Annual Report - Resilience of the Electric Grid in North Dakota

September 1, 2023

North Dakota Transmission Authority

OVERVIEW

The North Dakota Transmission Authority (Authority) was created by the North Dakota Legislative Assembly in 2005 at the request of the North Dakota Industrial Commission. The Authority's mission is to facilitate the development of transmission infrastructure in North Dakota. The Authority was established to serve as a catalyst for new investment in transmission by facilitating, financing, developing and/or acquiring transmission to accommodate new lignite and wind energy development. The Authority is a builder of last resort, meaning private business has the first opportunity to invest in and/or build needed transmission.

STATUTORY AUTHORITY

By statute, the Authority membership is comprised of the members of the North Dakota Industrial Commission. Claire Vigesaa was appointed Executive Director of the Authority on July 28, 2023, to succeed John Weeda who was appointed Director of the Authority in February 2018. The Executive Director works closely with the Industrial Commission Administrative Office staff.

The second Annual Report on the status of the Resilience of the Electric Grid in North Dakota has been prepared as directed by the 67th legislative Assembly in Senate Bill No. 2313 and is being provided to the Legislative Council and North Dakota Industrial Commission with copies being sent to the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) and Minnkota Power Cooperative (MPC).

The resilience of the Electric Grid is dependent on the generation and transmission portion of the Grid working together seamlessly. This report explores the adequacy of generation and the ability of the transmission system to deliver the generation to location where it is in demand. The system must also be able to withstand adverse conditions from weather events and from equipment failures.

NORTH DAKOTA INDUSTRIAL COMMISSION

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Executive Summary

The electric grid is “transitioning” according to the popular description of those working to change the industry. It is becoming apparent that “transforming” would be a more descriptive term to use. The generating resources that the grid has depended on for decades are rapidly being phased out and technologies that do not have the same attributes are being added. The market designs are not incenting decisions that are important to sustain reliability in the process. During the past year those closest to the industry have raised the alarm that we cannot sustain the pace of change and still keep the grid reliable and resilient. Both the Federal Energy Reguatory Commission and the North American Electric Reliability Corporation have issued warnings about grid reliability

This report explores factors leading to this critical reliability situation. In addition to the grid “transition” leading to reliability concerns, the EPA has issued a series of proposed regulations this past year that would have a devastating impact on the dispatchable resources that the grid depends on for reliability.

Summary of Activities

Whether the issue is project development or legislative initiatives, the Authority is actively engaged in seeking ways to improve North Dakota’s energy export capabilities along with transmission capabilities within the state. To be successful Authority staff must understand the technical and political challenges associated with moving energy from generator to satisfied customer. The key elements of this report are to be a discussion of the adequacy of the grid to meet the demand of loads within North Dakota and for continued export of electricity from North

Dakota; the resilience of the State's Electricity Grid and the plans of generation owners, developers, or operators to add or remove generation assets connected to the grid.

This report has been compiled with outreach to transmission system owners and operators, both independent system operators of the transmission grid in North Dakota, potential developers, and generation owners. The Authority commissioned two separate studies during the past year to provide an independent evaluation of the resource adequacy of the grid, the historical performance of types of resources on the grid and the potential cost of keeping the grid supplied. In addition, the announcements from the ISOs, news articles, Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and other industry sources have been utilized to present the grid resilience review more completely in this report. The information in this report is from publicly available sources and from collaboration with the owners.

The desire for more information on the Electric Grid is a result of the occurrence of rolling outages of the SPP grid over portions of North Dakota in February 2021 and an abundance of grid alert events from both MISO and SPP. These alerts require utilities to operate conservatively and minimize the risk of unexpected events. In some cases, planned maintenance is postponed because it is important to keep the grid from experiencing an outage or reduction in service. All these factors point to a grid whose resources are stretched during peak demand times and adverse weather conditions.

The Generation Grid and Independent System Operators

The electric grid is a marvelous network that must work together flawlessly moment to moment. Electricity must be generated the moment it is needed or drawn from a storage device the moment it is needed. While some areas of the country are having a degree of success, storage devices have not matured to being widely deployed. Technology leaders are also promoting the idea that technologies such as grid forming inverters for inverter-based generation such as solar and wind will be valuable to the resiliency of the grid. The international literature search shows that some of these technologies are being deployed but have not demonstrated good commercial success. At this time there are no installations in North Dakota that we can reference. Another important grid stabilization technology is static VAR compensation. The first installation of this technology is scheduled in the next couple of years in the New Town area.

The controls for the grid manage the generation resources and balance the flow of electricity from source to demand in a manner that avoids overload and shortages. A failure on the grid (typically called a fault) must be dealt with immediately to prevent large portions of the grid to be affected. Adverse weather conditions such as winter storms Uri and Elliot have taken the grid to the brink and caused outages over wide areas in the country. Severe weather in the summer can also take out portions of the grid due to lighting, wind, and other factors. Summer is a time of high demand for much of the country and can push the limits of generation. The ISOs have also been finding

that the spring and fall, which historically have been times of lower demand, are also pushing the grid to its limits due to maintenance of generation resources and transmission lines. So, controls need be able to respond to those changes in real time and that has become more challenging in recent years with the transition of generating resources.

The generation grid in North Dakota is managed by two Independent System Operators. They are Midcontinent Independent System Operator (MISO) located in Carmel, Indiana. The other is the Southwest Power Pool (SPP) located in Little Rock, Arkansas. These systems both operate the transmission grid in their area of responsibility, they conduct market operations to select the lowest cost and operationally appropriate generating units to serve the grid each day. They monitor the grid continuously and make adjustments to correct the day ahead planning to the reality of the day. Since there is very little available option to store electricity, these operations must match the generation with the demand continually.

Midcontinental Independent System Operator (MISO)

All the utilities in North Dakota with the exception of Western Area Power Administration (WAPA) and Basin Electric Power Cooperative (BEPC) and their members are members of MISO. Since the service territory of many of those utilities intermingle with areas served by BEPC, the territory of MISO and SPP are likewise mingled.

While MISO continues to operate the transmission grid for North Dakota in a safe and reliable manner, the grid is showing signs of needing improvement in several ways. One easy indicator of sufficient capacity of the grid is to look at the real time market data (LMP) which demonstrate what electricity is selling for at nodes through-out the MISO system. It is very common to see major price differences between the ND price and prices in Illinois, Indiana, Michigan, and other states in that region. The difference is most apparent on days when demand is higher than average for heating or cooling. A price factor of 2 to 3 to 10 times is not uncommon. It is often driven by the fact that there is more electricity generation available to be exported from North Dakota than the transmission capacity can transport to demand outside of North Dakota.

The NERC seasonal capacity assessments and the 5-year capacity assessment both point to MISO reliability being at risk. One of the risk factors that is rising in importance is fuel supply. Hydro, Nuclear and Coal all have fuel reserves that are known and predictable. The experience of the recent winters has revealed a need for improvement of natural gas supply for generations.

The summer 2023 assessment below rates over 2/3 of the US at elevated risk as well as Ontario in Canada.

Southwest Power Pool (SPP)

Western Area Power Administration (WAPA), Basin Electric Power Cooperative (BEPC) and several of their member systems are direct members of the Southwest Power Pool (SPP). All customers and member systems (of WAPA & Basin) are ultimately participants in SPP through WAPA and BEPC's membership. Basin Electric Power Cooperative (BEPC) is in the process of making substantial investments in western ND to strengthen their 345 kV transmission system. A new line from near Killdeer, ND north to the Johnson Corner will increase the reliability of service to the very active area of the Bakken oil field. A new line from Leland Olds Station near Stanton, ND to a substation near Tioga ND will provide a 345 kV loop to increase reliability of service to the entire Bakken oil field.

BEPC will also be working with Sask Power to build two 230 kV lines from the BEPC system in NW North Dakota into the southern part of Saskatchewan. Those lines will be used for export to Canada with potential of power flowing into ND at times.

SPP has collaborated with MISO in the JTIQ study to identify mutually beneficial transmission development at the SEAMS. A JTIQ project from near West Fargo, ND to near Bigstone, SD is expected to provide generation interconnect capability to the SE part of ND.

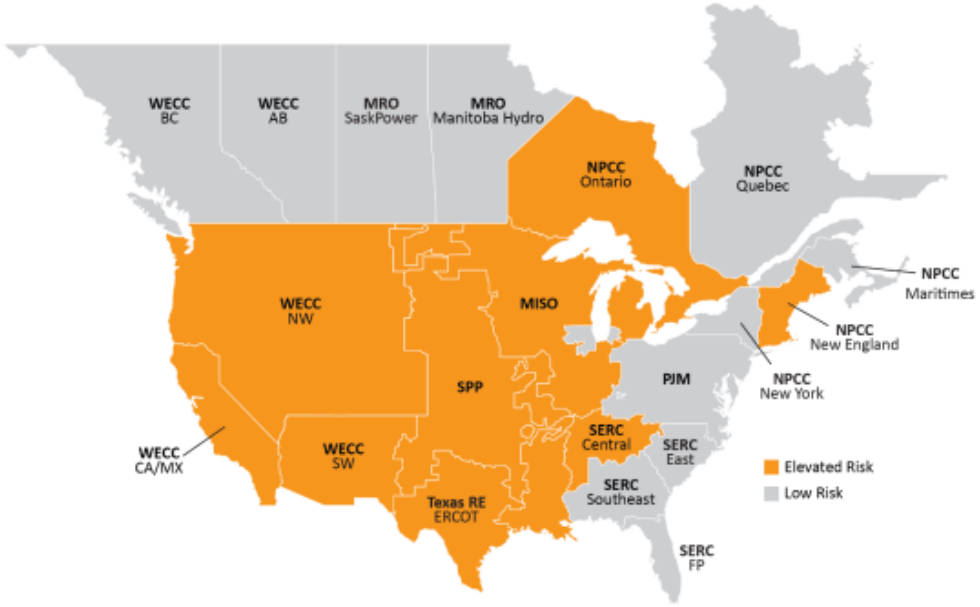
All new projects in SPP are subject to curtailment (forced to reduce production) through the dispatch agreement. This curtailment will have a negative impact on payback of the investment on virtually any type of generation resource.

Like other Regional Transmission Organizations, SPP has increased staff resources focused on reliability and system resilience. SPP has several member groups/staff reviewing data/trends and working on new policies/procedures to address reliability and resiliency issues. The groups include:

- Operating Reliability Working Group
- Ambient Adjusted Ratings Implementation Committee
- System Operating Limits Task Force
- Supply Adequacy Working Group
- Reliability Compliance Advisory Group

NERC reliability risk assessment

Summer Reliability Risk Area Summary



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

The 2022-2023 assessment showed several areas of the country at risk and New England are at risk for natural gas supply. The actual experience was that natural gas generation did not show up in the real time generation during winter storm Elliot across a much broader area of the eastern US.

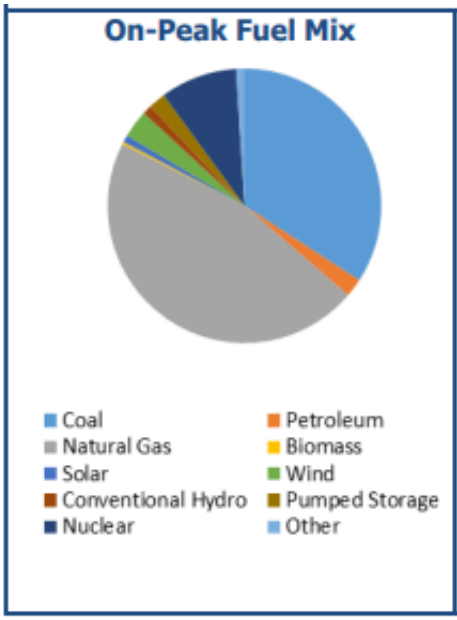
Winter Reliability Risk Area Summary

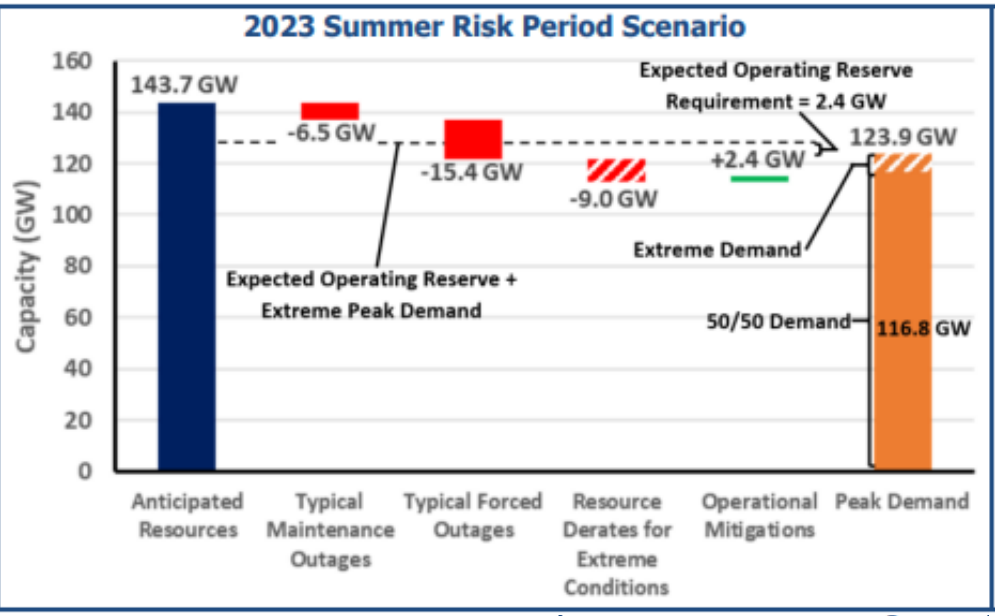
Highlights

- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

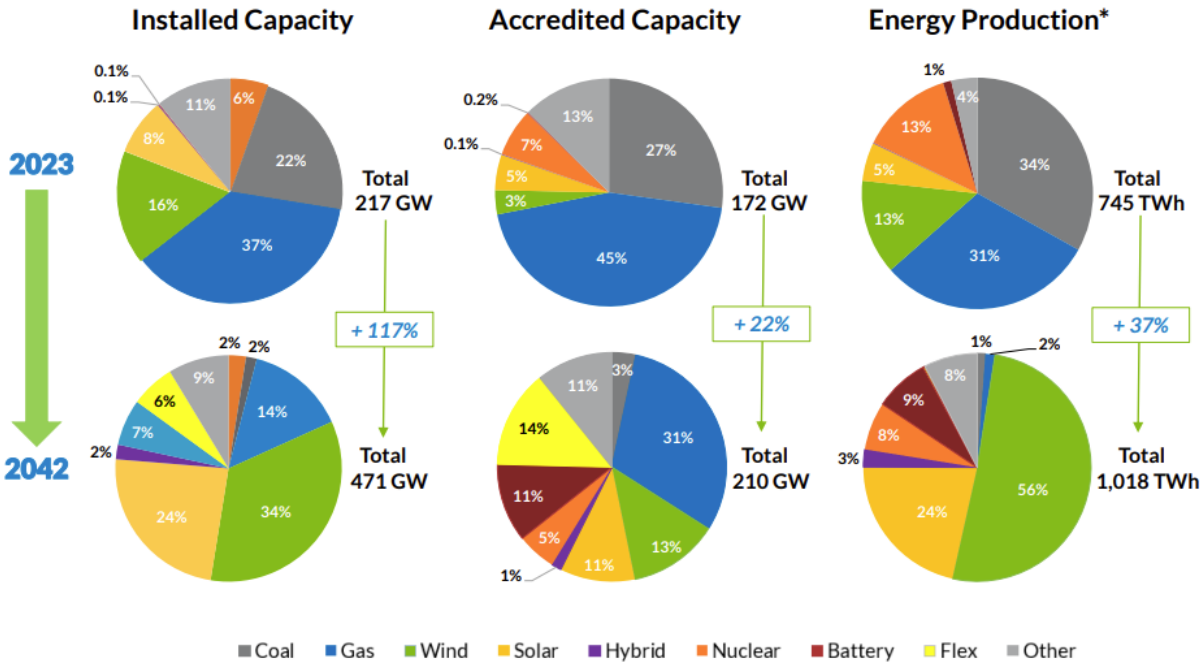




MISO Internal Assessment

MISO internal assessment of resources and demand is shown in the graphic below. The projections are for major loss of coal generation capacity being replaced by wind and solar with some natural gas. The graphic also shows their projected demand increase from 2023 to 2042.

MISO's Future 2A anticipates significant resource additions, retirements and load growth with a trend towards increasing renewables



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*Data updated July 10, 2023. Futures do not account for all operational-level reliability needs and attributes that may require different levels of resources. Resource additions may be subject to adjustment based on new accreditation rules. "Other" includes biomass, geothermal, hydro, oil, pumped hydro, demand response, and non-pv distributed generation (and energy efficiency for installed capacity). *Pie chart is greater than 100% due to energy storage charging and discharging.*

MISO

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

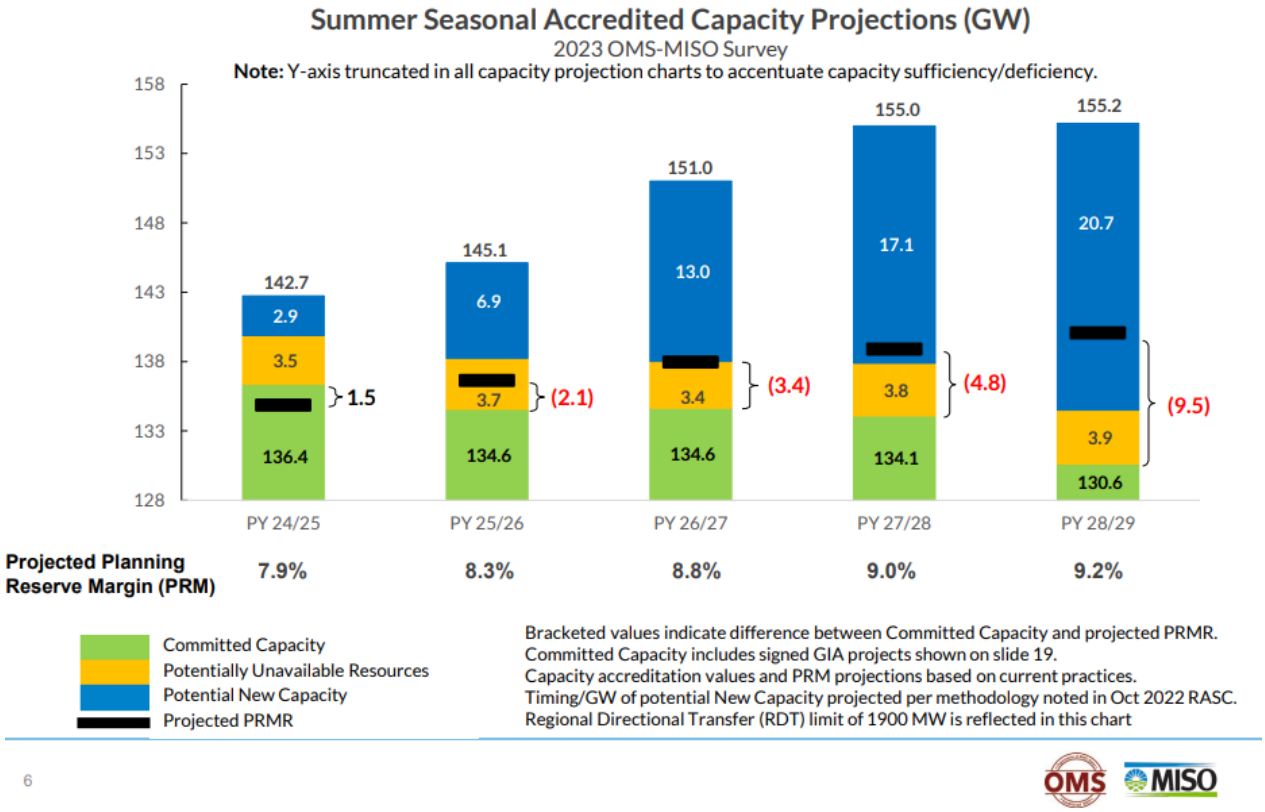
Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

The graphic below shows the MISO system becoming short of generating resources as soon as the 25/26 planning year. Each progressive graphic shows that gap growing to 9.5GW of capacity by 28/29 planning year.

Committed Capacity shows declines over survey window with potential resource deficits starting in PY 2025/26



The cost that developers are assessed to get an interconnection agreement is another measure of transmission capacity limitations. Those costs that come from the transmission studies have increased dramatically in recent years. Even though those interconnection costs are increasing,

they do not include evaluation of the need or cost of adding transmission that will relieve the congestion caused by adding resources to the grid.

MISO does have a Long-Range Transmission Planning (LRTP) approved in July of 2022. Ottertail Power Company and Montana Dakota Utilities are moving forward with the line approved from Ellendale to Jamestown, ND. It will have a beneficial impact on the ability to export power from ND, however, permitting and construction of those lines will likely take at least 5 years. Additional lines in South Dakota and Minnesota were also approved and are key to increasing the export capacity from North Dakota. The cost allocation method that has been chosen to pay for those additional lines is primarily to load which means that all loads in the area including North Dakota will have higher rates to pay that tariff.

Southwest Power Pool (SPP) Internal Assessment

In the graphics above in the NERC section you can see that the NERC assessment shows SPP at elevated risk of outage in the summer 2023, they have not been identified as at elevated risk of outages for the winter of 22/23. Despite that, SPP is very clear that now is the time to act on future resources as they see the system risk increasing as resources retire. They are calling for retirement delays and a focus on what resources will be needed in the future.

The table below shows the system wide projections as well as the Basin Electric portion which is indicative of North Dakota.

DEMAND PROJECTIONS

SPP Footprint

Reliability Peak Load (MW)		
2025	2028	2033
59,739	62,239	65,181

Future 1 Annual Energy (GWh)		
2025	2028	2033
308,159	326,883	348,747

Future 2 Annual Energy (GWh)		
2025	2028	2033
307,029	325,939	348,901

Basin Electric (SPP only)

Reliability Peak Load (MW)		
2025	2028	2033
5,765	6,122	6,855
9.65%	9.83%	10.52%
% of Total SPP Peak Load		

Future 1 Annual Energy (GWh)		
2025	2028	2033
39,382	42,199	47,746
77.98%	78.68%	79.51%
Annual Load Factor (%)		

Future 2 Annual Energy (GWh)		
2025	2028	2033
39,382	42,218	47,885
77.98%	78.72%	79.74%

Reliability Peak: Total of peak hour amount (Non-Coincident Peak)
Hourly Energy: Annual energy amount for SPP footprint

MW: Megawatt
GWh: Gigawatt-hour (GWh) is 1,000 MWh

Independent analysis of SPP and MISO grid resilience

NDTA commissioned and independent studies of Forecasting Resource Adequacy in the Southwest Power Pool through 2035. The study utilized historical data to analyze 4 years of actual generation to forecast what resources can be expected to show up during peak demand times. This method is called Highest Certainty Deliverability (HCD). The report data shows that this method of analyzing what accreditation values points to the current methods of resource accreditation being more favorable toward wind and solar resources than the HCD analysis. This presents the question of whether there will be adequate resources available to supply peak demand at a time when demand is high and weather conditions are unfavorable.

The second important piece of the work is to analyze the impact that EPA proposed rules will have on resilience of the generation grid. The graphics on this impact are very dramatic when applying logical assumptions on which generating resources will shut down rather than make huge expenditures to comply with these rules. This graphic shows SPP becoming weather dependent to meet peak by 2026 and by the end of the decade to be weather dependent for over one third of peak demand. SPP and many others have realized that this is not a scenario that we can depend on.

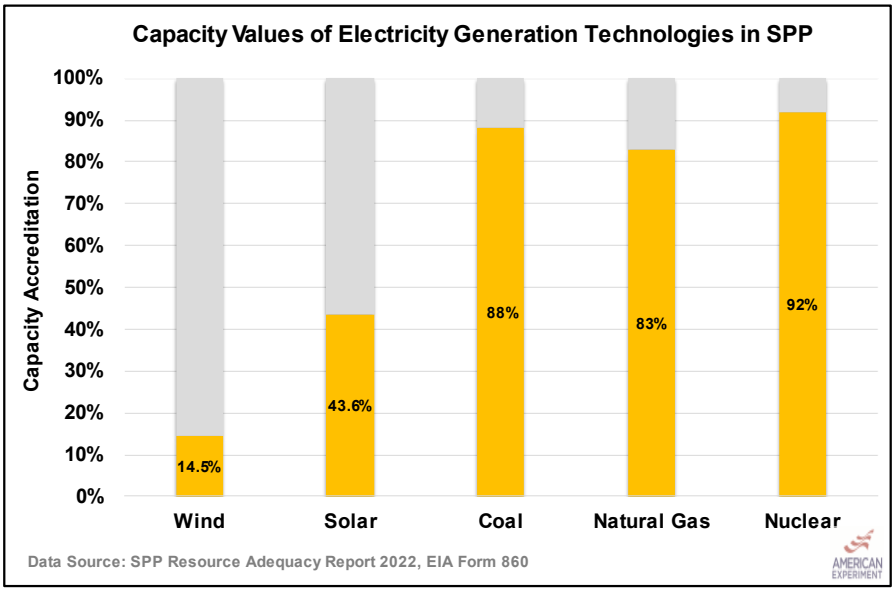
The full report also analyzes the cost of building resources to comply with the EPA proposed regulations. In summary, the cost is projected to be in the hundreds of billions of dollars.

These concerns come at a time when SPP is already concerned about meeting demand under the current mix of renewable and dispatchable generation. MISO has also been expressing concern about resource adequacy and has a committee addressing how to address that challenge.

The full report is available on the North Dakota Industrial Commission Web site. A few of the key graphics are included below.

SPP's 2022 Capacity Accreditation by Resource

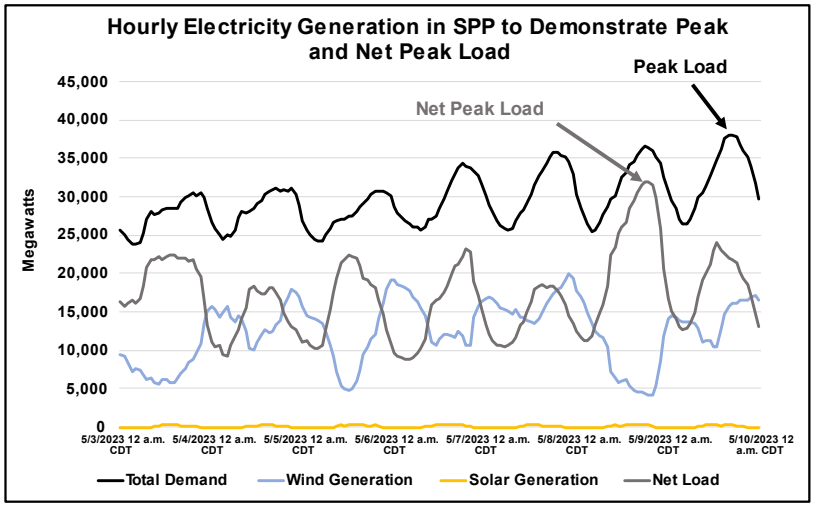
- Technologies are given different accreditation values based on their reliability during times of peak electricity demand.
- Nuclear, coal, and natural gas get the highest accreditation values.
- Wind and solar get much lower accreditation values.



Methodology- Developing a Standardized Capacity Accreditation for Renewable Resources

Assess wind and solar variability during peak load and net peak load hours

- **Peak Load:** The hours with the highest electricity demand.
- **Net peak load:** Gross demand minus wind and solar generation, which allows us to assess the highest demand hours where wind and solar output is the lowest. This is the standard new wind and solar resources should be judged by going forward.



Methodology- Developing a Standardized Capacity Accreditation for Renewable Resources

- Used the last 4 years of data from EIA Hourly Grid Monitor and Form 923. Peak and net peak occurred on July 19, 2022, and August 6, 2019, respectively.
- Highest Certainty Deliverability (HCD) to assess wind and solar accreditation.
  - Sample size of 2,000 hours for wind & solar of the highest peak & net peak hours across 4 years.
  - Took the mean of the lowest 25 percent of wind and solar output during those hours to come up with our accredited capacity values for peak and net peak.
- Using this methodology, we developed peak capacity and net peak capacity values for wind and solar.

	Peak Accreditation	Net Peak Accreditation
Wind	11.8%	7.5%
Solar	16.4%	20.4%

How does the ND Study's HCD Approach Differ from SPP's Proposed New Seasonal ELCC Approach?

- HCD peak accreditation values for wind and solar are consistent with SPP's ELCC values (summer and winter for wind, winter for solar).
- HCD net peak accreditation values for wind and solar are lower than SPP's ELCC values.

<u>HCD approach is valuable for a few reasons</u>:

- As more wind & solar are added to the grid, net peak will become more challenging than peak load demand.
- HCD manages the downside of wind & solar at net peak compared to ELCC and is more empirical than the options MISO is considering as they move away from ELCC to a Direct-LOL accreditation approach.

SPP APPROACH

Table 1. Summer Wind ELCC Tier Result

2022 Allocated ELCC Summer Wind by Tier (MW)			
	TIER 1	TIER 2	TIER 3
Tier ELCC (MW)	2,952	404	1,978
Tier Nameplate (MW)	13,211	2,808	16,448
Tier ELCC (%)	22%	14%	12%

Table 2. Winter Wind ELCC Tier Result

2022 Allocated ELCC Winter Wind by Tier (MW)			
	TIER 1	TIER 2	TIER 3
Tier ELCC (MW)	2,949	654	2,083
Tier Nameplate (MW)	11,745	4,274	16,448
Tier ELCC (%)	25%	15%	13%

Table 3. Summer Solar ELCC Tier Result

2022 Summer ELCC Solar			
	TIER 1	TIER 2	TIER 3
Tier ELCC (MW)	181	0	202
Tier Nameplate (MW)	235	0	327
Tier ELCC (%)	77%	0%	62%

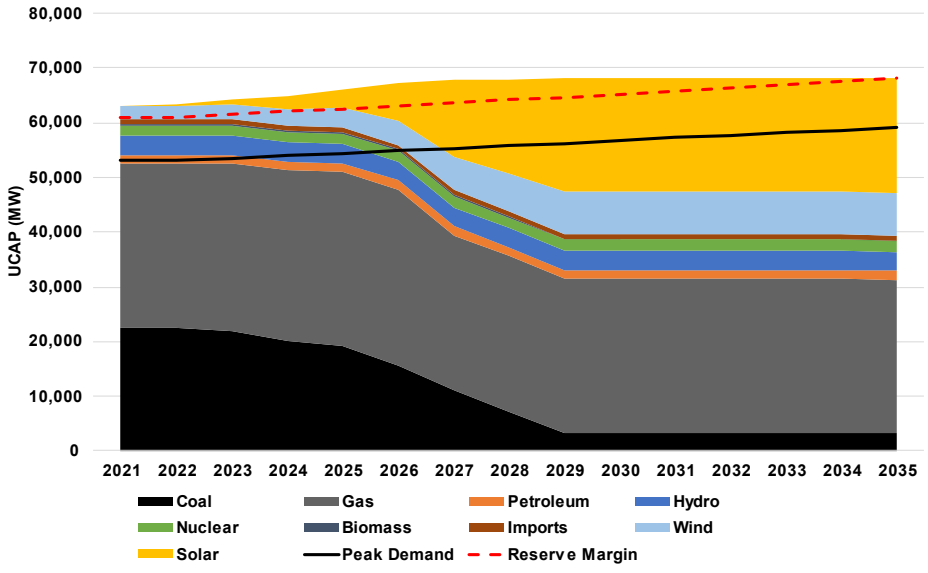
Table 4. Winter Solar ELCC Tier Result

2022 ELCC Winter Solar			
	TIER 1	TIER 2	TIER 3
Tier ELCC (MW)	87	0	86
Tier Nameplate (MW)	235	0	327
Tier ELCC (%)	37%	0%	26%

HCD ALTERNATIVE APPROACH

Highest Certainty Deliverability	Peak Accreditation	Net Peak Accreditation
Wind	11.8%	7.5%
Solar	16.4%	20.4%
Reserve Margin	12.0%	12.0%

OTR & CCR Scenario: Capacity Shortfall Risk



Year	Reserve Margin
2022	19%
2023	20%
2024	20%
2025	21%
2026	22%
2027	21%
2028	20%
2029	19%
2030	18%
2031	18%
2032	17%
2033	16%
2034	16%
2035	15%

Estimated firm capacity using net peak load capacity accreditation values for wind (7.5%) and solar (20.4%), 92% for nuclear, 88% for coal, 83% for natural gas, and 90% for other thermal generators. Under this scenario, SPP is dependent on intermittent resources to meet peak load by 2026.

Conclusions

1. **Our findings represent a best-case scenario for reliability due to our HCD accreditation standard.**

2. **Different standards, such as seasonal accreditation ELCC being explored by SPP, will produce varying levels of reliability that must be examined in light of these results.**

3. **Costs were relatively modest due to the large amount of thermal capacity remaining on the SPP system through 2035, but costs increase substantially as more thermal retirements occur and Load Responsible Entities (LREs) attempt to replace this lost generation with wind, solar, and battery storage.**

4. **Policymakers must understand the challenges regarding reliability, resiliency and affordability that are growing every year.**

Recommendations

Policy Recommendations in Light of Findings of the Study:

1. **PAUSE RETIREMENTS:** The timeline of coal and natural gas retirements in SPP, even in the reference case, is too short for replacement capacity to come online.
2. **STUDY THE IMPACT OF THE MERCURY AND AIR TOXICS STANDARDS:** EPA's MATS rule could force the closure of lignite -fired generators, posing large regional risks to SPP and MISO.
3. **ANCHOR ACCREDITATION TO FORESEEABLE WEATHER RISKS:** Even if wind and solar resources are built in time, there is still a chance that they may be performing under SPP's and our updated accredited values, meaning capacity shortfalls may still present challenges to grid operators. This is because at any given time, wind and solar may be producing no electricity at all.
    - SPP should have the same reliability standards for wind and solar as it does dispatchable energy sources like coal, natural gas, and nuclear, meaning it would require wind and solar to meet capacity obligations 7/8 ^{ths} of all peak hours of the year, which is a standard dispatchable units meet or exceed. Our method of accreditation – the Highest Certainty Deliverability – can better assess wind and solar reliability based on this standard.
    - Ultimately, the goal is to appropriately measure and price the variability of wind and solar, instead of foisting the costs of that variability on the entire system.

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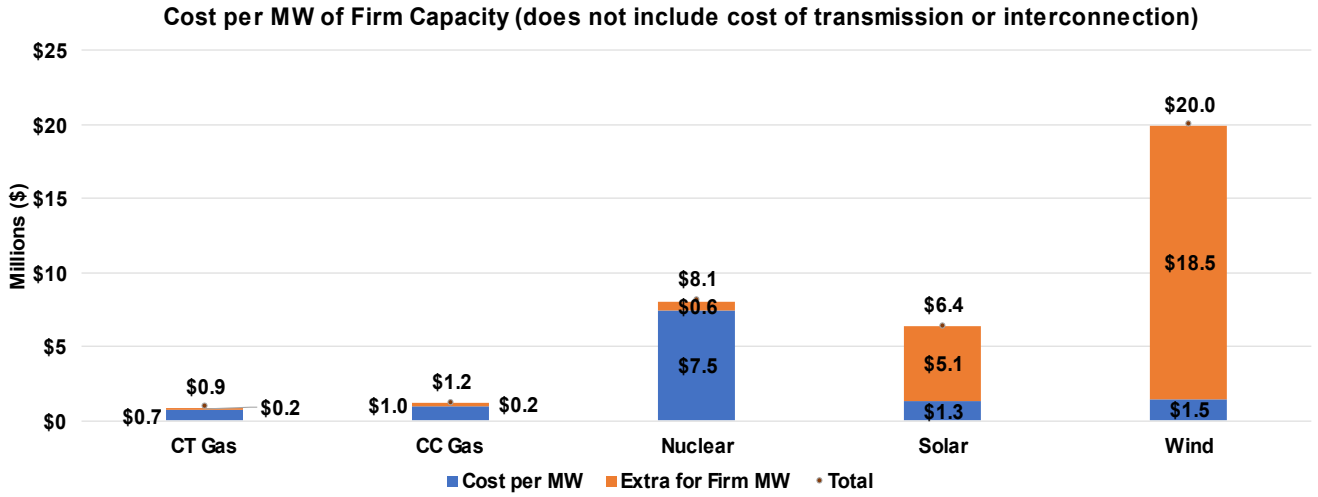
Recommendations (*continued*)

4. LOOK BEYOND LCOE: Make clear that capital cost per MW installed of wind and solar is vastly different than capital cost per FIRM MW installed of wind and solar. Example below:



The cost per firm MW of capacity for wind and solar are based on net peak HCD values of 7.5% and 20.4%, respectively. These values will decline as more wind and solar are connected to the grid, and thus the cost per firm MW will increase.

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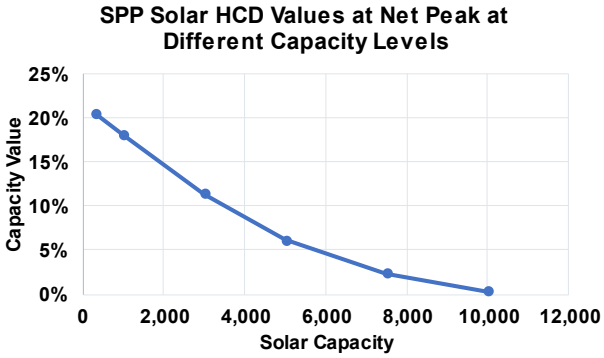
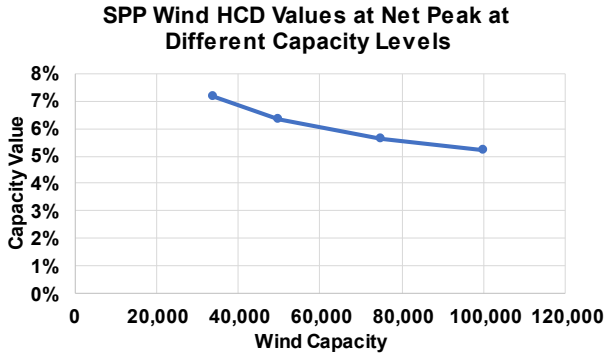
Recommendations (*continued*)

5. Change HCD Accreditation to reflect rising penetrations wind and solar: Solar's ability to help meet net peak load diminishes greatly over time because its hours of generation are constrained by daylight. Wind's ability to help meet net peak load diminishes less than solar because wind generation can occur at any time.





a. Wind values assume 10,000 MWs of solar capacity on the system.

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Recommendations (*continued*)

6. Investigate capacity values for battery storage resources: Regional transmission organizations are currently trying to develop capacity accreditation metrics for storage. These capacity values should take into account the reliability of the electric system that would be responsible for charging the batteries.

SPP is considering seasonal capacity accreditation metrics for storage based on market penetration and storage duration.

Table 3: Summer ELCC Accreditation of 4-hour, 6-hour, and 8-hour ESR

Duration \ Capacity	1,000 MW	3,000 MW	5,000 MW
4-hour	100%	96%	84%
6-hour	100%	98%	95%
8-hour	100%	97%	96%

Table 4: Winter ELCC Accreditation of 4-hour, 6-hour, and 8-hour ESR

Duration \ Capacity	1,000 MW	3,000 MW	5,000 MW
4-hour	83%	71%	51%
6-hour	83%	79%	58%
8-hour	89%	82%	61%

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Congestion (putting too much generation into the transmission system) has also been a growing problem on the SPP system. SPP does not evaluate congestion during the generation interconnect queue process so there is little means of monitoring the impact of congestion other than through the transmission planning process. That has been lagging the actual congestion. The following graph illustrates the growth of too much power being put into the transmission system (congestion). As a result, the ISO shuts down some wind generation (curtailments). Since wind generation produces a tax credit when generating this over-generation also causes negative pricing (producers pay to put power on the transmission system). While these are SPP wide illustrations both are applicable to the North Dakota portion of the grid also.

Independent Analysis of MISO Grid Resilience

Determining Resource Mix

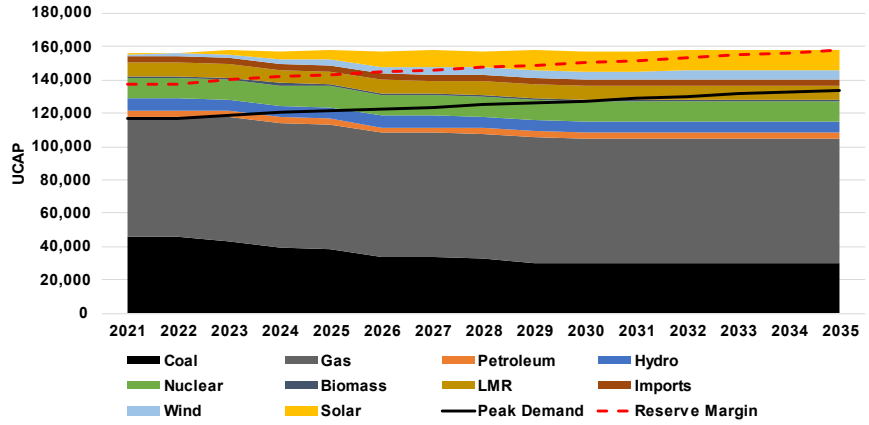
The ISOs are responsible for the reliability of the grid, but they state very clearly that they are fuel agnostic and do not dictate the choice of generation resources attached to the grid. That is defined as a state responsibility. The role of the ISOs is to have market designs and tariffs that encourage the right mix of resources. Both MISO and SPP are in the process of changing the market designs to provide more financial incentives to keep dispatchable resources on the grid to facilitate a more predictable and manageable transition of the grid without compromising reliability.

NDTA commissioned a study of the MISO grid to have an independent evaluation of the resource adequacy. The study started with a review of actual data over four years of generation showing

up for the peak demand days. This was evaluated on a "net peak" demand basis which is a recognized approach to looking at what is needed to meet demand above and beyond the renewable generation in operation.

The other factor that is facing the grid is the impact of proposed EPA regulations on the resources on the grid. The results are presented with the current business plans of retirements and additions and the projected impact of retirements driven by the proposed EPA regulations. The graphics below present the key points of the studies that NDTA commissioned be performed by the Center for the American Experiment.

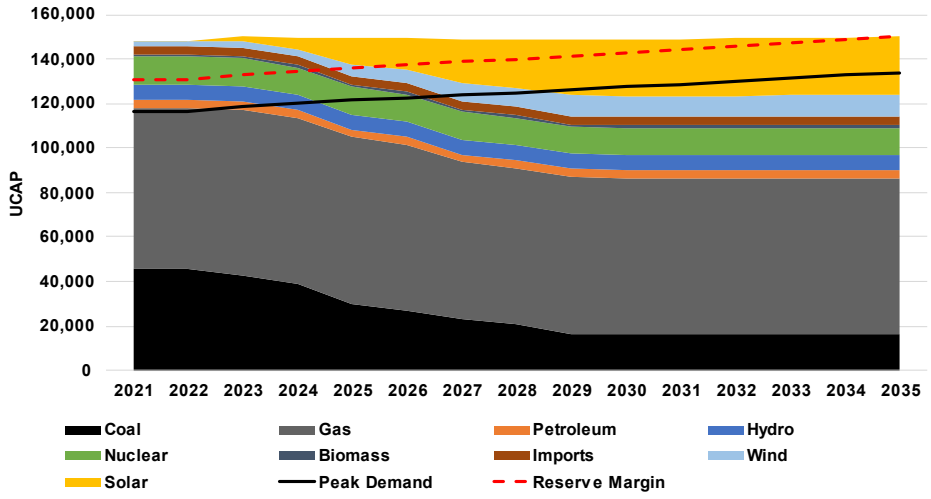
Even With No EPA impact
MISO Relying Upon Weather & Imports for Reserve



Estimated firm capacity using net peak load capacity accreditation values for wind (5.8%) and solar (12%), 95% for nuclear, and 90% for other thermal generators. Different than MISO cleared UCAP (unforced [accredited] capacity).

Year	Reserve Margin
2022	34%
2023	32%
2024	30%
2025	30%
2026	28%
2027	**27%**
2028	**26%**
2029	**25%**
2030	**23%**
2031	**22%**
2032	**21%**
2033	**20%**
2034	**19%**
2035	**18%**[3]

MISO OTR + CCR Scenario: Capacity Shortfall Risk



Year	Reserve Margin
2022	34%
2023	33%
2024	31%
2025	**30%**
2026	**28%**
2027	**27%**
2028	**25%**
2029	**24%**
2030	**23%**
2031	**22%**
2032	**21%**
2033	**20%**
2034	**19%**
2035	**18%**

Estimated firm capacity using net peak load capacity accreditation values for wind (5.8%) and solar (12%), 95% for nuclear, and 90% for other thermal generators. Different than MISO cleared UCAP (unforced [accredited] capacity). Under this scenario, MISO would be dependent on intermittent resources to meet peak load.

Additional details for the study are available on the North Dakota Industrial Commission web site where the full report is available. The full study includes discussion of the methodology, the assumptions used, and the conclusions reached. The data there is similar to the information included above for the SPP study but based on MISO modeling.

When you review resources shown in the colors on the graphs against the peak demand plus margin shown by the dotted lines, weather dependent resources are required to meet peak demand beginning right now and getting increasingly more dependent in the near-term future. If the wind is blowing and the sun is shining, we will make it through without notice. On the other hand, if the weather is adverse, the ISOs will be short of meeting peak demand. Comparing the reference scenarios to the scenarios with the impact of the EPA proposed regulations the weather dependency becomes a major resiliency concern quickly. That is not a risk that should be accepted. A solution must be found. Even though North Dakota generating resources are less impacted, as part of the ISOs we will be expected to bear our share of keeping the lights on throughout the ISOs.

The other factor that has been apparent in both winter storm Elliot and winter storm Uri is the number of megawatts of dispatchable generation that did not show up in the market as expected. A substantial percentage of that was due to problems with the gas supply to the units. Supply was impacted by physical limitations in the gas supply and in some cases by contractual limitations. The coordination of the gas and electricity market has been identified as a contributing factor.

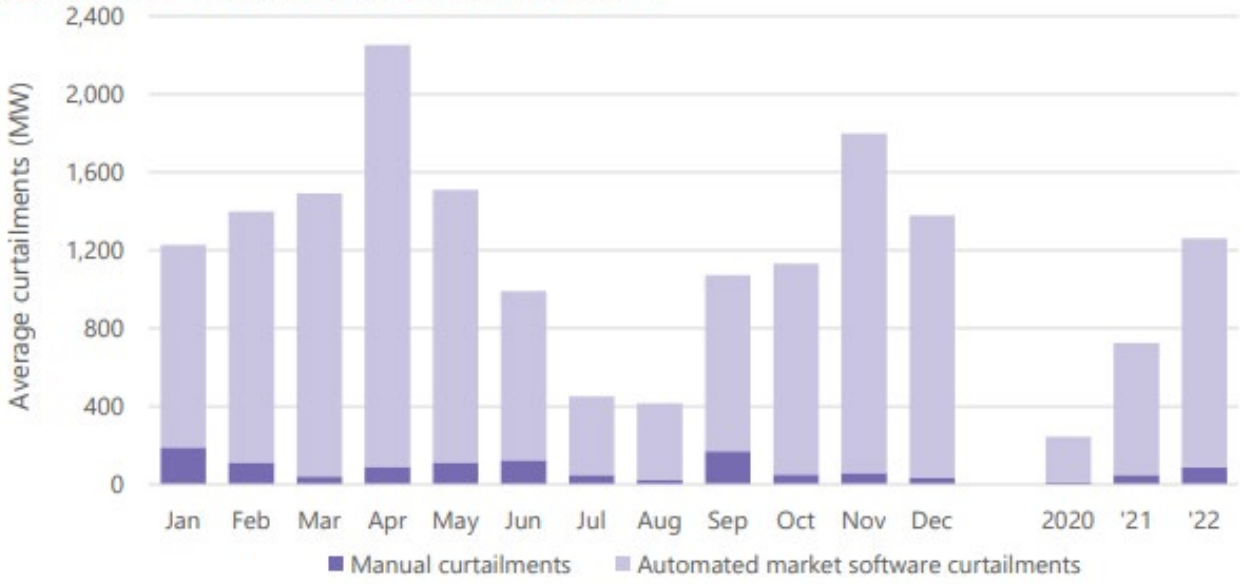
Some of the units did not show up due to the failure of the units to perform in cold weather. NERC and issued regulations know at EOP-11 and EOP-12 that require utilities to take measures to increase availability and reduce unexpected cold weather operational issues.

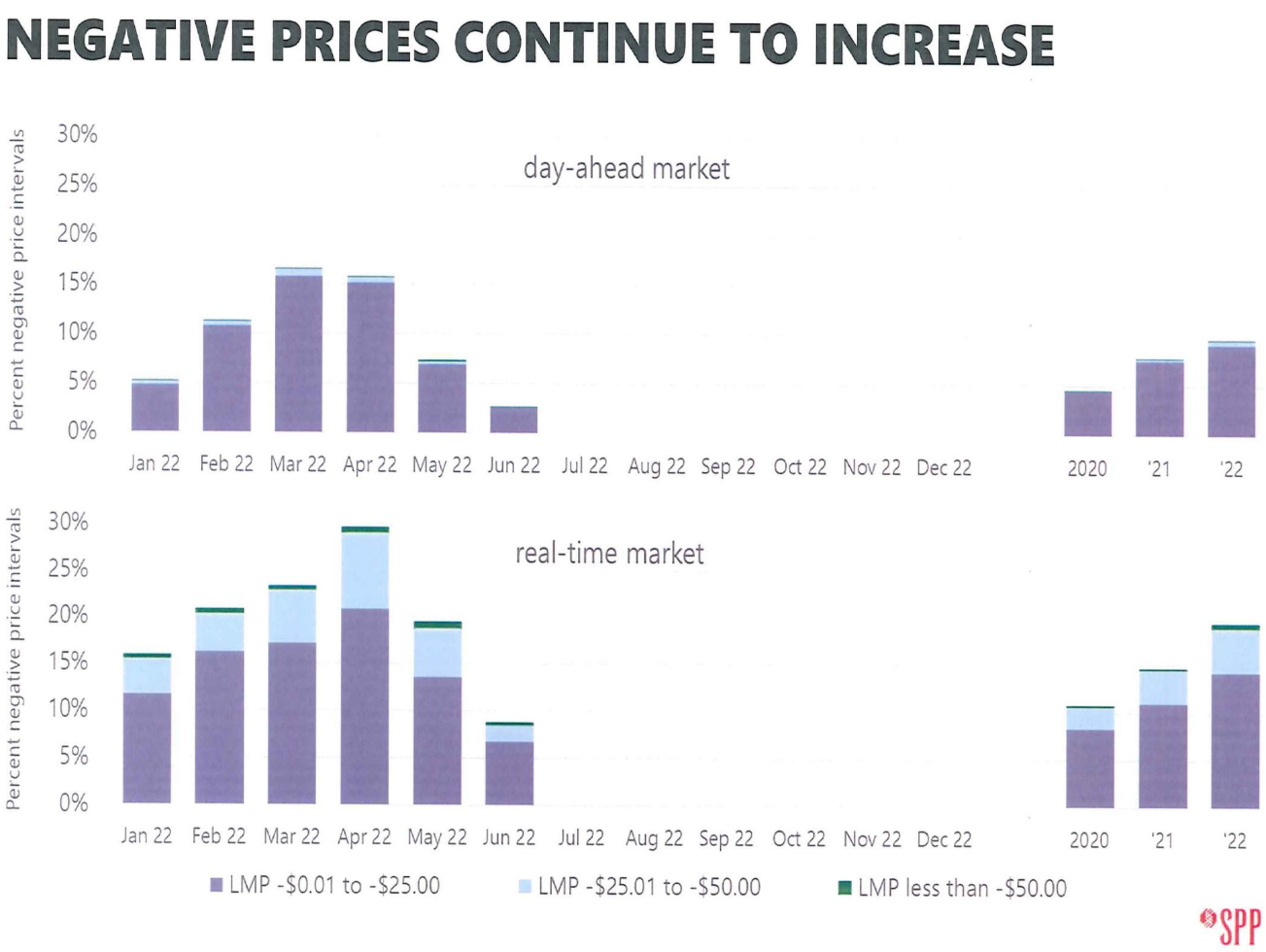
These weather-related problems have had very little impact on generation within North Dakota but can affect North Dakota through the power pools if an overall shortage occurs again.

Market impacts

The market prices are a indicator of the health of the grid. The graphic below shows that negative prices continue to increase. This is one metric to determine the adquacy of the transmission grid to get energy from the generator to market and it is an indicator of the mix of generation on the grid. Negative pricing only works for generating resources that have a subsidy. Currently wind and solar can offer into the market at a negative price. Most other forms of generation need to offer into the market at a price that covers their variable cost. The current market prices electrons at the same price, with adjustments for location, ancillary services, etc. This picture of the market is causing the ISOs to rethink the market matrics in an effort to reward dispatchable generation enough to keep them in business. Negative prices are not good for the business and curtailments impact the investors ability to make a return on their investment.

Figure 2–32 Curtailments for wind resources





The Current Generation Resources in North Dakota

Renewable generation - North Dakota has 4330 MW of wind generation in service based on EIA data for 2022. 16,571 MWh of electricity was produced from wind generation in 2022. That amount of electricity generated from that total capacity gives an average capacity of 43%. A capacity factor of 43% is higher than average in the country.

Solar generation
North Dakota does not currently have any utility scale generation facilities in service, although some are in the MISO and SPP queues.

Thermal coal generation

North Dakota currently has thermal coal generation in service at six locations. These sites include a total of 10 generating units. The combined capacity of the units is approximately 4,048 MW. The capacity factors for 2021 ranged from 65% to 91%.

Project Tundra is continuing at the Milton R Young Station with a decision expected in early 2024 on constructing a carbon capture system for that station.

Rainbow Energy closed on a transaction to buy the Coal Creek Station and the DC transmission line on May 1, 2022. They have continued the operation of the plant in a similar manner. They are moving forward with the CO2 capture assessment that was started by Great River Energy and expect to complete that study in early 2024. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity that will be available on the Nexus DC line.

Both carbon capture projects are visualized as important to preserving the life of those plants and increasing their market appeal to satisfy the desire to have low carbon electricity. The loss of approximately 30% of the plant capacity to operate the carbon capture system will be a loss of base load generation available to the grid and will have an impact on resilience. The net effect, however, of keeping the plants operating vs. a shutdown due to market pricing or carbon regulation will be a positive to the grid resiliency.

Hydro generation

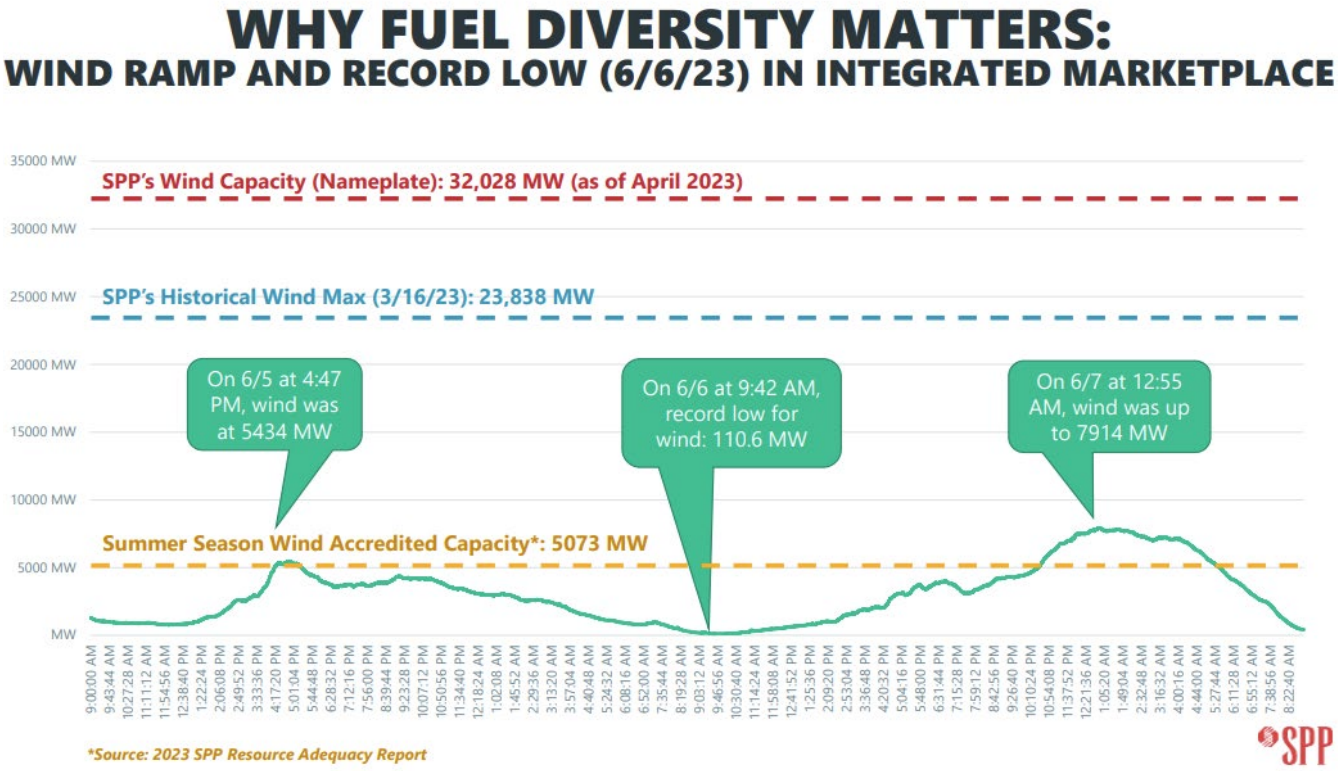
North Dakota has one hydro generation site containing 5 units with a total capacity of 583 MW. The average capacity factor declined and in 2021 was approximately 43%. Volume of water flowing in the river has been a limiting factor in hydro generation during drought years.

Natural gas generation

North Dakota has three sites for electric generation utilizing natural gas. These three sites contain 21 generating units with total capacity of 596.3 MW. These units include reciprocating engines and gas turbines. Total generation in ND using natural gas for 2021 was 1.445 GWhr. This amount has been steady for 2019 thru 2021.

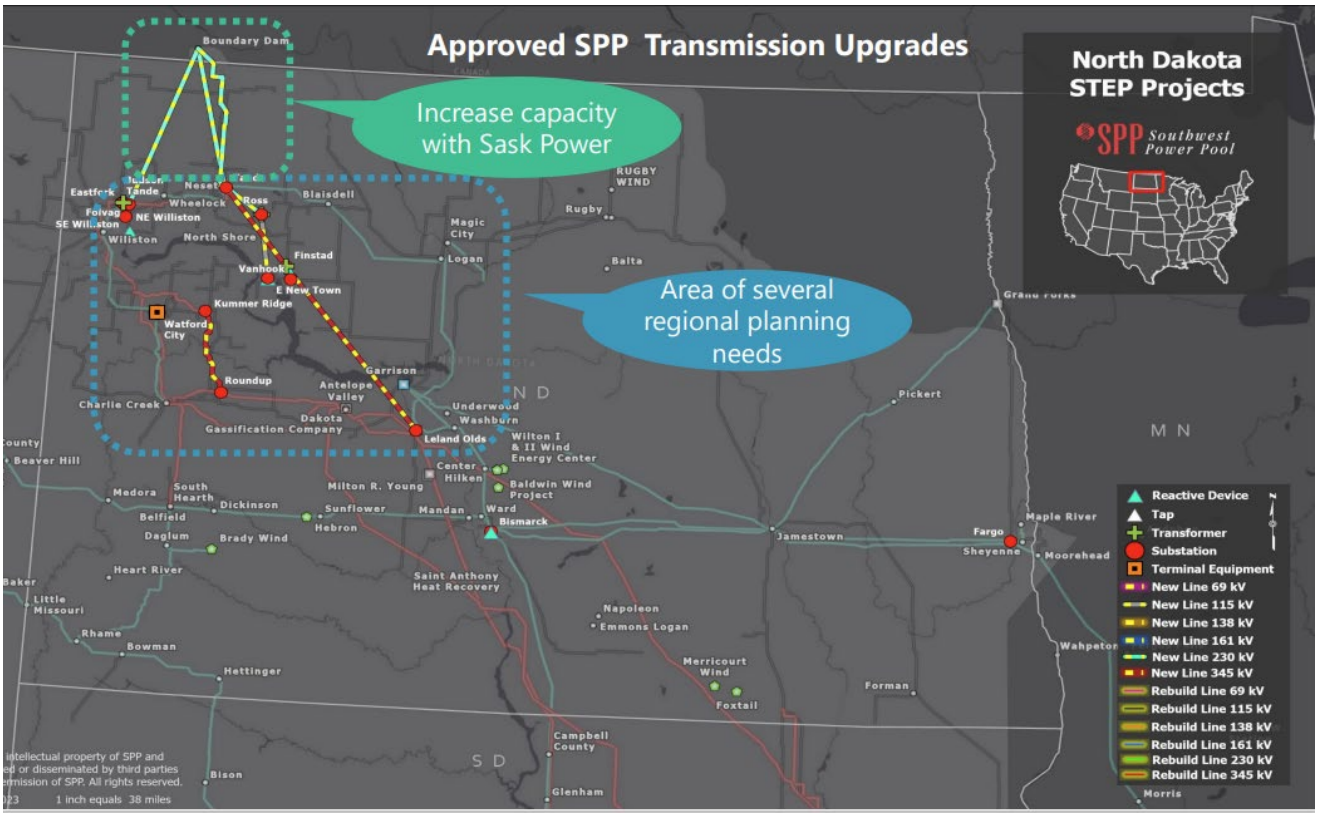
Total Generation

The combined total of all types of utility scale generation is approximately 9508 MW. The 4,250 MW of wind generation receives a reduced capacity accreditation in the ISO since it is intermittent.

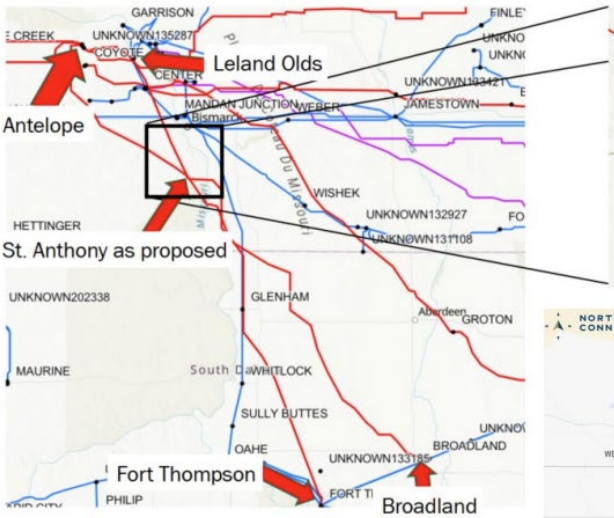


Transmission Planning

Transmission planning is done at various levels. Each of the ISOs that serve North Dakota have a long-range transmission planning process. Those plans are reflected in the graphics below. In addition to their planning processes, they have also engaged in a Joint Transmission Interconnection Queue which looks at the seams between the two ISOs and seeks solutions that will optimize the abilities of the two systems to operate together efficiently. Transmission can ease resource shortages by moving power longer distances, but it cannot solve the resource adequacy issues that are causing the reliability warnings to be issued.



GRID UNITED - NORTH PLAINS CONNECTOR (NPC) INTERCONNECTION

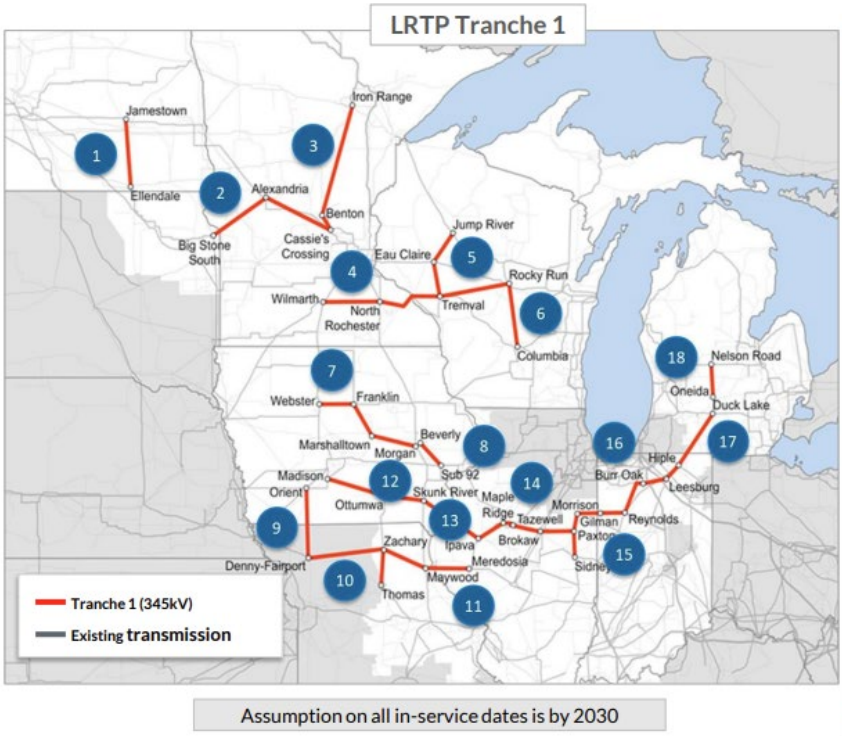


NPC Description:

- 1500MW, HVDC Interconnection Tie between the eastern and western interconnection
- Integration and exchange of power between various utility grids
- West-to-East or East-to-West Flow ability

SPP 33

Tranche 1 represents the first iteration and includes 18 projects across the MISO Midwest subregion estimated at $10.3 billion



Assumption on all in-service dates is by 2030

ID	Project Description	Est. Cost ($M, 2022)
1	Jamestown – Ellendale	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	$574M
3	Iron Range – Benton County – Cassie's Crossing	$970M
4	Wilmarth – North Rochester – Tremval	$689M
5	Tremval – Eau Clair – Jump River	$505M
6	Tremval – Rocky Run – Columbia	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	$755M
8	Beverly – Sub 92	$231M
9	Orient – Denny - Fairport	$390M
10	Denny – Zachary – Thomas Hill – Maywood	$769M
11	Maywood – Meredosia	$301M
12	Madison – Ottumwa – Skunk River	$673M
13	Skunk River – Ipava	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	$261M
17	Hiple – Duck Lake	$696M
18	Oneida – Nelson Rd.	$403M
	Total Project Portfolio Cost	$10.3B

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Costs as of 6/1/2022, and are subject to change (costs represent "overnight" costs)

MISO

In addition, DOE is engaged in a study of the national grid utilizing carbon reduction and renewable mandates as assumptions to meet state goals and mandates. While much of this study does not show an impact on North Dakota it is informative to understand the magnitude of the transmission buildout that is required to meet those goals.

Cold Weather Operations

Federal Energy Regulatory Commission (FERC) has issued orders to address failures of generation to meet availability expectations during winter storms. This has resulted in the North American Electric Reliability Council (NERC) issuing standards Emergency Operation and Preparedness EOP11-01 and EOP 11-02. These standards contain expectations for each segment of the industry that affects reliability. Each entity is subject to compliance audits of their compliance with all aspects of the standard that applies to them.

In the standards, the Generation owners must address capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints. In addition, they must analyze each Generating unit(s) minimum: design temperature; or historical operating temperature; or current cold weather performance temperature determined by an engineering analysis.

FERC is revising their orders based on grid performance during winter storm Yuri in 2021. This work is expected to result in NERC issuing EOP 11-03 with more stringent requirements.

The goal of these standards is to make the grid more reliable in the face of cold weather events. The analysis that generation owners must perform to demonstrate how the standards will be met will determine whether there is any impact on the capacity that is available to the grid operators under certain weather conditions.

Without regulations the North Dakota Generating units have a nearly unblemished record of reliability during the worst winter events in North Dakota history. With regulations in place the expectation will be the same.

Conclusions

The current grid is meeting the needs of North Dakota for internal state consumption but is a limiting factor in export of electricity to other regions. The “all of the above” approach that North Dakota has taken to energy is proving it’s worth in the current electrical grid condition. North Dakota cannot “carry it alone” so it is important to get collaboration from other states in the two ISOs to be sure the resources on the grid are reliable.

Recent approval of two additions to the Basin Electric Power Cooperative (BEPC) 345 kV system that will supply western ND oilfield and industrial expansion is much needed and timely for future development.

BEPC has plans in place to respond to that demand but will need to monitor the actual development closely to keep up with the growth.

The review of the 10-year plans of the Utilities in North Dakota shows their commitment to a resilient and reliable grid. The resource choices they identify do not jeopardize that objective

The combined capacity of projects in the three Interconnection queues is 10,816 MW. Basin Electric Power Cooperative has 1085 Mw of gas fired generation planned. Other developers have 730 MW of battery storage planned. The current technology that is available for battery storage is typically 4 hours of duration, so the 730 MW of battery installations will help the ISOs smooth the first 4 hours of transition of wind and solar changes in generation.

The remaining 9000 MW of generation in the queue is weather dependent. Wind has a current 39% capacity factor in North Dakota and solar has a projected capacity factor between 15 and 20%. That magnitude of queue requests far exceeds the projected capacity demand in North Dakota during favorable weather conditions but will have gaps in generation during unfavorable weather conditions. This capacity can only be absorbed by the grid with substantial increased export capacity.

Critical expansion of the grid is reaching approval stages in both MISO and SPP. Recent approval by MISO of the first tranche of the LRTP will improve ND ability to export, but the expansion is a few years too late to keep up with the appetite that developers have to increase renewable generation in ND.