NORTH DAKOTA GRID RESILIENCY PLAN

Final Report

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NOMENCLATURE

AIFG	Aging Infrastructure Focus Group
BEPC	Basin Electric Power Cooperative
BES	bulk electric system
CCR	coal combustion residuals
CCUS	carbon capture, utilization, and sequestration
CIP	critical infrastructure protection
CITAP	Coordinate Interagency Transmission Authorization and Permits
CPEC	Central Power Electric Cooperative
DC	direct current
DER	distributed energy resources
DOE	Department of Energy
DPP	detailed project proposal
EEA	Energy Emergency Alert
EERC	Energy & Environmental Research Center
EIC	Eastern Interconnection
ELCC	effective load-carrying capacity
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EV	electric vehicles
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulation Commission
G&T	generation and transmission
GI	generation interconnection
GW	gigawatts
HCD	highest certainty deliverability
IoT	internet of things
IOU	investor-owned utility
ITP	integrated transmission plan
LMP	locational marginal price
LOLE	loss of load expectation
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 Toxicity Standards
MCC	marginal congestion cost
MDU	Montana Dakota Utilities
MEC	marginal energy component
MISO	Midcontinent Independent System Operator
MLC	marginal loss cost
MRO	Midwest Reliability Organization
MRES	Missouri River Energy Services

NOMENCLATURE (continued)

MRV	monitoring, reporting, and verification
MTEP	MISO transmission expansion plan
MW	megawatt
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NMPA	Northern Municipal Power Agency
NREL	National Renewable Energy Laboratory
NRI	National Risk Index
NWS	National Weather Service
OTR	Ozone Transport Rule
PRM	planning reserve margin
RC	reliability coordinator
RTO	regional transmission organizations
SCADA	Supervisory Control and Data Acquisition
SCRIPT	Strategic and Creative Re-Engineering of Integrated Planning Team
SPP	Southwest Power Pool
STEP	SPP Transmission Expansion Plan
TOP	transmission operator
WAPA	Western Area Power Administration

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 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, policy-driven transitions, and grid transformation).

North Dakota's electric grid is managed by the 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 the state of 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 grid resiliency plan complements the North Dakota State Energy Security Plan (SESP), which is in compliance with U.S. Department of Energy (DOE) requirements. The following are specific tasks carried out for this study:

- Exploring North Dakota electricity infrastructure, operational conditions, bulk and wholesale energy markets, reliability, resource adequacy, planning efforts of MISO and SPP, and other factors that have an impact on North Dakota grid resiliency.
- Identifying the 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 the gaps and opportunities for improving grid resiliency.
- Providing recommendations for risk mitigation.

In this study, historical data on weather events, 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. The highest relative risks to the North Dakota grid are identified as ice/snowstorms, changing resource mix/resource adequacy, supply chain interruptions, and cyberattacks.

The changing resource mix is challenging grid resilience as there is a high penetration of variable renewable resources into the grid and a 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 percentages that 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 like solar and wind. While the energy value of renewables may be enough to cover the thermal unit retirement, there will be a shortfall of generation capacity and dispatchability which translates into the lack of ability to cover load during peak periods. This effect is demonstrated by the forecasted depletion of the planning reserve margin.

Generation resource adequacy is a critical component of grid resiliency. This was demonstrated 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. The Electric Reliability Council of Texas (ERCOT) and PJM have also used load shedding to mitigate generation inadequacy. Forecast generation reserve margins are decreasing in both MISO and SPP. Both regional transmission organizations (RTOs) are predicted to be out of required reserve margins by 2027, and these forecasts do not account for the multiple proposed U.S. Environmental Protection Agency (EPA) rules that will result in the closure of multiple GWs of coal-fired generation. For example, SPP predicts that EPA's Ozone Transport Rule will result in the loss of 9.7 GW of dispatchable generation. The CO_2 rule will require 90% CO_2 capture on all coal generation; This rule will mean an estimated cost of $1.4B for Project Tundra at the Young Station. It is not known how many coal plants can financially survive such a high cost for compliance. The coal combustion residuals rule threatens 5.8 GW in MISO, including 1.1 GW at the Coal Creek Station. The fundamental issue is renewable generation is not providing adequate replacement for the dispatchable capacity provided by existing thermal generation.

North Dakota will always be in a battle with extreme weather. The utility survey confirmed that ice and snowstorms are the most severe threat facing utilities. The transmission and distribution systems must maintain their resiliency as electric service is often most crucial during extreme weather events. The recent supply chain issues are emerging as a serious threat. During a storm recovery operation, substantial amounts of replacement of storm-damaged transmission and distribution system parts are 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.

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 physical and 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. Cyberattacks are a constant threat demonstrated by successful attacks on critical facilities elsewhere in the country. The recent substation gunfire attack shows North Dakota is not immune to attention from terrorists.

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. For example, winter weather can increase load above forecasts, cause transmission line outages, and cause generation outages simultaneously. 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 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.

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 are posing unprecedented challenges to the 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. This is mainly because of the 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 cost, 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 made by the electric sector to meet customer expectations amidst the rapid evolution of the electric grid, the reliability of electrical transmission and distribution networks is still a problem for several reasons listed above. This problem is anticipated to grow more quickly as the effects of the replacement of dispatchable thermal generation with renewable variable energy resources continue and customer demand for electricity increases, and it calls for power system planners, operators, and decision-makers to have a deeper understanding of grid reliability and resiliency.

North Dakota is a significant producer and exporter of power, and 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% of the state's electricity generation in 2021), wind energy has recently contributed significantly to the market, making up to 34% of total generation. Electric generation and transmission 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 the grid reliability and resiliency. Therefore, the goal of this study is to develop a grid resiliency plan for the state of North Dakota by assessing the risks that various threats pose to the North Dakota electric grid and addressing gaps in improving grid resiliency. This report gives a summary of various tasks performed to evaluate grid resilience in North Dakota. The following are specific tasks carried out for this study:

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

- Identifying the potential threats to North Dakota electric grid resilience.
- Defining the impacts and consequences of these threats.
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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 [2]. Both concepts are interrelated. Table 1 provides a comparison of the attributes of grid reliability and resiliency [3].

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 areas that have 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 [4]. Power system planning is becoming even more crucial because of increased reliability and resiliency risks.

National Renewable Energy Laboratory (NREL) researchers define grid reliability using three Rs: resource adequacy, operational reliability, and resilience [5]. 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 needs to consider resource adequacy, operational reliability, and resilience to mitigate reliability risks.

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

Table 1. Comparison of the Attributes of Grid Resiliency and Reliability [3]

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	North American Electricity Reliability Council, FERC,[2] 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 impacts can include business losses and interrupted natural gas and water delivery to customers because of power outages.
[2] Federal Energy Regulatory Commission.

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 the addition of an increasing 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 analyzes 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. Extreme weather events can damage the transmission or distribution infrastructure and interrupt the power supply.

The Grid Reliability Report 2021 [6] highlights that the North Dakota electric grid is reliable and has systems in place to ensure long-term reliability. The U.S. grid is today, however, increasingly vulnerable to risks from natural disasters, supply chain problems, 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 subjected to these threats and vulnerabilities. This report mainly 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

This section discusses the general makeup of the North Dakota grid and has 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 the grid operators that operate the electric grid 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, and the 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 the EIC, which covers a diverse landscape ranging from Florida in the south to Saskatchewan in the north (Figure 1).

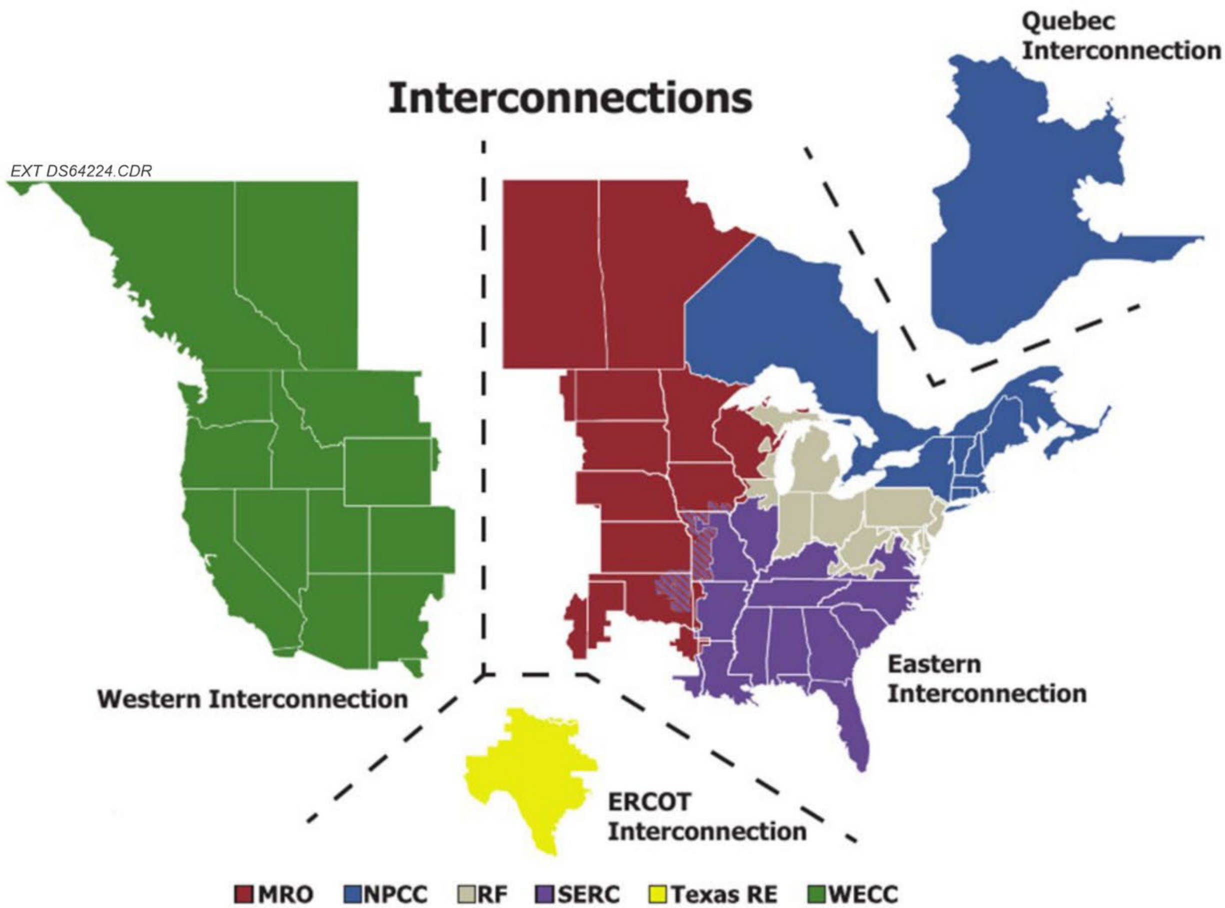


Figure 1. U.S. transmission system interconnections [8].

As a result of FERC Order 2000 in 1999 [9], several regional transmission organizations (RTOs) were formed within the EIC. The 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, 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.

The 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, Montana Dakota Utilities (MDU), and Minnkota Power Cooperative (Minnkota) are members of MISO. However, Minnkota maintains its own transmission tariff.

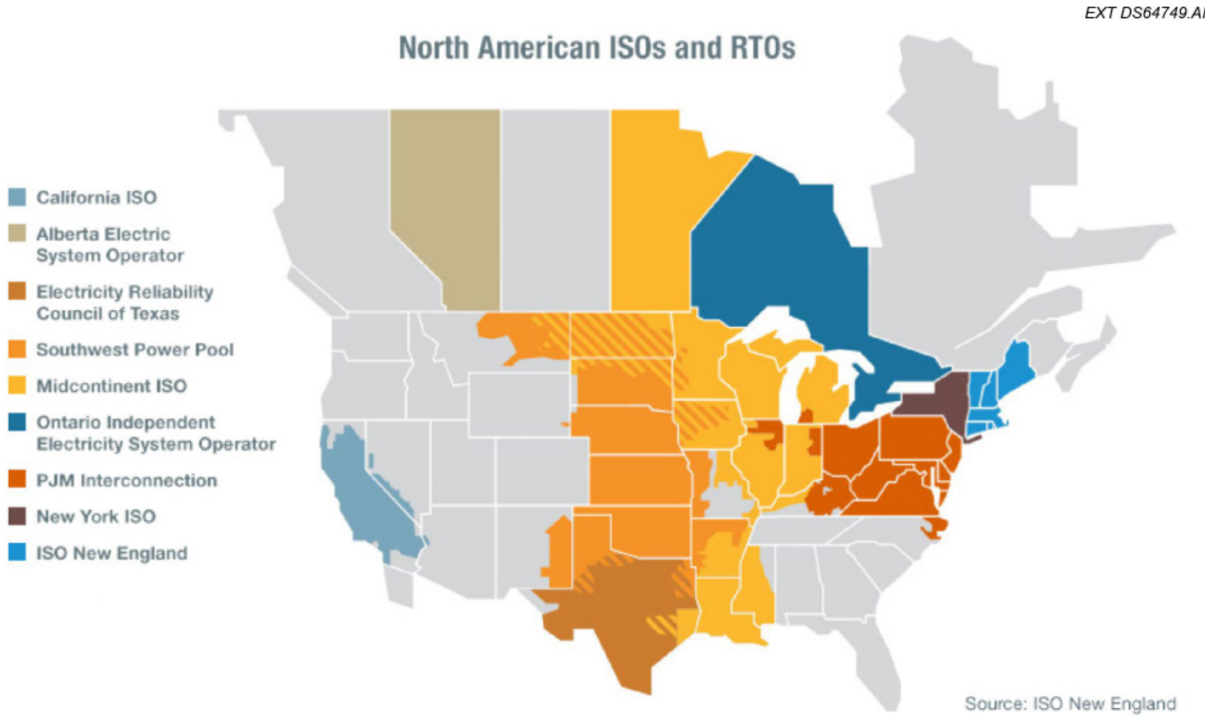


Figure 2. U.S. RTO coverage [10].

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 190 gigawatts (GWs) [11], with around 42% natural gas, 27% coal, 22% renewables, 7% nuclear, and 2% other sources (Figure 3) and a summer peak load of 127 GW.

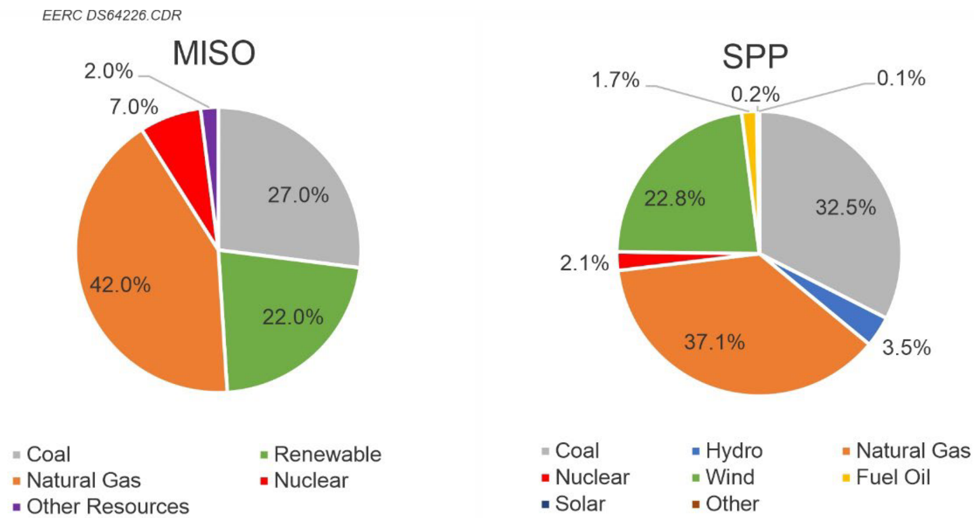


Figure 3. MISO and SPP resource mix as of May 2023.

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 72,000 miles of transmission lines. It has a total nameplate generating capacity of 98 GW, with 37.1% natural gas, 32.5% coal, 22.8% wind, 3.5% hydro, 2.1% nuclear, 1.7% fuel oil, 0.2% solar, and 0.1% other fuel sources (Figure 3). It set a record coincident peak load of 53 GW in July 2022 [12]. SPP is in the process of expansion into the Western Interconnection. It presently operates the Western Energy Imbalance Service market, serves as the Western Interconnection Reliability Coordinator, and is developing an RTO with several Western Interconnection 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 the 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 transmission elements, variation in loads (including demand response), and variation in weather-based generation resources while ensuring the balance of generation and load. Therefore, a resource adequacy study is very complex.

It is the responsibility of each load responsible entity (LRE), as known as load-serving entity (LSE), in an RTO to ensure they have made arrangements to obtain sufficient accredited generation capacity to meet their 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 Otter Tail Power are MISO LSEs while BEPC is a SPP LRE.

Accredited capacity differs from nameplate capacity. Accredited capacity is the capacity of a facility that can be counted on to meet an LRE's peak load requirement. Nameplate capacity is the maximum megawatts (MWs) 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). ELCC is 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 2022 ELCC Wind and Solar Study Report, wind accreditation is typically 15%–17%. Typical solar generation accreditation is 68% in the summer and 33% 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 2022 Summer Reliability Assessment [13]: "*Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.*" This was due to a forecast load growth of 1.7% combined with a 2.3% less generation capacity compared to the summer of 2021 [13].

Also, MISO Maximum Generation Emergency Declarations have increased steadily over the last 14 years. Table 2 shows the data from the MISO Maximum Generation Emergency Declarations report through December 2022 (updated 02/10/2023) [14].

Table 2. MISO Maximum Generation Emergency Declarations, 2009–2022 [14]

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

The NERC 2023 summer reliability assessment shows a change from "high risk" to "at risk" versus the summer of 2022 because of a 1% reduction in the peak load forecast and additional power imports from an increase in firm transmission capacity. This has increased the anticipated reserve margin by 2%. However, there is a reliance on wind generation to perform during peak load conditions [15].

The MISO 2022 Regional Resource Assessment 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 amount 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.

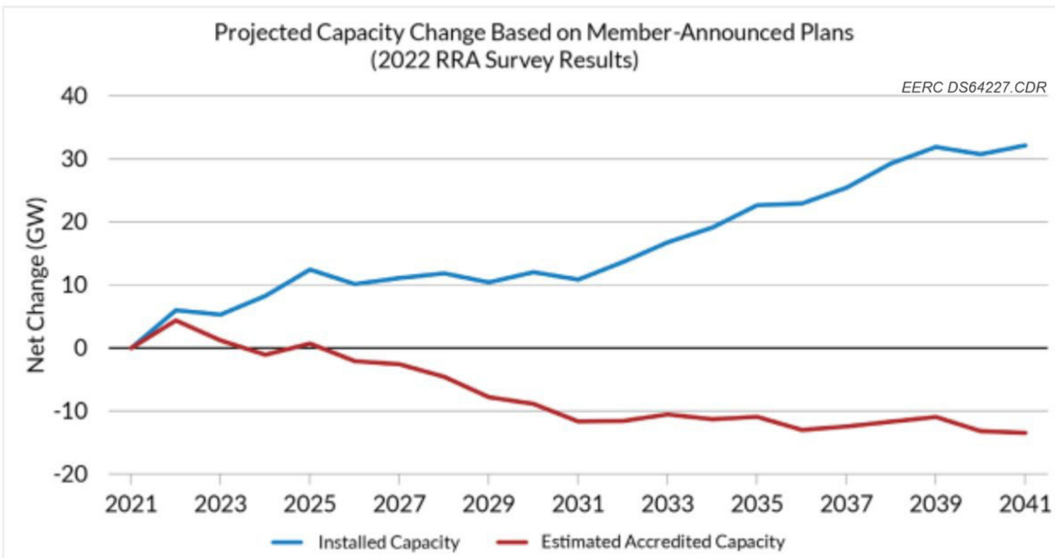


Figure 4. MISO projected capacity changes, 2022 Regional Resource Assessment [15].

The lack of MISO-accredited capacity is reflected in the graph in Figure 5. The required load plus reserve is plotted with the black line. The existing accredited resources are represented by the darkish-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 [15], "*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.*"

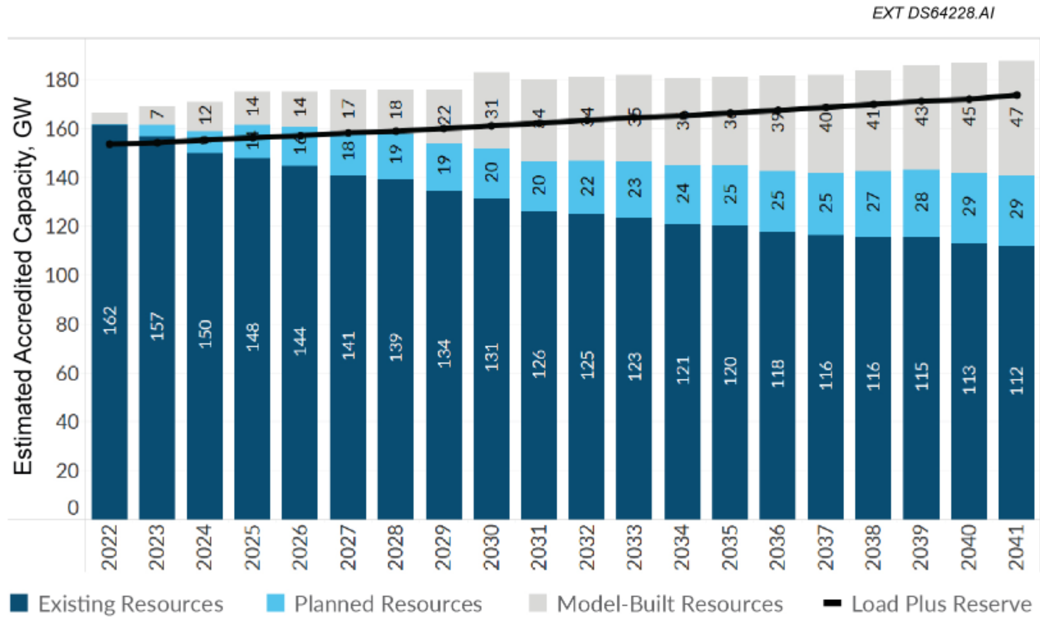


Figure 5. MISO-projected resource, load, and reserves forecast, 2022 Regional Resource Assessment [15].

MISO later states in the 2022 Regional Resource Assessment [15], "*Importantly, member plans often do not provide resource information for the full 20-year study period, and not every member participated in the survey. Especially for later years, the model-built 'gap' is more likely an information gap than a planning gap.*" Then MISO concludes, "*Members may need to build more than 100 GW of new installed capacity within the next 10 years, an unprecedented volume for the MISO region.*"

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.

MISO covers a large geographic area. It divides its system into ten local resource zones (LRZ). 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 the MISO LRZ01, as shown in Figure 6. A plot of LRZ01 resource, load, and reserve forecast is provided in Figure 7. The 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. Also, LRZ01 shows the same dependency on model-built resources to meet resource adequacy needs.

Figure 6. LRZ01 footprint, 2022 Regional Resource Assessment [16].

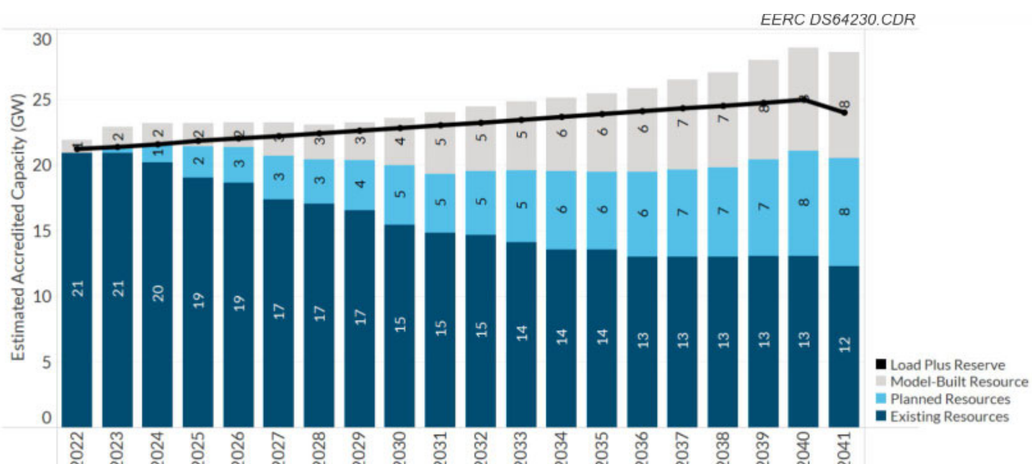


Figure 7. LRZ01 projected resource, load, and reserves forecast, 2022 Regional Resource Assessment [16].

SPP Resource Adequacy and PRM

According to the NERC 2023 Summer Reliability Assessment [13], 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 a peak load period.

SPP performs an annual resource adequacy study and a biennial loss of load expectation (LOLE) analysis. This is required by SPP as documented in Attachment AA in the SPP Transmission Tariff. 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.

SPP published the results of its most recent resource adequacy study in a report entitled 2023 SPP Resource Adequacy Report dated June 15, 2023 [17]. The report is a compilation of each of SPP's LREs individual resource adequacy status. In order to ensure that SPP has sufficient overall adequacy, each of its participating LREs must demonstrate sufficient adequacy as well. If an LRE has insufficient capacity, then it can be subjected 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.

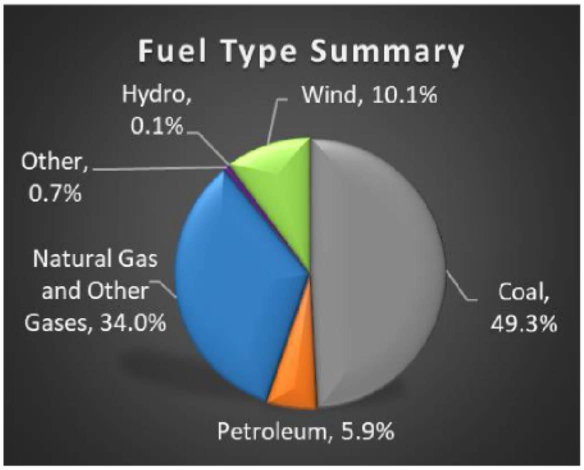
In North Dakota, the primary LREs are BEPC and WAPA. BEPC provides the LRE function as part of its "all requirement" power supply obligation to its member cooperatives. The WAPA LRE obligation covers its allocation of federal hydropower energy to its preference customers. A summary of results from the SPP 2023 Resource Adequacy Report is provided for BEPC and WAPA in Figures 8 and 9, respectively [17].

All LREs in SPP met their resource adequacy requirements with PRMs in excess of the criteria that existed in the summer of 2023. The SPP criteria is 15% for most LREs, including BEPC. However, LREs with primarily (>75%) hydro-based resources (such as WAPA) had 9.89% PRM criteria. BEPC's PRM was 26.0% for 2023, and WAPA's PRM was 26.9% [17].

While the 2023 results met criteria, the 2023 SPP Resource Adequacy Report forecasted a steady decline in the PRM. By the summer of 2027, SPP as a whole will not meet its 15% PRM criteria. This forecast is provided in the graph in Figure 10 and the table in Figure 11.

The LOLE is a statistical analysis of multiple scenarios and considers load growth, generation additions and retirements, unit outages, and other variables that will affect generation adequacy over the next 5 years. A primary deliverable from the LOLE study is the system PRM required to meet the LOLE criteria.

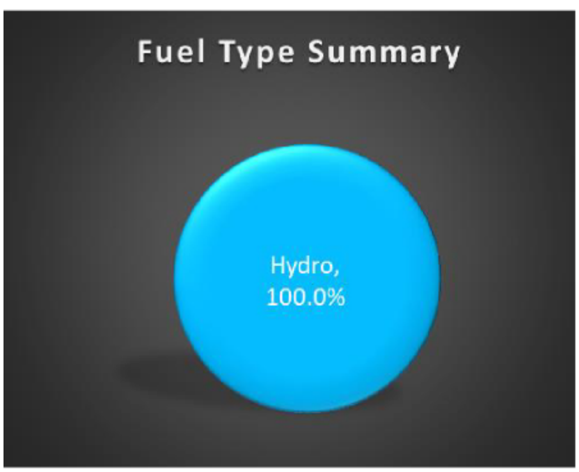
BASIN ELECTRIC POWER COOPERATIVE *EXT DS64719.AI*



Capacity Summary	Unit	2023
Capacity Resources	MW	3,574
Firm Capacity Purchases	MW	948
Deliverable Capacity Purchases	MW	54
Firm Capacity Sales	MW	0
Deliverable Capacity Sales	MW	0
External Firm Power Purchases	MW	0
External Firm Power Sales	MW	0
Confirmed Retirements	MW	0
Total Capacity	**MW**	**4,576**
Demand Summary		
Forecasted Peak Demand	MW	3,636
Internal Firm Power Sales	MW	0
Internal Firm Power Purchases	MW	4
Controllable and Dispatchable DR	MW	0
Net Peak Demand	**MW**	**3,632**
Requirements Summary		
Resource Adequacy Requirement	**MW**	4,177
Excess Capacity	MW	399
Deficient Capacity	**MW**	0
LRE planning reserve margin	%	**26.00**
Planning Reserve Margin	%	15.00

Figure 8. BEPC resource adequacy results, SPP 2023 report [17].

WESTERN AREA POWER ADMINISTRATION – UGP *EXT DS64720.AI*



Capacity Summary	Unit	2023
Capacity Resources	MW	2,353
Firm Capacity Purchases	MW	0
Deliverable Capacity Purchases	MW	0
Firm Capacity Sales	MW	441
Deliverable Capacity Sales	MW	0
External Firm Power Purchases	MW	0
External Firm Power Sales	MW	0
Confirmed Retirements	MW	0
Total Capacity	**MW**	**1,910**
Demand Summary		
Forecasted Peak Demand	MW	759
Internal Firm Power Sales	MW	746
Internal Firm Power Purchases	MW	0
Controllable and Dispatchable DR	MW	0
Net Peak Demand	**MW**	**1,505**
Requirements Summary		
Resource Adequacy Requirement	**MW**	1,654
Excess Capacity	MW	256
Deficient Capacity	**MW**	0
LRE planning reserve margin	%	**26.90**
Planning Reserve Margin	%	9.89

Figure 9. WAPA resource adequacy results, SPP 2023 report [17].

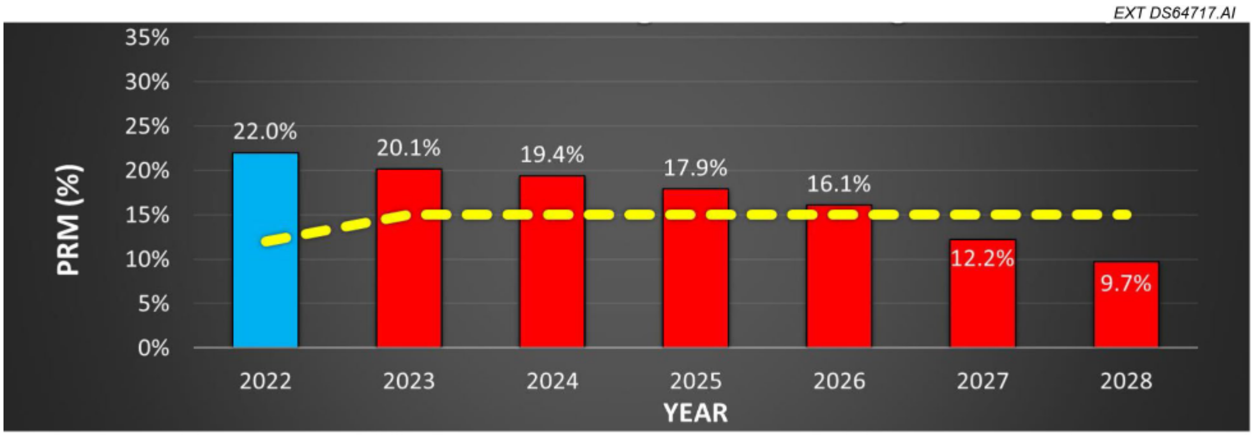


Figure 10. SPP PRM forecast, SPP 2023 report [17].

Table 1: SPP 2023 to 2028 Summer Season Outlook

EXT DS64718.AI

Demand Summary *(Units – MW)*	2023	2024	2025	2026	2027	2028
Total LRE Forecasted Net Peak Demand	53,954	54,661	55,575	56,270	57,256	57,552
Controllable and Dispatchable Demand Response[6]	829	1,353	1,489	1,772	1,798	1,807
Energy Efficiency and Conservation	249	324	384	435	480	517
Stand-by Load Under Contract	25.4	25.4	25.4	25.4	25.4	25.4
Capacity Summary *(Units – MW)*	2023	2024	2025	2026	2027	2028
Total Capacity[7]	64,822	63,380	63,357	61,707	59,630	57,430
Capacity Resources[6]	64,076	64,746	64,980	64,765	63,740	62,651
Confirmed Retirements	122	382	382	382	382	382
Unconfirmed Retirements	0	1,878	2,155	3,610	4,603	5,719
Other Capacity Adjustments – Additions	0	0	0	0	0	0
Other Capacity Adjustments – Reductions	128	128	128	128	128	128
External Firm Capacity Purchases	259	304	324	344	344	349
External Firm Capacity Sales	617	592	592	592	592	592
External Firm Power Purchases	1,355	1,355	1,354	1,354	1,295	1,295
External Firm Power Sales	0	0	0	0	0	0
SPP BA Area Planning Reserve[8]	20.1%	19.4%	17.9%	16.1%	12.2%	9.7%
Planning Reserve Margin *(As specified in SPP Planning Criteria)*	15%	15%	15%	15%	15%	15%
Total LRE Resource Adequacy Requirement	61,970	62,783	63,828	64,627	65,761	66,102
Total LRE Excess Capacity	2,784	1,694	904	-166	-2,964	-4,389
Total Generator Owner Excess Capacity *(Excludes Generator Owner uncommitted Deliverable Capacity of wind resources)*	67	781	780	856	1,436	1,436

Figure 11. SPP PRM forecast data, SPP 2023 report [17].

At the time of the 2021 LOLE study, the SPP PRM was 12% for the majority of its members [17]. Each LRE in the SPP RTO must demonstrate annually sufficient generation capacity to cover its peak load plus the required PRM.

However, the results of the SPP 2021 LOLE indicated that a 12% PRM was not adequate to meet the 1 day in 10 years LOLE criteria. Therefore, in 2022, SPP performed an analysis to review the results of the 2021 LOLE study and investigated adjusting the PRM. SPP determined the cause of the declining PRM is the replacement of thermal generation with variable energy resources. SPP is concerned about the 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 criteria 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 and established a winter PRM requirement. Previously, the SPP LREs were only required to demonstrate a summer PRM. Several SPP LREs are concerned that the increase to 15% by the summer of 2023 is too quick and puts them at risk of deficiency payments. They have filed a protest with FERC. The subject of PRM in the SPP footprint is evolving and further changes are likely.

Generation Interconnection Process Delays

As the reserve margins are decreasing, the ability of the RTOs to process new generation interconnections in a timely manner is an issue that needs to be addressed.

All generation additions are managed by the RTOs through their generation interconnection (GI) process. The GI requests are placed in a queue and studied in the order they are received or through measures of their project in service progress. There is typically an open season. 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 talk 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-kV lines in North Dakota when the adjacent 115-kV system had sufficient capacity with much less expensive upgrades. The system support from the wind farms could have benefited the load-serving 115-kV system area, instead the wind power is 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 5 years behind schedule. For example, the MISO 2017 study was completed in 2023 [18].

RTOs are attempting to speed up the process by increasing deposits and other fees and establishing a first ready, first served type of process. The FERC has also adjusted its rules [19]. Unfortunately, one component of the new FERC rules financially penalizes the RTOs for missing study deadlines. By rushing the study effort, the engineers will have less time to optimize their transmission solutions. Therefore, they will simply provide overbuilt solutions. Or worse, in their haste, the engineers will not catch mistakes and provide incorrect solutions. Neither effort will eliminate the cluster process which will inherently have 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, Ozone Transport Rule (OTR), coal combustion residuals (CCR), carbon capture, utilization, and sequestration (CCUS), and Mercury and Air Toxicity Standards (MATS).

Ozone Transport Rule (OTR)

The 2015 Ozone National Ambient Air Quality Standard (Ozone Transport Rule) will add the requirement to install NO_x controls to many coal and natural gas fuel generators by 2026. This is a tremendous burden for the owners of these generators and the operators of the transmission system. For example, catalytic reduction equipment was installed by BEPC at its Laramie River Station generation facility. The project cost was $250 million and it took 5 years from planning to completion. While the OTR does not affect generation located in North Dakota, thousands of MWs of accredited generation are at risk in the MISO and SPP areas. Since the 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 [20].

SPP wrote a letter to EPA dated August 17, 2022, [21] 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.*" This is a total of 9684 MW of dispatchable generation at risk. Figure 11 shows a total SPP generator owner excess capacity of 1436 MW in 2027. A reduction of 9684 MW would leave SPP -8248-MW deficient.

MISO provided comments on the EPA rule on June 21, 2022 [22]. Its comments included 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-unit scenarios assume 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 projected number of hours in 2026 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's feedback, the OTR will severely impact resource adequacy across the region. It will be expensive at $250 million per generator and will be impossible to meet EPA's 2026 deadline assuming a 5-year project schedule.

Table 3. MISO Ozone Transport Rule Resource Adequacy, MISO comments to EPA [22]

Y2026	MW of Impacted Generation	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

Coal Combustion Residuals (CCR) Rule

Another impending EPA rule is the disposal of CCRs, also known as fly ash. Coal-fired power plants may be required to improve their fly ash disposal sites to meet the new EPA rule [23]. In North Dakota, this rule could impact the Coal Creek Station, owned by Rainbow Energy. 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's compliance plan application, and meanwhile, public comments are being processed. 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. 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 SPP-connected generation are affected by the CCR rule.

Regional Haze Rule

Otter Tail Power and MDU are concerned about EPA's regional haze rule's effect on the Coyote Generation Station. The North Dakota Department of Environmental Quality has determined that Coyote Station does not require emission reductions to comply with the regional haze rules. However, if EPA does not accept this conclusion, then Coyote Station may require significant upgrades. In its "Application for Supplemental Resource Plan Approval 2023–2037" to the Minnesota Public Utilities Commission, Otter Tail Power 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 [24]. In the submittal, Otter Tail Power recognizes that if it cannot find an entity to replace its Coyote Station ownership participation, the station will likely be closed. The MDU 2021 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 [25]. Should this plant retire, the system would lose 425 MW of dispatchable power.

Minnesota Power is in the process of withdrawing from its 227-MW ownership share in the Milton R. Young Unit 2 generator [26]. This will be complete by the end of 2026. Minnesota Power will use the Center, North Dakota, to Duluth, Minnesota, DC transmission line to import wind power from North Dakota into its system.

Carbon Capture, Utilization, and Sequestration

EPA posted a new rule regarding New Source Performance Standards (111b and d) on May 23, 2023. This proposed rule would require coal-fired power plants that are scheduled to operate after 2039 to capture at least 90% of their CO_2 emissions [27].

Several North Dakota utilities are developing carbon capture, utilization, and sequestration (CCUS) projects. These projects will remove approximately 90% of the CO_2 from power plant emission and inject the CO_2 1 mile underground into compatible geologic formations where the CO_2 will be permanently stored. These projects are challenging to develop. They have a high capital and operating cost and consume large amounts of electrical energy. However, they will allow dispatchable, reliable base load generation to remain in operation while meeting the requirements of low CO_2 emissions. Also, income streams may be available from 45Q direct payments or enhanced oil recovery to offset the expense of the CCUS equipment. The economics of CCUS are critical because, ultimately, all coal-fired generation in North Dakota is bid into the SPP or MISO energy markets and, therefore, compete with other sources of power. Low bid prices will be required to get the yearly runtime hours needed to generate the income streams that high capital cost projects with long payback periods require.

Minnkota 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.

Rainbow Energy (Rainbow) is also investigating CCUS at its Coal Creek Station near Washburn, North Dakota. In partnership with the Energy & Environmental Research Center (EERC), Rainbow received a $38 million award from the U.S. Department of Energy (DOE) to investigate CCUS solutions at the Coal Creek Station [28].

Mercury and Air Toxicity Standards (MATS)

On April 5, 2023, EPA posted a modification to the Mercury and Air Toxicity Standards (MATS) [28]. The proposed 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 proposed 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 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 [29]. Figure 12 shows the North Dakota transmission lines. Within North Dakota, management of the transmission system and its reliability operation is a function of the 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

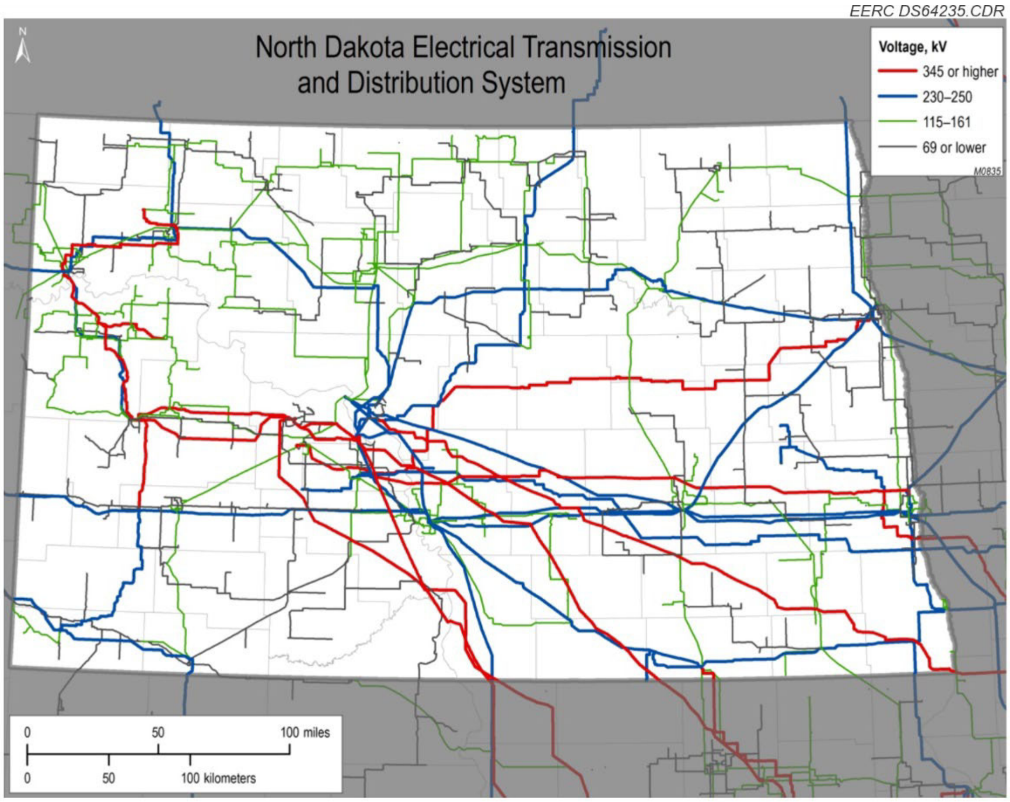


Figure 12. Transmission lines in North Dakota.

require action. The RTOs perform this role as part of their NERC-defined responsibility as a reliability coordinator (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 criteria violation during a simulated outage, the RC can direct real-time redispatch, flowgate 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.

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 the 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 needed to accommodate the generation requests. These studies are done in a grouped manner based on the 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 the stakeholders as well as several SPP workgroups and then is submitted to the SPP board for approval. After board approval, the reliability projects are assigned to effected 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 [30], 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 northwest 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 13). The total cost estimate of these projects is $725 million.

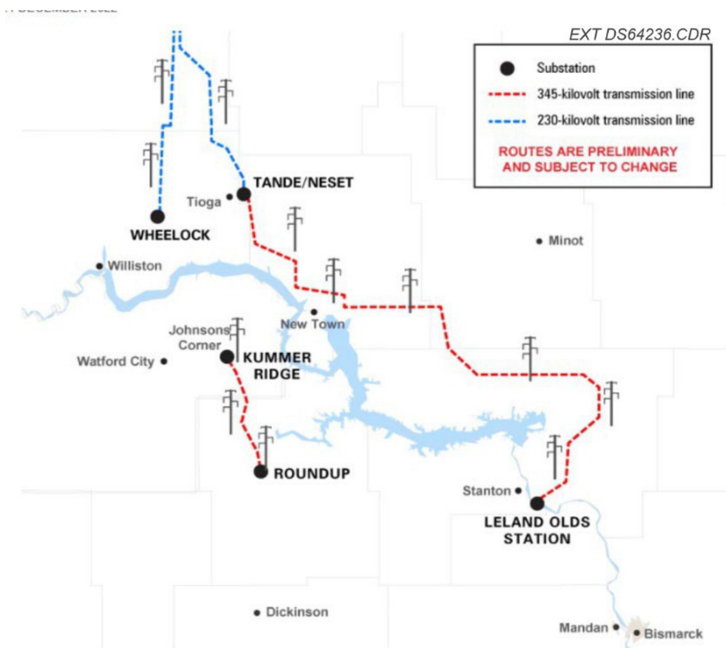


Figure 13. BEPC's proposed transmission projects [31].

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 multivalue project process that incorporates high-level policy, regulation, and economic considerations.

The 2021 LRTP [32] considers three scenarios called futures. These futures are a base case assuming utility resources 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 14). The project is being developed by Otter Tail Power and MDU. It will be an 85-mile-long, 345-kV transmission line connecting Otter Tail'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 into 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–cost ratio between 2.6 and 3.8.

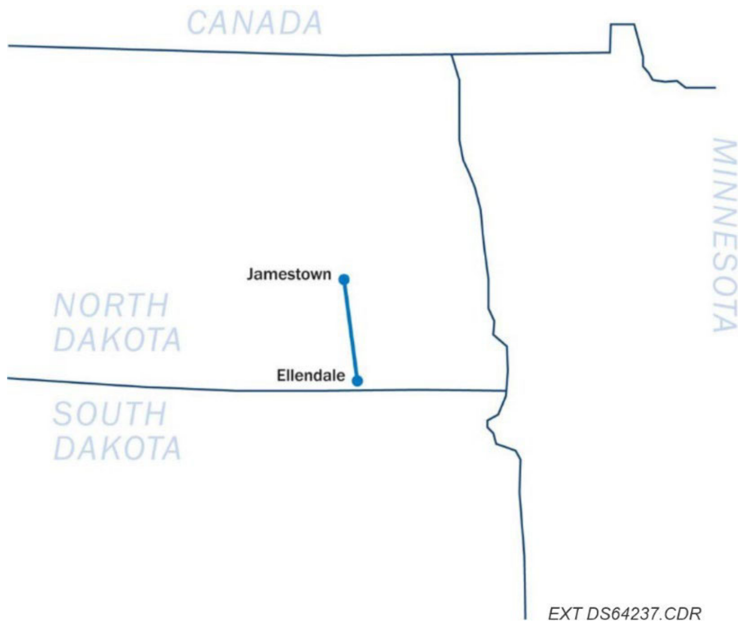


Figure 14. Jamestown–Ellendale 345-kV transmission line [33].

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 Districts "R-Project," a \$400MM 345-kV transmission line, has been stuck in the NEPA process since 2013 [34].

In order to expedite the permitting process, DOE is proposing a Coordinate Interagency Transmission Authorization and Permits (CITAP) Program [35]. 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

The RTOs perform a yearly reliability study. SPP's process is the Integrated Transmission Plan, while MISO's process is the MISO Transmission Expansion Plan. 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 the forecast will be inaccurate because of the 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, their 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. The short-term mitigation is the addition of under voltage load-shedding relays, out of merit order operation of generation, and the establishment of special operating guides. New projects under construction identified by the SPP reliability study process will restore the required transmission capacity. The 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 the regional impact which is covered by the annual reliability studies.

Electric vehicles (EVs) are hard to predict from a load-forecasting perspective. It is likely that retail rates will discourage charging during system peak load periods, limiting the 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 of the impact of EVs on its transmission system operations [36]. 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 the high market price signals. 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 the lower-voltage distribution systems which may have difficulty accommodating the electrical needs of the 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 forecast 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).

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 15). 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 the 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 MWs that flow across a particular path on the transmission system that exceed the amount of MW capacity that path can accommodate without violating system operating criteria, such as thermal overload or voltage excursions.

The LMP at any location is the summation of the MEC, MLC, and MCC. The MLC and MCC can have positive or negative adjustments to the MEC. The variability of the LMP across the geographical footprint of the RTO can distort the normal stacking of the 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 flowgate in western North Dakota that is frequently flagged on SPP's LMP heat map.

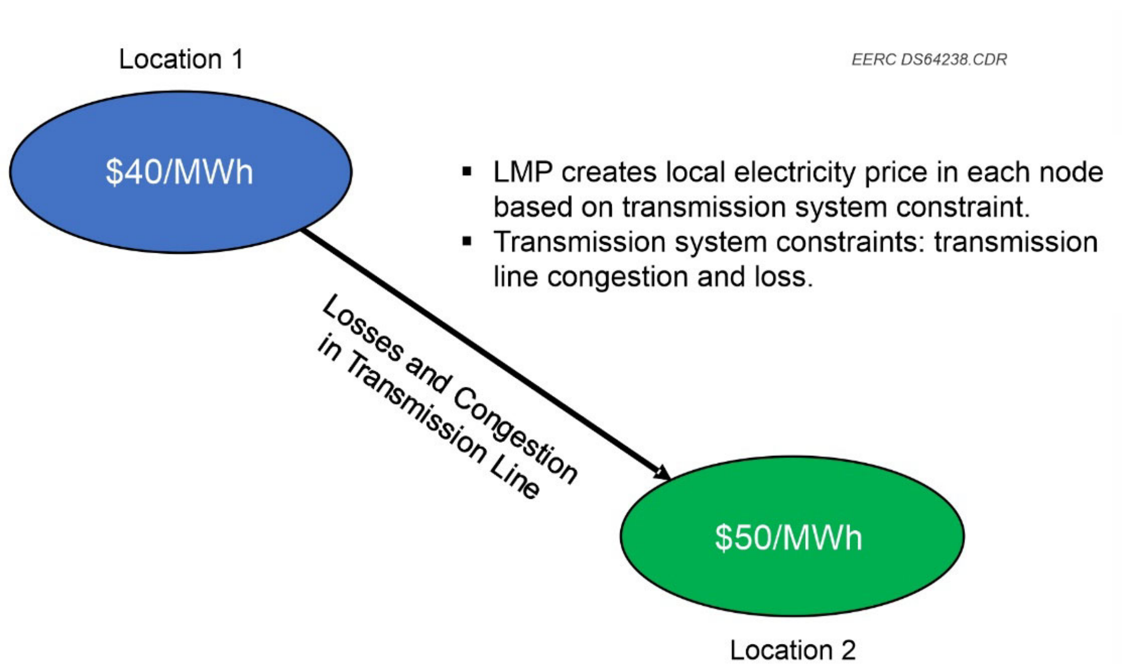


Figure 15. LMP.

When Bakken area loads are high and area generation is out of service, the LMP prices rise because of congestion on the western North Dakota flowgate. This provides an incentive for the operation of the 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 flowgate and the congestion is relieved.

Figure 16 shows an actual LMP map of SPP. The LMP prices are defined by color along the left side of the map, and the 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. The LMP prices in western Kansas are negative, as shown by the dark purple color. The 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 the power flow across the congested element and relieve the transmission congestion.

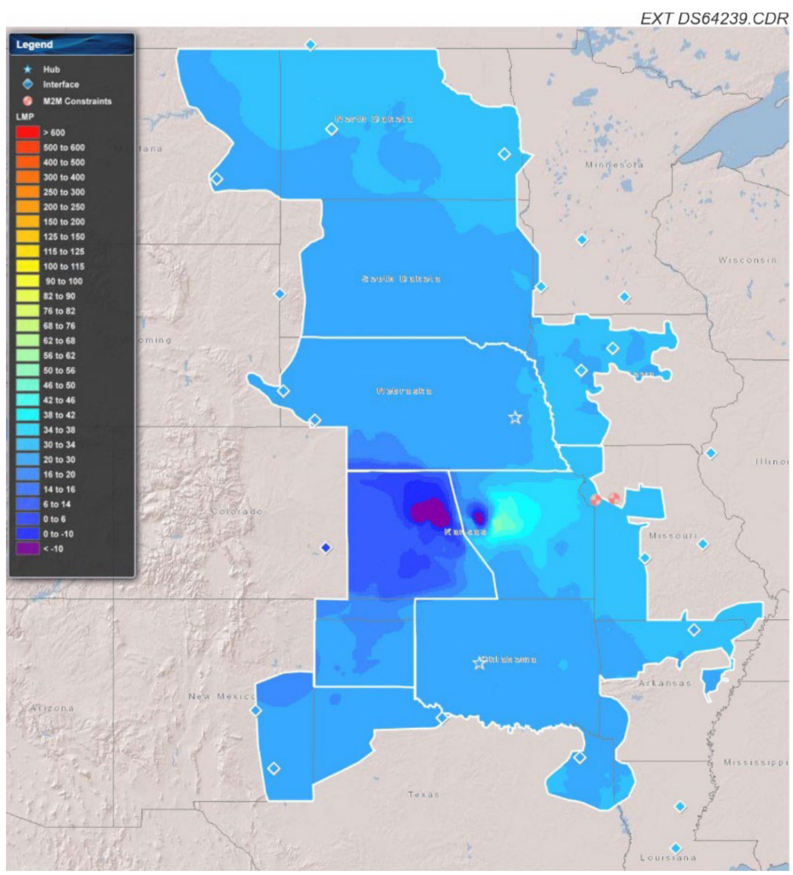


Figure 16. Example SPP LMP map [37].

Electric Power Generation and Transmission Providers in North Dakota

North Dakota's electric providers can be classified into three categories: rural electric generation and transmission (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 Minnkota Power are the rural G&T cooperatives in North Dakota (Figure 17). Otter Tail Power, MDU, and Xcel Energy are the IOUs currently operating in North Dakota (Figure 18). Missouri River Energy Services and the Northern Municipal Power Agency (NMPA) provide electric energy to North Dakota's municipal power utilities.

Figure 17. North Dakota rural G&T cooperatives [38].

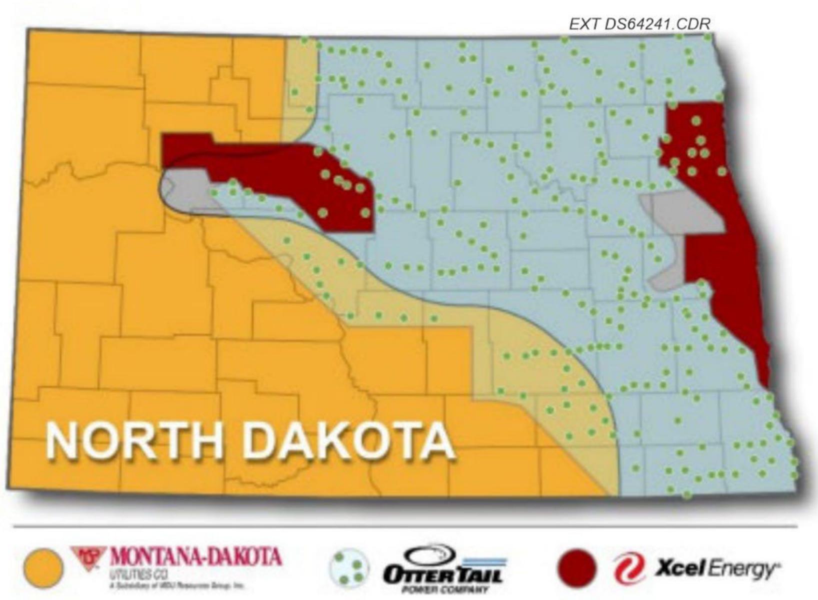


Figure 18. North Dakota IOUs service territories [39].

Rural Electric Generation and Transmission 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 7384 MW at the end of 2022. Figure 19 shows a breakdown of BEPC's generation mix [40].

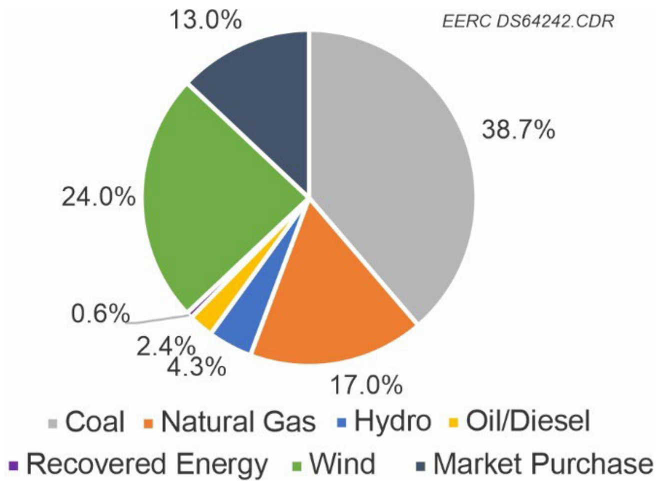


Figure 19. Fuel generation mix of BEPC [40].

BEPC's member systems are located in both the Eastern and Western Interconnections. To enable power transfers between the Eastern and Western Interconnections, 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.

According to SPP's Resource Adequacy Report, BEPC has a net capacity of 4576 MW in the SPP region in 2023. It has peak demand of 3632 MW, which makes its resource adequacy requirement 4177 MW. Currently, its PRM stays at 26.0%, significantly above the SPP's PRM requirement of 15% [41].

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 [42]. 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. The Barr Engineering report, Power Forecast in 2021 [43] predicted that these efforts in western North Dakota would cause the energy demand to increase in the coming years (Figure 20). This study considered two model scenarios: 1) low scenario and 2) consensus scenario subjected to regulatory changes, technological advancements, and price volatility. SPP considered this load growth while calculating its PRM.

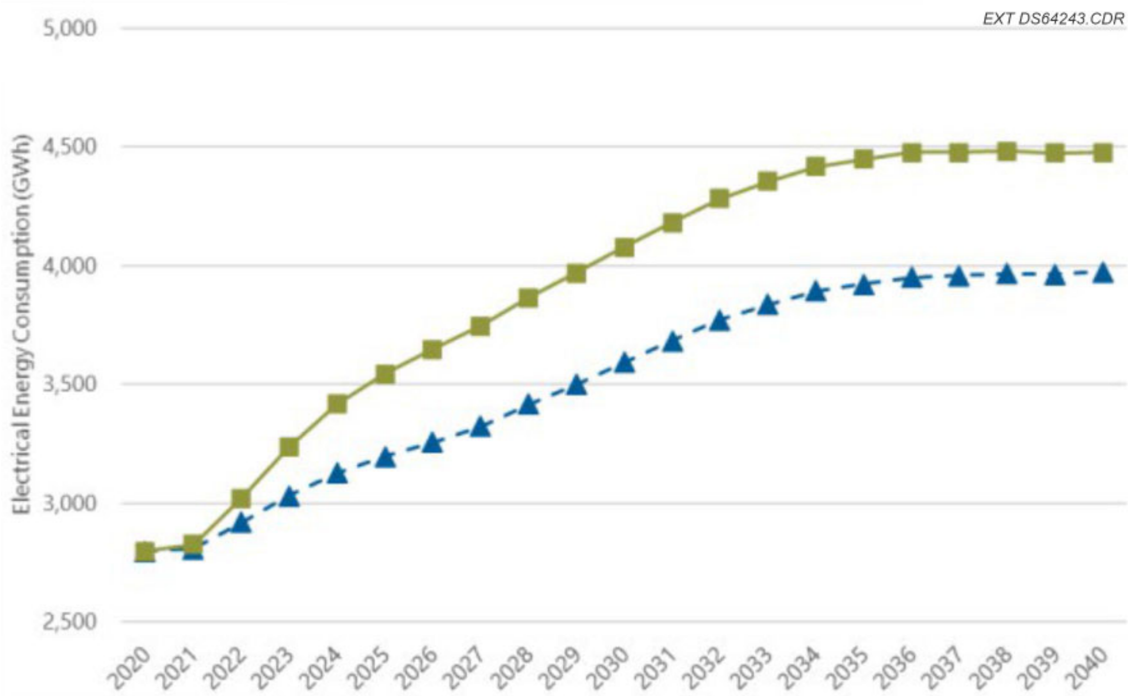


Figure 20. Oil and gas production forecast electrical energy consumption in western North Dakota [43].

Minnkota

Minnkota is a not-for-profit electric generation and transmission 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. Minnkota is the operating agent for NMPA, which serves Grafton, North Dakota, and Park River, North Dakota, as well as nine municipal utilities in Minnesota. Minnkota serves nearly 137,000 consumer accounts in Minnesota and North Dakota [44].

Minnkota has most of its power generation plants in North Dakota. Minnkota has generation capacity and purchases of over 1400 MW. Figure 21 shows the generation resource mix of Minnkota.

Minnkota is a MISO market participant and has an obligation to maintain MISO's resource adequacy requirements. It requires generation capacity exceeding the customer demand and load forecasts by an adequate margin. Minnkota's winter peak is 985 MW in 2022, and it is projected to rise to around 1069 MW in 2036. This high-load growth projection considers annual 1.8% increase of load [45]. Minnkota'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 Minnkota's generation capability is well above customer demand, Minnkota evaluates its customer profile every year.

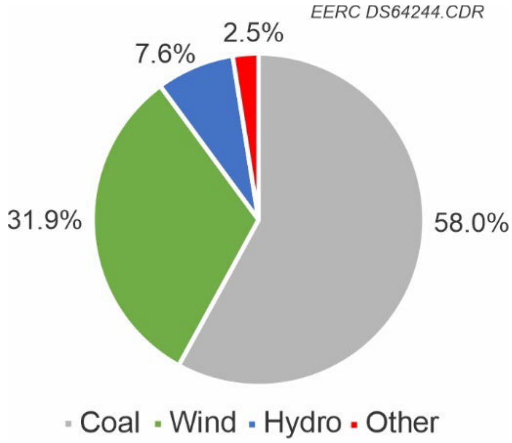


Figure 21. Fuel generation mix of Minnkota.

Investor-Owned Utilities

Otter Tail Power

Otter Tail Power 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 22 shows the service area of Otter Tail Power in Minnesota, North Dakota, and South Dakota. Otter Tail's generation mix includes coal-fired plants, hydroelectric plants, wind power, solar power, and combustion turbines [46]. Otter Tail Power is a market and transmission-owning member of MISO RTO. Figure 23 shows the energy generation mix of Otter Tail Power. Its current generation capacity is around 1215 MW.

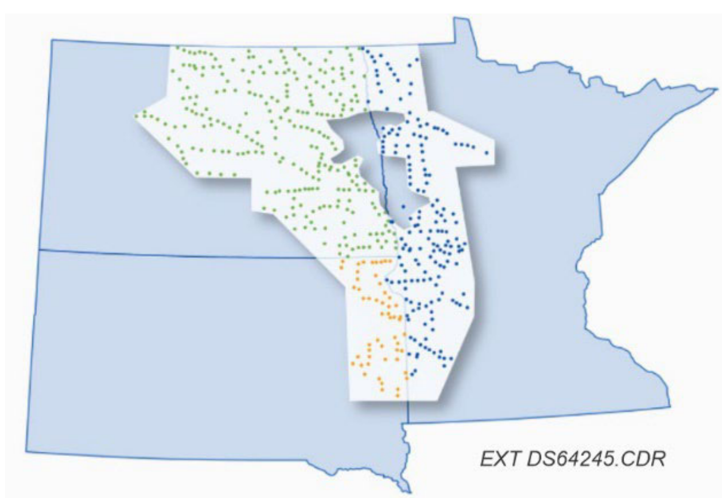


Figure 22. Service area of Otter Tail Power [46].

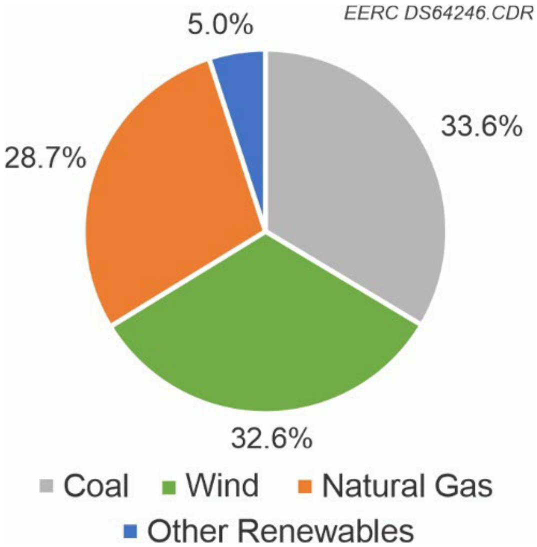


Figure 23. Resource generation mix of Otter Tail Power.

In 2027–2028, Otter Tail Power will add 200 MW of solar generation to its portfolio. It is also planning to add 200 MW of wind generation within a 2029 time frame. The company is planning to move toward renewable generation. Therefore, it will not be willing to make any large capital investment on Coyote Station and will withdraw from 35% ownership interest in case any large investment is needed for plant operation [24]. Otter Tail Power has a nameplate generation capacity over 1200 MW. The demand projection indicates a peak load growth of 931 MW until 2030. 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 Otter Tail Power.

Montana–Dakota Utilities

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 24 shows the service territory of MDU. MDU has 656 MW of generation capacity. The utility has observed summer peak demand of 611.5 MW and winter peak demand of 582.1 MW [47]. 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 is 144 MW. MDU is adding a second 88-MW combustion turbine generator at Heskett in 2023. Figure 25 shows the generation resource mix for MDU [47].

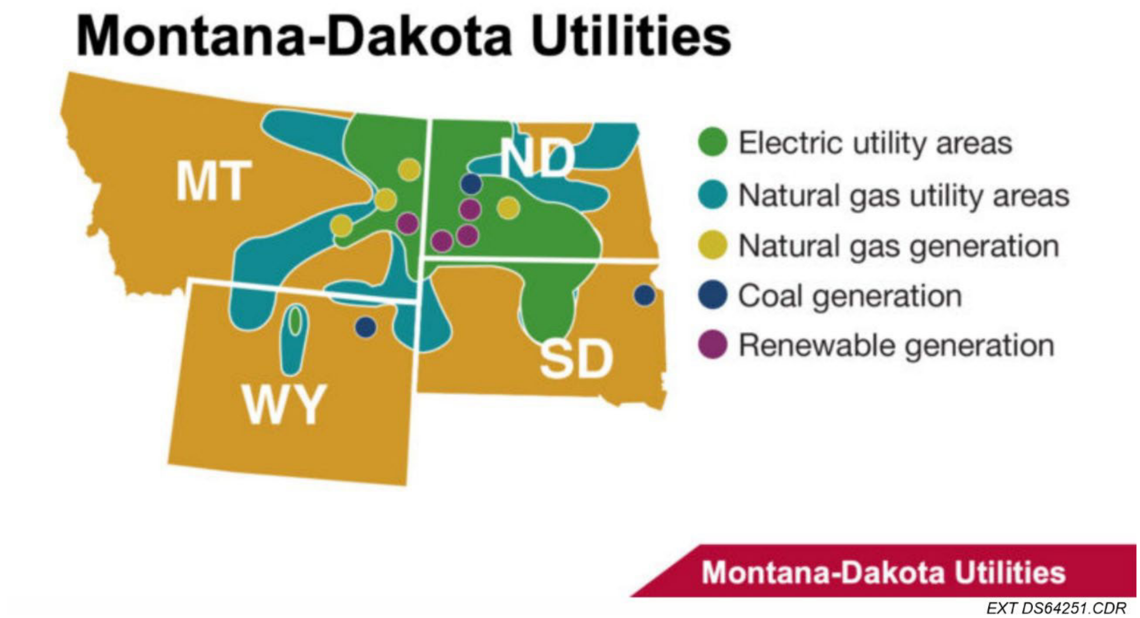


Figure 24. Service area of MDU [48].

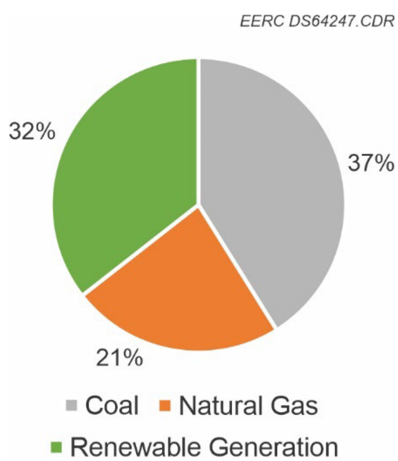


Figure 25. MDU generation energy mix.

Xcel Energy

Xcel Energy is the largest generation utility in LRZ01 of MISO. 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 that serve a combined total of more than 3.6 million electricity customers and 2 million natural gas customers in eight states. Figure 26 shows the service area of Xcel Energy. In North Dakota, Xcel Energy serves the cities of Minot, Grand Forks, and Fargo.

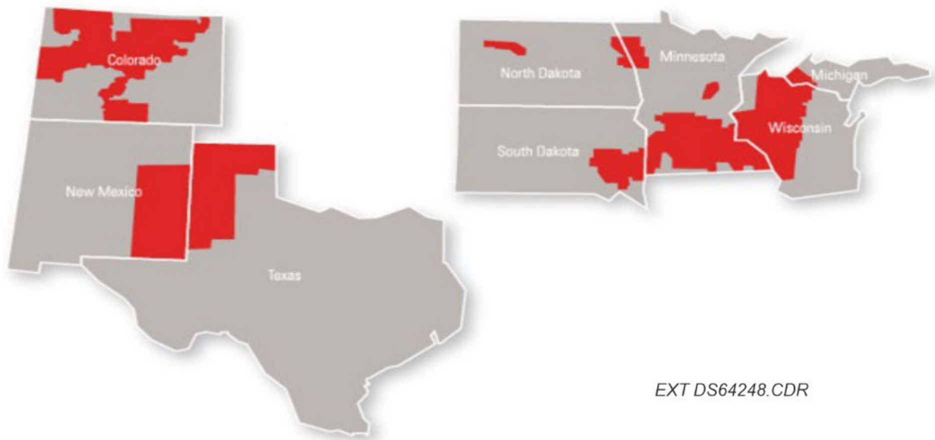


Figure 26. Service area of Xcel Energy [49].

Figure 27 displays the fuel generation mix of Xcel Energy in 2020 and its plan for 2030. In its integrated resource plan, Xcel Energy outlined an addition of 1300 MW of solar by 2026, 600 MW of solar and/or storage between 2028 and 2030, and 600 MW of solar and 2150 MW of wind (or equivalent combination of wind, solar, and/or storage) between 2027 and 2032. It also indicated the retirement of coal plants and a need for 800 MW of firm dispatchable resources between 2027 and 2029. Figure 28 shows the installed capacity of Xcel Energy in different states. It has 500 MW of wind power installed in North Dakota. However, it has around 11,267 MW of unforced capacity in the Upper Midwest. Being a part of MISO LRZ01, Xcel Energy in North Dakota will be subjected to future capacity risks associated with this zone.

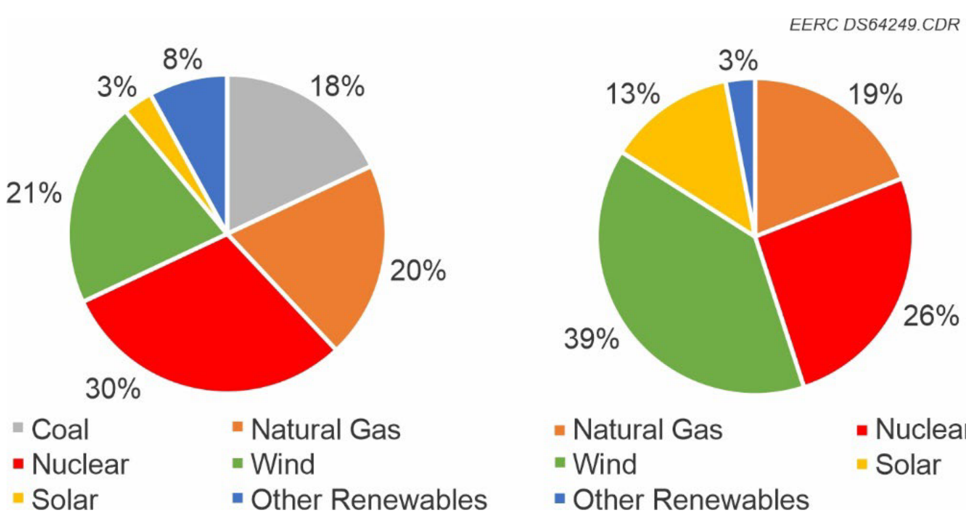


Figure 27. Fuel generation mix of Xcel Energy a) 2020 and b) preferred in 2030 [50].

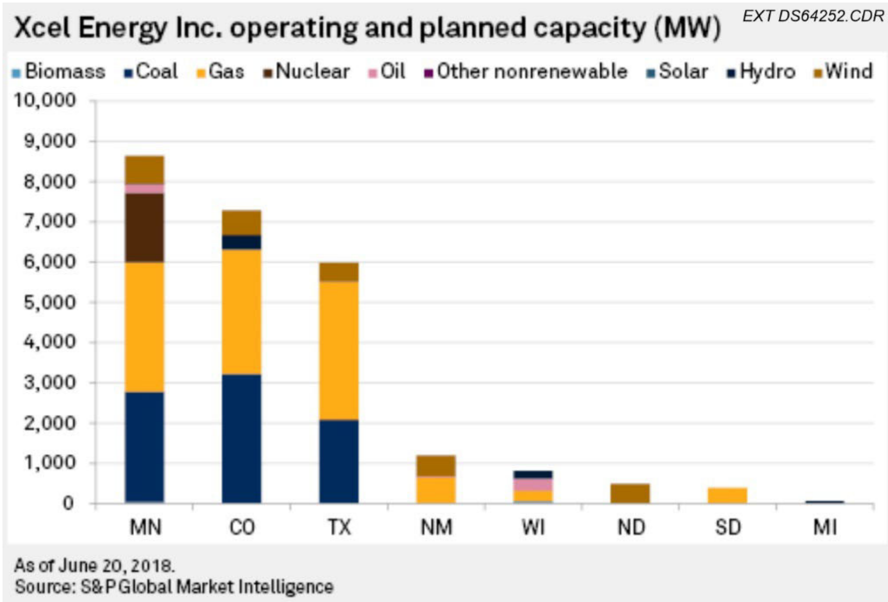


Figure 28. Installed capacity of Xcel Energy according to fuel mix [49].

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.

NMPA

NMPA is a wholesale power supplier to the municipalities of Grafton and Park River in North Dakota as well as 12 others in Minnesota. Its power is provided by the Coyote Generation Station near Center, North Dakota, and delivered through a transmission wheeling arrangement with Minnkota.

Distribution Co-Ops in North Dakota

There are 16 electric distribution cooperatives in North Dakota. Figure 29 shows the map of distribution co-ops in North Dakota [51]. All of these distribution co-ops are consumer-owned and serve thousands of members. Table 4 shows the details of the service territory and electricity suppliers of these distribution cooperatives.

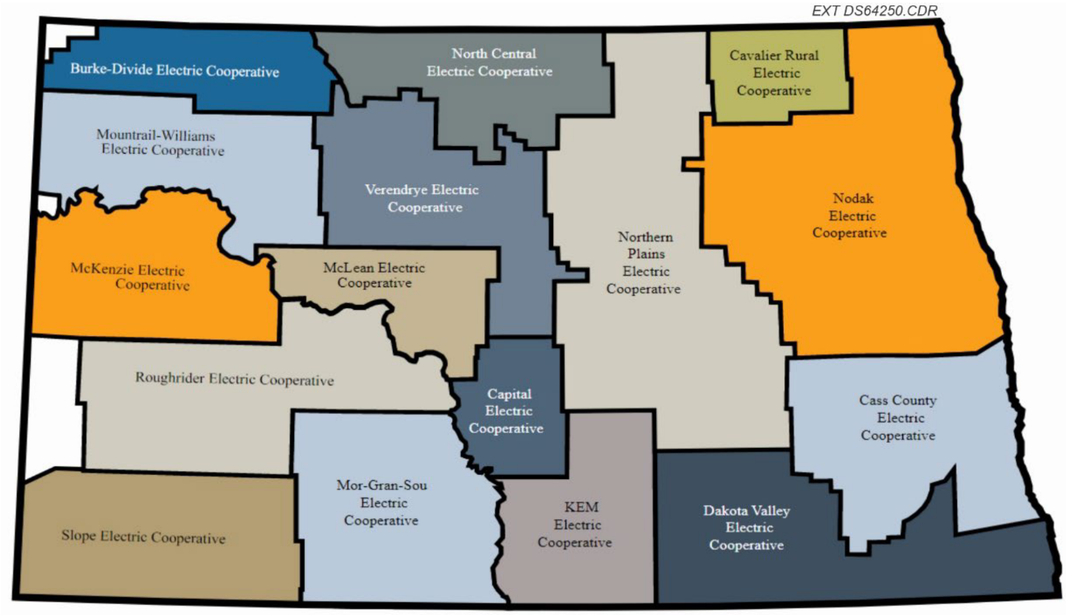


Figure 29. Map of distribution co-ops in North Dakota.

Table 4. Service Territory and Energy Supplier of North Dakota Electricity Distribution Cooperatives [52–56]

Distribution Cooperatives	Service Territory (county)	Energy Supplier
Nodak Electric Cooperative	Pembina, Walsh, Ramsey, Nelson, Steele, Grand Forks, Griggs, Benson, Eddy, Traill, Cass	Minnkota
Cass County Electric Cooperative	Cass, Ransom, Barnes, Richland, Griggs, Trail, Steele, LaMoure, Dickey, Stutsman	Minnkota
Cavalier Rural Electric Cooperative	Cavalier, Towner	Minnkota
Dakota Valley Electric Cooperative	Richland, Ransom, Sargent, LaMoure, Dickey, Logan, McIntosh, Stutsman	BEPC, WAPA
Northern Plains Electric Cooperative	Benson, Eddy, Foster, Griggs, Kidder, Stutsman, Wells, Pierce, Ramsey, Towner, Rolette	BEPC, WAPA
KEM Electric Cooperative	Emmons, Kidder, Logan, McIntosh	BEPC, WAPA
Capital Electric Cooperative	Sheridan, Burleigh	CPEC
Verendyre Electric Cooperative	Sheridan, Wells, Pierce, McHenry, Ward, Renville, McLean	CPEC
North Central Electric Cooperative	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 our 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. 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).

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. The grid operators ensure grid reliability by following approved planning and operating procedures as per NERC and FERC standards while considering anticipated grid events. Grid resilience focuses on the 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 the emerging climate challenges along with the 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 30).

Figure 30. 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's Regional Risk Assessment, and NERC assessments are used to identify the potential threats to the state electric grid. For this study, a detailed survey was sent to the major investor-owned and cooperative utility companies in North Dakota. Eleven utilities and cooperatives provided their survey feedback and identified potential threats and their likelihood and impacts on the North Dakota grid. Table 5 illustrates the potential threats to the North Dakota grid.

Table 5. 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 the state of North Dakota have been evaluated for natural hazards based on the 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

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 31). 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 the repair activities.

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" of ice with a 40-mph wind [57]. 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 the ones that exceed 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 32). Cass County has a very high risk, and Grand Forks and Emmons 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.

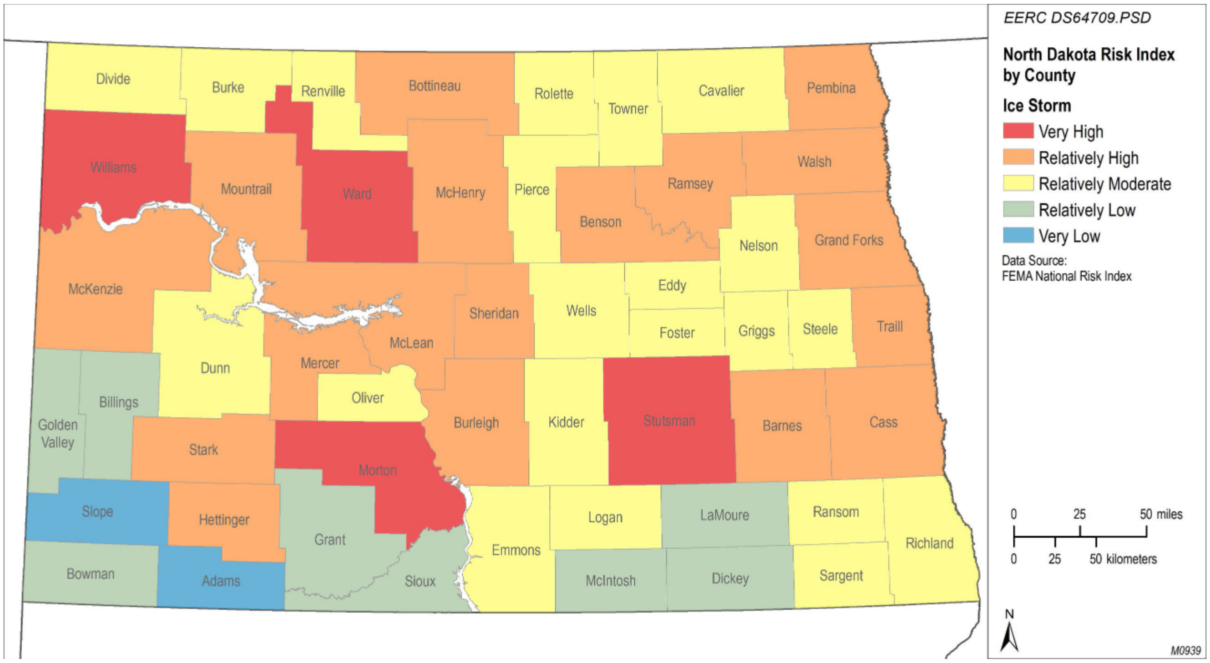


Figure 31. FEMA risk index for ice/snowstorms in North Dakota.

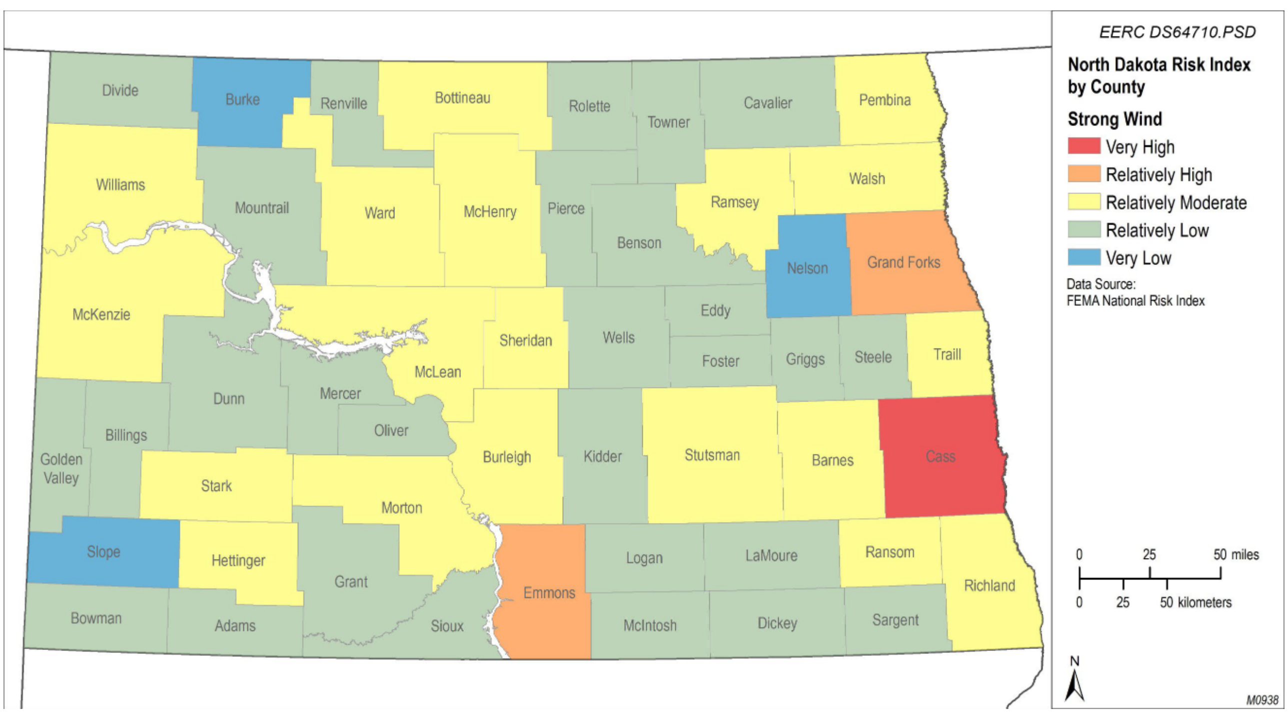


Figure 32. FEMA risk index for high wind in North Dakota.

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 the cold wave classification based on location. The risk of a cold wave in North Dakota is shown in Figure 33. In North Dakota, many counties experience a very high risk of cold waves in the winter. Grid infrastructure may become physically challenged during the 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 their heaters during extended cold spells, the load demand will rise and may lead to sustained power shortages.

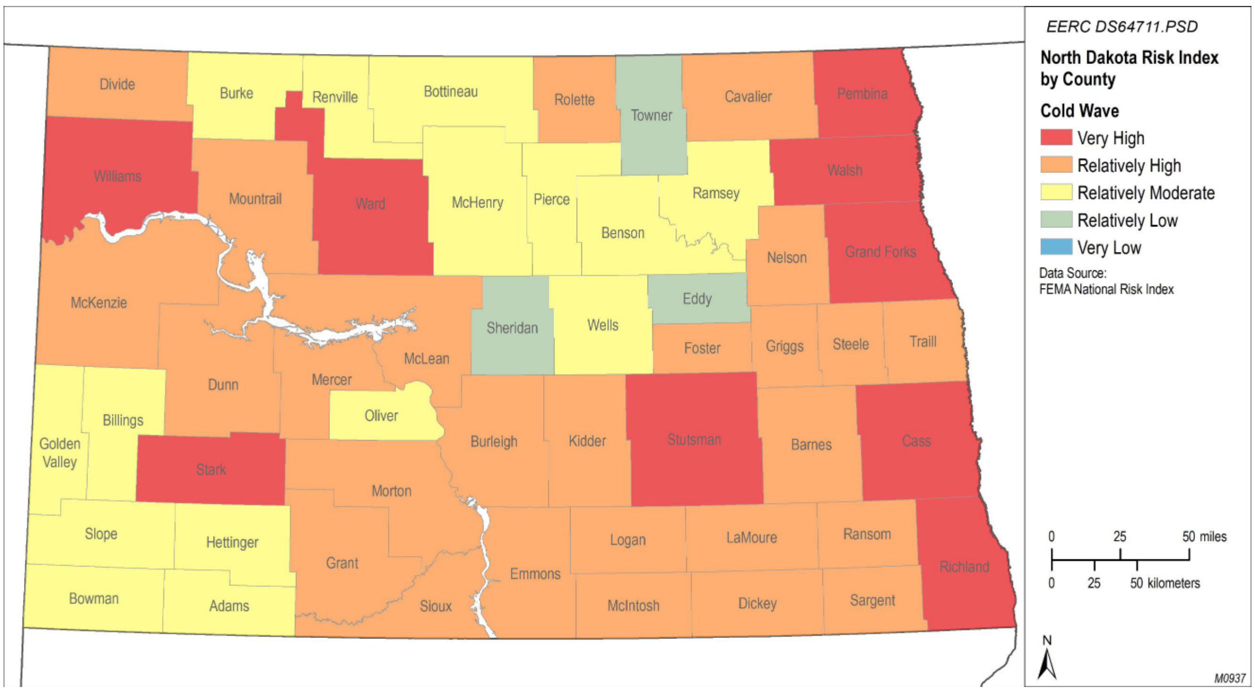


Figure 33. FEMA risk index for cold waves in North Dakota.

Lightning and Thunderstorm

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 34 shows the lightning risk for North Dakota. Lightning creates power surges that, in turn, burn down the transmission or distribution network equipment, while thunderstorms have the potential to bring down power lines.

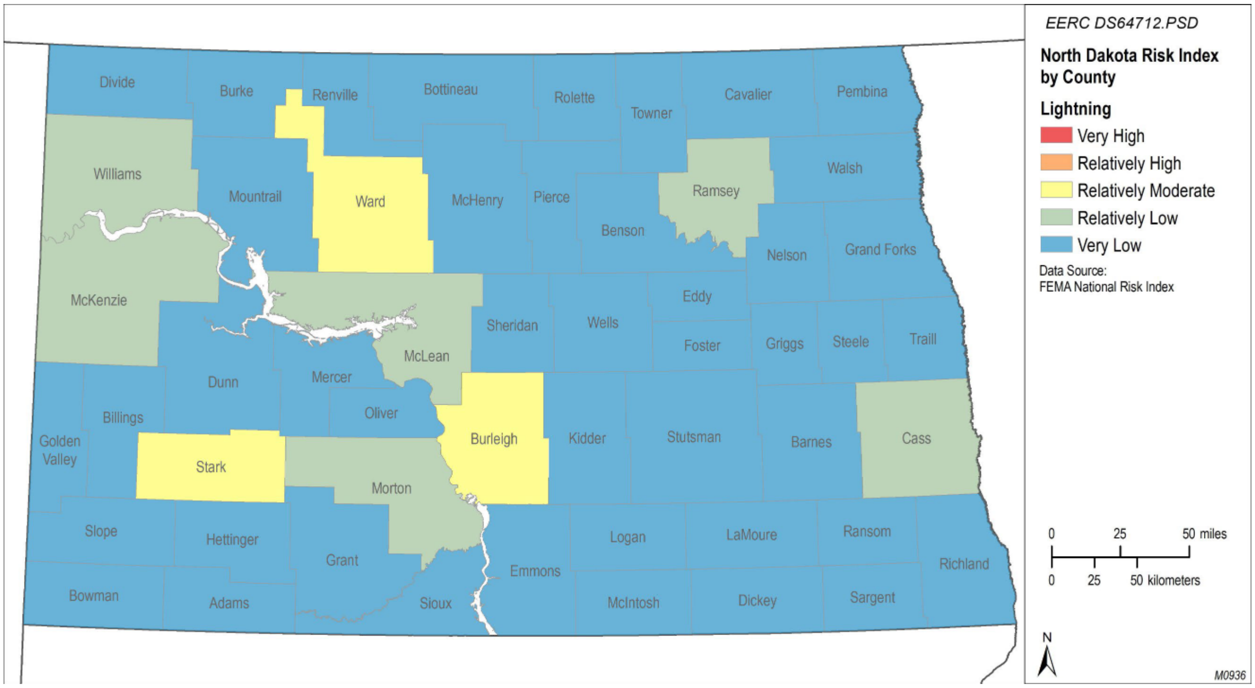


Figure 34. FEMA risk index for lightning and thunderstorms in North Dakota.

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 flooding of 1997. Figure 35 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 County have relatively high and moderate risks of tornadoes, respectively. The tornado risk for North Dakota is shown in Figure 36. 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 the electric line poles and uprooting the substation and protective devices.

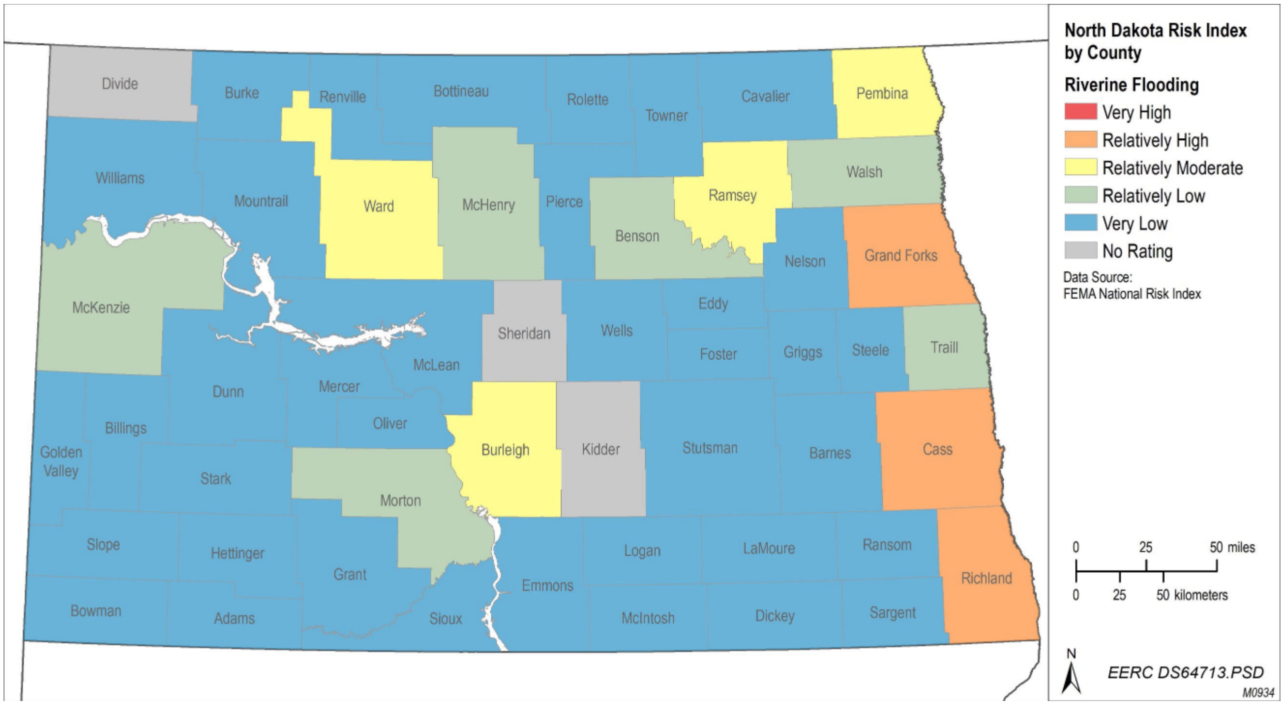


Figure 35. FEMA risk index for riverine flooding in North Dakota.

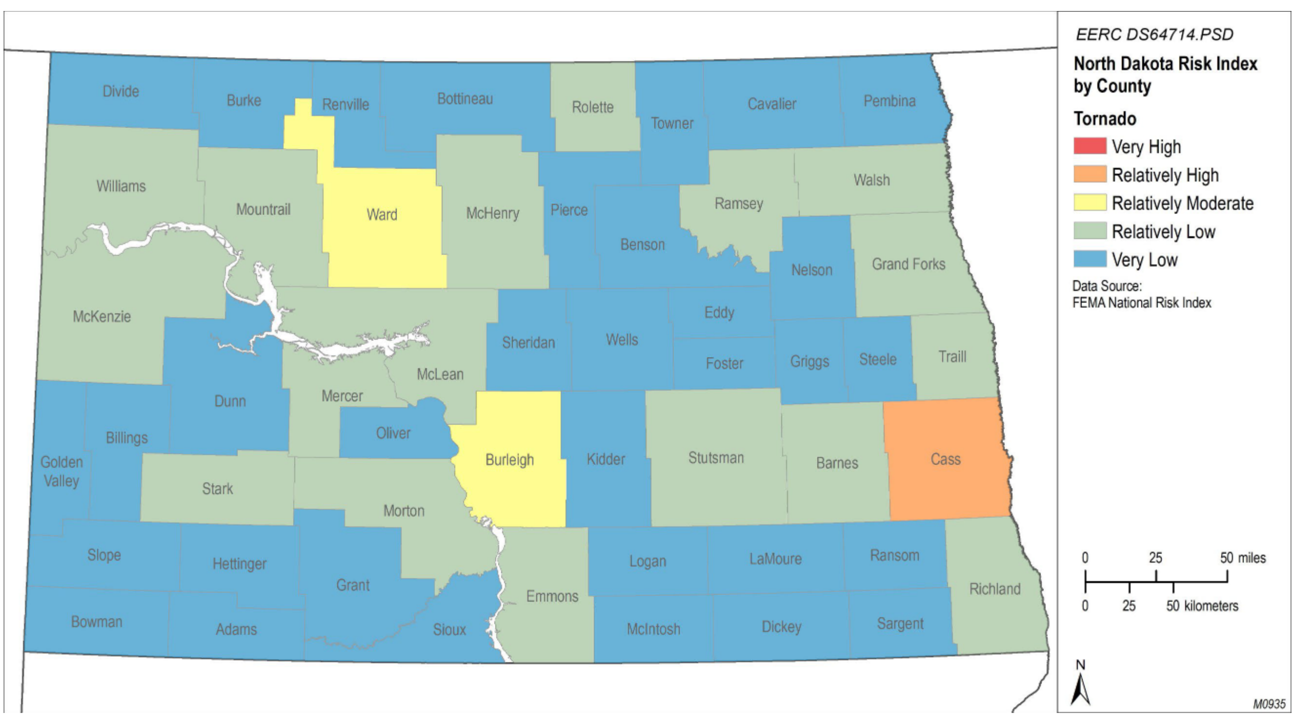


Figure 36. FEMA risk index for tornadoes in North Dakota.

Technological Threats

The 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 percentages that 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 the thermal unit retirement, there will be a shortfall of generation capacity and dispatchability which translates into the lack of ability to cover load during peak periods. This effect is demonstrated by the forecasted depletion of 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 ERO Reliability Risk Priorities Report [58]. Generation must continuously match load; therefore, a lack of generation is an immediate threat to grid reliability and resiliency.

Inverter-based resources (IBR) 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 are adding additional tools and monitoring equipment to gather real-time data. More studies are required on this topic to determine the level of risk [19].

Aging Grid Infrastructure

The 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 [59], 70% of power transformers are 25 years or older, 60% of 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 the age and condition of transmission facilities [60]. The SCRIPT report noted that there is little collaboration between the local transmission owners and SPP regarding the management of existing transmission facilities. Blending the needs of local transmission replacement with the 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). The AIFG is active this year to create processes to integrate age and condition criteria into the existing SPP Integrated Transmission Planning Process. It has a deadline of January 2024 to present a recommendation to the SPP Transmission Working Group.

Man-Made Threats

The survey responses from the 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 the emerging threats [58]. Accidents are unintentional and generally include accidental cutting of wire, vehicles hitting overhead line poles, or ground-mounted equipment. Any form of accident at a grid facility can disrupt the grid operations and consumer access to electricity. Any intentional damage or destruction of grid infrastructure will be considered vandalism. Supply chain disruptions frequently have a negative influence on grid operations, reliability, and resiliency. A lack of manufacturing materials might result in the unavailability of equipment, and utilities have no control over supply chain problems. Cybersecurity breaches can jeopardize sensitive data and expose the grid to outside attackers.

Supply Chain Interruptions

The 2023 MRO Regional Risk Assessment identified material and equipment availability as a defined risk for the first time. Also, a DOE paper dated December 12, 2022, described the supply chain crisis [61]. 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 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 [62].

Solving the 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 CA 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 the physical security measures.

Despite the 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 $10M [63]. 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.

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 the 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 [64]. 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 [61]. The Colonial Pipeline attack of May 7, 2021, is an example of a ransomware attack on critical energy infrastructure [65].

The first well-known grid scale attack was against Ukraine in 2015 and resulted in outages to 250K 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
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 [58] 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 such as energy storage, and electric vehicles, it is critical to address the 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. The tax incentives for renewables allow bidding into the RTO power markets at artificially low prices. This undercuts the marginal prices that dispatchable generation bid. 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. It can be evaluated based on the 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 is developed using the utilities' survey responses, and the relevant rank of the risk is determined by assessing the threat likelihood score and threat impact score. Table 6 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.

The impacts are assessed based on the extent of service disruption caused by the threat, its effect on capital and operating costs, and the 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 7. The maximum score is 5 for threats with a significant impact, and the lowest is 1 for threats with a minimal impact.

Table 6. Classification of Threat Likelihood [61]

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.

Table 7. Classification of Threat Impacts [61]

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 the 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 37 shows the survey responses on the impact of the possible threats on the North Dakota grid. The ice/snowstorms are considered to have the highest impact on the 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.

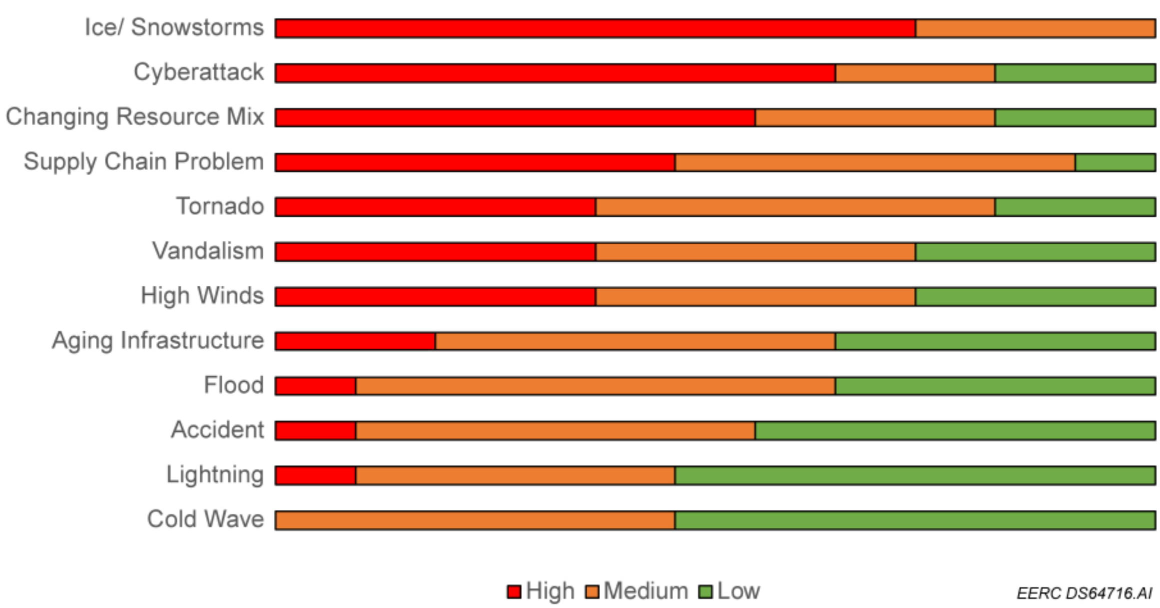


Figure 37. Survey responses on the impact of the possible threats on the North Dakota grid.

Risk scores are calculated as the product of the threat likelihood and threat impact scores. These scores are displayed in a risk matrix heat map, which shows the risk's relative ranking (Table 8).

The ice/snowstorm is ranked the highest, and it is the only threat ranked in the likely/severe category. This is likely no surprise to North Dakota residents. The 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 8. 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 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 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.

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 usage 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 the tension between the 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 the overhead line pole and mount line 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 and they are listed below:

- Construction of generation, transmission, and distribution system above flood elevation.
- Use floodwall or dike for a substation design in flood zone area. Use reinforced concrete or concrete blocks to strengthen the wall.
- Data collection and communication equipment are placed in an enclosure with flood resistant door.
- Add float switches to grid structures, and connect to Supervisory Control and Data Acquisition (SCADA) system to monitor water level in surrounding area [66].

Lightning

Lightning is the typical cause of failure for overhead lines. Lightning can cause temporary or permanent disruption of the system. Typically, lightning arresters are used for mitigating momentary 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 [67]. Adding a backup system or loop-fed distribution system design can mitigate the momentary or temporary interruption for sensitive loads. Loop distribution systems are generally reliable, require less conductors, and have low voltage fluctuations.

Long-Term Mitigation for Generation Resource Inadequacy

NERC has an active project titled "Energy Assurance with Energy-Constrained Resources." A team is presently working on creating applicable NERC standards to address the adequacy issue. 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 the MISO and SPP RTOs must be reversed. This will require North Dakota utility industry stakeholders to engage in changing policies at the RTOs and NERC. Utilities must be incentivized to build more generation. A carrot-and-stick approach may work, the 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 in the RTO and NERC committees.

Also, 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, shortages of generation resources outside of North Dakota can lead to load curtailments inside of North Dakota. Therefore, additional generation added within North Dakota may not prevent load shedding if the SPP or MISO RTO is short overall. However, distributed energy resources (DER) 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 the cost and overhead of market participation. 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 [68].

During Winter Storm Uri, one of the reasons for the shortage of generation resources was the impact of the 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 4/1/2023), 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 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 lesson learned reports. This document is a valuable resource for generator owners needing to evaluate their cold-weather mitigation strategy [69].

As more wind and solar are added to the grid, net peak will become more challenging than peak load demand. The RTOs should consider other methods to determine the 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 [70, 71].

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, they determine 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 utilities 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

In the event of total grid failure North Dakota is well positioned for a 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 its 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 NFPA standard for Tier 1 facilities. Historically these generators have little use beyond their standby service. However, with the push toward distributed energy resources (DER, mentioned previously) these standby generators may participate in the 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 stand by 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 to dedicated mines. And 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 Energy Emergency Alerts. They increment in increasing levels of severity with the highest alert being an Energy Emergency Alert Level 3 (EA3). 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 EA3 was implemented during winter storm Uri in February 2021.

Mitigation for Ageing Grid Infrastructure

Transmission and distribution entities should monitor new RTO policies addressing age and condition replacement and cost recovery options for the 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 located in remote locations. Utilities should investigate what sort of measures can be used to protect the facility, limit the 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 spart parts and equipment in stock or readily available. For example, the 2022 ice storm in northwestern North Dakota destroyed 4000 poles [72], 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 the manpower. In addition, equipment manufacturers responded fast and, in many cases, surged production. It is possible this was a best-case example because of its 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.

The 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 upon 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 cyber security 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.

Aging Workforce and Skilled Labor Shortage Mitigation

Programs addressing skilled worker training are in place at locations such as Bismarck Polytechnic School. 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 9 shows a summary of mitigation strategies to address the risks impacting the reliable, resilient, and secure operations of bulk power system.

Table 9. 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.

Continued. . .

Table 9. Summary of Risk Mitigation Strategies (continued)

Threats	Applicability	Mitigations
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 distributed energy resources (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.
Cyber Threat	Generation, transmission, and distribution utilities	• Hire and train dedicated cybersecurity personnels. • Create backup of computer systems. • Use experts to test the system and find out the vulnerabilities and recommend solutions.

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 Basin Electric 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 cyber security, following the 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 cyber security 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.

- 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 highest certainty deliverability (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 has developed a North Dakota electric grid resiliency plan in which the state's electricity infrastructure, operational conditions, bulk and wholesale energy markets, reliability, resource adequacy, planning efforts of the grid operators, and other factors that have an impact on grid resiliency are analyzed.

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 generation and transmission 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 are compiled to identify potential threats to electric grid resilience, evaluate their impacts and consequences, and rank the 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 the ice/snowstorm is the only risk that is classified in the likely/severe category, ranking highest overall. The changing resource mix, supply chain interruptions, and cyberattack 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 the grid assets or interrupt the grid services and cripple the functioning of critical infrastructures. Repairing the grid assets in a timely manner is complicated by the inability to quickly procure replacement materials due to supply chain disruptions. The authors recommend the state of 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 MWs 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 MWs 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 the 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 the legal and political realms as well.

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