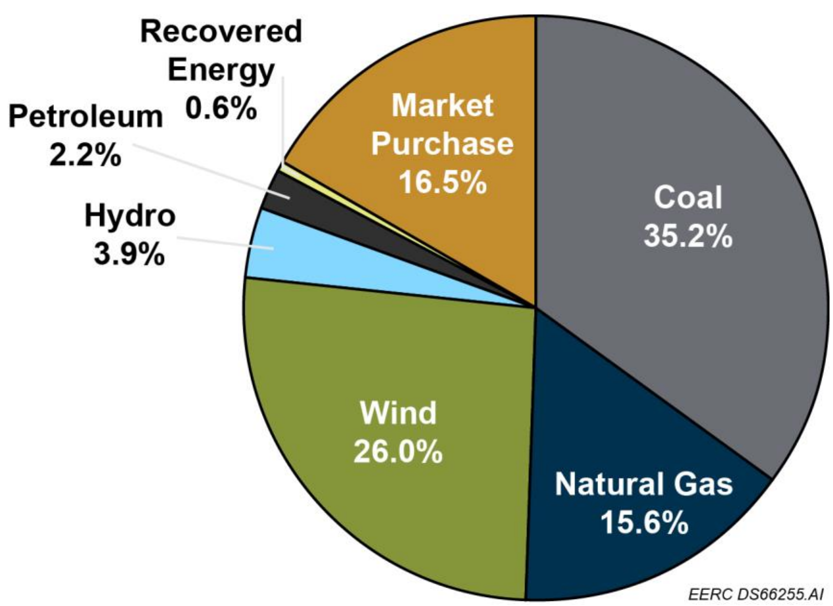

Figure 25. Fuel generation mix of BEPC.

[71] Basin Electric Power Cooperative, 2024, www.basinelectric.com/about-us/organization/At-a-Glance/index (accessed July 2024).
[72] Southwest Power Pool, 2024, www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf (accessed October 2024).

In MISO, BEPC has approximately 450 MW of peak load in LRZ01 and 75 MW in LRZ03. BEPC serves this load with generation resources acquired from the MISO market or bilateral agreements with other entities.[73]

According to the BEPC 2023 integrated resource plan (IRP), BEPC peak summer load is expected to reach 5500 MW by 2032 (Figure 26). This could increase if potential data center load comes to fruition.[70]

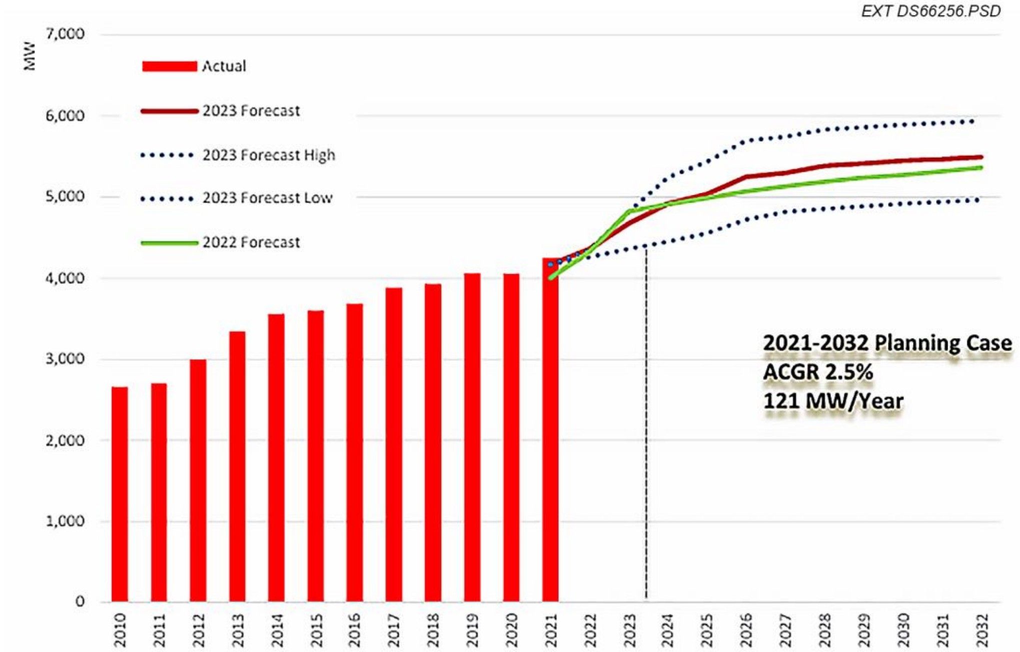

Figure 26. Basin forecast of summer electric demand.

BEPC has announced plans to construct a 1400-MW natural gas-fired combined cycle power plant in North Dakota. The in-service date is 2030.[74] It presently has Pioneer Station Phase IV under construction, with an in-service date in 2025–26. It consists of a 600-MW combination of natural gas-fired simple cycle and reciprocating engine generators located west of Williston, North Dakota.[75] This resource will be used to service BEPC load in the SPP system.

To meet its MISO load obligation, BEPC is partnering with Dairyland Power Cooperative and ALLETE to develop the Nemadji Trail Energy Center (NTEC), a proposed 600-MW gas-fired

[73] Basin Electric Power Cooperative, 2023, www.wapa.gov/wp-content/uploads/2023/11/basin-electric-2023-irp-5-year-report.pdf (accessed October 2024).
[74] McKenzie County, 2024, https://county.mckenziecounty.net/News/Plans-to-build-a-natural-gas-fired-plant-in-ND (accessed October 2024).
[75] Basin Electric Power Cooperative, 2024, www.basinelectric.com/News-Center/news-briefs/Construction-update-at-Pioneer-Generation-Station-Phase-IV (accessed October 2024).

combined cycle power plant. It is located in Superior, Wisconsin, and interconnects into MISO Zone 1. Basin Electric will own 30% of the project.[76]

Upper Missouri G&T Cooperative and CPEC both source their power from BEPC and WAPA. CPEC serves six distribution cooperatives and around 50,000 customers. Annual peak demand of CPEC is 483 MW in the winter and 335 MW in the summer.[77] Upper Missouri G&T Cooperative serves 11 distribution cooperatives, has its operations in North Dakota and Montana, and 96.87% of its power comes from BEPC. It had an average demand of 1555.2 MW in 2020. The Bakken shale field and related oil and gas activity lie within the Upper Missouri G&T Cooperative service area. Barr Engineering's power forecast in 2021[78] predicted that these efforts in western North Dakota would cause energy demand to increase in the coming years.

MPC

MPC is a not-for-profit electric G&T cooperative headquartered in Grand Forks, North Dakota. It provides wholesale electric energy to 11 member–owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota. MPC is the operating agent for NMPA, which serves Grafton, North Dakota, and Park River, North Dakota, as well as nine municipal utilities in Minnesota. MPC serves nearly 137,000 consumer accounts in Minnesota and North Dakota.[79]

MPC and NMPA jointly operate as a "joint system" because of their shared ownership of transmission facilities and MPC's role as NMPA's operating agent. The Joint System meets its capacity and energy requirements through MPC's aggregated generation. MPC and NMPA's joint system has most of its power generation plants in North Dakota. They have nameplate generation capacity of 1332.5 MW.[80] Figure 27 shows the generation resource mix of the MPC.

MPC is a MISO market participant and has an obligation to maintain MISO's resource adequacy requirements. It requires generation capacity exceeding customer demand and load forecasts by an adequate margin. MPC's winter peak is 994 MW in 2023, and it is projected to rise to around 1069 MW in 2036. This high-load growth projection considers annual 1.8% increase of load. MPC's current nameplate capacity is larger than the forecasted winter peak demand in 2036. However, load growth can change drastically and is subjected to demand forecast uncertainty. To ensure MPC's generation capability is well above customer demand, MPC evaluates its customer profile every year.

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[76] Basin Electric Power Cooperative, 2024, www.basinelectric.com/News-Center/basin-today-stories/How-Basin-Electrics-new-partnership-in-Wisconsin-builds-on-a-long-term-strategy (accessed October 2024).
[77] Central Power Electric Cooperative, 2024, https://centralpwr.com/quick-facts (accessed July 2024).
[78] Barr Engineering, 2021, www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-Power-Forecast-Study-Update-21.pdf (accessed October 2024).
[79] Minnkota Power Cooperative, 2024, https://www.minnkota.com/minnkota-website/our-power/minnkota-about-us (accessed July 2024).
[80] Minnkota Power Cooperative, 2022, https://assets.website-files.com/5ef212e2cdca1e094063db4e/62d062e4a190aaacf6237297_2022%20Integrated%20Resource%20Plan.pdf (accessed July 2024).

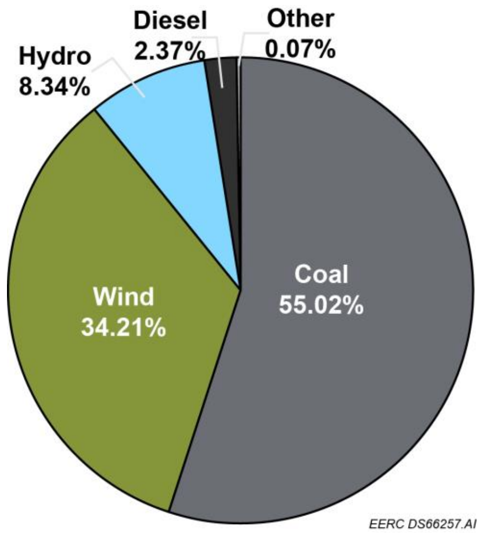

Figure 27. Fuel generation mix of MPC.

Investor-Owned Utilities

OTPCO

OTPCO is an investor-owned electric utility that provides electricity for residential, commercial, and industrial customers in Minnesota, North Dakota, and South Dakota. Its service area spans over 70,000 miles. It has a total of 59,181 customers in North Dakota. Figure 28 shows the OTPCO service area in Minnesota, North Dakota, and South Dakota. OTPCO's generation mix includes coal-fired plants, hydroelectric plants, wind power, solar power, and combustion turbines.[81] OTPCO is a market and transmission-owning member of a MISO RTO. Figure 29 shows the energy generation mix of OTPCO. Its current generation capacity is around 1100 MW.

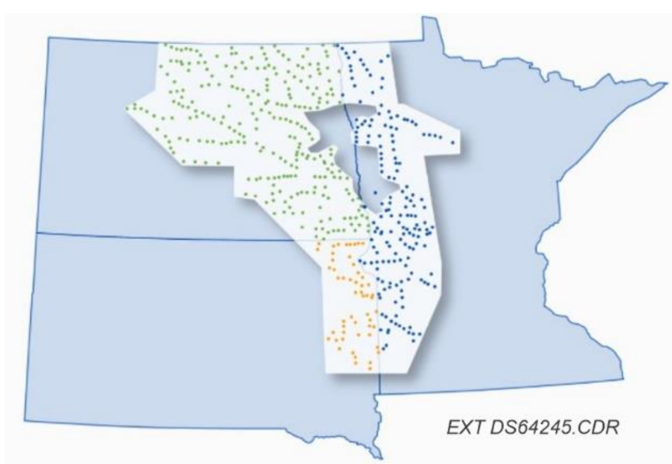

Figure 28. OTPCO service area.

[81] Otter Tail Power Company, 2024, www.otpco.com/about-us/energy-generation/ (accessed October 2024).

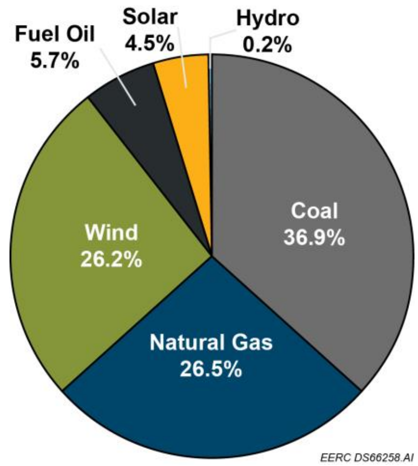

Figure 29. OTPCO resource generation mix.

The company is planning to move toward renewable generation. According to its 2024 IRP, OTPCO will add 200–300 MW of solar generation, 150–200 MW of wind generation, and 20–75 MW of battery storage through 2029. On May 30, 2024, the Minnesota Public Utilities Commission approved OTPCO's IRP. One of the conditions of approval was that Coyote Station generation could only be provided to customers in Minnesota under emergency conditions from 2026 through 2031. The demand projection indicates a peak load growth of 943 MW until 2031.[82] However, around one-third of generation capacity is dependent on wind. The new generation capacity addition will also be renewable. These factors are required to be considered for long-term grid reliability of OTPCO.

MDU

MDU is a subsidiary of MDU Resources Group, Inc., a diversified natural resources company based in Bismarck, North Dakota. MDU is a MISO market participant and transmission owner. It provides electricity and retail natural gas to parts of Montana, North Dakota, South Dakota, and Wyoming. The MDU service area covers more than 168,000 square miles and serves about 410,000 customers. Figure 30 shows the service territory of MDU.[83] MDU has 656 MW of generation capacity. The utility has observed summer peak demand of 588.8 MW in the summer of 2023. MDU's projected summer peak by the end of 2040 is 639.2 MW, while the winter peak is expected to reach 620.3 MW.[84] MDU has recently retired its old coal-fired plants, Lewis and Clark and Heskett 1 and 2 power stations. The combined capacity of these two power stations was 144 MW. In July 2024, MDU placed a second 88-MW combustion turbine generator at Heskett in service. Figure 31 shows the generation resource mix for MDU.[85]

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[82] Otter Tail Power Company, 2024, https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=285# (accessed October 2024).
[83] Montana–Dakota Utilities Co., 2024, www.montana-dakota.com/in-the-community/about-us/ (accessed October 2024).
[84] Montana–Dakota Utilities Co., 2024, www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/2024-ND-IRP-Volume-1-non-print.pdf (accessed October 2024).
[85] Montana–Dakota Utilities Co., 2022, www.montana-dakota.com/wp-content/uploads/2022/03/MISO_Generation_Handout-March-2022.pdf (accessed October 2024).

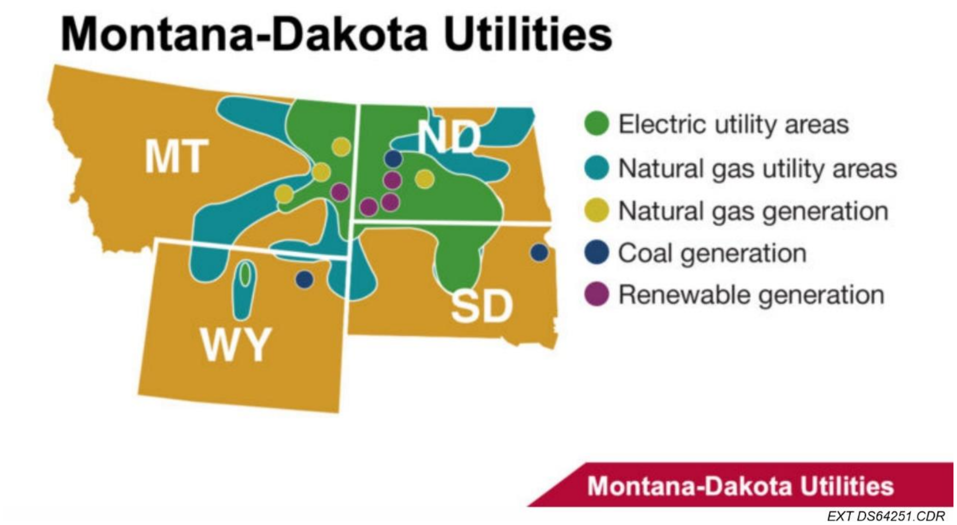

Figure 30. MDU service area.

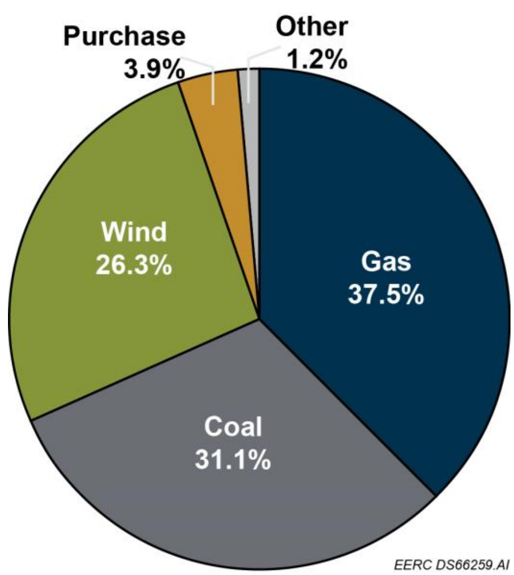

Figure 31. MDU generation energy mix.

Xcel Energy

Xcel Energy is the largest generation utility in MISO LRZ01. It has four operating utilities: Northern States Power Company Minnesota and Northern States Power Company Wisconsin in Minnesota, North Dakota, South Dakota, and Wisconsin; Public Service Company of Colorado in Colorado; and Southwestern Public Service Company in New Mexico and Texas, which serve a combined total of more than 3.6 million electricity customers and 2 million natural gas customers in eight states. Figure 32 shows the service area of Xcel Energy. In North Dakota, Xcel Energy serves the cities of Minot, Grand Forks, and Fargo.

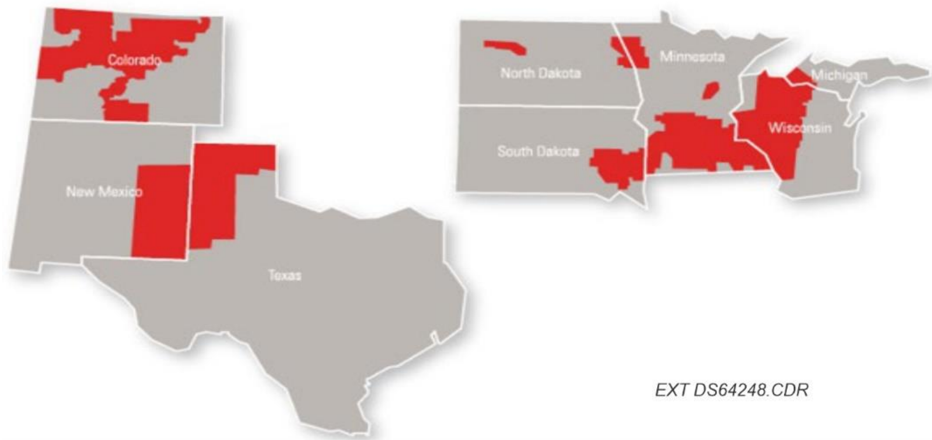

Figure 32. Xcel Energy service area.[86]

Figure 33 displays the Xcel Energy fuel generation mix in 2024. In its IRP, Xcel Energy announced the retirement of all its coal plants by the end of 2030, resulting in a reduction of 2400 MW of baseload generation capacity. Additionally, 1700 MW from power purchase agreements is set to expire between 2025 and 2028. To replace these resources and meet increasing demand, Xcel Energy plans to add 4300 MW of wind and solar generation by 2030. This includes solar resources from community solar gardens (CSGs) and distributed solar, along with 600 MW of stand-alone storage to optimize the system performance.[87] Figure 34 shows the Xcel Energy preferred planned resource addition until 2036. It has 500 MW of wind power installed in North Dakota. Being a part of MISO LRZ01, Xcel Energy in North Dakota will be subjected to future capacity risks associated with this zone.

Municipal Utilities in North Dakota

There are eight municipal electric utilities in North Dakota. They are served either by Missouri River Energy Resources (MRES) or NMPA.

MRES

MRES is a wholesale power supplier to the municipalities of Valley City, Hillsboro, Lakota, Riverdale, Northwood, and Cavalier in North Dakota as well as many others in Minnesota, Iowa, and South Dakota. MRES is a member of SPP and MISO.

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[86] S&P Golbal Market Intelligence, 2018, www.spglobal.com/marketintelligence/en/news-insights/trending/hket0zxvuq6rblqc1u8i7q2 (accessed July 2024).

[87] Xcel Energy, 2024, www.house.mn.gov/comm/docs/QuTxkS7XWk2ri4NTdBl9kg.pdf (accessed October 2024)

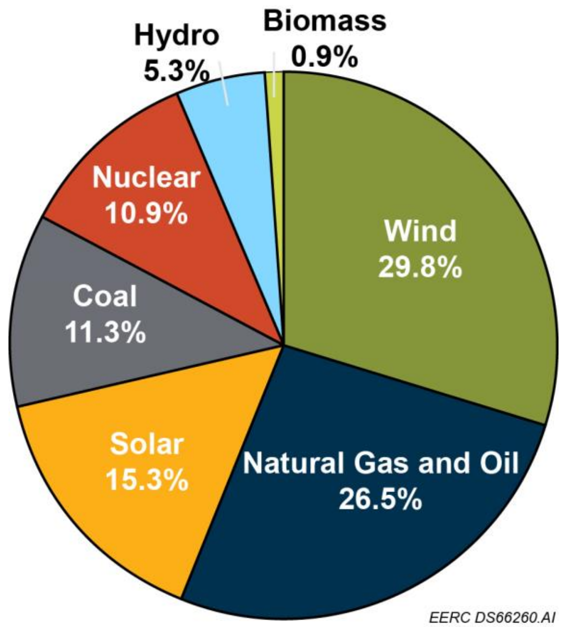

Figure 33. Fuel generation mix of Xcel Energy in 2024.

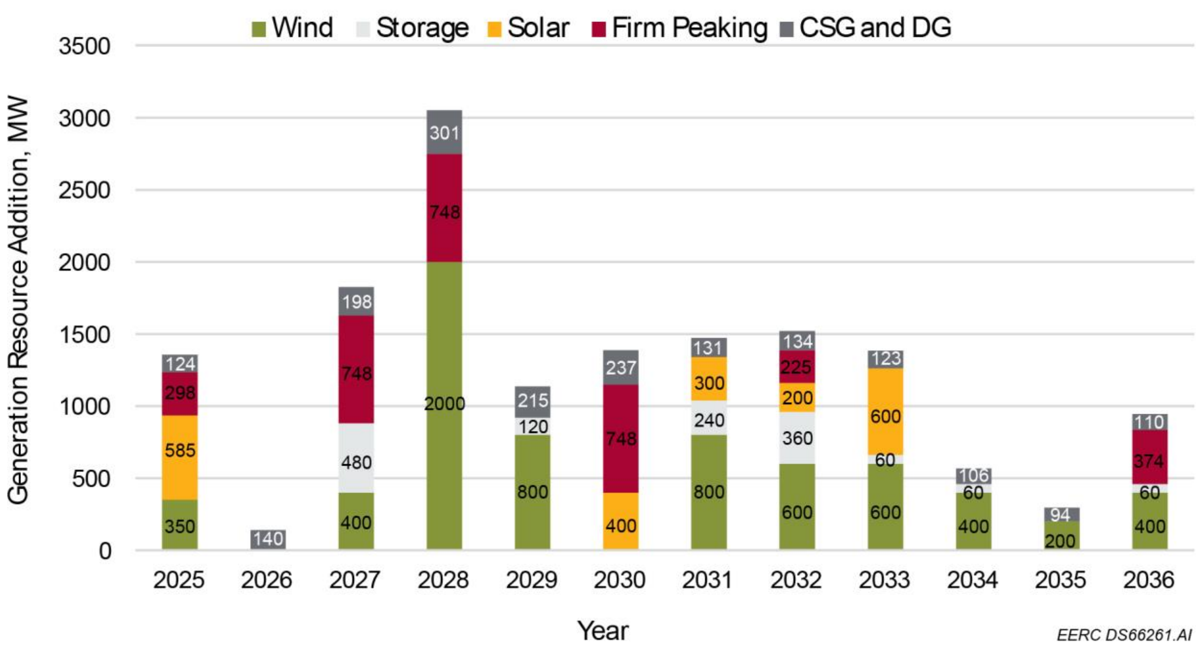

Figure 34. Xcel Energy preferred resource addition until 2036.

NMPA

NMPA comprises 12 municipal utilities, ten in northwestern Minnesota and two in eastern North Dakota (Grafton and Park River), serving around 15,800 customers. NMPA is a Class B member of MPC and appoints a nonvoting liaison to attend MPC's board of directors meetings. It holds a 30% ownership stake in Coyote coal plant in Beulah, North Dakota, as well as a proportional interest in MPC's transmission system based on its load ratio share.

Distribution Cooperatives in North Dakota

There are 16 electric distribution cooperatives in North Dakota. Figure 35 shows the map of distribution cooperatives in North Dakota.[88] All of these distribution cooperatives are consumer-owned and serve thousands of members. Table 7 shows the details of the service territory and electricity suppliers of these distribution cooperatives.

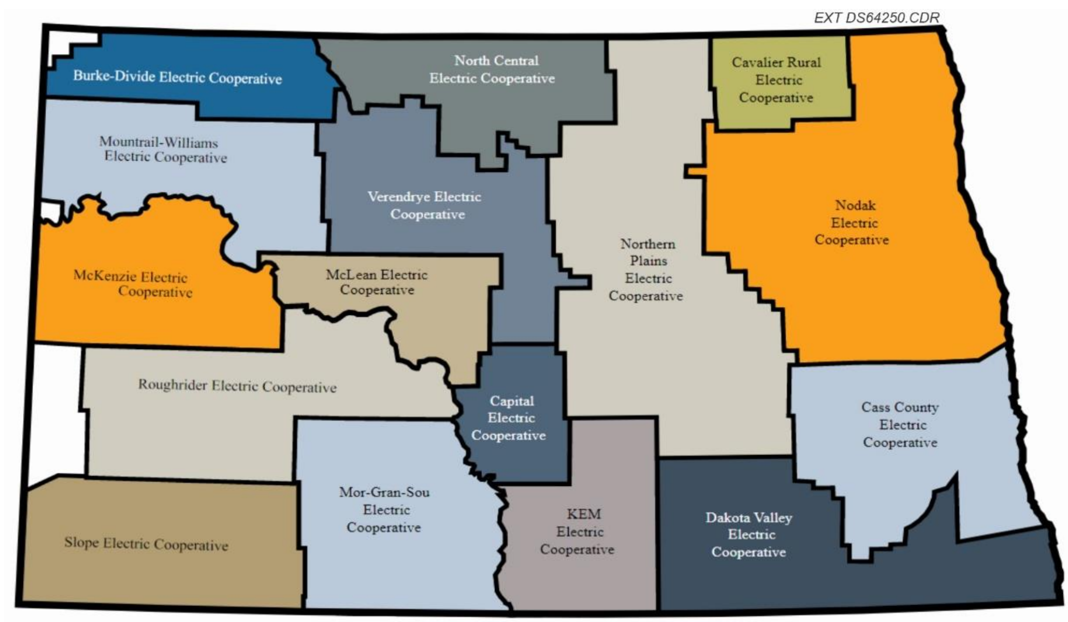

Figure 35. Map of distribution cooperatives in North Dakota.

[88] North Dakota Association of Rural Electric Cooperatives, 2024, www.ndarec.com/content/ndarec-members (accessed July 2024).

Table 7. Service Territory and Energy Supplier of North Dakota Electricity Distribution Cooperatives[89, 90]

Distribution Cooperatives	Service Territory (county)	Energy Supplier
Nodak Electric Cooperative[91]	Pembina, Walsh, Ramsey, Nelson, Steele, Grand Forks, Griggs, Benson, Eddy, Traill, Cass	MPC
Cass County Electric Cooperative[92]	Cass, Ransom, Barnes, Richland, Griggs, Trail, Steele, LaMoure, Dickey, Stutsman	MPC
Cavalier Rural Electric Cooperative	Cavalier, Towner	MPC
Dakota Valley Electric Cooperative	Richland, Ransom, Sargent, LaMoure, Dickey, Logan, McIntosh, Stutsman	CPEC
Northern Plains Electric Cooperative	Benson, Eddy, Foster, Griggs, Kidder, Stutsman, Wells, Pierce, Ramsey, Towner, Rolette	CPEC
KEM Electric Cooperative	Emmons, Kidder, Logan, McIntosh	BEPC, WAPA
Capital Electric Cooperative	Sheridan, Burleigh	CPEC
Verendrye Electric Cooperative	Sheridan, Wells, Pierce, McHenry, Ward, Renville, McLean	CPEC
North Central Electric Cooperative[93]	Bottineau, Rolette, Renville, McHenry, Pierce	CPEC
McLean Electric Cooperative	McLean, Mountrail, Sheridan	CPEC
Roughrider Electric Cooperative	Billings, Dunn, Mercer, Oliver, Stark, Golden Valley	Upper Missouri G&T Cooperative
Slope Electric Cooperative	Adams, Bowman, Hettinger, Slope	Upper Missouri G&T Cooperative
Mor-Gran-Sou Electric Cooperative	Morton, Grant, Sioux	BEPC, WAPA
McKenzie Electric Cooperative	McKenzie, Dunn	Upper Missouri G&T Cooperative
Mountrail–Williams Electric Cooperative	Mountrail, Williams	Upper Missouri G&T Cooperative
Burke–Divide Electric Cooperative	Burke, Divide, Mountrail, Ward, Renville	Upper Missouri G&T Cooperative

NORTH DAKOTA GRID RESILIENCE ASSESSMENT

As climate changes, catastrophic weather events like snowstorms, heat waves, hurricanes, floods, and other natural disasters are becoming more frequent and increasing large-scale power outages[94]. Additionally, evolving challenges such as changing fuel mix, resource inadequacy, supply chain interruptions, aging infrastructure, and physical and cyberattacks are impacting grid reliability and resiliency. Ensuring that the grid infrastructure is more resilient is critical so that communities can thrive in the face of catastrophic weather events and adapt to changing conditions (technological developments, cyber and physical threats, and socio-economic shifts).

[89] Central Power Electric Cooperative, 2024, https://centralpwr.com/quick-facts (accessed July 2024).
[90] Upper Missouri Power Cooperative, 2024, https://uppermo.com/our-members (accessed July 2024).
[91] Nodak Electric Cooperative, 2024, www.nodakelectric.com/about-nodak-electric-cooperative (accessed July 2024).
[92] Cass County Electric Cooperative, 2024, https://casscountyelectric.com/about-us (accessed July 2024).
[93] North Central Electric Cooperative, 2024, www.nceci.com/about-ncec (accessed October 2024).
[94] Eaton, 2024, www.eaton.com/us/en-us/products/backup-power-ups-surge-it-power-distribution/backup-power-ups/blackout-and-power-outage-tracker.html (accessed November 2024).

A grid cannot be resilient if it is not reliable. Grid reliability offers a level of certainty that electricity will keep flowing and the lights will remain on during normal grid events (frequent but low-consequence events such as generator outage, loss of transmission, equipment failure, and system faults) or that there will be few customer outages. Grid operators ensure grid reliability by following approved planning and operating procedures in accordance with NERC and FERC standards while considering anticipated grid events. Grid resilience focuses on system performance under extreme conditions (less frequent and high-consequence events such as catastrophic weather events and cyberattacks). In order to respond to and recover from anticipated and unanticipated grid disruptions and to minimize grid outages and their impacts, both grid reliability and resilience must be ensured in the planning, operational, and future phases of the grid. Given emerging climate challenges along with grid transformation and evolving regulatory environments, a grid resilience plan is critical. This study has developed a resilience plan that focuses on comprehensive resilience assessment to identify and prioritize risks to the reliable, resilient, and secure operations of the North Dakota electrical grid. This plan also includes recommendations on mitigation strategies to enhance grid resilience and reduce the frequency and consequences of grid outages caused by disruptive events. This study has made use of a framework for resilience assessment that includes baseline assessment, threat identification and impacts, risk analysis, and risk mitigations (Figure 36).

Figure 36. Resilience assessment framework.

Baseline Assessment

The baseline assessment has been performed to understand the existing conditions of the North Dakota state grid and to determine the ability of the state's grid operators and transmission and distribution utilities to plan for, respond to, and recover from anticipated and unanticipated disruptions. The findings of the baseline assessment are discussed in the previous section on the North Dakota grid overview.

Threat Identification

Any event that could disrupt, damage, or destroy any portion of the electricity grid can be considered a threat to the power grid. This study has considered three categories of threats, natural, technological, and man-made threats, that can impact electricity generation, transmission, distribution, and end users in North Dakota. Historical data on weather events, Federal Emergency Management Agency (FEMA) risk profiles, utility data/partner surveys, MRO regional risk assessments, and NERC assessments are used to identify potential threats to the state electric grid. For this study, a detailed survey was sent to major investor-owned and cooperative utility companies in North Dakota. Eleven utilities and cooperatives provided survey feedback and identified potential threats and their likelihood and impacts on the North Dakota grid. Table 8 illustrates the potential threats to the North Dakota grid.

Table 8. Potential Threats to North Dakota Grid

Natural	Technological	Man-Made
– High Winds – Cold Wave – Ice/Snowstorms – Tornado – Flood – Lightning	– Changing resource mix – Aging infrastructure	– Supply chain interruptions – Cyberattacks – Terrorism – Accidents – Skilled labor shortage – Energy policy

Natural Threats

Natural threats vary widely and are mostly geography- and location-specific. FEMA has identified the potential natural threats throughout the United States. The potential negative impact caused by a natural threat/hazard is explained by the National Risk Index (NRI). FEMA provides an NRI for each county in the United States. The NRI employs a scoring system out of 100, where 100 is the highest risk and 1 is the lowest. According to FEMA's website, "Risk is defined as the potential for negative impacts as a result of a natural hazard. The risk equation behind the Risk Index includes three components – a natural hazards component (Expected Annual Loss); a consequence enhancing component (Social Vulnerability); and a consequence reduction component (Community Resilience). The datasets supporting the natural hazards and consequence reduction components have been standardized using a min-max normalization approach. The dataset supporting the consequence enhancing component was acquired in a normalized format, allowing for easy incorporation into the National Risk Index risk calculation. Using these three components, a composite Risk Index score and hazard type Risk Index scores are calculated for each community (County and Census tract) included in the Index."

Using FEMA risk maps and index, all counties in North Dakota have been evaluated for natural hazards based on frequency of hazards, annual loss of population, and properties. Because of the frigid cold weather and prolonged winter, North Dakota is susceptible to cold waves, ice storms, high winds, tornadoes, riverine floods, and lightning. Every county in North Dakota, however, is susceptible to specific natural hazards to varying degrees (low, medium, or high), and the details are provided below.

Ice/Snowstorms

An ice storm is a freezing rain that leads to significant ice accumulations of over 0.25 inches. The most severe threat to the transmission and distribution system is a large ice storm with high winds. North Dakota has a very high risk of ice storms because of its harsh winter weather. The majority of the counties in North Dakota are either at relatively high or moderate risk for ice storms (Figure 37). With a risk rating of 29.6 out of 100, Benson County has the highest risk. Ice buildup on power lines can result in outages, either directly by adding weight and causing the connections to break or indirectly by causing tree branches to fall on the lines. In both cases, the severity of the storm can also delay repair activities.

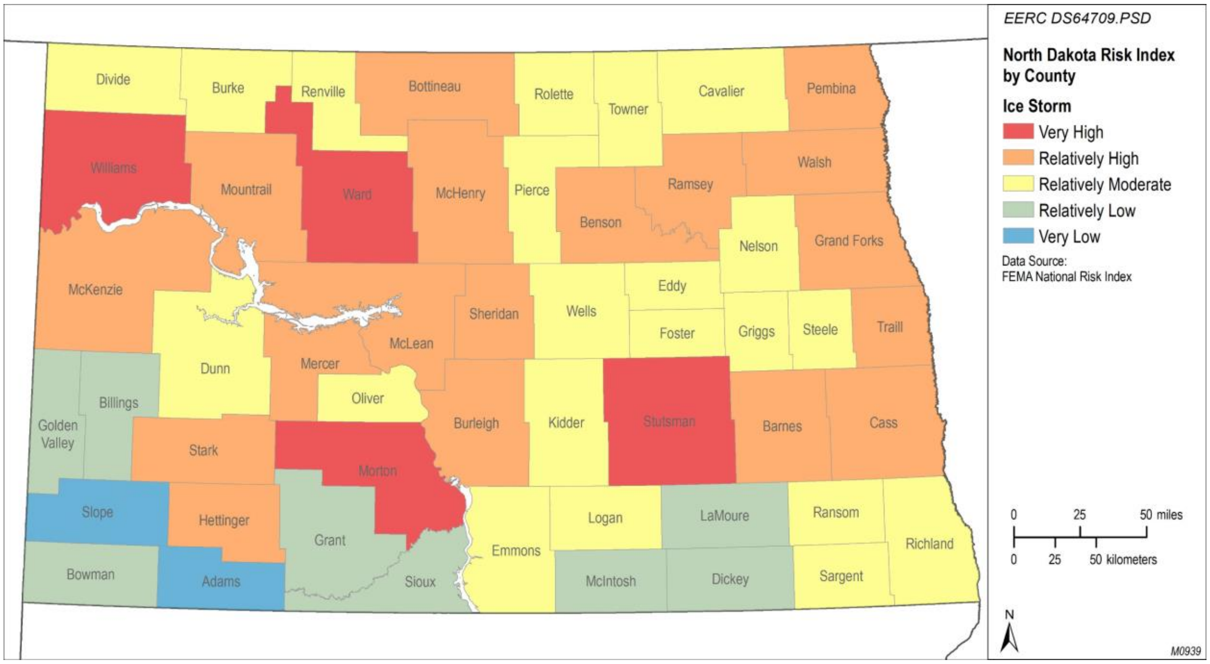

Figure 37. FEMA risk index for ice/snowstorms in North Dakota.

The National Electric Safety Code (NESC) provides standards for transmission line design. Transmission lines are designed based on the ability to accommodate a load, which is the weight of the conductor and the tension of the conductor between structures. The load will be significantly increased by the force of wind and the additional weight of ice accumulation on the conductors. This requires transmission lines to accommodate 0.5 inches of ice with a 40-mph wind.[95] North Dakota is located within the NESC heavy-loading area. This standard may be inadequate for North Dakota, and utilities can design to a higher standard.

A common ice storm damage failure mode is a cascading structure failure. This single point of failure propagates along the line and results in failure of multiple transmission or distribution structures.

High Winds

Strong winds, which are often referred to as those exceeding 58 mph, can be destructive. North Dakota is susceptible to strong winds, and most counties in North Dakota have a relatively moderate risk of strong winds (Figure 38). Cass County has a very high risk, and Grand Forks and Emmons Counties have a relatively high risk of strong winds. Power outages can be caused by high winds that damage power poles and lines. Strong winds can also cause power lines to vibrate and gallop between them, which may result in power outages.

[95] NEI Electric Power Engineering, 2024, www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/final-nei-report-appendix-f-overhead-line-construction.pdf (accessed October 2024).

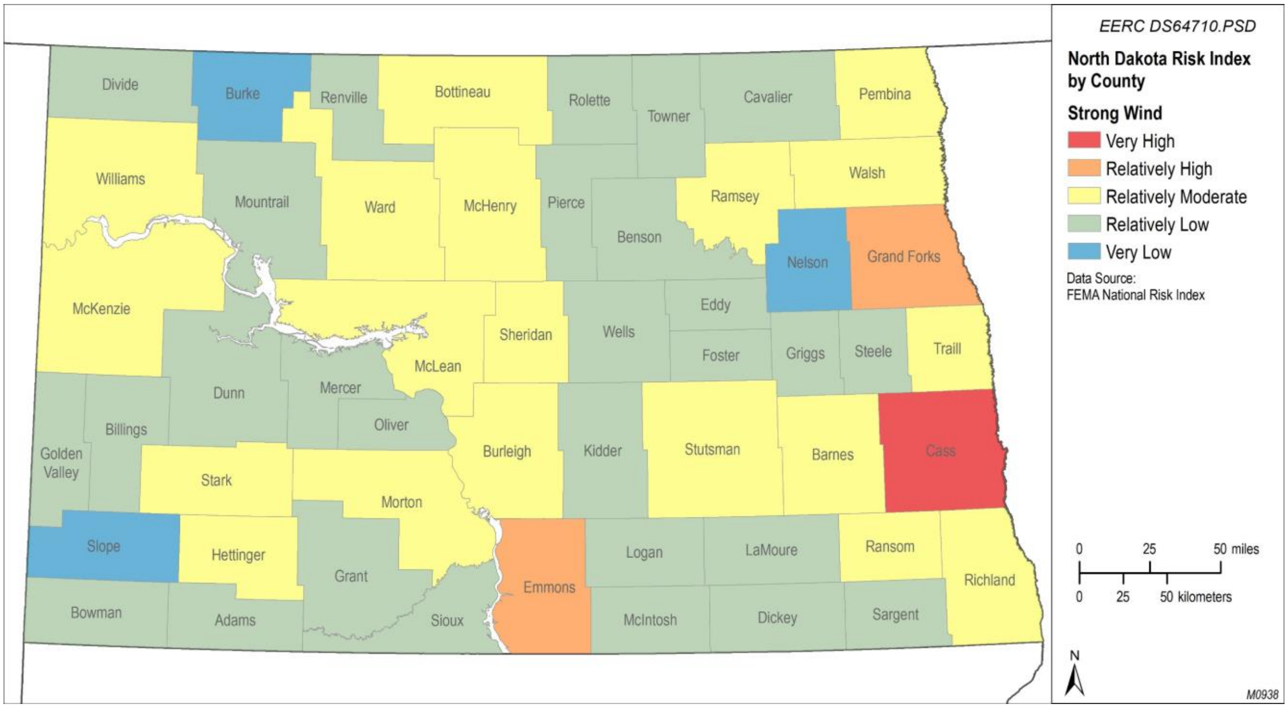

Figure 38. FEMA risk index for high wind in North Dakota.

Cold Waves

Cold waves are defined as sudden drops in temperature and continuous low temperatures. The local National Weather Service (NWS) weather forecast office determines cold wave classification based on location. The risk of a cold wave in North Dakota is shown in Figure 39. In North Dakota, many counties experience a very high risk of cold waves in the winter. Grid infrastructure may become physically challenged during harsh and extended winter weather. As electric cables and power lines become stiffer, fuel supply equipment is susceptible to freezing and power generation may reduce. Additionally, when more people turn on and turn up their heat during extended cold spells, load demand will rise and may lead to sustained power shortages.

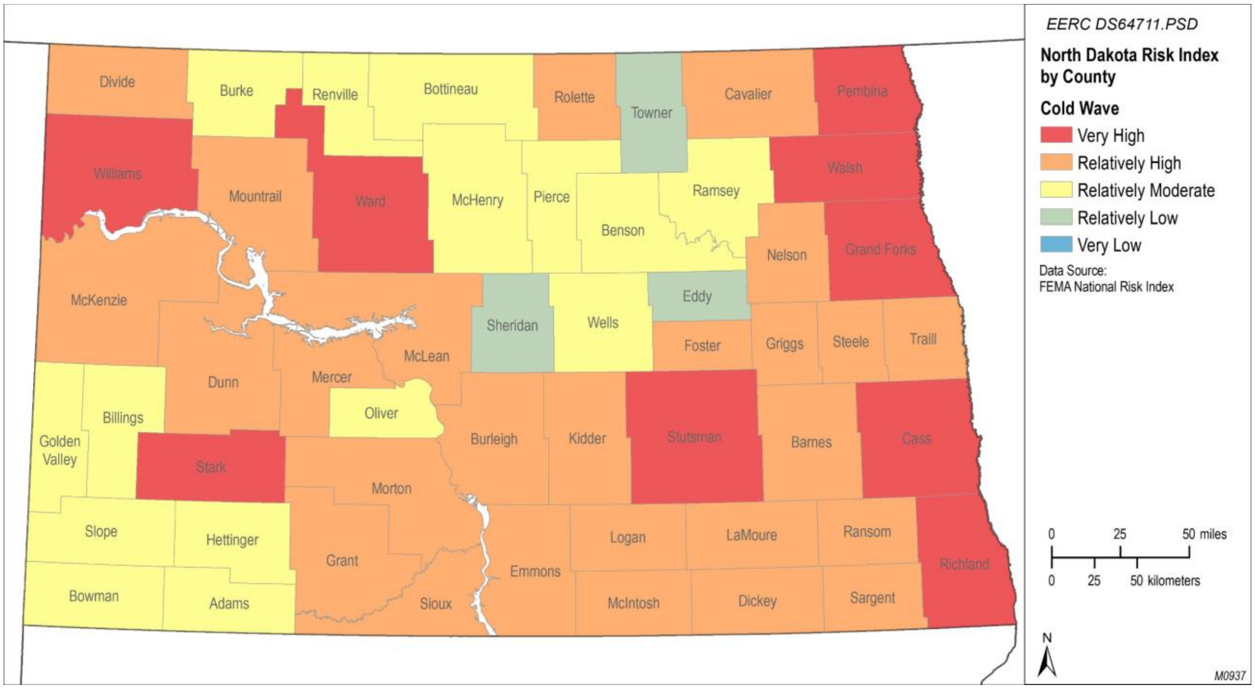

Figure 39. FEMA risk index for cold waves in North Dakota.

Lightning and Thunderstorms

Lightning and thunderstorms can cause massive damage to electrical distribution and transmission systems. Burleigh, Ward, and Stark Counties in North Dakota have a moderate risk of lightning. Figure 40 shows the lightning risk for North Dakota. Lightning creates power surges that, in turn, burn down transmission or distribution network equipment, while thunderstorms have the potential to bring down power lines.

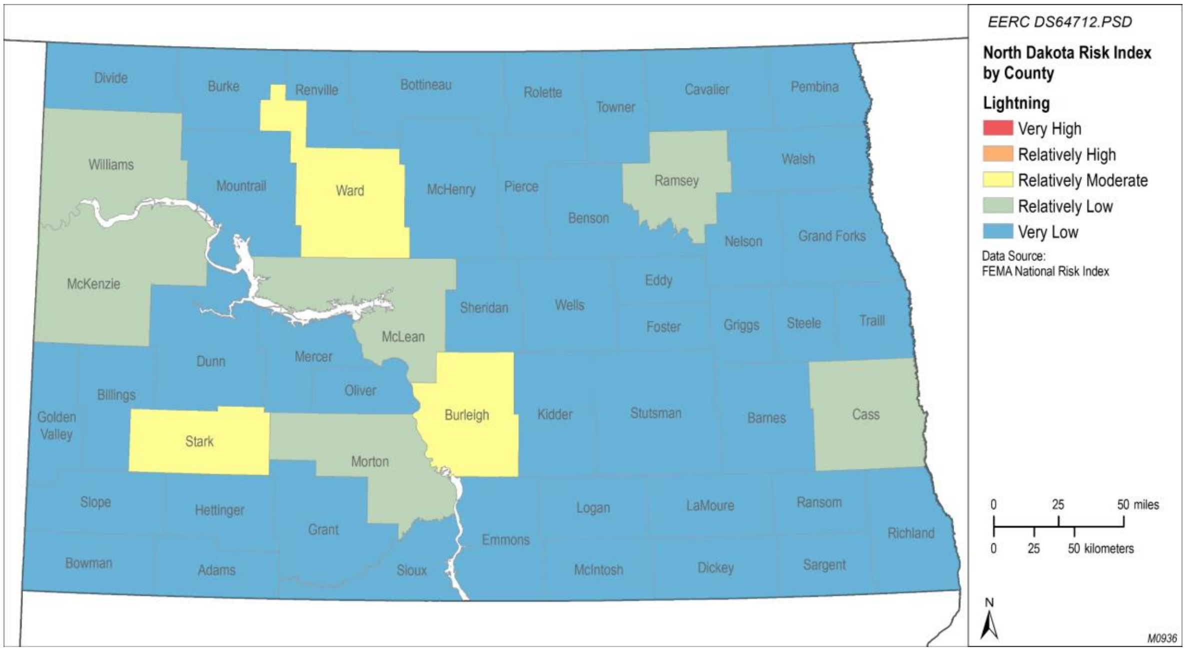

Figure 40. FEMA risk index for lightning and thunderstorms in North Dakota.

Riverine Flooding

Riverine flooding, or river floods, occur when river water overflows and spills into adjacent dry lands because of the overcapacity of the river's natural channels. Because of the low-lying Red River Valley, Grand Forks, Cass, and Richland Counties in North Dakota are at a high risk of riverine flooding. The largest annual loss in Grand Forks was associated with the Red River flood of 1997. Figure 41 shows the flooding risk of North Dakota counties. Flooding can damage substation components and underground lines and will, therefore, cause power outages.

Tornadoes

Tornadoes can pose a severe threat to the distribution and transmission grid. According to FEMA, Cass, Ward, and Burleigh Counties have relatively high and moderate risks of tornadoes, respectively. The tornado risk for North Dakota is shown in Figure 42. In Cass County, tornadoes occur 1.34 times a year on average. Tornadoes can cause damage to the transmission and distribution system by knocking down electric line poles and uprooting substations and protective devices.

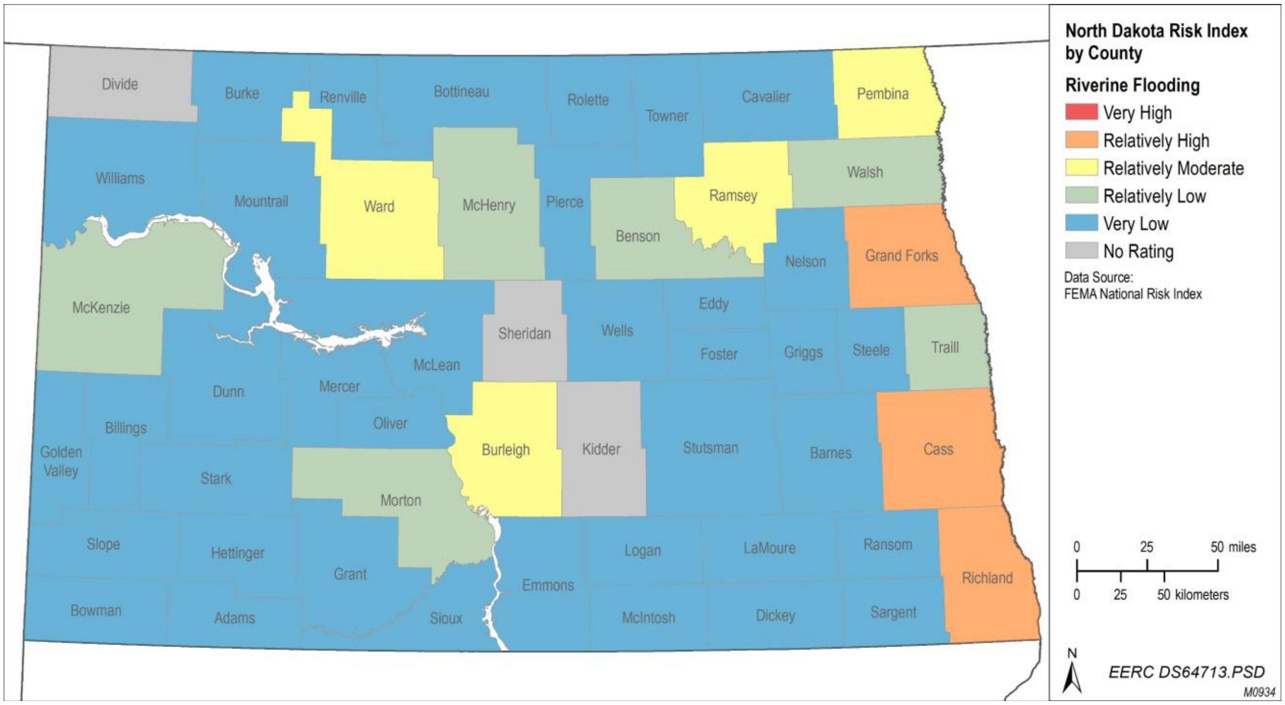

Figure 41. FEMA risk index for riverine flooding in North Dakota.

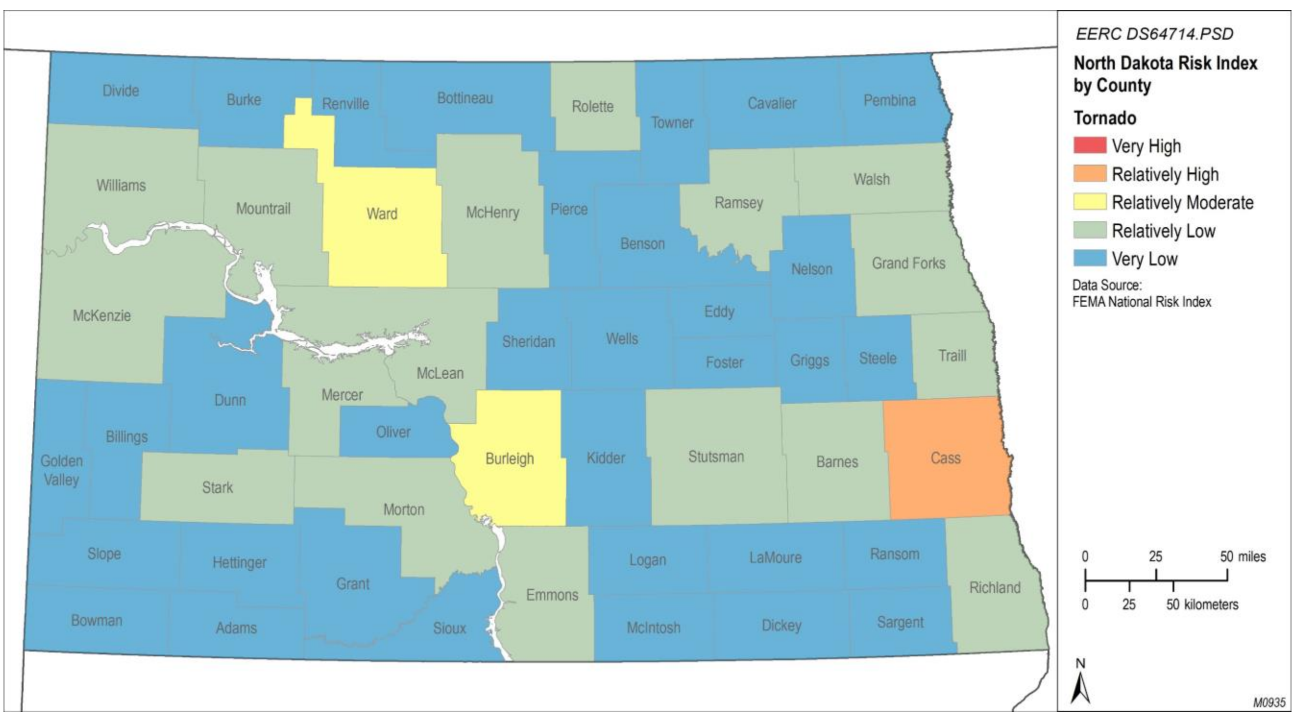

Figure 42. FEMA risk index for tornadoes in North Dakota.

Technological Threats

Technological threats are often caused by unpredicted equipment or infrastructure failure or grid outages. According to utility survey responses, the major technological threats to the North Dakota grid are changing resource mix, resource inadequacy, and aging infrastructure.

Changing Resource Mix

The changing resource mix is challenging grid resilience as there is high penetration of variable renewable resources into the grid and the growing number of traditional baseload plants that are being prematurely retired. This is leading to increased uncertainty and reduced planning reserve margins. The poor accreditation percentage at which renewables (15%–30%) are rated versus conventional thermal generation (80%–90%) is the primary cause of the decrease in planning reserve margin. The changing resource mix is replacing reliable, dispatchable thermal generation with variable energy resources. While the energy value of renewables may be enough to cover thermal unit retirement, there will be a shortfall of generation capacity and dispatchability, which translates into lack of ability to cover load during peak periods. This effect is demonstrated by the forecasted depletion of the planning reserve margin.

Generation adequacy is a threat as demonstrated by the forecast of declining planning reserve margin in both SPP and MISO. SPP is forecasted to fall below 15% criteria by 2027. MISO will be short of existing and planned generation by 2028. NERC has identified energy policy and grid transformation as the No. 1 and No. 2 grid reliability risks in its 2023 electric reliability organization (ERO) reliability risk priorities report.[96] Generation must continuously match load; therefore, a lack of generation is an immediate threat to grid reliability and resiliency.

Inverter-based resources (IBRs) cause their own challenges. Solid-state inverters are the primary technology used by wind and solar to produce electricity. Traditional generation uses a synchronous coupling of the electromagnetic field of the generator with the grid. This coupling allows the turbine/generator to store and release energy from the inertia of the spinning machine. This effect introduces a natural stabilization to the grid during grid disturbances. IBRs lack this inherent capability. As IBRs start to replace conventional generation, the stability of the grid may decrease. RTOs are studying this phenomenon and adding additional tools and monitoring equipment to gather real-time data. More studies are required to determine the level of risk.[97]

Aging Grid Infrastructure

Recent winter storms have exposed how the aging transmission and distribution systems are becoming more vulnerable to natural disasters and operational stress under peak demand. According to a 2015 DOE report,[98] 70% of power transformers are 25 years or older, 60% of

[96] North American Electric Reliability Corporation, 2023, www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf (accessed October 2024).
[97] VanNess Feldman LLP, 2023, www.vnf.com/ViewMailing.aspx?MailingId=45061&MailKey=6066091 (accessed October 2024).
[98] Southwest Power Pool, 2024, www.spp.org/Documents/65423/20210924%20SCRIPT%20Report%20of%20Recommendations%20as%20Revised%20and%20Approved%20During%20the%20Meeting.docx (accessed October 2024).

circuit breakers are 30 years or older, and 70% of transmission lines are 25 years or older. However, it is difficult to determine age and condition replacement. For example, heavily loading a transformer will cause loss of expected life, but a lightly loaded transformer might have a longer life span. Another example is the aging of wooden poles at different rates in different climates. Thus age is not an absolute replacement criterion, even though it is indicative. The condition of equipment/infrastructure can be a useful indicator; using the previous examples, transformer insulating oil can be tested, and there are nondestructive wood pole tests.

In 2021, the SPP Strategic and Creative Re-engineering of Integrated Planning Team (SCRIPT) recommended changes to SPP's transmission-planning processes to include consideration of age and condition of transmission facilities. The SCRIPT report noted that there is little collaboration between local transmission owners and SPP regarding management of existing transmission facilities. Blending the needs of local transmission replacement with SPP regional processes could result in a more efficient expansion plan. Because of this recommendation, the SPP Transmission Working Group created the Aging Infrastructure Focus Group (AIFG). As a result of AIFG analysis, in 2024, SPP is integrating age and condition criteria into the existing SPP integrated transmission-planning process.

Man-Made Threats

Survey responses from utilities have shown that there are potential human-caused threats to the North Dakota grid, including supply chain disruptions, physical and cyberattacks, and accidents. In addition, the 2023 ERO reliability risk report highlights energy policy and skilled labor shortage as emerging threats. Accidents are unintentional and generally include accidental cutting of wire and vehicles hitting overhead line poles or ground-mounted equipment. Any form of accident at a grid facility can disrupt grid operations and consumer access to electricity. Any intentional damage or destruction of grid infrastructure is considered vandalism. Supply chain disruptions frequently have a negative influence on grid operations, reliability, and resiliency. A lack of manufacturing materials might result in unavailability of equipment, and utilities have no control over supply chain issues. Cybersecurity breaches can jeopardize sensitive data and expose the grid to outside attackers.

Supply Chain Interruptions

The 2024 MRO regional risk assessment identified supply chain compromise as a high risk. Impact was ranked as major and likelihood as possible.[99] Also, a DOE paper dated August 2023,[100] described the supply chain crisis and the efforts of the federal government to address the situation.[101] These assessments describe the effect of the global pandemic causing manufacturing challenges because of a lack of workers, materials, and logistical problems. Also, the demand for electrical equipment is increasing in part to accommodate the addition of renewable energy generation. Therefore, the supply and demand sides of the supply chain are stressed. This has led

[99] Midwest Reliability Organization, 2024, www.mro.net/document/mro-2024-regional-risk-assessment/?download (accessed October 2024).

[100] U.S. Department of Energy, 2023, www.energy.gov/sites/default/files/2023-08/Supply%20Chain%20Progress%20Report%20-%20August%202023.pdf (accessed October 2024).

to inventory shortages and extended equipment lead times, which have a negative impact on maintenance and new construction schedules of grid infrastructure. Both factors negatively affect grid resiliency by delaying the addition of new facilities or the replacement of failed equipment. For example, large power transformers now have a lead time of 2 years. A Deloitte Insights report regarding electric power supply chains reports that 86% of industry experts surveyed saw increased cost and 64% saw project delays as consequences of supply chain issues.[102]

Solving supply chain issues is difficult as so much of the equipment is manufactured overseas. For example, according to the DOE paper, 82% of large power transformers are imported. There is only one U.S. manufacturer of special steel required for these transformers. The U.S. government is providing mixed signals. DOE has been directed to use the Defense Production Act to increase transformer production. However, as of December 2022, Congress had not authorized any funds to DOE to implement the authorization. Meanwhile, DOE is considering forcing transformer manufacturers to switch to a more efficient steel, which will further limit the sources of steel.

Vandalism and Terrorism

Unauthorized physical access may be used to carry out a physical attack or as the first access strategy for a cyberattack. The Metcalf, California, substation attack of April 16, 2013, demonstrated the vulnerability of transmission substations to physical attack. In response, NERC created reliability standards (CIP-014) addressing physical security. However, they only apply to transmission facilities operated at 500 kV or higher or 230 kV or higher if a defined measure of outage impact criteria is met. Otherwise, it is up to the transmission facility owner to determine physical security measures.

Despite NERC standards, physical security is still an issue. A 230-kV substation in the Bakken area of North Dakota was the target of an attack on May 13, 2023. A high-powered rifle was used, several high-voltage apparatuses were damaged, and the total damage was approximately $10 million.[103] However, because of the redundant design of the local transmission system, there were no long-term customer outages. Graffiti reported to be left on the site indicates the attack may have been related to an environmental protest. A similar substation attack in North Carolina in 2022 caused an outage to 40,000 people.

A new physical threat is drones. As demonstrated in the Ukraine war, drones can be used for surveillance and/or attacks. Attacking from the air will not be stopped by traditional physical security measures like fences and walls.

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[102] Deloitte Insights, 2022, https://img.saurenergy.com/2022/11/us175668_pu-r-supply-chain-resilience-report.pdf (accessed October 2024).

[103] Bismarck Tribune, 2023, https://bismarcktribune.com/news/state-regional/crime-courts/canadian-man-accused-of-damaging-substation-in-north-dakota-being-in-country-illegally/article_a9cb389a-218d-11ee-8597-bf72062d84cd.html (accessed October 2024).

Cybersecurity

In recent years, the Internet of Things (IoT) has significantly improved the sensing and communication capabilities of systems, but this also exposes grid infrastructure to cybersecurity vulnerabilities and attacks. Malicious attackers seek to exploit vulnerabilities in utility networks to disrupt normal operations of the bulk power system. Potential cyberattacks against the bulk power system will negatively impact the resilience of grid infrastructure and compromise consumer access, public safety, business, and national security, possibly with economic implications.

According to NERC, "Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. [104] This results in increased risks to these Cyber Assets."

These risks could be a cyber hack that attempts to gain information or even control of a cyber asset or it could be a ransomware attack that corrupts a computer system in some fashion. Electric utilities saw an increase in ransomware attacks in 2021 focused on corporate systems.[105] The Colonial Pipeline attack of May 7, 2021, is an example of a ransomware attack on critical energy infrastructure [106]

The first well-known grid-scale attack was against Ukraine in 2015 and resulted in outages to 250,000 people. The intrusion was accomplished via a successful phishing attack. Another example is the 2020 Solarwinds attack in the United States. Solarwinds provides software to help thousands of businesses (including utilities) manage their networks, systems, and information technology infrastructure. In 2020, their software was corrupted by a cyberattack that went undetected for several months.

NERC Critical Infrastructure Protection (CIP) standards set the rules utilities must follow to ensure their facilities are protected by regulating, enforcing, monitoring, and managing their security. These standards apply specifically to cybersecurity. The first iteration of these standards was created following the great northeast blackout of 2003. The standards have grown and evolved in scope regularly and continue to keep pace with threats and technological changes. The following is a list of active NERC CIP standards:

CIP-002 – Cyber Security – Bulk Electric System (BES) Cyber System Categorization
CIP-003 – Cyber Security – Security Management Controls
CIP-004 – Cyber Security – Personnel & Training
CIP-005 – Cyber Security – Electronic Security Perimeter(s)
CIP-006 – Cyber Security – Physical Security of BES Cyber Systems

[104] North American reliability Corporation, 2024, www.nerc.com/pa/Stand/Cyber%20Security%20Permanent/Cyber_Security_Standards_Board_Approval_02May06.pdf (accessed October 2024).
[105] Midwest Reliability Organization, 2024, www.mro.net/document/mro-2024-regional-risk-assessment/?download (accessed October 2024).
[106] Cybersecurity & Infrastructure Security Agency, 2023, www.cisa.gov/news-events/news/attack-colonial-pipeline-what-weve-learned-what-weve-done-over-past-two-years (accessed October 2024).

CIP-007 – Cyber Security – System Security Management
CIP-008 – Cyber Security – Incident Reporting and Response Planning
CIP-009 – Cyber Security – Recovery Plans for BES Cyber Systems
CIP-010 – Cyber Security – Configuration Change Management and Vulnerability Assessments
CIP-011 – Cyber Security – Information Protection
CIP-013 – Cyber Security – Supply Chain Risk Management
CIP-014 – Physical Security

Adherence to these standards will not only help protect a utility from a cyberattack but also avoid possible financial penalties should NERC find that a utility is out of compliance.

Aging Workforce and Skilled Labor Shortage

As the baby boomer generation ages into retirement, there will be a shortage of skilled workers. This is especially challenging post-COVID as worker shortages are affecting all areas of the economy. The 2023 ERO reliability risk report highlights that "The BPS is becoming more complex, and the need to model, analyze, and operate the BPS at higher fidelity further exacerbates training, staffing, and workforce issues. Competition for available skilled workers is becoming a roadblock and an emerging risk." As the grid evolves to embrace newer energy technologies, smarter controls, distributed energy resources (DERs) such as energy storage and EVs, it is critical to address skilled workforce needs.

Energy Policy

Energy policy in the form of federal and state mandates and incentives to transition from thermal dispatchable generation to renewable generation is causing the reduction in generation reserve margins. Tax incentives for renewables allow bidding into the RTO power markets at artificially low prices. This undercuts the marginal prices that dispatchable generation bids. Therefore, dispatchable thermal generation does not run frequently enough to earn enough revenue to remain financially viable. Mandates simply prevent the consumption of electricity generated by thermal generation. Policies in the form of environmental regulations require huge investments in pollution control equipment. Therefore, energy policy threats to dispatchable generation manifest in lower income and higher costs.

Risk Analysis

When the bulk power system is exposed to threats, essential resources or grid assets may be lost, damaged, or destroyed, and grid services may be interrupted, which is referred to as risk. Risk can be evaluated based on threat likelihood and consequences (or impacts). Risk analysis is an important step in resilience assessment because it allows risks and mitigation strategies for the North Dakota state grid to be prioritized. In this study, a risk matrix was developed using utility survey responses, and the relevant rank of the risk was determined by assessing threat likelihood score and threat impact score. Table 9 lists the five categories of threat likelihood and associated scores considered for this study. A threat will have a threat likelihood score of 5 if it has a high probability of occurring, as opposed to 1 for threats with a small probability of occurring.

Table 9. Classification of Threat Likelihood

Threat Likelihood Score		
Categorical	**Numerical**	**Description**
High	5	High probability of occurrence. Historic data show frequent occurrences over the years.
Medium-High	4	Likely to occur. Had occurred in the past.
Medium	3	Can occur sometime.
Low-Medium	2	Less likely to occur but possible sometimes.
Low	1	Low probability of occurrence. The possibility of occurrences is very low or rare.

The impacts are assessed based on extent of service disruption caused by the threat, its effect on capital and operating costs, and health and safety of the communities. The threat impact has been classified into five categories: severe, major, moderate, minor, and negligible and is scored as summarized in Table 10. The maximum score is 5 for threats with a significant impact, and the lowest is 1 for threats with a minimal impact.

Table 10. Classification of Threat Impacts

Threat Impact Scores		
Categorical	**Numerical**	**Description**
Severe	5	Large-scale power outage for an extended period of time with significant financial impacts. Widespread impacts to BPS across North America.
Major	4	A significant or comparatively large number of customers will be impacted. Emergency or critical operation mode.
Moderate	3	Medium consequences in terms of power and financial losses. Smaller areas or fewer customers will be affected. Specific functions of the system will be affected.
Minor	2	Limited financial or system impacts. Can be resolved by system upgradation over the years or using a backup system.
Negligible	1	Low severity on the system and has little to no impact. The failure will be resolved by backup systems. Very limited financial impacts.

Figure 43 shows survey responses on the impact of possible threats to the North Dakota grid. Ice/snowstorms are considered to have the highest impact on North Dakota transmission and distribution grids, followed by cyberattack and changing resource mix. Aging infrastructure, vandalism, high winds, tornadoes, and supply chain problems are other threats with major impacts on the grid.

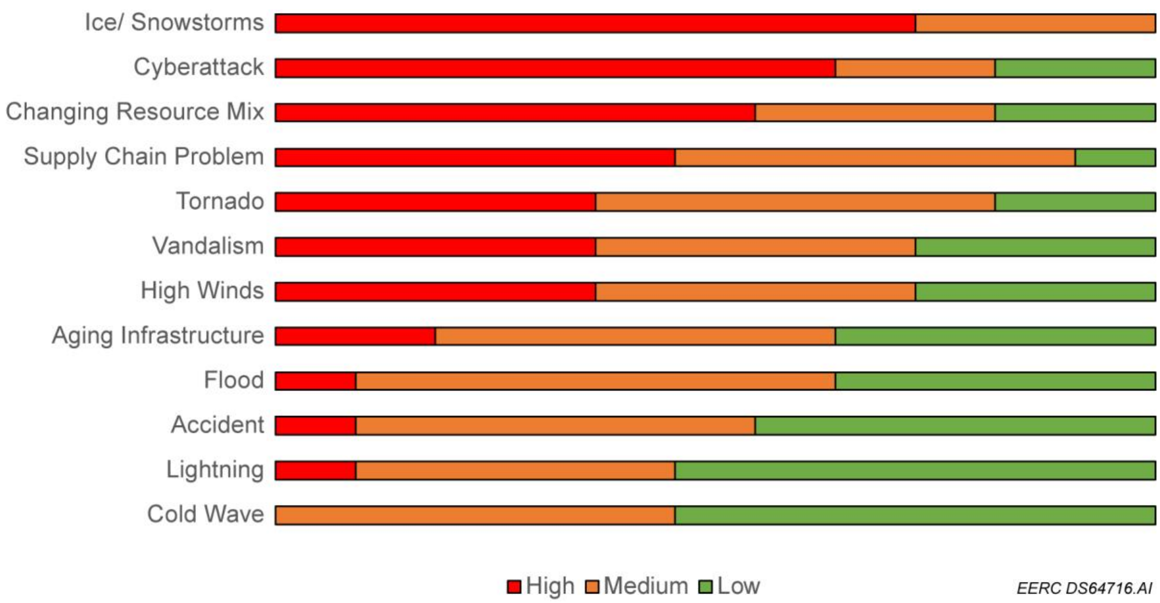

Figure 43. Survey responses on the impact of possible threats to the North Dakota grid.

Risk scores are calculated as the product of threat likelihood and threat impact scores. These scores are displayed in a risk matrix heat map, which shows the risk's relative ranking (Table 11).

Ice/snowstorms are ranked the highest and are the only threat ranked in the likely/severe category. This is likely no surprise to North Dakota residents. Changing resource mix, supply chain interruptions, and cyberattack followed with rankings in the possible/major impact category. The next-ranked threat was high winds with a likely/moderate ranking. Aging grid infrastructure can fail because of stress caused by natural events or unexpected peak loads.

Table 11. Risk Matrix

Consequence/Impact		**Threat Likelihood**				
		5	**4**	**3**	**2**	**1**
		Almost Certain	**Likely**	**Possible**	**Unlikely**	**Very Unlikely**
5	Severe		Ice/ snowstorms			
4	Major			Changing resource mix, supply chain interruptions, cyberattacks		
3	Moderate		High winds	Aging infrastructure, flood	Tornado, vandalism	
2	Minor		Cold wave, lightning	Accident		
1	Negligible					

Although some of the individual risks appear to be moderate, when combined with other common-mode risks, they can have a significant impact on bulk power system resiliency. For example:

- Winter weather can increase load above forecasts, cause transmission line outages, and cause generation outages simultaneously. Age and condition of the grid can increase the likelihood of storm outages, and supply chain issues can delay repair of damaged equipment. Depending on the severity of the initial threat, this combination can propagate across large regions of the grid as happened with Winter Storm Uri.

- EPA regulations cause multiple coal-fired generation stations to retire prematurely, leaving the RTO region dependent on renewable generation and imports from adjacent areas to meet peak load needs. A summertime high-pressure system covers the RTO footprint, bringing extremely hot temperatures and low wind. A band of severe weather forms with local high winds, lightning, and tornadoes. Multiple critical transmission lines are damaged, and the transmission path being used to import critical amounts of power is degraded. The resulting loss of resources results in low grid frequency and widespread, uncontrolled underfrequency load shedding.

- A flood damages an important substation and destroys a large transformer. The replacement transformer is not available for 2 years because of supply chain issues. The transformer has an unusual design, and no spare is available. The outage of the transformer degrades the capacity of an important transmission path and causes significant regional transmission congestion. This congestion causes system performance issues in a load-serving zone which suffers from voltage instability. Constant rotating load shedding is required during high loads until the transformer is replaced.

Risk Mitigation Strategies

This study recommends various mitigation strategies that will allow generation, transmission, and distribution utilities to use risk profiles and mitigation strategies for recurring resilience assessments. Some recommendations are specifically targeted at the group or entity leading the mitigation action while others are more general and can apply to different entities including utilities, regional grid operators, policymakers, and regulators. This study did not analyze resource requirements for mitigation actions.

Ice/Snowstorm

Utilities should ensure their design standards account for all reasonable North Dakota weather assumptions. A common practice to limit cascading structure failure is the use of "storm structures." These are dead-end type structures that can handle line tension and, therefore, stop the cascading failure of tangent structure failures. Utilities should examine the installation of storm structures to reduce the impact of ice storm damage.

High Winds

To reduce the impact of high wind on distribution and the transmission grid, the following measures can be followed to reduce the risk of pole capitulation and line breakage:

- Improve tension between overhead lines. This method can be expensive and will be difficult to implement once the line has been built.

- Use interphase spacers to maintain acceptable distances between phase conductors.

- Increase the height of overhead line poles and mount lines above trees or vegetation.

- Prune trees and vegetation regularly.

- Select pole materials with higher strength, and reduce pole-mounted components.

- Use deeper pole foundations and concrete or special fill materials at the foundation.

- Replace overhead lines with underground wires.

Riverine Flood

Substations and ground-based distribution and transmission equipment are vulnerable to flooding damage. Flooding can damage ground-based equipment, causing power outages. Typical substations are constructed in the open air and visible to everyone. The communication system and temperature control systems are generally enclosed within a shed. Several mitigation steps could be taken to reduce the impact of flooding as follows:

- Construction of generation, transmission, and distribution system above flood elevation.

- Floodwall or dike for substation design in flood zone area. Use reinforced concrete or concrete blocks to strengthen the wall.

- Data collection and communication equipment placed in enclosure with flood-resistant door.

- Monitor water level in surrounding area by adding float switches to grid structures and connecting to supervisory control and data acquisition (SCADA) system.[107]

Lightning

Lightning, the typical cause of failure for overhead lines, can cause temporary or permanent disruption to the system. Typically, lightning arresters are used for mitigating momentary

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[107] Federal Emergency Management Agency, 2024, www.fema.gov/sites/default/files/documents/fema_p-2181-fact-sheet-4-3-electric-power.pdf (accessed October 2024).

disruptions. A shorter distance between lightning arresters contributes to a lower voltage surge and reduces flashovers. Lightning can also induce temporary faults in the overhead lines. The fault can be cleared by reclosers or breakers. However, in some cases, momentary interruptions can be a major concern for sensitive loads.[108] Adding a backup system or loop-fed distribution system design can mitigate momentary or temporary interruption for sensitive loads. Loop distribution systems are generally reliable, require fewer conductors, and have low voltage fluctuations.

Long-Term Mitigation for Generation Resource Inadequacy

NERC has an active project entitled "Energy Assurance with Energy-Constrained Resources" through which a team is presently working on creating applicable NERC standards to address adequacy issues. New or improved NERC standards are a powerful tool to help address the issue, as failure to meet NERC standards can result in significant financial penalties.

The trend of decreasing planning reserve margins of MISO and SPP RTOs must be reversed. This will require North Dakota utility industry stakeholders to engage in changing policies at RTOs and NERC. Utilities must be incentivized to build more generation. A carrot-and-stick approach may work; RTOs can provide market incentives to increase the rate of return for dispatchable generation, while NERC can toughen its penalties should a load-responsible entity not acquire sufficient resources. North Dakota utilities are well represented on RTO and NERC committees. In addition, North Dakota utility industry stakeholders need to hold EPA accountable for the actions of its proposed rules on coal-fired generation. This effort will be legal and political.

As demonstrated by Winter Storm Uri, generation resource shortages outside North Dakota can lead to load curtailments inside North Dakota. Therefore, additional generation added within North Dakota may not prevent load shedding if the SPP or MISO RTO is short overall. However, DERs may be helpful. DERs are small generators ranging from kW to 10 MW. They are too small to independently participate in RTO markets because of cost and overhead. Local utilities should encourage participation of DERs in the RTO market through power purchase agreements or similar arrangements that relieve the administrative burden on the DERs. Also, recent FERC Rule 2222 is meant to allow individual, small DERs to "aggregate" and be brought into the RTO markets as market participants.[109]

During Winter Storm Uri, one of the reasons for the shortage of generation resources was the impact of cold weather on many generating stations and their fuel supplies in the southern United States. In response, NERC created Reliability Standard EOP-011-2 (Emergency Preparedness and Operations, effective April 1, 2023), which addresses generating resource cold-weather preparedness plans and training for generating resource maintenance or operations personnel on cold-weather preparedness plans. This standard will help mitigate the risk of loss of generation during unusual cold-weather events.

Also, in June 2023, NERC published a reliability guideline entitled "Generating Unit Winter Weather Readiness – Current Industry Practices – Version 4." This document provides guidance

[108] NEMA Arresters, 2024, www.nemaarresters.org/lightning-proof-distribution-line/ (accessed October 2024).
[109] Federal Energy Regulatory Commission, 2024, https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet (accessed October 2024)

to generator owners regarding how to evaluate cold-weather risks to critical components. The document also provides a comprehensive listing and links to cold-weather electrical generator operation lessons-learned reports. This document is a valuable resource for generator owners needing to evaluate their cold-weather mitigation strategy.[110]

As more wind and solar are added to the grid, net peak will become more challenging than peak load demand. RTOs should consider other methods to determine accreditation of generation capacity. For example, the highest-certainty deliverability (HCD) approach examines a sample size of 2000 hours for wind and solar of the highest peak and net peak hours across 4 years. It calculates the mean of the lowest 25% of wind and solar output during those hours to come up with the accredited capacity values for peak and net peak.[111, 112]

HCD manages the downside of wind and solar at net peak compared to ELCC and is more empirical than the options MISO is considering as it moves away from ELCC to a direct LOL accreditation approach.

Short-Term Mitigation for Generation Inadequacy

Adding new generation resources takes years of planning, permitting, engineering, and construction. In the short-term, utilities can only react to the RTO energy emergency alerts. As these alerts are ramped up in real time, utilities will respond by placing all available generation in service. Once that action is exhausted, the only remedy is shedding load.

During Winter Storm Uri in February 2021, SPP declared an energy emergency alert Level 3 (EEA3) for several hours over 2 days. This declaration resulted in controlled load shedding across the SPP footprint, including North Dakota. When SPP declares an EEA3, it determines the amount of load that needs to be shed. The amount of cuts are pro rata shared among the SPP member transmission operators. In North Dakota, the transmission operator is WAPA. WAPA then determines how the cuts are distributed across its system. WAPA and its customer utilities have a procedure in place to determine how the load cuts are communicated and implemented in a fair manner with the least disruption. To minimize impacts of load curtailments, individual utility load shed plans protect critical loads and limit the outage time to any individual load. Utilities keep these plans current and communicate them to WAPA regularly.

Blackout Mitigation

[110] North American Electric Reliability Corporation, 2023, www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v4.pdf (accessed October 2024).

[111] Orr, I., Rolling, M., and Bennett, B., 2023, www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/Southwest%20Power%20Pool%20Resource%20Adequacy%20OTR%20CCR%20v%202%205-23-2023.pdf (accessed October 2024).

[112] Nasi, M. Bennett, B., Orr, I., and Rolling, M., 2023, www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/5-23%20FINAL%20FULL%20Long%20Format%20NDTA%20MISO%20Study%20Results%20.pdf (accessed October 2024).

In the event of total grid failure, North Dakota is well positioned for quick recovery. Restoring the transmission system from a total blackout is called a black start. WAPA has a black start procedure that is regularly updated and practiced. Hydroelectric facilities are inherently easy to black-start. The Missouri River dams with their hydroelectric facilities are available to “jump start” the remainder of the transmission system. The process is for each of the hydroelectric facilities to energize independently. Then adjacent transmission lines are placed into service. Loads served by these lines are energized, as serving some load is helpful to maintain voltage regulation. Then in an incremental manner, additional lines and loads are placed in service, with a priority of connecting to thermal generators. Generation and load must always be balanced; therefore, this process continues in a careful manner until the system is completely restored. This process could last 2 to 3 days depending on the extent of the blackout. North Dakota and portions of adjacent states can operate as an independent network separate from the rest of United States if necessary.

Therefore, a critical load, such as a hospital, water treatment, telecom, etc., should have arrangements for standby power sources with at least 3 days of fuel supply which also is the National Fire Protection Association (NFPA) standard for Tier 1 facilities. Historically these generators have little use beyond their standby service. However, with the push toward DERs, these standby generators may participate in RTO markets and generate revenue for their owners. Also, some utilities provide an incentive to use standby generation as a form of load control to lower peak load demand. Entities that require standby generation should explore this option, which may provide additional revenue.

A potential weakness to the North Dakota generation fleet is the supply of natural gas to combustion turbine generation facilities. The primary source of fuel for these units is the Northern Border pipeline. The pipeline imports Canadian and Bakken produced natural gas. Natural gas-fired combustion turbines do not store fuel on-site. Therefore, the reliability of this fuel source should be considered as part of generation resource availability.

North Dakota coal-fired generation is located adjacent or near dedicated mines. Coal plants located remote from mines typically keep a 60–90-day stockpile to mitigate the threat of railroad service disruptions. Therefore, fuel adequacy for these facilities is not an issue.

Mitigation for Lack of Generation

Should either MISO or SPP forecast a shortage of generation resources, they will issue EEAs. They increment in increasing levels of severity, with the highest alert being EEA3. At this level, the RTO is utilizing operating reserves such that it is carrying reserves below the required minimum and has initiated assistance through its reserve-sharing group. The RTO foresees or has implemented firm load obligation interruption. In SPP, an EEA3 was implemented during Winter Storm Uri in February 2021.

Mitigation for Aging Grid Infrastructure

Transmission and distribution entities should monitor new RTO policies addressing age and condition replacement and cost recovery options for grid infrastructure.

Mitigation of Vandalism and Terrorism

Electrical facilities are inherently vulnerable to attack because of their fixed location, size, and ease of damage. Also, they are frequently in remote locations. Utilities should investigate what sort of measures can be used to protect the facility, limit potential damage, increase the odds of perpetrator apprehension, and expedite repair of the facility.

Protective walls or fences that block line of sight into the substation may protect against gunfire attacks. Security cameras and other intruder sensors can give law enforcement time to respond as well as provide evidence useful for criminal prosecution. Utilities should coordinate with local law enforcement to establish a security plan.

Physical Damage Mitigation and Supply Chain Interruption Mitigation

Mitigation of supply chain risk and physical risk is similar. Utilities need to have either spare parts and equipment in stock or readily available. For example, the 2022 ice storm in northwestern North Dakota destroyed 4000 poles,[113] not to mention the associated conductor, hardware, and transformers. The entire region was without power initially, with the last customer not restored until 28 days after the storm. The system was repaired with the help of numerous other utilities and contractors providing manpower. In addition, equipment manufacturers responded quickly and, in many cases, surged production. It is possible this was a best-case example because of it being a spring ice storm. The situation could have been much worse if it had been a fall ice storm immediately following a major early fall hurricane. In that scenario, the hurricane recovery effort would have emptied manufacturer stockpiles and manufacturers would have been busy responding to hurricane damage replacements, meaning their ability to respond to ice storm-related damage would have been delayed.

Mitigation for damage repair could be the establishment of coordinated equipment stockpiles in North Dakota to be shared among North Dakota utilities. This stockpile would reduce the reliance on external suppliers in an emergency.

Cyber Threat Mitigation

Aside from following NERC standards, utilities can follow these guidelines to secure their electric assets and also their business-related cyber assets:

- Create an incident response plan, and practice that plan with tabletop exercises.
- Create a dedicated cybersecurity functional group. Fully staff and train this group.

[113] Basin Electric Power Cooperative, 2022, www.basinelectric.com/News-Center/news-briefs/spring-snowstorm-causes-damage-to-member-systems (accessed October 2024).

- Back up and patch computer systems.
- Hire a white hat entity to probe computer security and recommend improvements.

Aging Workforce and Skilled Labor Shortage Mitigation

Programs addressing skilled worker training are in place at locations such as Bismarck State College High school students can be made aware of the good high-paying jobs that are available in the energy industry that can be had through vocational-type training.

Table 12 shows a summary of mitigation strategies to address the risks impacting the reliable, resilient, and secure operations of the bulk power system.

Other Recommendations

- FERC rulemaking regarding the generation interconnection process must be further improved. North Dakota transmission stakeholders should ensure transmission analysis engineer recommendations are provided to FERC. This will ensure that generation interconnection requests are processed promptly with an optimized transmission improvement solution.

- North Dakota transmission entities should support the implementation of DOE's CITAP Program to expedite regulatory approval of transmission line projects.

- Transmission facility owners should review and, if necessary, improve the physical security of their substations, especially exposure to gunfire.

- Transmission facility owners should consider a statewide stockpile of critical transmission material. The stockpile should include common items such as distribution poles and hardware that are essential to repair storm damage. Also, utilities should consider acquiring spare transformers to replace units that are especially critical. The recent substation attack impact was mitigated because BEPC has a spare transformer program.

- Transmission facility owners should consider designing their transmission lines to standards more than the NESC heavy-loading criteria. Also, "storm structures" should be added along long stretches of straight route segments to minimize cascading structure failure.

- Regarding cybersecurity, following NERC CIP standards will provide a basic level of protection. But in addition, utilities should:
  - Create an incident response plan and practice that plan with tabletop exercises.
  - Create a dedicated cybersecurity functional group. Fully staff and train this group.
  - Back up and patch computer systems.
  - Hire a white hat entity to probe computer security and recommend improvements.

Table 12. Summary of Risk Mitigation Strategies

Threats	Applicability	Mitigations
Ice/Snowstorms	Generation, transmission, distribution utilities	• Establish structural design and operational process standards for utilities to withstand inclement cold weather. • Limit cascading structure failure.
Tornadoes/High Winds	Transmission and distribution utilities	• Replace overhead lines with underground wires. • Use interphase spacers. • Transmission and distribution poles with deeper foundation, less components, and durable pole material. • Maintain space between vegetation and overhead lines.
Riverine Flood	Generation, transmission, distribution utilities	• Maintain flood elevation for construction of grid structures. • Vulnerable equipment in enclosed structure with flood-resistant door. • Integration of sensors to monitor water level in flood-prone area.
Lightning	Transmission and distribution utilities	• Lightning arresters and appropriate transmission and distribution grid protection system. • Add backup systems for sensitive loads. • Loop distribution system.
Generation Resource Adequacy	Generation, transmission, and distribution utilities	• Incentivize installation of dispatchable generation. • Generation stakeholders must defend against EPA's coal generation proposed rules. • Implement cold-weather preparedness plans in generation utilities. • Deploy DERs through local utilities. • Ensure reliable natural gas transportation and storage of coal. • Controlled load-shedding during extreme emergencies. • Readiness of hydroelectric facility in case of black start.
Aging	Transmission and distribution utilities	• Implement RTO policies regarding aging infrastructure, replacement condition, and cost recovery option.
Supply Chain Interruption	Transmission and distribution utilities	• Build a diverse supplier base. • Total visibility of supply chain: improve supplier network beyond Tier 1 or 2 suppliers. • Encourage refurbishment and recycling of distribution and transmission grid equipment.
Vandalism and Terrorism	Generation, transmission, and distribution utilities	• Protective walls or fences, security cameras, and sensors in grid facility. • Devise security plan with consultation of local law enforcement agency.

- Generation resource adequacy shortfalls may be the most severe threat to grid resiliency. This problem is primarily caused by federal government policies. NERC has identified energy policy as the No. 1 risk to reliability. Therefore, mitigation will be legal and political:
  - Transmission utility stakeholders should hold EPA accountable for the actions of its proposed rules on coal-fired generation through legal and political action.
  - North Dakota transmission stakeholders that hold positions in NERC, SPP, or MISO committees should promote viewpoints that strengthen generation accreditation and reserve standards.
  - Utilities should create policies to encourage the expansion of DERs via the processes the RTOs are establishing to meet FERC Rule 2222. Entities that own or are considering backup generation should consider placing their units in a DER program.
  - Generation-owning entities should ensure that they meet new NERC Cold-Weather Preparedness Standard EOP-011-2 and review the NERC reliability guideline "Generating Unit Winter Weather Readiness – Current Industry Practices–Version 4."
  - Owners of combustion turbine generation dependent on a sole source of fuel should investigate the reliability of that source and make arrangements for other fuel sources if necessary and practical.
  - The RTOs should consider other options to calculate generation capacity accreditation such as the HCD approach.

- Load-serving entities should ensure that their load-shedding plan is up to date and can be implemented with as little disruption as possible. The plan should be coordinated with the load-serving entities transmission operator regularly.

- The RTOs should update their inverter-based resource integration studies to ensure that grid stability is not being degraded as IBRs continue to replace conventional synchronous generation.

CONCLUSION

This study developed a North Dakota electric grid resiliency plan that analyzes the state's electricity infrastructure, operational conditions, bulk and wholesale energy markets, reliability, resource adequacy, planning efforts of grid operators, and other factors that have an impact on grid resiliency. The authors have surveyed multiple sources of information to develop this grid resiliency plan. A comprehensive reliability survey was conducted with input from the major North Dakota electric utilities. The latest G&T reliability reports from NERC, MISO, SPP, and MRO were reviewed. The latest grid reliability-related policies from FERC, DOE, and EPA were analyzed. All these data were compiled to identify potential threats to electric grid resilience, evaluate their impacts and consequences, and rank resilience risks to the North Dakota electric grid. This study also recommends various mitigation strategies that will allow generation, transmission, and distribution utilities to use risk profiles and mitigation strategies for recurring resilience assessments.

The results of the risk analysis indicate that ice/snowstorms are the only risk classified in the likely/severe category, ranking highest overall. Changing resource mix, supply chain interruptions, and cyberattacks followed, with rankings in the possible/major impact category. The next-ranked risk was high winds, with a likely/moderate ranking. These risks may cause potential damage to grid assets or interrupt grid services and cripple functioning of critical infrastructure. Repairing grid assets in a timely manner is complicated by the inability to quickly procure replacement materials because of supply chain disruptions. The authors recommend North Dakota consider establishing a depot of common materials that could be drawn from by utilities to repair storm damage.

NERC has identified energy policy and grid transformation as the No. 1 and No. 2 grid reliability risks in its 2023 ERO reliability risk priorities report. Energy policy is driving changes in the planning and operation of the bulk power system. Renewable generation is an energy resource and is proving to be an inadequate substitution for thermal generation in regard to providing capacity. This risk is demonstrated by the forecast of declining planning reserve margin in both SPP and MISO in spite of thousands of megawatts of renewable generation additions. SPP is forecast to fall below 15% criteria by 2027. MISO will be short of existing and planned generation by 2028. And these estimates do not include the proposed EPA rules that will force the retirement of thousands of megawatts of thermal generation. Generation must continuously match load; therefore, a lack of generation is an immediate risk to grid reliability and resiliency. North Dakota electric utility stakeholders must engage in RTO, NERC, and FERC processes to raise the bar on generation accreditation requirements to ensure the trend of decreasing reserve margins is reversed. EPA's overreach must be challenged in legal and political realms as well.