FUTURE-PROOFING NORTH DAKOTA'S ELECTRICAL INFRASTRUCTURE TO ENABLE EXPANSION IN AN EVOLVING ENERGY LANDSCAPE

Final Report

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NOMENCLATURE

AC	alternating current
ACCC	AC Contingency Calculation tool
AI	artificial intelligence
BEPC	Basin Electric Power Cooperative
DC	direct current
DER	distributed energy resources
EERC	Energy & Environmental Research Center
EIA	U.S. Energy Information Administration
EPRI	Electric Power Research Institute
ERAS	expedited resource adequacy study
EV	electric vehicle
FEED	front-end engineering and design
GI	generation interconnection
GW	gigawatt
GWh	gigawatt-hour
ISO	independent system operator
ITP	integrated transmission plan
kV	kilovolt
kWh	kilowatt-hour
LMP	locational marginal price
LNG	liquefied natural gas
LRE	load responsible entity
LRZ	load resource zone
LTRA	long-term reliability assessment
MCC	marginal congestion cost
MEC	marginal energy component
MEM	market economic model
MISO	Midcontinent Independent System Operator
MLC	marginal loss cost
MOPC	Market and Operations Policy Committee
MRO	Midwest Reliability Organization
MTEP	MISO transmission expansion plan
MW	megawatt
MWh	megawatt-hour
NDEX	North Dakota export
NDTA	North Dakota Transmission Authority
NERC	North American Electric Reliability Corporation
PROMOD	Hitachi energy production cost model
PS	price-sensitive
PSC	Public Service Commission
PSE	Power System Engineering, Inc.
PSS®E	Power System Simulator for Engineering

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NOMENCLATURE (continued)

RTO	regional transmission organization
SPP	Southwest Power Pool
STEP	SPP transmission expansion plan
TO	transmission owner
UMZ	Upper Missouri Zone
WAPA	Western Area Power Administration

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EXECUTIVE SUMMARY

Overview

The Energy & Environmental Research Center (EERC), in collaboration with Power System Engineering, Inc. (PSE), conducted a transmission reliability study on behalf of the North Dakota Transmission Authority (NDTA) to evaluate the ability of the existing electric transmission system to serve current and future demand across the state of North Dakota.

The state is experiencing rapid growth in large, energy-intensive industrial and commercial developments, including data centers, artificial intelligence computing clusters, and cryptocurrency-mining operations. These large loads present both economic opportunities and significant challenges to the transmission network, potentially requiring major generation and transmission reinforcements to maintain reliability and meet demand.

This study aimed to assess North Dakota's grid capability to support current and future load growth while identifying reliability needs, market impacts, and transmission constraints. Through integrated reliability and economic analyses, this study evaluated how large-load additions influence transmission loading, system reliability, transmission congestion, electricity market prices, generation dispatch, and renewable generation and curtailment.

The reliability study used Southwest Power Pool's (SPP's) integrated transmission planning 2025[1] (ITP2025) powerflow models for the 2026, 2029, and 2034 seasonal peaks. Powerflow analyses were performed under both system-intact (N-0) and contingency (N-1) conditions using Siemens PTI's Power System Simulator for Engineering (PSS®E) and the AC Contingency Calculation (ACCC) tool. The analysis focused on thermal loading, voltage performance, and the system's ability to absorb new large-load scenarios considering eastern (East), central (Central), and western (West) regions of North Dakota (Figure ES-1). Table ES-1 provides a breakdown of the various large-load scenarios within each area by interconnecting substations.

[1] https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/ (accessed October 2025).

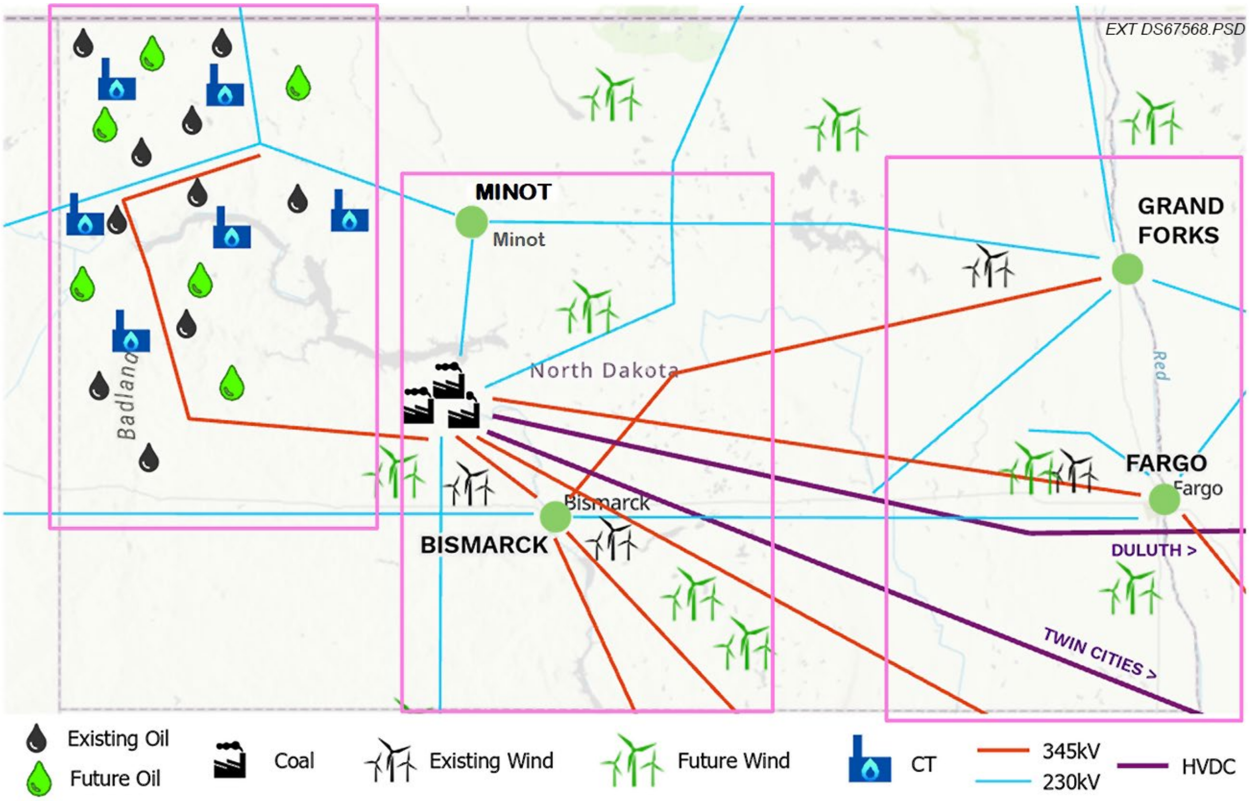

Figure ES-1. North Dakota system map.

Table ES-1. Large-Load Scenarios with Interconnecting Substations

East 1400 MW	Central 1100 MW	West 600 MW
• Coal Creek 230 kV, 200 MW	• Coal Creek 230 kV, 500 MW*	• Coal Creek 230 kV, 200 MW
• Bison 345 kV, 200 MW	• Center 345 kV, 300 MW	• Judson 345 kV, 200 MW
• Buffalo 345 kV, 200 MW	• Leland 345 kV, 300 MW	• Pioneer 345 kV, 200 MW
• Ellendale 345 kV, 200 MW		
• Jamestown 345 kV, 200 MW		
• Maple 345 kV, 200 MW		
• Prairie 345 kV, 200 MW	*Total	

The economic study utilized the SPP market economic model (MEM) from ITP2025, based on joint Midcontinent Independent System Operator (MISO)–SPP datasets to ensure regional market consistency and coordinated system interactions. The analysis followed the Future 1 – reference case models for the years 2026, 2029, and 2034, incorporating SPP's assumptions for fuel prices, load growth, generation expansion, policy considerations, and transmission topology under both N-0 and N-1 conditions. Large-load scenarios for 2029 and 2034 were developed to evaluate the economic and operational impacts of significant new large-load additions on overall system performance.

A nodal dispatch analysis was conducted using the Hitachi Energy PROMOD security-constrained unit commitment and economic dispatch model, covering the full SPP region with emphasis on North Dakota, particularly MISO Local Resource Zone 1 (LRZ01) and SPP Upper-Midwest Zone (UMZ). PROMOD simulated hourly economic dispatch for all 8760 hours in a year to evaluate energy prices, generation output, transmission flows, and congestion patterns.

Summary of Key Findings

- System Performance Under Base Conditions – The existing North Dakota transmission system demonstrates adequate performance under current conditions, with only a limited number of thermal and voltage violations observed in the base models.

- Impacts of Large Loads – When additional large-load scenarios (600–1400 MW) were introduced into the study models, the number of thermal and voltage violations increased significantly. Voltage issues were concentrated primarily on the 115-kV network, particularly in western North Dakota, where voltages dropped below transmission owner (TO) criteria during N-1 contingencies.

- Thermal Overloads and Equipment Stress – Under large-load scenarios, 22–75 miles of transmission lines exceeded thermal limits during summer peaks and 75–198 miles during winter peaks. Four transformer overloads were also identified, indicating potential substation capacity constraints.

- Regional and Economic Sensitivities – The western portion of the state exhibited the greatest sensitivity to new industrial load growth. Large loads need to be added to the local utilities load forecast and uploaded into the regional transmission organization's (RTO's) planning database as quickly as possible. This will ensure the RTO's transmission upgrade process will capture the impact of the large loads and implement the required reinforcements. This process has already added hundreds of miles of 345-kV backbone transmission in North Dakota and avoided future congestion or curtailment risks. The potential for transmission investment underscores the need for coordinated planning to balance system reliability, economic growth, and ratepayer impacts.

- The addition of large loads without the addition of equivalent generation increased both congestion and locational marginal prices (LMPs). However, incorporating a price-sensitive load curtailment mechanism for these large loads helped alleviate congestion and reduced the resulting LMP impacts.

- The introduction of large loads consumed energy that was otherwise being curtailed as a result of transmission limitations on the North Dakota export (NDEX) interface. Consequently, thermal generation dispatch and renewable energy output increased to meet the additional demand.

Recommendations

- Stakeholder Engagement – The RTO's transmission planning processes are dependent on stakeholder input. Engagement by North Dakota entities in these processes as stakeholders will ensure that North Dakota area reliability issues are addressed and cost-effective transmission additions are implemented.

- Targeted Transmission Reinforcements – Prioritize RTO-identified upgrades to the 115-kV and select 230-kV corridors in western and central North Dakota where large-load growth is most likely and voltage violations were most prevalent.

- Transformer and Substation Expansion – Address observed transformer overloads through proactive capacity expansion or parallel transformer installation at high-risk substations.

- Enhanced Coordination Within Industry – Coordinate enhanced research and analysis efforts related to gathering accurate data regarding the characteristics of large loads. This data should include electrical performance and market response data. Share these data among NDTA, the Public Service Commission (PSC), utilities, and RTOs (SPP and MISO) to help inform the existing planning process, align forecasts, model assumptions, large-load interconnection procedures, and project priorities across jurisdictions.

- Load-Siting Guidance for Developers – Encourage early engagement between large-load developers and utilities to align project siting with available capacity, minimizing the need for major network reinforcements and improving project feasibility.

- Integrated Planning of Generation and Transmission – Coordinate with upcoming RTO resource adequacy, generation expansion, and reliability studies to ensure that new generation and transmission upgrades are planned in tandem to maintain system resilience.

- Economic and Cost–Benefit Evaluation – Support the RTO's high-level cost–benefit assessment of candidate reinforcement projects to identify the most cost-effective reliability improvements and inform funding and policy decisions.

- Coordinate the large load's own reliability criteria with what the local TO can reasonably provide. Investigate the large load's ability to curtail during network transmission and/or generation constraints. If the large load has on-site backup generation capability, evaluate whether this resource can be utilized to offset exposure to high LMPs by self-generating power during periods of elevated prices.

- Support the RTO's and local utilities' power market impact studies of large-load additions. This is important as the pace of large-load additions is likely to exceed the pace of generation additions. This study showed that the addition of large load without corresponding generation additions and transmission reinforcements has the potential to raise power market prices through increases in congestion and energy costs.

Future Study/Next Steps

Future study considerations:

- Large-load electrical characteristics — Investigate the response of large loads under transmission system disturbances, including voltage and frequency trip settings. Examine market behavior to understand how large loads respond during transmission congestion and energy emergencies.

- Refined Load Forecasting – Update and refine the large-load forecast to reflect confirmed data center and industrial development timelines, ensuring realistic scenario modeling for future scenarios.

- Transmission Reinforcement Planning – Identify specific project options (e.g., reconductoring, transformer additions, or new transmission lines) to alleviate thermal and voltage violations under large-load scenarios and analyze those options for use in the RTO planning process.

- Integration with Resource Expansion Studies – Support future RTO study analysis with ongoing generation and resource adequacy assessments and generator interconnection planning to ensure that both supply and transmission infrastructure evolve in tandem to maintain reliability.

- Power Market Impact Studies – Support RTO and utility market economic analysis with additional large-load scenarios and the latest planning assumptions. Review impacts of generation additions and transmission reinforcements on power market prices through congestion and energy costs.

- Follow-On Study –Leverage the analytical framework, datasets, and regional insights from this phase to extend the work in a consistent, data-driven manner, building on established methods, validated assumptions, and stakeholder input.

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INTRODUCTION

Background

North Dakota has experienced significant growth in electricity demand driven by the expansion of large industrial and commercial loads, including manufacturing, mining, oil and gas, and agricultural processing in recent years. Emerging large-load facilities, such as data centers are further contributing to increased energy consumption. Understanding and planning for this load growth is critical to ensure that the state's generation and transmission systems can reliably meet current and future energy needs.

The Energy & Environmental Research Center (EERC), in collaboration with Power System Engineering, Inc. (PSE), conducted a transmission reliability study on behalf of the North Dakota Transmission Authority (NDTA). The primary goal of this project was to evaluate the ability of North Dakota's electrical grid to accommodate current and future load growth while identifying system needs, electricity market prices, transmission bottlenecks, and potential solutions to support a reliable and resilient state electrical grid.

North Dakota Grid Overview

The regional electrical grid connects North Dakota to Minnesota, Montana, Wyoming, South Dakota, and Canada. It is managed by Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), both of which are regional transmission organizations (RTOs). MISO and SPP each independently manage a power market, oversee the planning and operation of a bulk power transmission system, and are responsible for ensuring reliable operation within their footprints. MISO and SPP operational footprints are illustrated in Figure 1.

MISO and SPP

MISO manages one of the largest energy markets in the world and consists of over 500 market participants, serving approximately 45 million customers. MISO's total daily market capacity is 207 gigawatts (GW), with a fuel type mix of approximately 40% natural gas, 26% coal, 19% renewables, 14% nuclear, and less than 1% other sources,[1] with a summer peak load of 122 GW, occurring in July 2024.[2]

The MISO system spans an extensive geographic area across 15 states as well as Manitoba and Saskatchewan, Canada.[3] MISO is broken down into ten local resource zones (LRZs), designed so load demand and resources within the LRZ are connected by sufficient transmission, ensuring access to generation. North Dakota is located within MISO LRZ01, as shown in Figure 2.

[1] www.misoenergy.org/meet-miso/media-center/corporate-fact-sheet/ (accessed October 2025).
[2] www.rtoinsider.com/113608-miso-on-track-wrap-summer-122gw-peak/ (accessed October 2025).
[3] www.mro.net/about/ (accessed October 2025).

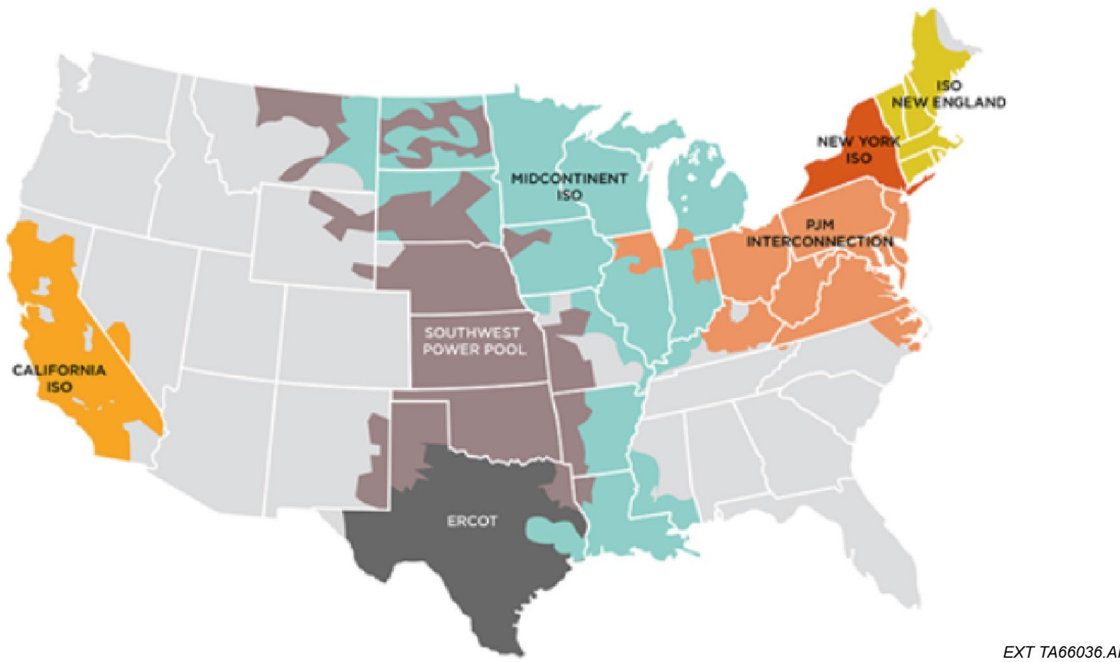
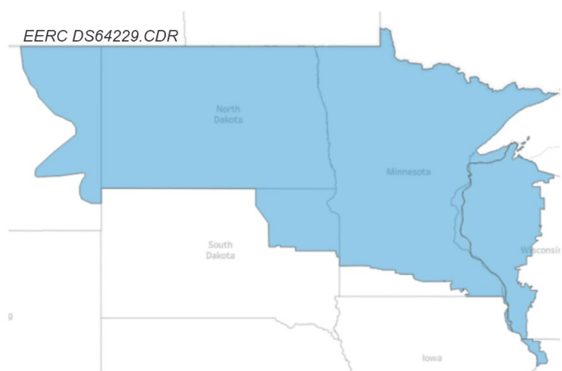


Figure 1. Footprints of U.S. independent system operators (ISOs). MISO also includes Manitoba and Saskatchewan, Canada (Federal Energy Regulatory Commission, 2024).



LRZ01[1]: Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Montana-Dakota Utilities, Northern States Power, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency

Figure 2. MISO LRZ01 footprint.

Just like MISO, SPP is a large regional transmission operator, serving more than 18 million people across 15 states. SPP's total market capacity is 65.6 GW, with a fuel type mix of approximately 28% natural gas, 25% coal, 42% renewables, 5% nuclear, and <1% other fuel sources, with a summer peak load of 56 GW, occurring in July 2024.[4] The portion of North Dakota served by SPP is part of the Upper Midwest Zone (UMZ). The SPP UMZ comprises the transmission assets of the Western Area Power Administration (WAPA), Heartland Consumers Power District, and Basin Electric Power Cooperative (BEPC) and forms the backbone of the high-voltage grid across eastern Montana, North Dakota, and South Dakota (Figure 3).

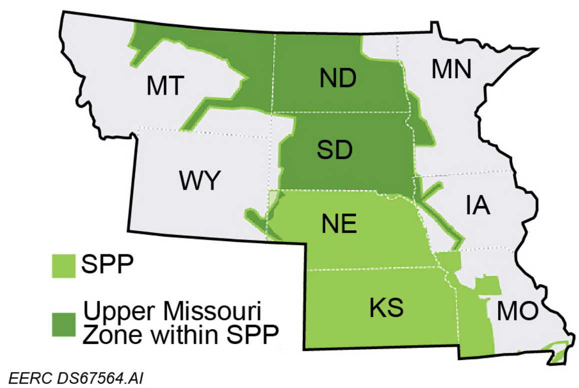


Figure 3. SPP UMZ footprint.

North Dakota

North Dakota is a significant producer and exporter of electricity. The state's 65,000 miles of transmission and distribution lines transport roughly twice as much electricity as it typically consumes.[5] Coal-fired power plants continue to generate most of the state's electricity (~54% in 2024). Wind energy has recently contributed significantly to the market, making up ~35% of total generation (Figure 4). While little change has occurred within the last few years to the mix of fuel sources utilized in North Dakota's electricity generation, future growth in renewables, specifically additional wind and possibly some solar, is expected.

[4] www.spp.org/about-us/fast-facts/ (accessed October 2025).
[5] www.ndstudies.gov/energy/level2/module-3-coal/transmission-and-distribution (accessed October 2025).

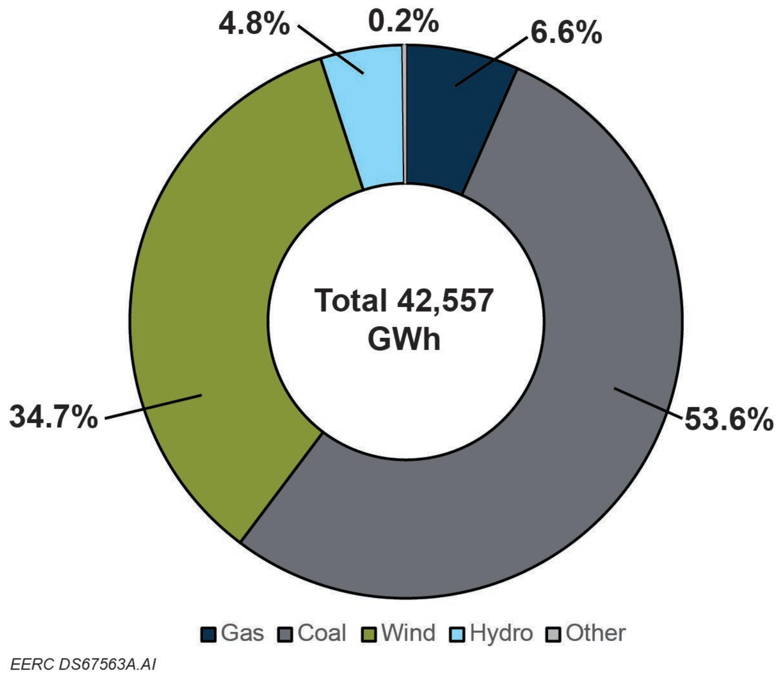


Figure 4. North Dakota generation mix (% of total annual generation by fuel type) in 2024.[6]

The U.S. Energy Information Administration (EIA) annual electric power industry report (Form EIA-860) survey dataset shows that North Dakota has 101 generating units, with a summer total nameplate capacity of approximately 10,162 megawatts (MW) (last updated 2024).[7] Figure 5 depicts generation capacity over the last 10 years, which generally trends up, with small dips occurring in 2019 (down 3%) and 2023 (down 5%). Overall, net generation is up approximately 16.5% over the 10-year period between 2014 and 2024. Total annual net generation for 2024 was 42,557 gigawatt-hours (GWh).[8]

North Dakota customers consumed ~29,700 GWh in 2024 (Figure 6).[9] Businesses consume a majority share of electricity in North Dakota, amounting to 84% of total demand. Industrial and commercial demand has outpaced growth in the residential sector, with larger gaps appearing around 2013/2014 and relative annual growth since. Industrial customers consume the most electricity, accounting for 46% of demand, followed by commercial customers at ~38%; residential customers comprise the smallest consumer pool, making up the remaining ~16% of total demand. Major industries include oil and gas extraction and processing, mining (lignite), and agriculture.

[6] https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvs1u&geo=000000g&sec=g&linechart=ELEC.GEN.ALL-ND-99.A&columnchart=ELEC.GEN.ALL-ND-99.A&map=ELEC.GEN.ALL-ND-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin= (accessed October 2025).
[7] www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel (accessed October 2025).
[8] www.eia.gov/state/print.php?sid=ND#tabs-4 (accessed October 2025).
[9] www.eia.gov/electricity/data/ (accessed October 2025).

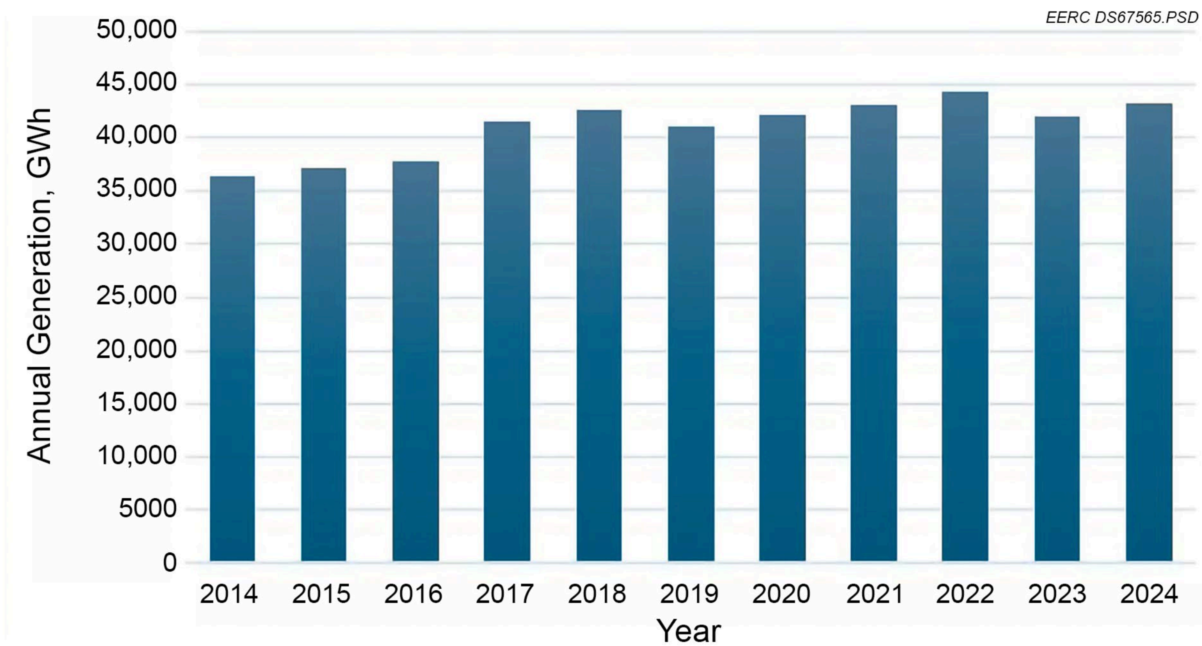


Figure 5. North Dakota annual net generation since 2014.[10]

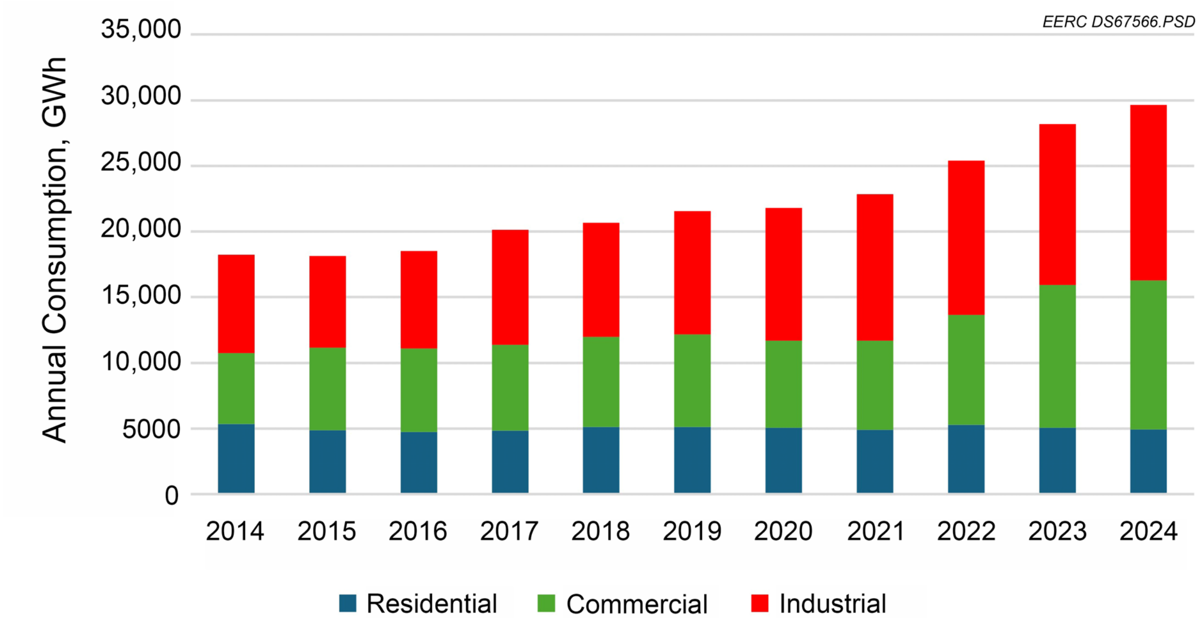


Figure 6. Comparison of annual electricity consumption by customer type.

[10] www.eia.gov/electricity/data/browser/#/topic/gggterwqq0?agg=2,0,1&fuel (accessed October 2025).

Although North Dakota's net generation currently exceeds its in-state electricity consumption, the anticipated growth of large commercial and industrial loads could significantly increase pressure on the grid, necessitating upgrades to transmission infrastructure and the development of additional generation resources.

Key Players

North Dakota has a mix of 37 utility providers broken down by ownership type as follows. A majority of providers are electrical cooperatives, with 21 entities providing service to approximately 222,000 customers. Municipality-controlled utilities account for another 12 providers, servicing approximately 11,400 customers. The three investor-owned utilities, Montana–Dakota Utilities Co., Northern States Power Company – Minnesota, and Otter Tail Power Company, service an additional 249,000 customers, while the single federally owned utility provider (WAPA Hydro) services 21 accounts. As of 2024, combined, these providers serve just under 486,000 customers in North Dakota with an average rate under 10 cents/kilowatt-hour (kWh) (avg. 9.56 c/kWh).[11]

Large-Load Growth

North Dakota is emerging as a prime candidate and an ideal location for various high-demand, energy-intensive facilities driven by industrial expansion across multiple sectors, including manufacturing, mining, oil and gas, artificial intelligence (AI), and cryptomining. Adapted from SPP, Table 1 summarizes large-load types, highlighting their typical size, operational profiles, and demand response potential. North Dakota has abundant energy production to meet the large-load demand, has ideal average temperatures to facilitate smoother operational conditions, and provides incentives to attract businesses as it assists job growth and provides economic growth for the state.

North Dakota continues to experience in-state growth and increasing electricity demand driven by the development of oil and gas production, processing, and transportation capabilities in the Williston Basin. Additional growth is occurring within the manufacturing and agricultural processing industries across the state. The benefits of the state's location in the northern Great Plains are aiding the quick deployment of data centers and cryptomining facilities across the state, with several new facilities expected to come online over the next 3 to 5 years. Table 2 lists the known large-load facilities either recently built, currently operational, or expected to come into service within the time frame covered in this study. These facilities come from a range of industries already discussed and have the potential to add an additional 2 GW of demand onto the state's electrical grid by 2030.

[11] www.eia.gov/electricity/data.php#sales (data from forms EIA-861-schedules 4A and 4D and EIA 861S) (accessed October 2025).

Table 1. Examples of Large Loads[12]

Large-Load Type	Description	Typical Size, MW	Load Profile	Appetite for Demand Response
Manufacturing (Heavy Industry)	Steel, cement, other plants	20–500+	Cyclical, shift-based	Low
Mining Operations	Extraction and primary processing of minerals (specifically lignite)	10–300+	Shift-based, varies with production	Medium
Oil and Gas Facilities	Refineries, liquefied natural gas (LNG), compressor stations	10–500+	Continuous with routine maintenance	Low
Agricultural Processing	Grain drying, food processing, cold storage	5–50	Seasonal with steady processing demand	Medium
Waste/Water Treatment	Water intake, pumping, and treatment	5–100+	Generally flat with time-of-day variation	Low
Data Centers/ Cyptocurrency Mining	Data processing and storage facilities, high-power mining operations	5–300+	Flat, continuous 24/7 operation/flat, responsive to price fluctuation	Low/high
Electric Vehicle (EV)-Charging Stations	High-power, fast EV charging	1–50	Peaky, high during travel demand	Medium

Data centers can be quickly deployed compared to the long-term planning and procurement strategies required for grid operators to meet the load demand and get out of the shadow of reactive response. Based on the Electric Power Research Institute's (EPRI's) technology deployment timeline (Figure 7), developing new generation facilities, grid enhancements, or upgrading distribution, can take 3 to 4 years just to get out of the planning and procurement phases, sometimes taking 10 or more years before projects are completed and operational.[13] Data centers can come online in as little as 2 years. Major generation projects, including renewable or thermal projects, could be completed within 5–7 years on the grid deployment timeline, while nuclear, hydro, and related transmission projects push the timeline to completion around the 9–10-year mark. This outlook highlights the difficulties grid operators will face when dealing with the quickly evolving adoption of AI and cryptocurrency and the associated demand for significant processing capabilities from data and mining centers.

[12] www.rtoinsider.com/wp-content/uploads/2025/07/High-Impact-Large-Load-Policy.pdf (accessed October 2025).
[13] www.energy.gov/sites/default/files/2024-04/Dr.%20Arshad%20Mansoor%20and%20Maria%20Pope%20 Presentation.pdf (accessed October 2025).

Table 2. Existing and Future Large-Load Facilities

Site	Purpose	Developer	Status	MW	Aggregated Total Demand by year, MW
Ellendale	Blockchain	Applied Digital	In service	180	**626**
Jamestown	Blockchain	Applied Digital	In service	106	
Williston	Blockchain	Atlas Power	in service	240	
Grand Forks	Blockchain	Core	in service	100	
Ellendale	Data center	Applied Digital	2025	100	**726**
Treton	Water processing/ chemical production	Wellspring Hydro[14]	2026	30–50 est.†	**1106–1126**
Ellendale	Data center	Applied Digital	2026	150	
Coal Creek	Data center	Rainbow	2026	200	
Ellendale	Data center	Applied Digital	2027	150	**1556**
Harwood	Data center	Applied Digital	2027	280	
Grand Forks	Agricultural processing	Agristo	2028 est.	30 est.†	**1586**
Trenton	Oil and gas, gas-to-liquid processing	Cerilon[15]	2029 est.	200+ est.*	**2171–2286**
Minot	Iron smelting	Scranton[16]	2029 est.	300 est.*	
Beulah	Ore processing	Talon Metals[17]	2029 est.	50–150 est.†	
Bakken East (various)	Gas transmission	WBI Energy[18]	2029/2030 est.	35–50 est.†	
Grand Forks	Chemical Production	Northern Plains Nitrogen[19]	2030 est.	35 est.	**2321**

* Indicates facilities that may build their own on-site generation capacity.

† Estimated electricity demand (industry benchmark) based on proposed production capacity and operational conditions.

[14] www.ndic.nd.gov/sites/www/files/documents/Clean-Sustainable-Energy-Authority/Grant-Rounds--Final-Reports/Proposals/Grant-Rounds-9-1/C-5-D-Unlocking-the-Full-Potential-of-Produced-Wat.pdf (accessed October 202).

[15] www.psc.nd.gov/public/newsroom/newsrelease/2024/6-17 24%20Cerilon%20GTL%20Project%20 Williams%20County.pdf (accessed October 2025).

[16] www.ndic.nd.gov/sites/www/files/documents/Clean-Sustainable-Energy-Authority/Grant-Rounds--Final-Reports/Proposals/Grant-Rounds-9-1/C-5-C-Green-Pig-Iron-Production-Facility.pdf (accessed October 2025).

[17] https://talonmetals.com/wp-content/uploads/2025/05/2025-05-28-Talon-Metals-Site-Announcement-Final.pdf (accessed October 2025).

[18] www.wbienergybakkeneast.com/ (accessed October 2025).

[19] Northern Plains Nitrogen FEED (front-end engineering and design) Study (discussion with COO, October 2025).

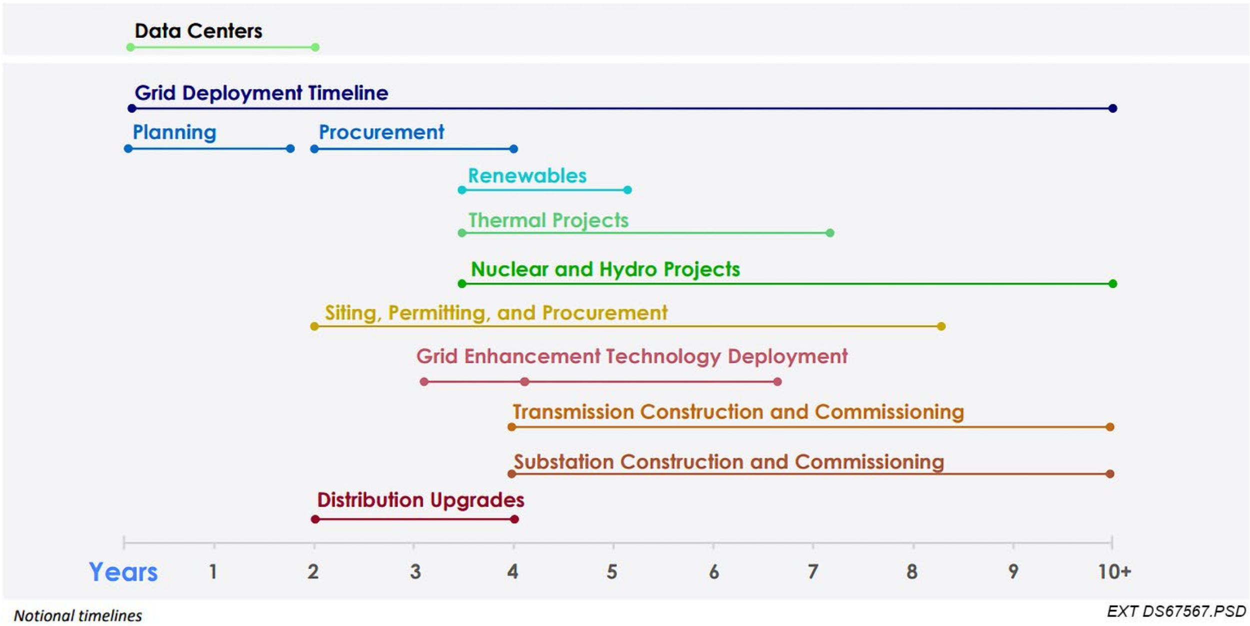


Figure 7. EPRI facility deployment timeline (Electric Power Research Institute, 2024).

Study Goals and Objectives

The primary goal of this project was to evaluate the ability of North Dakota's electrical grid to accommodate current and future load growth while identifying system needs, electricity market price impacts, and transmission bottlenecks and providing recommendations to support both near- and long-term planning and decision making for North Dakota's electricity sector.

To achieve this goal, the study incorporated both reliability and economic analyses to assess how large-load additions affect transmission line loading, system reliability, congestion, electricity prices, and generation dispatch. The analysis focused on the rapid expansion of large loads, which present both opportunities and challenges for North Dakota's electric utilities. In particular, the growing energy demand from data centers supporting cloud computing, AI, and cryptocurrency operations is contributing to a significant increase in statewide electricity consumption.

The study also highlights the potential need for additional generation resources, targeted transmission upgrades, adjustments to rate design, and enhancements to the large-load interconnection process to accommodate significant new loads. The findings may help utilities and regulators integrate new electric loads and generation resources while maintaining reliability and strengthening the resiliency of the state's electric grid.

METHODOLOGY

Models

Both reliability and market simulation models used in this study were derived from the SPP integrated transmission planning 2025 (ITP2025) study. Specifically, Siemens PTI's Power System Simulator for Engineering (PSS®E) and Hitachi Energy's PROMOD production cost models from the ITP2025 framework were utilized to ensure consistency between reliability and economic analyses. These models represent the most recent dataset releases from SPP and are currently under evaluation as part of the ongoing SPP transmission-planning assessment process.

For the reliability assessment, PSE analyzed six seasonal powerflow models representing summer and winter peak conditions for the years 2026, 2029, and 2034. In addition to these base cases, study models were developed to evaluate large-load scenarios under summer and winter peak conditions for 2029 and 2034.

For the economic study, the EERC analyzed SPP ITP2025 market economic models (MEMs) corresponding to the years 2026, 2029, and 2034 from the Future 1 reference case. In addition to the base cases, large-load scenarios were developed for the years 2029 and 2034 to assess the economic and operational impacts of significant new large-load additions on overall system performance.

Large-Load Scenarios

Several large loads were added at high-voltage locations. The selected locations are situated at existing 345- or 230-kilovolt (kV) substations spread across North Dakota where large-load projects are operational, underway or being considered, or likely have transmission capacity. Three scenarios were evaluated for large loads: east, central, and west North Dakota, including 600–1400 MW, as listed in Table 3. These scenarios are based in part on how much additional load the models would accommodate and solve without mitigation.

A representation of the North Dakota transmission system is included in Figure 8, depicting the east, central, and west zones for the large loads.

Table 3. Large-Load Scenarios with Interconnecting Substations

East 1400 MW	Central 1100 MW	West 600 MW
• Coal Creek 230 kV, 200 MW	• Coal Creek 230 kV, 500 MW*	• Coal Creek 230 kV, 200 MW
• Bison 345 kV, 200 MW	• Center 345 kV, 300 MW	• Judson 345 kV, 200 MW
• Buffalo 345 kV, 200 MW	• Leland 345 kV, 300 MW	• Pioneer 345 kV, 200 MW
• Ellendale 345 kV, 200 MW		
• Jamestown 345 kV, 200 MW		
• Maple 345 kV, 200 MW		
• Prairie 345 kV, 200 MW	*Total	

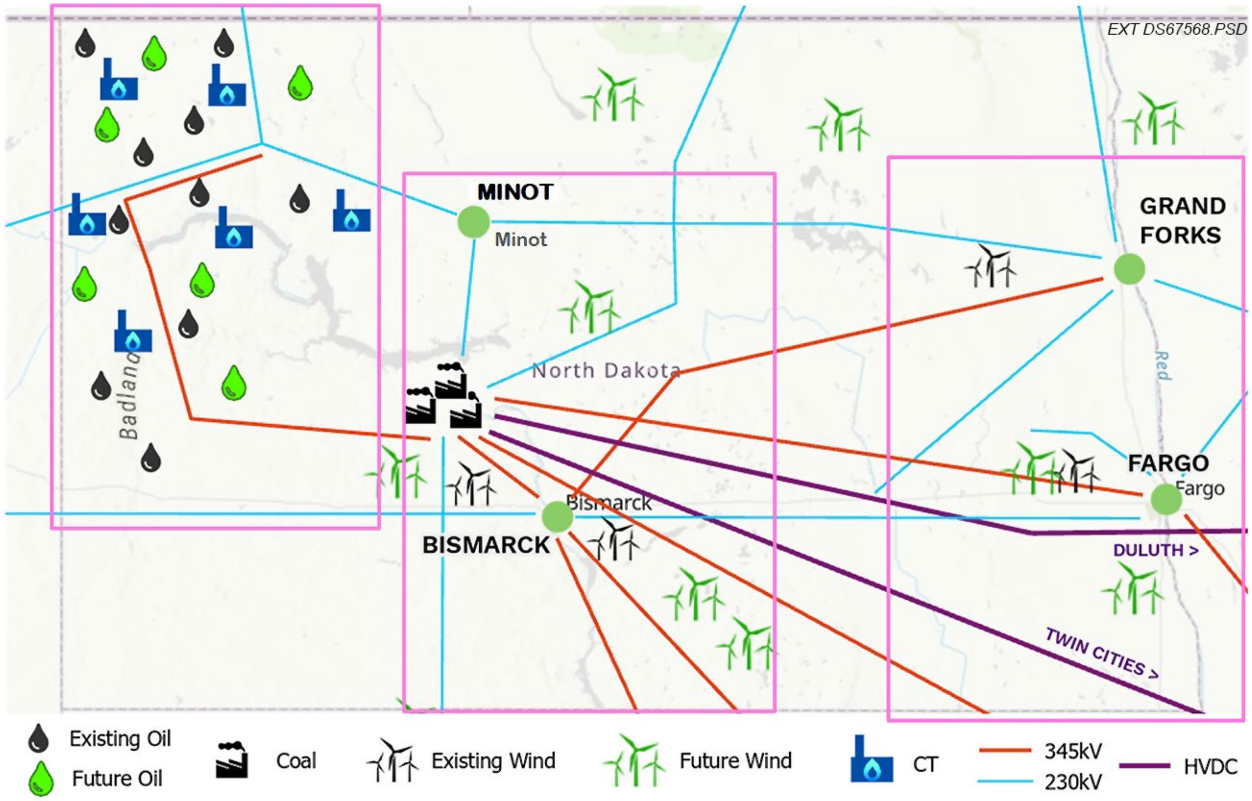


Figure 8. North Dakota system map.

RELIABILITY STUDY

The scope of the reliability study was to analyze seasonal noncoincident system peak conditions using powerflow models. The analysis focused on thermal and voltage grid conditions to determine the impacts from new large loads.

Model Input and Assumptions

Summer (S) peak and winter (W) peak forecast models representing Year 2 (2026/26), Year 5 (2029/29), and Year 10 (2034/34) were chosen for the analysis. The base models were analyzed to set a reliability baseline of the number of thermal and voltage violations that were observed. No changes to generation dispatch, peak demand, and system topology were made to the base models.

The North Dakota study area seasonal peak generation and load levels in the SPP ITP2025 base models were set by local balancing authorities, transmission owners (TOs), and/or ISOs/RTOs and illustrated in Figure 9.

Several North Dakota area transmission expansion projects are included in the SPP ITP2025 models. Table 4 illustrates the seasonal model where these transmission projects were placed in service.

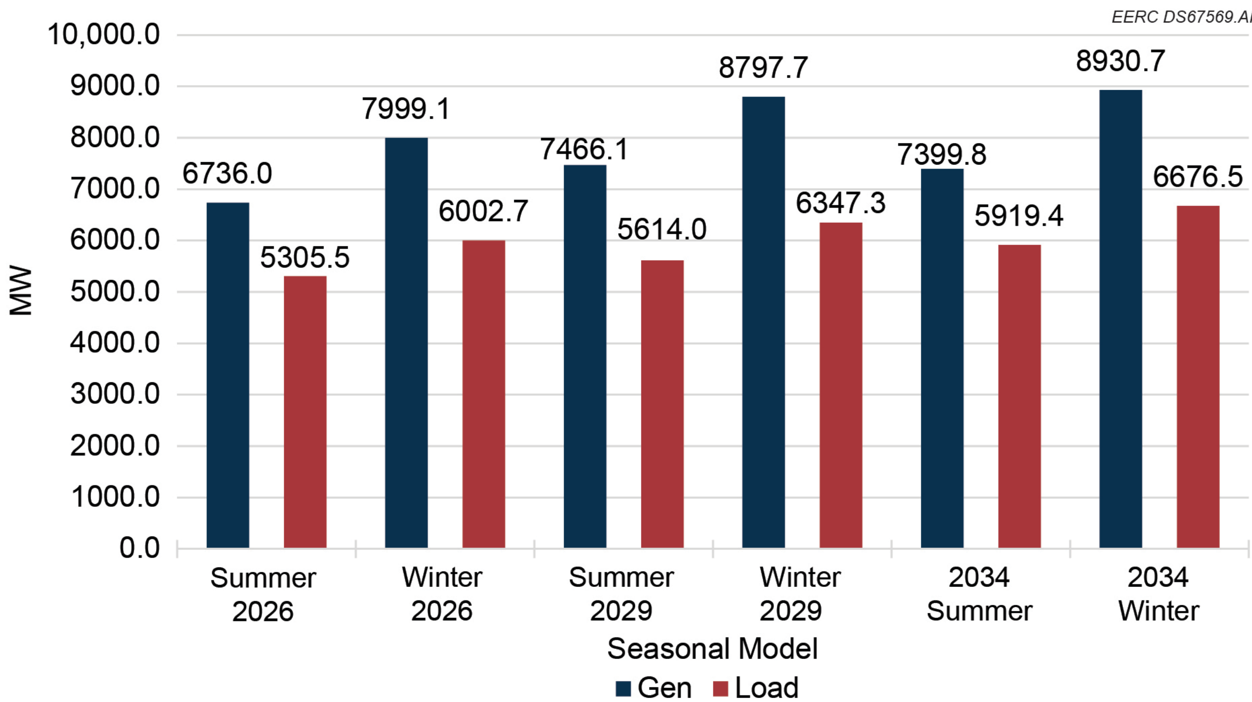


Figure 9. SPP ITP2025 North Dakota seasonal summer (S) and winter (W) peak generation and load.

Table 4. MISO and SPP Transmission Expansion Projects Modeled

Project ID and Name	26S	26W	29S	29W	34S	34W
SPP PID 92113 (ISD 12/31/25) Roundup–Kummer Ridge 345kV	✓	✓	✓	✓	✓	✓
SPP PID 92168 (ISD 12/31/25) Leland Olds–Tioga 345kV	X	✓	✓	✓	✓	✓
SPP PID 92371 (ISD 10/1/27) Tioga–New Boundary Dam 230kV	X	X	✓	✓	✓	✓
SPP PID 92372 (ISD 10/1/27) Wheelock–New Boundary Dam 230kV	X	X	✓	✓	✓	✓
SPP PID 94673 (ISD TBD) Twelve Mile–Spring Brook 345kV	X	X	X	X	✓	✓
SPP PID 94681 (ISD TBD) W Bank 115/345kV Transformer	X	X	X	X	✓	✓
SPP PID 94723 (ISD TBD) Logan–Crane Creek 345kV	X	X	X	X	✓	✓
MTEP 23368 (ISD 12/31/28) Jamestown–Ellendale 345kV	X	X	✓	✓	✓	✓

Analysis

The powerflow transmission analysis was performed with PSS®E and the AC Contingency Calculation (ACCC) tool. PSE performed steady-state thermal and voltage analysis using the following assumptions and criteria:

- N-0 system-intact conditions

- N-1 system contingencies
- Monitored North Dakota transmission facilities >100 kV
- Monitored transmission line and transformer loadings >100%
- Monitored North Dakota TO voltage criteria

Performing a N-0 and N-1 analysis on the base models resulted in a limited number of thermal and voltage criteria violations, as illustrated in Figure 10.

After the base models were analyzed, several assumptions were made to create the study models for the large-load analysis. Only the Year 5 and Year 10 seasonal peak models were used as more likely to realize new large loads. Existing North Dakota generator dispatch, including thermal (coal, natural gas, and oil) and intermittent (solar, storage, and wind) resources, was not changed from the base SPP ITP2025 models, with the exception of turning on the Pioneer station in the 2029 winter peak model. The models were not changed to include active MISO, Minnkota Power Cooperative, and SPP generation interconnection (GI) requests.

Thermal and Voltage Violations

The number of unique thermal and voltage violations have increased in the large-load scenarios, as illustrated in Figure 11. The voltage violations are mostly on the 115-kV system, with only one 345-kV bus and two 230-kV buses violating TO voltage criteria. The 115-kV transmission system in western North Dakota is more sensitive to contingencies, causing voltages to drop below TO criteria in the large-load scenario. Voltage violations in western North Dakota are more prevalent in the 2029 winter peak (29WIN) cases, even with Pioneer Generating Station modeled online in the study scenarios.

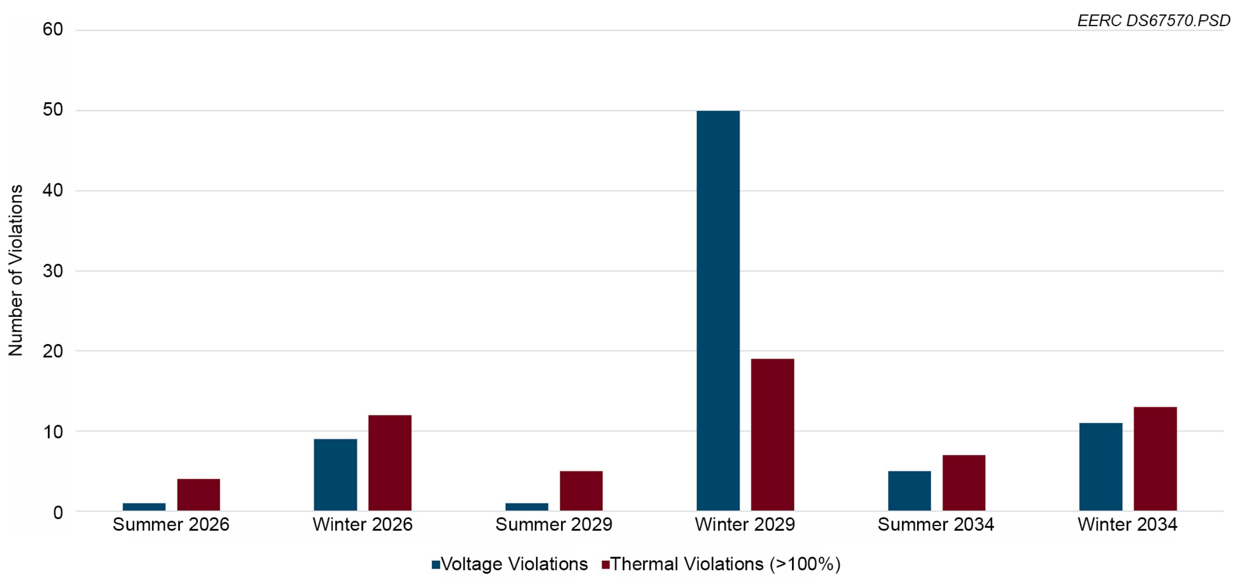


Figure 10. Base transmission results in the seasonal summer (SUM)/winter (WIN) peak model by forecast year (2026, 2029, 2034).

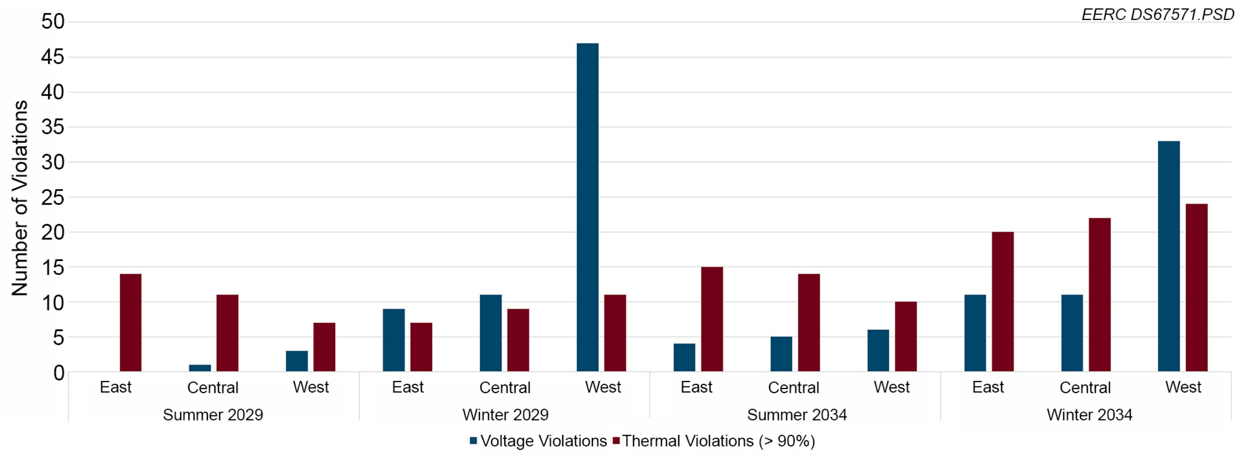


Figure 11. Thermal and voltage violation counts from the seasonal summer (SUM)/winter (WIN) peak model by forecast year (2026, 2029, 2034).

Overloaded Lines and Transformers

The thermal violations observed in the large-load scenarios include 22–75 miles of transmission lines in the summer peak scenarios and 75–198 miles of transmission lines in the winter peak scenarios, as illustrated in Figure 12. There were also four transformer overloads observed in these scenarios.

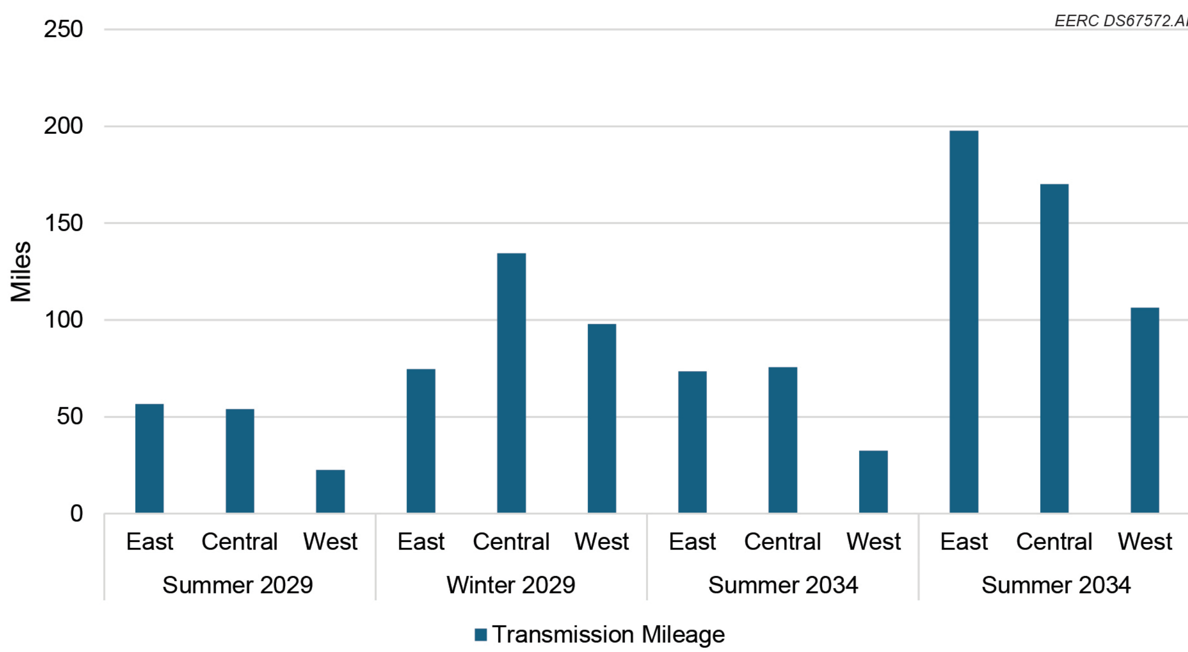


Figure 12. Thermal overload miles of transmission from the seasonal summer (SUM)/winter (WIN) peak model by forecast year (2026, 2029, 2034).

ECONOMIC STUDY

An electricity market economic study is conducted to evaluate how changes in system conditions such as new large loads, generation additions, or transmission upgrades impact the economic operation of the power grid. By simulating market-based generation dispatch under realistic operational and transmission constraints, the study provides insights into how the system responds economically under future outlook scenarios. Such a study offers insights into electricity market dynamics by evaluating how transmission congestion, fuel costs, generator availability, bidding strategies, and load growth influence market prices.

Model Input and Assumptions

This study utilized the SPP MEMs from the ITP2025, which aligns with the corresponding reliability model while excluding reactive power settings and incorporates market variables.[20] This model is based on joint MISO–SPP datasets, ensuring consistency across regional boundaries and capturing coordinated system interactions.

The analysis adopted the Future 1 reference case, as defined in the ITP2025 assessment scope, incorporating all key market-related assumptions and drivers, including fuel prices, load growth, generation expansion, policy considerations, and transmission topology. The study was performed under both N-0 and N-1 contingency conditions. The use of these assumptions ensures that the modeling results align with SPP's regional planning framework and provide a consistent analytical basis for evaluating system performance across multiple planning horizons.

To better understand the implications of large-load additions to the North Dakota grid, this study performed a nodal dispatch analysis using the Hitachi Energy PROMOD security-constrained unit commitment and economic dispatch model that spans the full SPP region. Given the scope of the analysis, emphasis was placed on results for MISO LRZ01 and SPP UMZ, with a particular focus on North Dakota. Accordingly, most results and discussions are presented for these two areas to capture localized market conditions, bus locational marginal prices (LMPs), congestion, and dispatch impacts resulting from the large-load additions.

PROMOD performs an hourly economic dispatch, simulating 8760 hours to represent a full year of system operation. It forecasts hourly energy prices, generation output, revenues, fuel use, external transactions, transmission flows, and congestion and loss costs both at zonal and nodal levels.

This analysis included a market simulation of the base case for the years 2026, 2029, and 2034 as well as the large-load central, east, east price-sensitive (PS) and west scenarios for the years 2029 and 2034. The hourly load profile of a representative large load with a high load factor (approximately 95%, operating near peak most of the time) was used and proportionally scaled to create hourly load profiles for different sizes and scenarios, preserving the same hourly shape and load factor characteristics. The new large loads were added at specific high-voltage locations (also known as substations or buses), as outlined in Section 2.2. No additional generation resources were incorporated in either the base case or the large-load scenarios beyond those already included in

[20] www.spp.org/documents/73387/2025%20itp%20assessment%20scope_v4.0.pdf, (accessed October 2025).

the original SPP models. This approach enables the assessment of how the projected generation fleet and transmission network would respond to significant new large-load additions. In the east PS scenario, large loads were represented as sales transactions in PROMOD that adjust demand (i.e., curtail) in response to market price signals, following the criteria outlined in Table 5.

Therefore, if the market simulation calculates an LMP of $150/megawatt-hour (MWh) for a specific hour at the large-load location, the large load will be completely curtailed.

Table 5. Large-Load Curtailment Criteria

Price	% Load Curtailment
$80/MWh	25
$100/MWh	50
$125/MWh	75
$150/MWh	100

The resource mix for MISO LRZ01 and SPP UMZ for the study years 2026, 2029, and 2034 was derived from the SPP ITP2025 MEMs (PROMOD data), representing the generation portfolio assumed in the Future 1 reference case. The corresponding resource mix and capacity distribution are illustrated in Figures 13 and 14.

For MISO LRZ01, projected hydroelectric, nuclear, oil, and coal generation (installed) capacity are expected to remain unchanged at 0.4, ~1.7, 0.8, and ~7.7 GW, respectively. Growth is expected among renewable energy and natural gas, including the addition of nearly 11 GW of wind capacity and almost 3 GW of solar capacity over the next 10 years. Natural gas growth is expected to add approximately 2.5 GW of additional capacity. Of note, battery storage, or storing generated electricity for use when demand increases, is becoming an increasingly feasible option for energy storage, and a minor adoption in LRZ01 will add a modest 0.3 GW to the grid (Figure 13). Projected total generation capacity amounts to 28.6 GW in 2026, 45.9 GW in 2029, and 46.1 GW by 2034. This growth represents an approximately 60.5% increase in generation capacity between 2026 and 2029 and an approximately 0.4% increase from 2029 to 2034. The noncoincident peak demand in MISO LRZ01 was projected to increase from 21,128 MW in 2026 to 21,178 MW in 2029, reaching 21,971 MW by 2034, indicating modest growth over the study period.

For SPP UMZ, the projected hydroelectric, coal, and gas generation capacity is expected to remain unchanged at 2.6, 2.1, and 2.1 GW, respectively. Similar to MISO LRZ01, most growth in SPP UMZ is expected to come in the form of renewable energy, including the addition of nearly 2 GW of solar and 3 GW of additional wind over the next 10 years. Battery storage is expected to grow to provide an additional 0.7 GW of capacity by 2034 (Figure 14). Projected total generation capacity amounts to ~10.8 GW in 2026, ~15.7 GW in 2029, and ~16.3 GW by 2034. This growth represents an approximately 45% increase in generation capacity between 2026 and 2029 and an approximately 4% increase from 2029 to 2034. The noncoincident peak demand in SPP UMZ was projected to rise steadily from 7089 MW in 2026 to 7589 MW in 2029 and further to 8051 MW by 2034, reflecting consistent load growth across the study horizon.

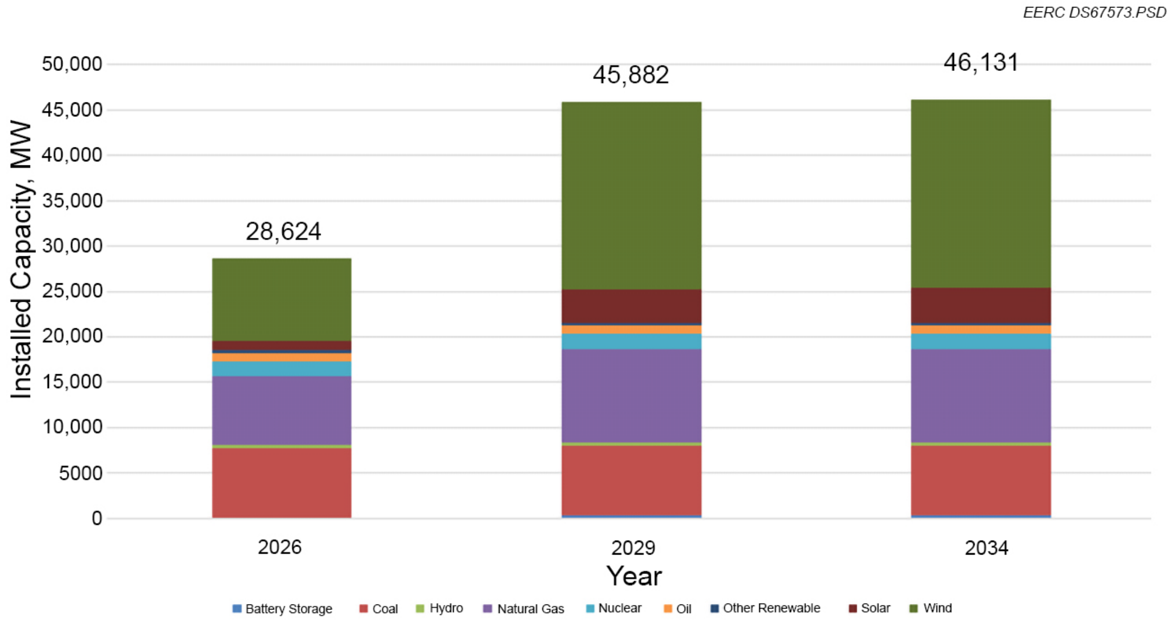


Figure 13. Projected electric generation capacity by fuel type for MISO LRZ01 by years 2026, 2029, and 2034.

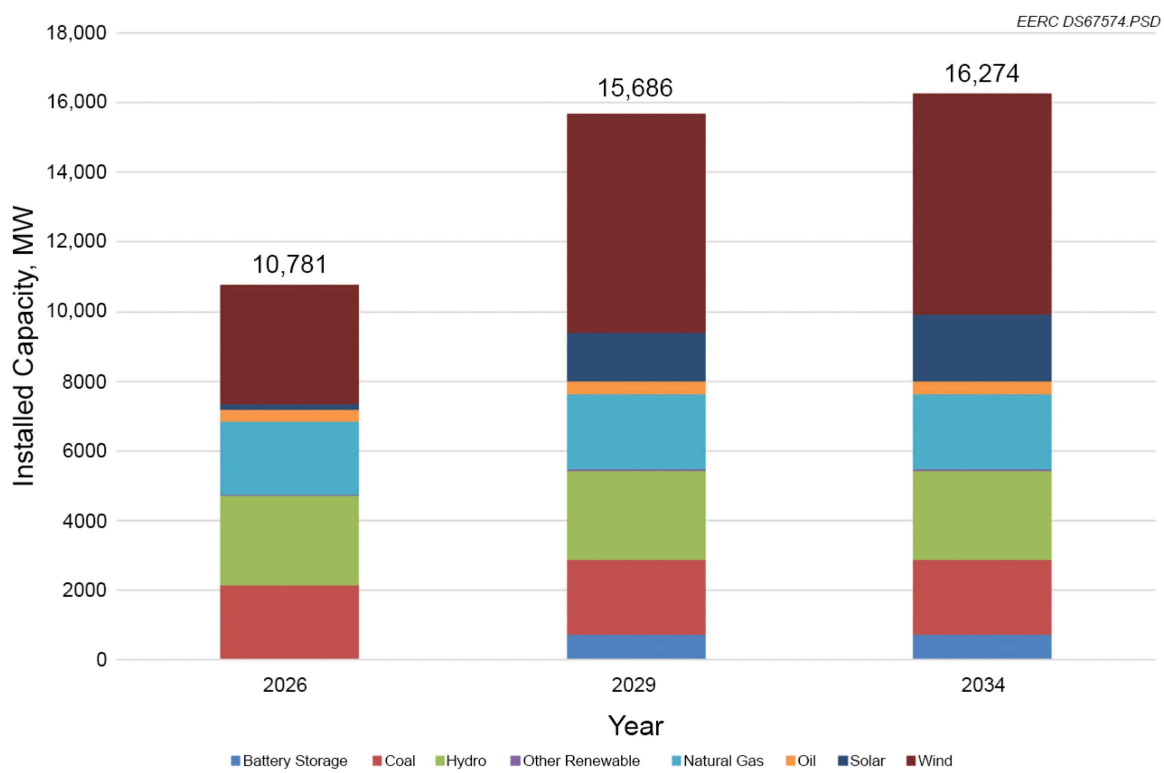


Figure 14. Projected electric generation resource by fuel type for SPP UMZ by years 2026, 2029, and 2034

Analysis

PROMOD simulation results included forecasts of hourly electricity prices, generation dispatch patterns, renewable curtailment, and transmission congestion, providing insights into system performance, market behavior, and operational impacts under the large-load scenarios. The analysis of these results is presented below.

LMP

The purpose of the SPP and MISO RTO markets is to match resources and loads and establish prices for wholesale electric energy. 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, 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 LMP. Losses are the energy wasted by the electrical friction of current traveling through a conductor. Depending on the location of a particular generator and load, a schedule can either increase or decrease system losses. These losses are calculated and defined as the marginal loss cost (MLC). Congestion can constrain generation schedules to load. Similar to losses, the location of the generator can either increase or decrease congestion. The congestion costs are defined as marginal congestion cost (MCC). Congestion is the amount of MW that flow across a particular path on the transmission system that exceeds the amount of MW capacity that path can accommodate without violating system operating criteria, such as thermal overload or voltage excursions.

LMP at any location is the summation of the MEC, MLC, and MCC. The MLC and MCC can have positive or negative adjustments to MEC. The variability of LMP across the geographical footprint of the RTO can distort the normal stacking of generation bids. If a generator is contributing to transmission system losses and/or congestion, its MLC and/or MCC 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.

The market study determined the LMP at the modeled large-load buses across various scenarios and compared them against the corresponding base case models. This comparison provides insight into the potential impacts of large-load additions on system congestion, price variability, and overall market behavior. Adding load without a corresponding increase in new generation additions will always increase LMP prices as more generation from the bid stack will be called upon to run, and the stack is ordered based on the bid price from lowest to highest. The highest bid price determines the marketwide MEC price. Table 6 presents the average LMP at large-load buses under base and large-load scenarios for 2026, 2029, and 2034. Overall, results indicate increasing price divergence between base and large-load conditions over time, reflecting the growing impact of load additions on system congestion and marginal generation costs. The east load PS case was effective in lowering the local LMP.

Table 7 shows the heat map of LMP differences between large-load scenarios and the corresponding base cases. The results show that the impact of large-load additions on LMP varies by region and season, reflecting evolving congestion and system conditions between 2029 and 2034. The following observations are made for various scenarios:

- Central scenario: Moderate LMP increases are observed across the system, with some buses showing strong seasonal variation, higher LMPs in winter.

- East scenario: The 2029 case exhibits the largest price differences, exceeding \$20/MWh in summer. By 2034, the magnitude of these differences declines but remains significant (around \$10–\$18/MWh), suggesting partial mitigation of congestion, possibly due to system reinforcements.

- East PS scenario: Similar trends are observed, with overall LMP differences narrowing from 2029 to 2034. Compared to the east scenario, most buses show moderate improvements as a result of the partial curtailment of large loads.

- West scenario: LMP differences are relatively low in 2029 but rise by 2034. This trend reflects growing congestion and increasing price signals over time.

Figure 15 illustrates an example of the LMP results, specifically showing values for July 2029.

The Buffalo bus, a 345-kV substation located west of Fargo, serves as an example for evaluating system impacts in the east scenario. In this scenario, about 1400 MW of new large load was added across several locations in eastern North Dakota, as summarized in Table 3. As expected, without any new generation being added to cover this additional load, the LMP trended higher, with two significant price spikes exceeding \$250/MWh in the first half of July 2029. As shown on the congestion component graph (Figure 15), a large increase in congestion costs is contributing to the LMP price spike.

For the same bus and time period, Figure 16 presents the east PS scenario LMP results, illustrating how curtailment of large loads during system stress conditions reduces congestion and moderates price volatility.

Table 6. Average LMP at Large-Load Buses Under Base and Large-Load Scenarios for 2026, 2029, and 2034

Average LMP, $/MWh

2026: Central	Base	
Bus Name	Summer	Winter
Center	38.79	38.69
Leland	36.15	34.10
Coal Creek	38.37	39.68

2026: East	Base	
Bus Name	Summer	Winter
Bison	10.90	14.66
Buffalo	14.01	17.37
Ellendale	30.31	26.94
Jamestown	22.13	24.46
Maple	8.10	12.24
Prairie	111.98	106.26
Coal Creek	38.37	39.68

2026: East PS	Base	
Bus Name	Summer	Winter
Bison	10.90	14.66
Buffalo	14.01	17.37
Ellendale	30.31	26.94
Jamestown	22.13	24.46
Maple	8.10	12.24
Prairie	111.98	106.26
Coal Creek	38.37	39.68

2026: West	Base	
Bus Name	Summer	Winter
Judson	41.57	39.71
Pioneer	41.55	39.70
Coal Creek	38.37	39.68

Min.:	8.10
Max.:	111.98

Average LMP, $/MWh

2029: Central	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Center	22.44	7.67	29.88	23.48
Leland	40.19	26.37	44.55	29.09
Coal Creek	30.22	31.77	34.07	36.60

2029: East	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Bison	38.09	22.22	61.29	38.50
Buffalo	37.41	21.10	62.65	38.49
Ellendale	36.24	18.60	48.68	31.96
Jamestown	34.72	18.35	49.29	34.53
Maple	38.40	22.14	61.79	38.34
Prairie	34.92	20.10	37.75	29.62
Coal Creek	30.22	31.77	33.03	34.81

2029: East PS	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Bison	38.09	22.22	55.37	37.80
Buffalo	37.41	21.10	56.45	37.58
Ellendale	36.24	18.60	47.34	31.03
Jamestown	34.72	18.35	47.70	33.06
Maple	38.40	22.14	55.73	37.72
Prairie	34.92	20.10	38.19	30.10
Coal Creek	30.22	31.77	32.84	34.81

2029: West	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Judson	–	–	60.06	43.27
Pioneer	51.43	34.97	59.27	43.20
Coal Creek	30.22	31.77	31.76	33.43

Min.:	7.67	**Min.:**	23.48
Max.:	51.43	**Max.:**	62.65

Average LMP, $/MWh

2034: Central	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Center	18.77	−8.44	29.09	−1.04
Leland	36.67	16.99	41.93	19.91
Coal Creek	33.00	23.02	40.28	37.01

2034: East	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Bison	32.46	6.53	48.69	16.94
Buffalo	29.92	4.75	48.50	16.23
Ellendale	31.13	3.43	46.21	13.66
Jamestown	29.50	2.44	47.60	14.09
Maple	32.62	6.36	48.54	16.62
Prairie	32.97	5.92	43.00	15.05
Coal Creek	33.00	23.02	38.57	34.03

2034: East PS	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Bison	32.46	6.53	47.27	16.36
Buffalo	29.92	4.75	46.58	15.53
Ellendale	31.13	3.43	44.39	13.04
Jamestown	29.50	2.44	44.94	13.05
Maple	32.62	6.36	47.13	16.10
Prairie	32.97	5.92	41.75	14.95
Coal Creek	33.00	23.02	38.67	34.03

2034: West	Base		Large Load	
Bus Name	Summer	Winter	Summer	Winter
Judson	47.10	26.60	56.43	32.80
Pioneer	46.65	26.34	55.90	32.54
Coal Creek	33.00	23.02	37.07	32.79

Min.:	−8.44	**Min.:**	−1.04
Max.:	47.10	**Max.:**	56.43

Table 7. Heat Map of LMP Differences at Large-Load Buses

2029 Cases			2034 Cases		
Difference (Large Load – Base), $/MWh			Difference (Large Load – Base), $/MWh		
2029 Central			**2034 Central**		
Bus Name	**Summer**	**Winter**	**Bus Name**	**Summer**	**Winter**
Center	7.44	15.81	Center	10.33	7.41
Leland	4.37	2.81	Leland	5.37	2.90
Coal Creek	3.85	4.83	Coal Creek	7.37	14.02
2029 East			**2034 East**		
Bus Name	**Summer**	**Winter**	**Bus Name**	**Summer**	**Winter**
Bison	23.20	16.29	Bison	16.10	10.34
Buffalo	25.24	17.39	Buffalo	18.58	11.48
Ellendale	12.45	13.31	Ellendale	15.08	10.23
Jamestown	14.57	16.18	Jamestown	18.10	11.64
Maple	23.39	16.20	Maple	15.96	10.26
Prairie	2.82	9.52	Prairie	10.03	9.14
Coal Creek	2.82	3.04	Coal Creek	5.51	11.03
2029 East PS			**2034 East PS**		
Bus Name	**Summer**	**Winter**	**Bus Name**	**Summer**	**Winter**
Bison	17.29	15.59	Bison	14.62	9.77
Buffalo	19.04	16.49	Buffalo	16.66	10.78
Ellendale	11.11	12.43	Ellendale	13.26	9.61
Jamestown	12.98	14.71	Jamestown	15.45	10.61
Maple	17.33	15.57	Maple	14.55	9.74
Prairie	3.27	10.00	Prairie	8.78	9.03
Coal Creek	2.62	3.04	Coal Creek	5.60	11.04
2029 West			**2034 West**		
Bus Name	**Summer**	**Winter**	**Bus Name**	**Summer**	**Winter**
Judson			Judson	9.32	6.21
Pioneer	7.84	8.23	Pioneer	9.25	6.20
Coal Creek	1.54	1.66	Coal Creek	4.07	9.80

Figure 15. LMP and its congestion component for Buffalo under the base case and east scenario – July 2029.

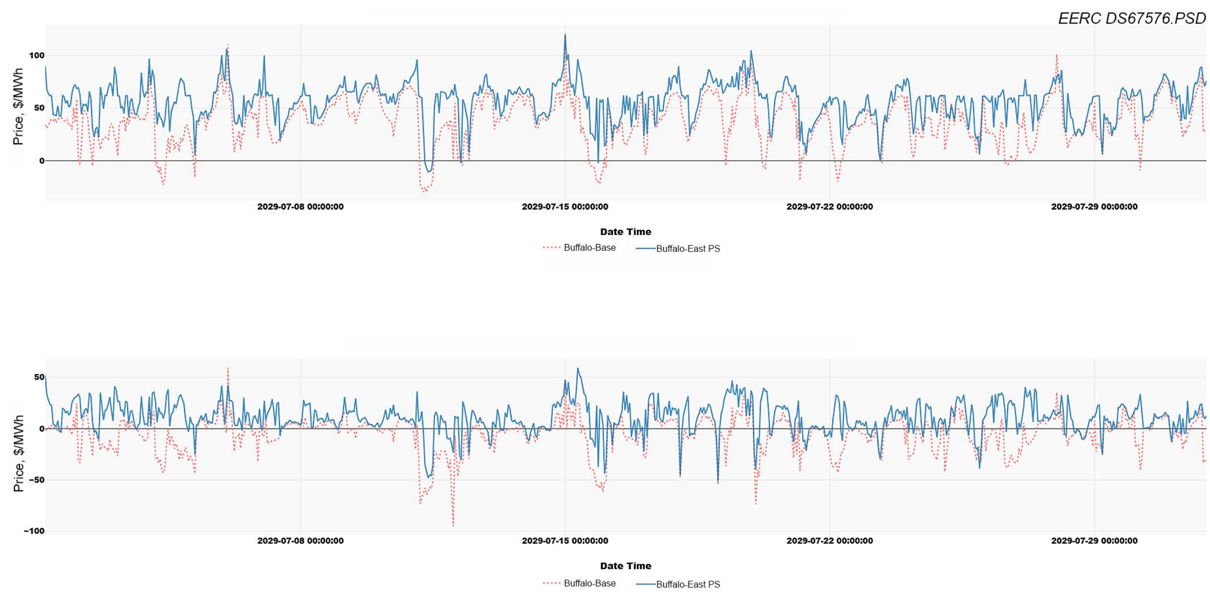


Figure 16. LMP and its congestion component for Buffalo under the base case and east PS scenario – July 2029.

NDEX Interface Flow

The measure of the AC powerflow export from North Dakota to South Dakota and Minnesota is referred to as North Dakota export (NDEX). It is a collection of AC transmission lines located at or near the North Dakota border and has an accepted rating of 2080 MW. The export definition does not include the direct current (DC) lines from the Young Station to Duluth or the Coal Creek Station to Minneapolis, which add another 2000 MW of capacity. A map of the NDEX facilities is provided in Figure 17.

Figures 18 and 19 present the calculated NDEX powerflows for the base case and the east scenario in July 2029. The export plateaus at the NDEX capacity of 2080 MW. When the powerflow exceeds this limit, the generation within North Dakota is curtailed just enough to ensure that the rating is not exceeded. A comparison of the base case with the east scenario shows that the graph is shifted toward a lower NDEX. This indicates that the large loads are consuming power within North Dakota that would otherwise be available for export. The other load scenarios show a similar response. Also, there is slightly less plateauing at the 2080-MW limit of the NDEX powerflow. This indicates there is less curtailment of generation within North Dakota as the generation that is otherwise being curtailed is being consumed by the large load.

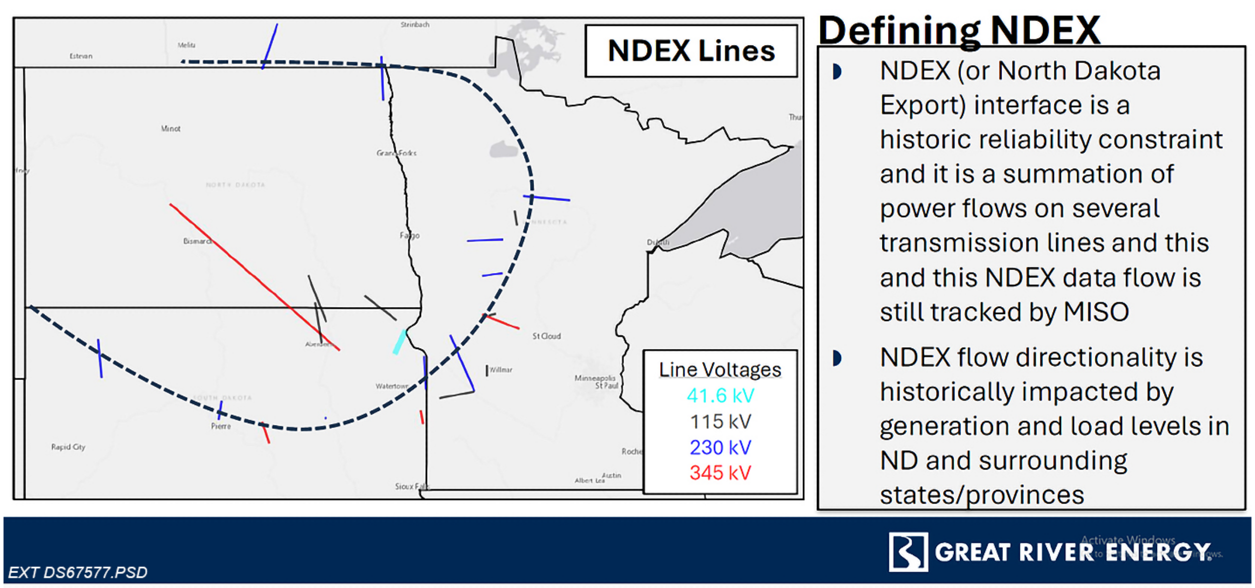


Figure 17. Map of NDEX interface.

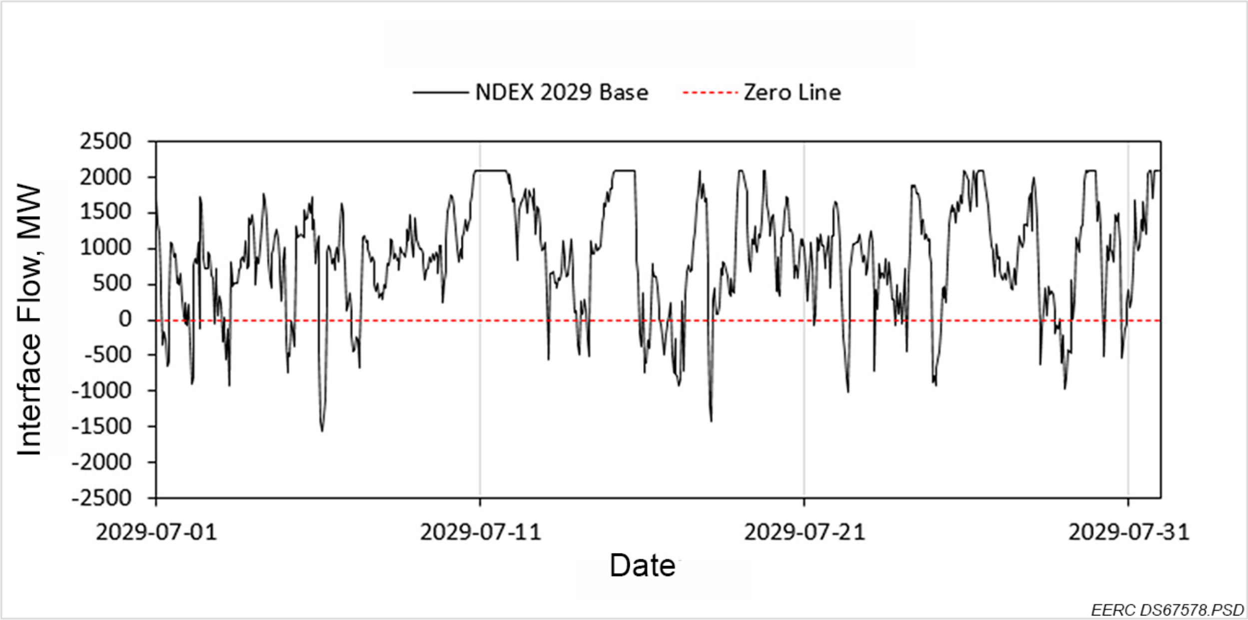


Figure 18. NDEX powerflow for the base case – July 2029.

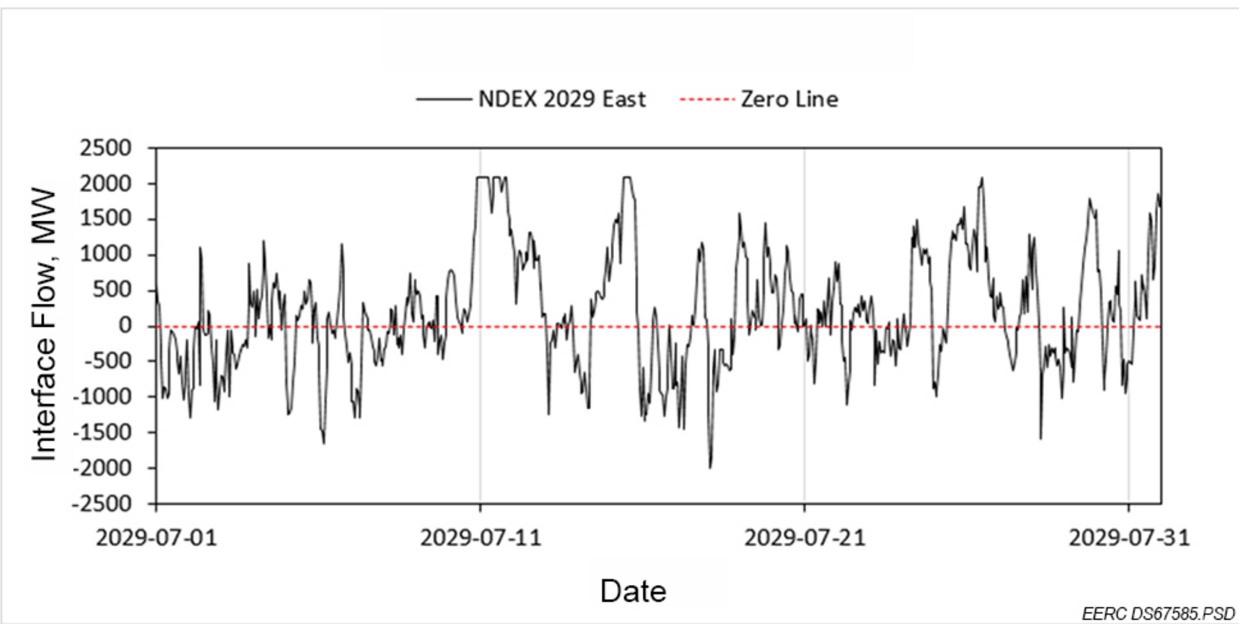


Figure 19. NDEX powerflow for the east scenario – July 2029.

Thermal Generation Dispatch

Generation dispatch in PROMOD optimizes unit commitment and energy flows to meet system load at minimal cost while respecting transmission and operational constraints. The dispatch analysis ensures units are committed and dispatched economically, considering fuel costs, start-up/shutdown costs, and variable operation costs.

The chart in Figure 20 shows the forecasted monthly thermal generation by fuel type for MISO LRZ01 across different scenarios in January and July 2034. Nuclear remains the largest single contributor in all modeled scenarios and in both January and July 2034, providing a steady baseline. Natural gas and coal-based electricity generation fluctuate across seasons, with higher contributions during July in most scenarios, reflecting seasonal demand variation. Hydro, oil, battery storage, and other renewables contribute relatively small amounts across all scenarios. Thermal generation output stays stable across central, east, and east PS scenarios; natural gas-fired generation exhibits a modest increase in energy output.

Figure 21 presents the thermal generation in SPP UMZ for January and July 2034, illustrating a consistent reliance on conventional units to meet demand across all scenarios. Coal remains the largest contributor in all scenarios, accounting for the majority of electricity generation, with dispatch showing a modest increase under large-load scenarios. Following coal, natural gas and hydro are the next most significant generation sources. Natural gas-fired generation remains relatively stable across scenarios, with a slight increase during summer, while hydro generation is consistent across all scenarios. While overall dispatch levels vary with load and renewable generation availability, thermal resources continue to play a critical role in maintaining reliability and balancing system operations during January and July. Similar results are observed for the year 2029.

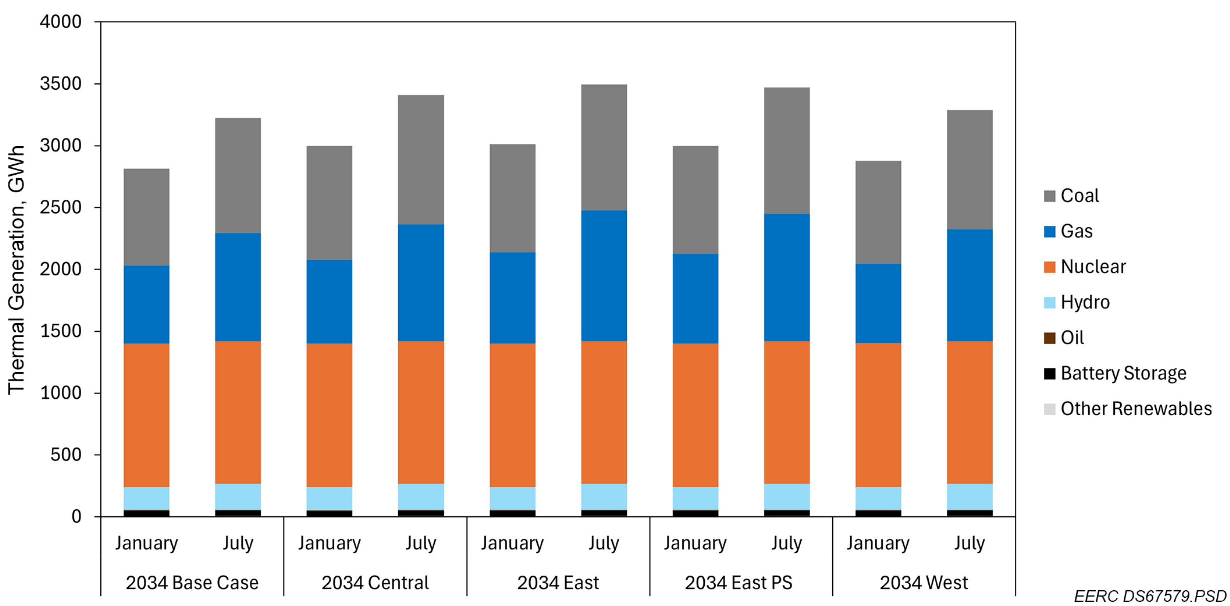


Figure 20. Forecasted monthly thermal generation in MISO LRZ01 across various scenarios – January and July 2034.

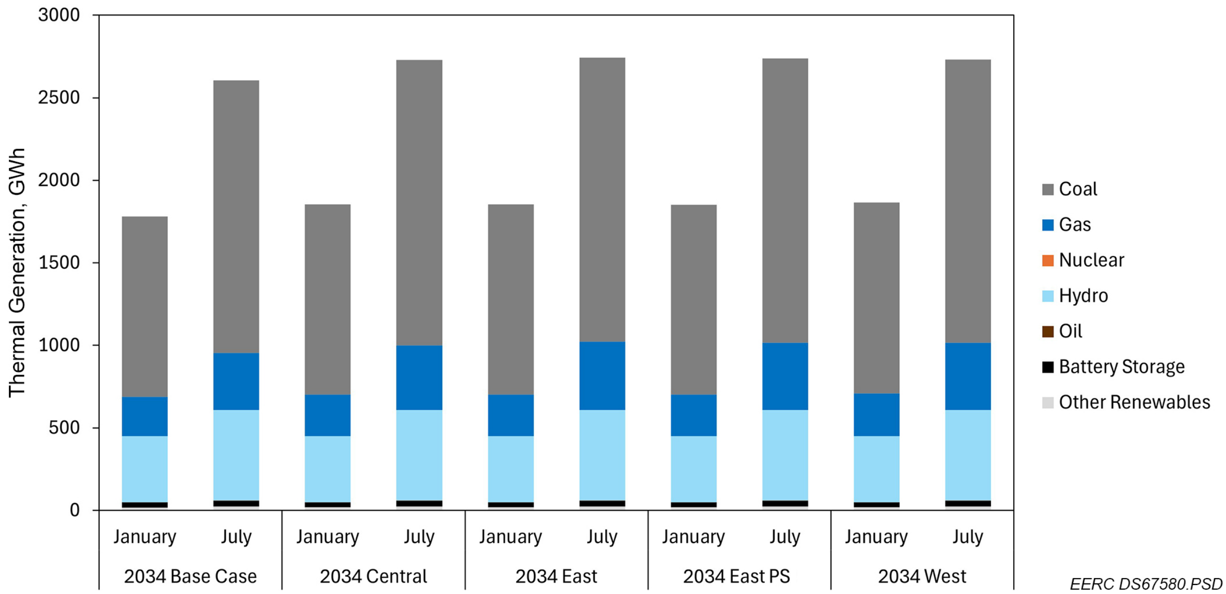


Figure 21. Forecasted monthly thermal generation in SPP UMZ across various scenarios – January and July 2034.

Renewable Generation and Curtailment

The monthly renewable generation outputs for MISO LRZ1 and SPP UMZ in January and July 2034 are presented in Figures 22 and 23, respectively. Wind generation shows a slight increase under the large-load scenarios, reflecting additional energy being utilized that would otherwise have been curtailed. This trend is also evident in the energy curtailment graphs, which indicate a modest reduction in curtailed wind energy in the large-load scenarios compared to the base case. Data are provided only for 2034 January and July, as the 2029 results are similar and therefore omitted.

Transmission Bottlenecks

Consistent with the earlier discussion of LMP results, the market simulation shows that the addition of large loads leads to increased congestion. An example of the impact, Figures 24 and 25 illustrate the number of hours of congestion for two transmission facilities. These facilities exhibited reliability deficiencies in the SPP ITP2025 study: the Fort Thompson 345/230-kV transformer and the Belfield–Charlie Creek 345-kV line. This congestion is expected, as the increased load is met by higher generation across the entire MISO/SPP regions. The additional power must be transmitted into North Dakota through the transmission system.

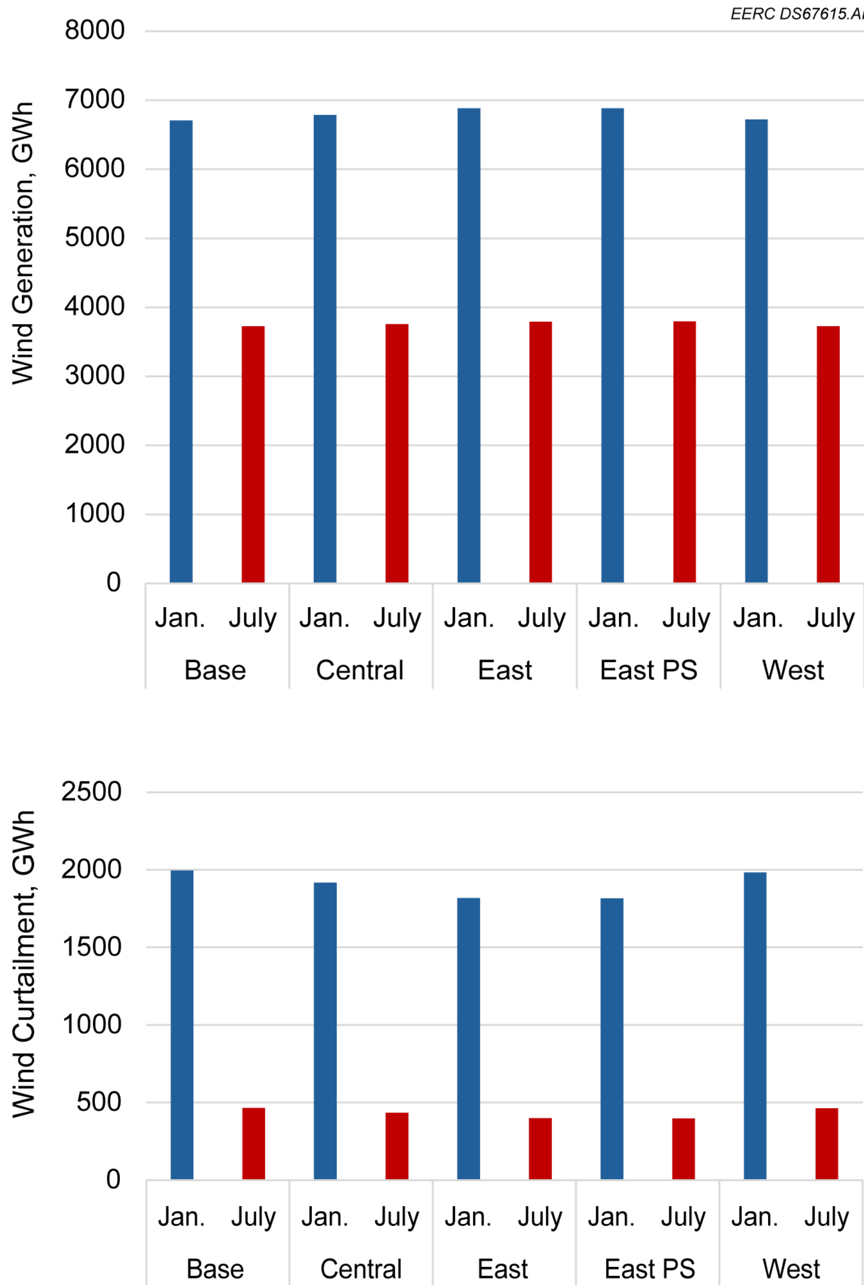


Figure 22. Monthly wind generation and curtailment in MISO LRZ01 by scenario – January and July 2034.

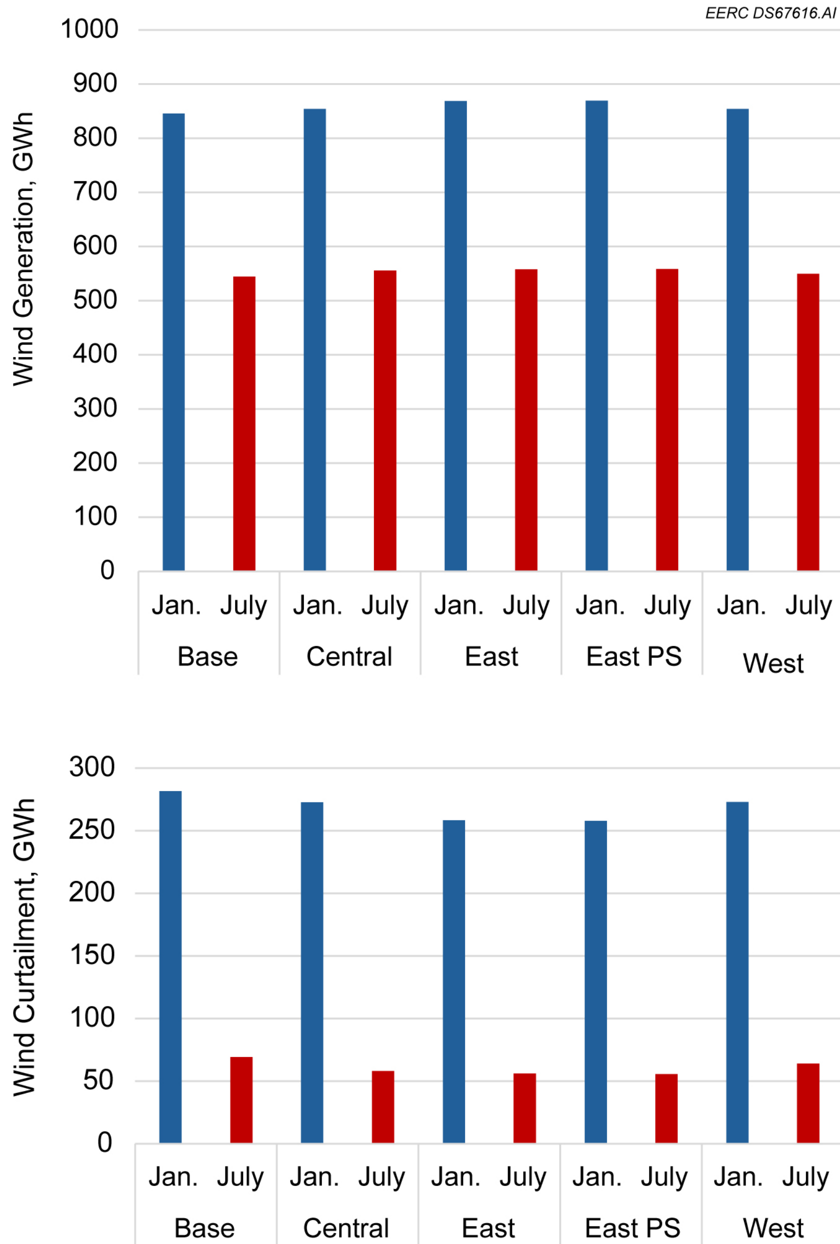


Figure 23. Monthly wind generation and curtailment in SPP UMZ by scenario – January and July 2034.

The Fort Thompson 345/230-kV transformer exhibits more binding hours in January than in July across all scenarios (Figure 24). In January, binding hours range from 256 in the base case to 318 in the east PS scenario, while in July, they range from 191 in the base case to 219 in the east scenario. The east and east PS scenarios have the highest binding hours compared to central and west scenarios. Figure 25 shows that the Belfield–Charlie Creek 345-kV line experiences higher binding hours in July 2034 than in January across all large-load scenarios, indicating increased operational constraints during summer. The west scenario experiences the highest binding hours, reaching 206 hours in July compared to 140 hours in the base case.

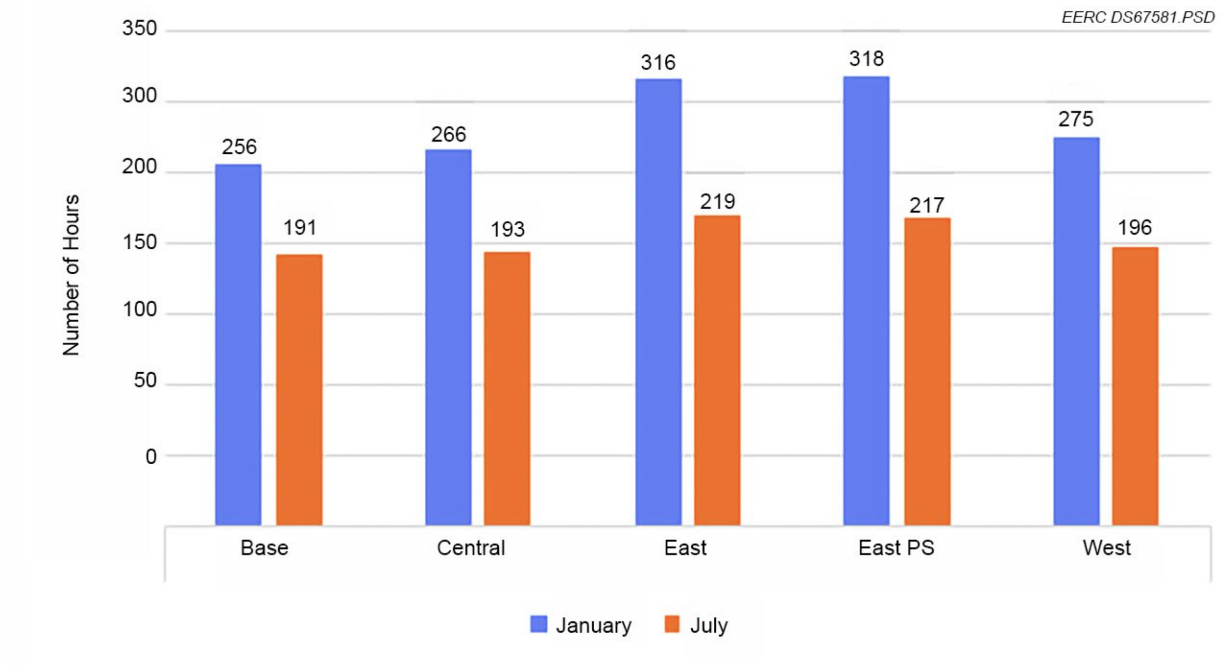


Figure 24. Monthly binding hours of Fort Thompson 345/230-kV transformer by scenario – January and July 2034.

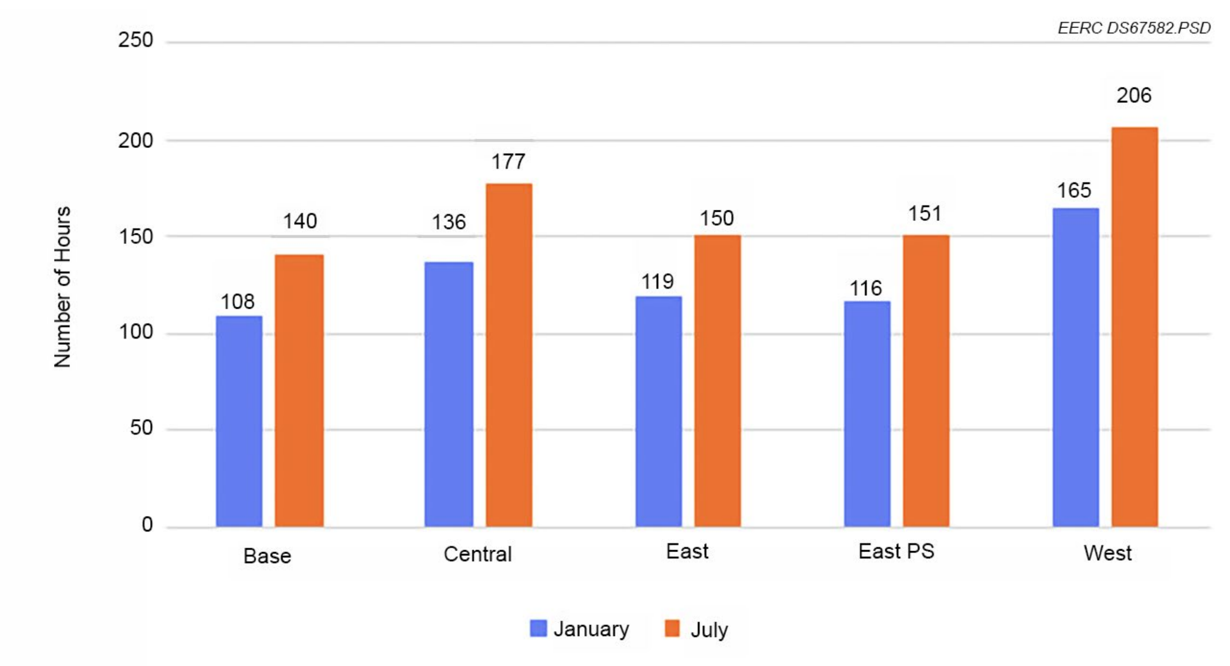


Figure 25. Monthly binding hours of Belfield–Charlie Creek 345-kV line by scenario – January and July 2034

Table 8 summarizes the top ten binding constraints observed in the large-load scenarios for January and July 2034. Many of the constrained lines such as the lines terminating at Center, Beulah, and Coyote, North Dakota, are located adjacent to significant coal and wind generation in western North Dakota. Increased power transfers from this generation area to serve the new load are causing the lines to reach their thermal limits. The Williston area congestion is related to Bakken load stressing the local transmission system. The SPP draft ITP2025 portfolio includes the Patent Gate–Pioneer 345-kV substation addition, which will address this area. The Spencer–Fort Randall line is located on the South Dakota–Nebraska border, and the Fort Thompson transformer is located near Pierre, South Dakota. The Macksburg–Creston line is located in Iowa. There are also impacts in eastern North Dakota in the Fargo and Devils Lake areas. No transmission upgrades for these areas meet the SPP 2025 benefit-to-cost criteria; thus any future congestion mitigation will be addressed by market redispatch action.

The facilities listed in Table 8 are also located in areas of economic congestion identified in Figure 26, as presented in the draft SPP ITP2025 assessment report Version 0.1 (dated July 24, 2025).[22]

Table 8. Top Ten Constraints Identified in the Large-Load Scenarios – January and July 2034

2034 Central	**2034 East**
Williston – Ren 115 kV	Ft. Thompson 345/230 kV Transformer
Macksburg – Creston 161 kV	Jamestown – Center 345 kV
Jamestown – Center 345 kV	Macksburg – Creston 161 kV
Sanderson – Pioneer 115 kV	Adams – Creston 161 kV
Ft. Thompson 345/230 kV Transformer	Devils Lake – Penn 115 kV
Sheyenne – Fargo 230 kV	Sheyenne – Fargo 230kV
Center – Square Butte 230 kV	Velva Tap – McHenry 115 kV
Beulah – Coyote 115kV	Granite Falls – Marshall 115 kV
Granite Falls – Marshall 115 kV	Langdon - Sweetwater 115 kV
Blue Lake – Hampton Corner 345 kV	Foxtail – Tatanka North 230 kV
2034 East PS	**2034 West**
Spencer – Fort Randall 115 kV	Forman – Forman 115 kV
Forman – Forman 115 kV	Adams – Creston 161 kV
Adams – Creston 161 kV	Nelson Lake – Stanton 230 kV
Sioux Falls – Moody County 115 kV	Winger – Bagley 115 kV
Jamestown – Center 345 kV	Macksburg – Creston 161 kV
Nelson Lake – Stanton 230 kV	Split Rock 230/115 kV Transformer
Helena – Sheas Lake 345 kV	Coyote 345/115 kV Transformer
Split Rock 230/115 kV Transformer	Sioux Falls – Moody County 115 kV
Center – Square Butte 230 kV	Paynesville – Wakefield 115 kV
Velva Tap – McHenry 115 kV	Center – Square Butte 230kV

[22] SPP ITP2025 Assessment Report Version 0.1 (accessed October 2025).

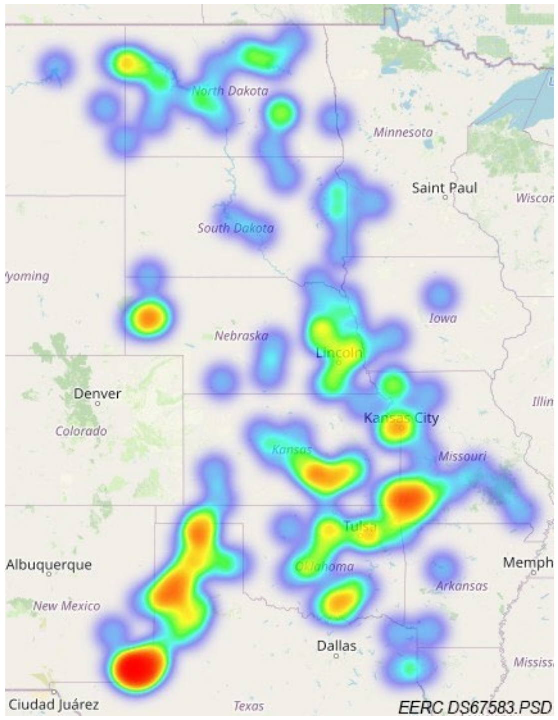


Figure 26. Map of maximum economic congestion across all MEM scenarios.[22]

INFRASTRUCTURE AND POLICY IMPLICATIONS

Generation Resources and Transmission Upgrade Need

Since the electric transmission network requires enough generation capacity to meet the load plus losses on a continuous basis, no large loads can be connected to the grid without considering the availability of generation capacity. Also, there must be adequate transmission capacity to move electric power from the generation to the network load.

The 2024 (updated July 2025) North American Electric Reliability Corporation (NERC) long-term reliability assessment[23] indicates both MISO and SPP RTOs are presently at elevated risk for energy shortfalls and will face challenges with adequate generation capacity. The 2024 assessment provides these highlights regarding SPP and MISO:

1. *SPP "There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages. "*

2. *MISO "MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities.*

[23]www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed October 2025).

Furthermore, generation installation delays result in uncertainty throughout the assessment time frame. As a result of these factors, MISO is facing capacity shortfalls in the next five years."

Therefore, there is a challenge in providing enough generation capacity to meet the needs of large GW-size loads. This challenge is being addressed in North Dakota. BEPC recently completed its Pioneer Station Phase 4 project, which adds 580 MW to the grid.[24] BEPC also recently announced the Bison generation station, which will be a 1400-MW gas-burning combined-cycle unit located near Epping North Dakota, which will be in service by 2030.[25]

Adding generation has been hobbled by the Federal Energy Regulatory Commission generation-queuing process. That process resulted in endless restudy as a result of interconnection customers canceling their requests after viewing the costs of their assigned network upgrades. When generation is removed from the study, the results are nullified, and the study must restart. For example, the 2018 SPP GI study was not completed until the end of 2024.[26]

Recognizing the existing process would not allow for timely generation connection to serve large loads as well as the overall decline of reserves, MISO and SPP each created a one-time expedited resource adequacy study (ERAS) process. This process provides a shortcut for utilities to add the generation resources required to meet their generation resource adequacy requirements. SPP is also transitioning to a new consolidated planning process, which is expected to accelerate the processing of GI requests.

The transmission system is being pushed harder as well. Figure 27, provided by SPP as part of its 2025 summer operations update at its Market and Operations Policy Committee (MOPC) meeting October 15, 2025, shows the steady increase in congested transmission constraints from 2015 to 2025.

Transmission improvements in North Dakota are underway. The MISO Tranche 1 portfolio includes the Jamestown to Ellendale 345-kV line, which will complete a 345-kV loop in southeastern North Dakota. The SPP ITP2024 portfolio includes a 345-kV line connecting Belfield to eastern Wyoming that will increase the power transfer capacity between North Dakota and the rest of SPP. The Tioga to Leland Olds 345-kV line is under construction. This line will complete a 345-kV load-serving loop into the Bakken oil/gas region and significantly improve that area's reliability and power import capacity.

[24]www.basinelectric.com/News-Center/news-briefs/Pioneer-Generation-Station-Phase-IV-now-in-operation, (accessed October 2025).
[25]www.basinelectric.com/News-Center/news-releases/Basin-Electric-to-build-1,400-megawatt-generation-facility-in-northwest-North-Dakota (accessed October 2025).
[26] https://opsportal.spp.org/Studies/GenList?yearTypeId=165 (accessed October 2025).

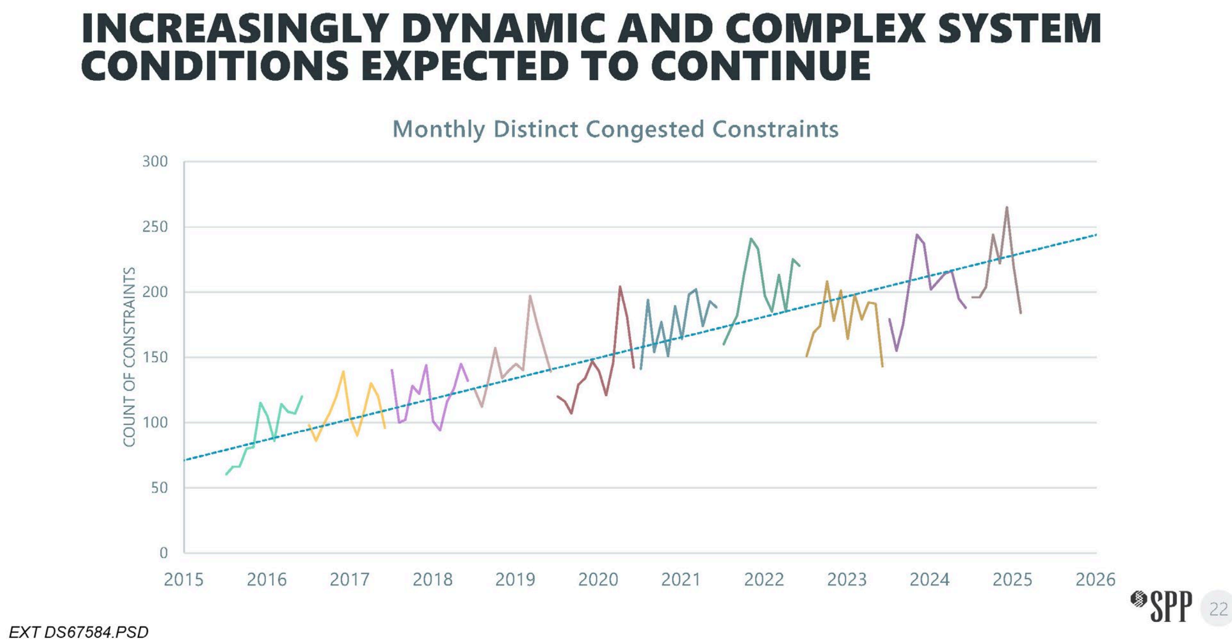


Figure 27. SPP congested transmission constraints.[27]

Future transmission upgrades will be determined by either the MISO transmission expansion plan (MTEP) or the SPP ITP processes. These processes are continually in motion and produce upgrade portfolios every 18 months for the MTEP and annually for the ITP. These processes perform reliability and economic analysis to determine the transmission deficiencies that need to be addressed and the associated required transmission network upgrades. The reliability analysis focuses on transmission system reliability, ensuring any NERC criteria violations are fixed. The economic analysis focuses on the cost of transmission congestion to determine if there are upgrades that can address the congestion in a cost-effective manner. Often a proposed project will have both reliability and economic attributes.

Rate Design

A large-load data center's primary concern regarding electric power is reliability. The term "five nines" is often used. This represents a reliability of 99.999%. While utility power delivery is highly reliable, it is typically in the range of 99.95%. This is also measured as loss of load expectation, which is typically rated at 1 day in 10 years. Therefore, in order to provide the required five nines reliability, a data center power solution will consist of a utility service plus the data center's own internal backup power source. Other types of large loads may not have the data center requirement for extreme reliability. These requirements will be addressed with the local utility during the interconnection application.

[27] www.spp.org/spp-documents-filings/?id=485095 (accessed October 2025).

The utilities' primary concern is acquisition of enough power and transmission to meet large-load needs. For a GW-type large load, the utility could face an investment of $2 billion–$3 billion to construct the required generation and transmission facilities. The utility would likely depreciate this resource over 30 to 40 years, while the processors in large-load data center servers have a turnover of 4 to 5 years. Other large loads could close for a variety of business reasons. This exposes the utility to a stranded cost risk should the large load disappear before the cost of the utility's investment gets paid off. This risk could result in higher rates for existing customers if they are exposed to the stranded cost.

As a form of risk management, utilities and large loads are creating partnerships and special power rates. There are several models being developed:

1. One concept is a market exposure-type arrangement that consists of passing the market rate for power directly to the large load. Should the market rate become too high, a generation resource adequacy shortfall occurs, and/or should transmission congestion occur, the large load will switch all or a portion of its load to its own standby generation and self-generate until the market power rate, resource adequacy, and/or transmission congestion returns to an acceptable level. The large load's bid price could be capped not to exceed a certain rate and/or they could also be forced to curtail prior to any emergency actions by the RTO. These actions would reduce the effect the large load has on electric market prices. The advantage to the utility is this sort of demand response would not count against its reserve requirement, and the utility would not be required to develop any large facilities. This approach could be risky to the large load as market conditions can change over time and grid curtailments may increase, forcing the large load to rely on its own generation more often than expected.

2. Another model is having the large load develop its own generation. The generation output could be sold to the local utility and become part of the utility's generation fleet. Then the utility would deliver the power back to the large load at a special rate associated with the cost of power of the large load's generation. This arrangement will protect the utility from the financial risk of building the generation, protect its other customers from rate impacts caused by accommodating the large load, and protect the large load from market rate exposure as the special rate is tied to the cost of the large load's generation.

3. Another option is the large load building its own generation and serving itself either connected to the transmission system or isolated. If connected to the transmission system, the large load would likely prefer to rely on the utility for backup power. However, it is possible the utility would not be interested in providing backup power as it would be a huge financial risk to find capacity in the market on short notice to provide to the large load. Therefore, the large load would likely have to provide its own generation redundancy to meet its reliability requirements. Another disadvantage is that if the large load serves itself via a grid connection, it will have to account for all the rules of utility operation, territorial integrity, and electricity market participation. However, if the self-generated large load has excess generation capacity it may be interested in selling that power into the power market.

Large-Load Interconnection Process

Interconnection to the electric transmission network in North Dakota is controlled by either the SPP or MISO RTOs.

Normal long-term load growth with an in-service date beyond 2 or 3 years is handled through the model-building process and studied via the MISO MTEP or the SPP ITP.

The normal study process takes about 2 years from the load forecast and submittal task to the completion of the transmission studies. This is too long to accommodate loads that can be placed in service within that time. Therefore, there are separate processes that allow these sorts of interconnection requests to be processed in a timely manner.

The RTOs work with the local utilities to coordinate the analysis of each interconnection. The local utilities handle the interconnection agreements, which define the terms and conditions of the physical interconnection facilities.

SPP is working on several proposals to improve its large-load interconnection process. It has relaxed the requirement to use only SPP interconnection process-approved generation and instead allows a local utility to point to committed projects as proof of resource adequacy. This had been a roadblock for new load when the SPP GI queue had long delays. Also, MISO and SPP are working on concepts to streamline the approval of new generation if it is directly associated with a large-load project. This concept is called colocating. SPP is also soliciting comments regarding a conditional large-load interconnection process that would allow the large-load service to be contingent upon real-time system status and generation adequacy.

CONCLUSIONS AND RECOMMENDATIONS

This study assessed the economic and reliability impacts of large-load additions in North Dakota within the MISO and SPP footprints through market and reliability analyses. The 2029 and 2034 base cases were compared with multiple large-load scenarios, east, central, west, and east PS, to evaluate the effects of load growth on North Dakota system performance, transmission utilization, and congestion. Key findings, risks and uncertainties, along with recommendations and future study considerations, are summarized below.

Summary of Key Findings

- System Performance Under Base Conditions – The existing North Dakota transmission system demonstrates adequate performance under current conditions, with only a limited number of thermal and voltage violations observed in the base models.

- Impacts of Large Loads – When additional large-load scenarios (600–1400 MW) were introduced into the study models, the number of thermal and voltage violations increased significantly. Voltage issues were concentrated primarily on the 115-kV network, particularly in western North Dakota, where voltages dropped below TO criteria during N-1 contingencies.

- Thermal Overloads and Equipment Stress – Under large-load scenarios, 22–75 miles of transmission lines exceeded thermal limits during summer peaks and 75–198 miles during winter peaks. Four transformer overloads were also identified, indicating potential substation capacity constraints.

- Regional and Economic Sensitivities – The western portion of the state exhibited the greatest sensitivity to new industrial load growth. Large loads need to be added to the local utilities load forecast and uploaded into the RTO's planning database as quickly as possible. This will ensure the RTO's transmission upgrade process will capture the impact of the large loads and implement the required reinforcements. This process has already added hundreds of miles of 345-kV backbone transmission in North Dakota and avoided future congestion or curtailment risks. The potential for transmission investment underscores the need for coordinated planning to balance system reliability, economic growth, and ratepayer impacts.

- The addition of large loads without the addition of equivalent generation increased both congestion and LMPs. However, incorporating a price-sensitive load curtailment mechanism for these large loads helped alleviate congestion and reduced the resulting LMP impacts.

- The introduction of large loads consumed energy that was otherwise being curtailed as a result of transmission limitations on the NDEX interface. Consequently, thermal generation dispatch and renewable energy output increased to meet the additional demand.

Key Risks and Uncertainties

Several factors introduce uncertainty into both the reliability and economic outcomes of this study:

- Load Development Timing and Location – The pace, scale, and geographic concentration of new large-load developments remain uncertain. Variations in siting decisions could substantially alter local reliability impacts.

- Generation Mix and Dispatch Changes – The study maintained fixed generation dispatch and did not account for potential new interconnections, retirements, or resource shifts that could materially affect powerflow, congestion, and market prices.

- Transmission Project Timing – The analysis assumed completion of planned SPP and MISO transmission upgrades in the ITP2025 models. Project delays or deferrals would increase reliability risks in the near term.

- Market and Economic Dynamics – Future wholesale market conditions, congestion pricing, and cost recovery mechanisms will influence the economic feasibility of new infrastructure investments.

- Regulatory and Policy Evolution – Changes in interconnection procedures, permitting requirements, or environmental regulations could impact both timelines and design choices for new transmission facilities.

- Large-load curtailments during high LMP were shown to mitigate LMP price spikes. However, the curtailment price points were just samples. Large loads will need to coordinate with the local TO to determine optimal curtailment prices. The optimal curtailment price should help mitigate the impact on existing power market prices while providing sufficient reliability for the large load. The same curtailment data is needed for energy emergency situations or transmission reliability events.

Large load electrical characteristics – The large loads response during transmission network disturbances is not well known. This response includes high or low voltage and network frequency load trip settings.

Recommendations

- Targeted Transmission Reinforcements – Prioritize RTO-identified upgrades to the 115-kV and select 230-kV corridors in western and central North Dakota where large-load growth is most likely and voltage violations were most prevalent.

- Transformer and Substation Expansion – Address observed transformer overloads through proactive capacity expansion or parallel transformer installation at high-risk substations.

- Enhanced Coordination Within Industry – Coordinate enhanced research and analysis efforts related to gathering accurate data regarding the characteristics of large loads. This data should include electrical performance and market response data. Share this data amongst NDTA, PSC, utilities and RTOs (SPP and MISO) to help inform the existing planning process, align forecasts, model assumptions, large-load interconnection procedures, and project priorities across jurisdictions.

- Load-Siting Guidance for Developers – Encourage early engagement between large-load developers and utilities to align project siting with available capacity, minimizing the need for major network reinforcements and improving project feasibility.

- Integrated Planning of Generation and Transmission – Coordinate with upcoming RTO resource adequacy, generation expansion, and reliability studies to ensure that new generation and transmission upgrades are planned in tandem to maintain system resilience.

- Economic and Cost–Benefit Evaluation – Support the RTO's high-level cost–benefit assessment of candidate reinforcement projects to identify the most cost-effective reliability improvements and inform funding and policy decisions.

- Coordinate the large load's own reliability criteria with what the local TO can reasonably provide. Investigate the large load's ability to curtail during network transmission and/or generation constraints. If the large load has on-site backup generation capability, evaluate whether this resource can be utilized to offset exposure to high LMPs by self-generating power during periods of elevated prices.

- Support the RTO's and local utilties' power market impact studies of large-load additions. This is important as the pace of large-load additions is likely to exceed the pace of generation additions. This study showed that the addition of large load without corresponding generation additions and transmission reinforcements has the potential to raise power market prices through increases in congestion and energy costs.

FUTURE STUDY/NEXT STEPS

Future study considerations:

- Large-load electrical characteristics — Investigate the response of large loads under transmission system disturbances, including voltage and frequency trip settings. Examine market behavior to understand how large loads respond during transmission congestion and energy emergencies.

- Refined Load Forecasting – Update and refine the large-load forecast to reflect confirmed data center and industrial development timelines, ensuring realistic scenario modeling for future scenarios.

- Transmission Reinforcement Planning – Identify specific project options (e.g., reconductoring, transformer additions, or new transmission lines) to alleviate thermal and voltage violations under large-load scenarios and analyze those options for use in the RTO planning process.

- Integration with Resource Expansion Studies – Coordinate future RTO study analysis with ongoing generation and resource adequacy assessments and RTO generator interconnection planning to ensure that both supply and transmission infrastructure evolve in tandem to maintain reliability.

- Power Market Impact Studies – Support RTO and utility market economic analysis with additional large-load scenarios and the latest planning assumptions. Analyze impacts of generation additions and transmission reinforcements on power market prices through congestion and energy costs.

Follow-On Study –Leverage the analytical framework, datasets, and regional insights from this phase to extend the work in a consistent, data-driven manner, building on established methods, validated assumptions, and stakeholder input.