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April 8, 2024

–Via U. S. and Electronic Mail–

Steven M. Kahl, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 0408
600 East Boulevard
Bismarck, ND 58505-0480

RE: XCEL ENERGY 2024-2040 NORTH DAKOTA RESOURCE PLAN
CASE NO. PU-24-___

Dear Mr. Kahl:

Northern States Power Company, doing business as Xcel Energy, is pleased to submit this 2024-2040 North Dakota Resource Plan to the North Dakota Public Service Commission pursuant to N.D.C.C. §§ 49-05-04.4 and 49-05-17. The ND Resource Plan includes a North Dakota Preferred Plan that has selected resources consistent with North Dakota energy policy and representing the least-cost plan for providing reliable service to our customers.

Pursuant to N.D.C.C. § 69-02-02-04, we will provide an original and seven hard copies of the public version of the ND Resource Plan, including the 2024-2040 Upper Midwest Integrated Resource Plan filed with the Minnesota Public Utilities Commission on February 1, 2024 in Docket No. E002/RP-24-67.

The North Dakota and the Upper Midwest resource plan filings contain trade secret information. In accordance with N.D.C.C. § 69-02-09-02, an Application for Trade Secret Protection is provided along with a single copy of the trade secret material in a sealed envelope marked **PROTECTED INFORMATION – PRIVATE**.

The Company sent the $250,000 filing fee required by N.D.C.C. § 49-05-04.4 to the Commission under separate cover.

We look forward to working closely with the Commission and Commission Staff on this filing.

1 PU-24-160 Filed 04/08/2024 Pages: 218
Integrated Resource Plan 2024-2040 - Redacted
Northern States Power Company
Alex Nisbet, Reg. Policy Specialist

Please contact me at (701) 241-8632 or alex.j.nisbet@xcelenergy.com if you have questions regarding this submission. Alternatively, you may wish to contact Christopher Shaw, Director of Resource Planning and Bidding, at (612) 330-7974 or christopher.j.shaw@xcelenergy.com.

Sincerely,

/s/

ALEX J. NISBET
REGULATORY POLICY SPECIALIST
NSPM REGULATORY

Encls
cc: Adam Renfandt
Victor Schock

2024-2040 NORTH DAKOTA RESOURCE PLAN

NORTHERN STATES POWER COMPANY
NDPSC CASE NO. PU-24-____
APRIL 8, 2024

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2024-2040 North Dakota Resource Plan

CHAPTER 1 – EXECUTIVE SUMMARY

I. INTRODUCTION

Northern States Power Company, a Minnesota Corporation, doing business as Xcel Energy (the Company) is pleased to present this 2024-2040 North Dakota Resource Plan (the ND Resource Plan). Our ND Resource Plan represents the least-cost resource mix that is consistent with North Dakota's statutes, rules, and policies and that would allow the Company to continue providing safe, reliable, and affordable service to our North Dakota customers, even as we forecast significant increases in customer load across our Upper Midwest service territory. In this ND Resource Plan we ask that the Commission approve the extension of the Prairie Island and Monticello Nuclear Generating Plants into the 2050's and approve the ND Preferred Plan resource acquisitions proposed through 2030.

We believe the ND Resource Plan presented in this filing would allow us to effectively serve our North Dakota customers consistent with North Dakota's planning process. In addition, as we demonstrate in this filing, our ND Resource Plan is largely aligned with the 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan) over the 2024-2030 timeframe. Throughout this filing we explain the reasons for this alignment and the benefits it provides to our customers.

The Company plans and operates a single Upper Midwest system that serves customers in five states. Consistent with the terms of the Settlement in Case No. PU-07-776, since 2008 we have filed our Upper Midwest Resource Plans with the North Dakota Commission on an informational basis and included in each of them an analysis of a Resource Plan scenario compliant with Federal and North Dakota laws.

As the Commission is aware, the North Dakota Century Code (NDCC) and the North Dakota Administrative Code (Admin Code) were revised effective January 1, 2023, to include new requirements for electric public utilities to file resource plans on a three-year cycle. This filing represents the Company's first resource plan developed specifically for North Dakota in response to North Dakota's statutes, rules, and policies. We believe this will provide the Commission with a better mechanism to evaluate our resource acquisition plans on a holistic level.

In prior years, the Commission's only vehicle to formally consider the Company's resource acquisitions was through individual Advance Determinations of Prudence

(ADPs). The ADP process, however, focused on individual resources; it did not provide the Commission with a comprehensive look at how a proposed resource fit into the Company's overall plan to serve its customers.[1] The new resource plan procedural framework set forth in the NDCC and the Admin Code provides a new forum for the Commission and electric public utilities to holistically review and plan resource acquisitions.

This resource plan also comes at a time when the Minnesota Public Utilities Commission (MPUC) is considering our 2024 Upper Midwest Plan, which we filed in Minnesota on February 1, 2024. In that proceeding, we noted that our 2024 Upper Midwest Plan will allow the Company to continue providing safe, reliable, and affordable service to our customers while further accelerating the Company's carbon-reduction strategy in line with Minnesota's policy goals, even as we forecast significant increases in customer load. Specifically, the Company's preferred plan in that proceeding (the Upper Midwest Preferred Plan) achieves several objectives, including the following:

- Carbon reductions that put the Company on track to achieve compliance with Minnesota's new "100 x 2040" law;[2]
- $464 million in Present Value of Revenue Requirements (PVRR) savings by 2040;[3]
- Sufficient firm dispatchable resource additions to ensure reliability; and
- Less than a one percent average annual increase in rates based on generic market pricing of new generation.

We recognize that at least some of these objectives are not consistent with North Dakota's statutes, rules, and policy preferences. As stated in the new resource plan requirements, this ND Resource Plan must include information on how the electric public utility intends to reconcile potential jurisdictional differences in resource selection.[4] As discussed below, we believe that, while they were developed to achieve some different policy goals, the ND Resource Plan and the Upper Midwest Resource

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[1] In its Order dated February 21, 2024 in Case No. PU-23-366, the Commission adopted the First Amended and Restated Settlement Agreement which removed the requirement that the Company must file ADP applications for proposed new construction, rehabilitation, or acquisition of certain resources. The original intent of the ADP obligation was to increase transparency and engage with the Commission regarding significant resource additions in advance of general rate proceedings. Now these resources will be considered in our integrated resource plans.

[2] *See* Minn. Stat. § 216B.1691, Subd. 2g (requiring that, by 2040, the Company "generate or procure sufficient electricity generated from carbon-free energy technology" equivalent to 100 percent of its retail electric sales to retail customers in Minnesota.)

[3] These savings include revenues from sales of excess energy into the MISO market.

[4] Admin Code § 69-09-12-04 3j.

Plan are largely consistent in the short-to-medium term, with similar rate impacts for our customers. As a result, we believe these plans allow us to move forward on a path that maintains the benefits of our integrated Upper Midwest System while aligning with the specific policy preferences in our different jurisdictions.

Section II below briefly describes the 2024 Upper Midwest Plan and the Upper Midwest Preferred Plan contained therein. Copies of the full 2024 Upper Midwest Plan have been provided to the Commission and Staff for your reference. Throughout the Executive Summary and this ND Resource Plan we will be comparing the ND Preferred Plan and the Upper Midwest Preferred Plan. This is intended to give context to the Commission for how the Company can "reconcile potential jurisdiction differences in resource selection."[5] With formal IRPs and corresponding outcomes, we will now be able to see where there are divergences between the two jurisdictions and seek to reconcile differences when possible.

As further discussed in Section III below and Chapter 4 of this ND Resource Plan, the resource additions in both the North Dakota Preferred Plan (ND Preferred Plan) and the Upper Midwest Preferred Plan largely align over the 2024-2030 timeframe. We think this is important because, while both of our plans include a 15-year planning horizon, there is generally more certainty in our projected near-term additions than those we project farther out. As shown below in Table 1-1, both preferred plans select the same firm capacity additions of 2,244 MW and standalone storage of 600 MW. Additionally, both plans include substantial wind resource additions through 2030: 2,000 MW in our ND Preferred Plan and 3,200 MW in the Upper Midwest Preferred Plan. Finally, our Upper Midwest Preferred Plan projects adding 400 MW of solar resources in 2030, which is not included in our ND Preferred Plan:

Table 1-1: Near-Term ND Preferred Plan and Upper Midwest Preferred Plan Resource Additions (MW)

North Dakota	**2027**	**2028**	**2029**	**2030**	**Total**
Standalone Storage	480	-	120	-	600
Wind	400	400	1,200	-	2,000
Solar	-	-	-	-	0
Firm Peaking	748	748	-	748	2,244
Upper Midwest	**2027**	**2028**	**2029**	**2030**	**Total**
Standalone Storage	480	-	120	-	600
Wind	400	2,000	800	-	3,200
Solar	-	-	-	400	400
Firm Peaking	748	748	-	748	2,244

[5] *Id.*

Another key element of this ND Resource Plan is our proposal to extend the lives of both the Monticello and the Prairie Island Nuclear Generating Plants into the 2050's. Within this ND Resource Plan we analyze in detail how the extension of our nuclear facilities impacts system reliability and rates for our customers. This analysis shows that extending our nuclear facilities provides benefits to our customers under a holistic analysis and is cost-effective across plans and scenarios. Specifically, the sensitivities analysis shows that our ND Preferred Plan baseload nuclear decisions to extend Prairie Island 1 and 2 and Monticello are likely to yield customer benefits relative to the Reference Case, even in a future where key assumptions change. As such, the Company will be seeking a determination of prudence in this proceeding regarding the extension of our two nuclear plants.

As discussed throughout this ND Resource Plan, our proposal represents the least-cost resource mix for the Company to continue providing our customers with safe and reliable service. We understand the need for our customers to the essential service that we provide at an affordable price. To that end, our average residential customer's electricity bill has remained below the national average, and our goal continues to be that our customers will experience average annual bill increases that are below the rate of inflation. The ND Resource Plan and the Upper Midwest Resource Plan will further that goal. The Present Value of Revenue Requirements (PVRR) over the 2024–2040 period for the ND Preferred Plan is similar to the cost shown for our Upper Midwest Preferred Plan—$37,640,000 for the ND Preferred Plan while that of the Upper Midwest Preferred Plan is $37,891,000.[6] As discussed below in Section III and Chapter 6 of this ND Resource Plan, this is projected to result in cost increases that continue to be below the national average.

The Company is committed to complying fully with all applicable statutes, rules and orders. We believe our ND Resource Plan reflects appropriate implementation of all resource planning requirements. The provided Attachment 1: Compliance Matrix reflects our inventory of requirements to be met and cross-references to the portions of the ND Resource Plan that fulfill each compliance item. Where required, information is provided (and so noted) in the 2024-2040 Upper Midwest Integrated Resource Plan filed with the MPUC on February 1, 2024 in Docket No. E002/RP-24-67 (copy provided).

[6] These PVRR costs reflect modeling that does not include market interactions. The Company did additional modeling without market sales or purchases for both the ND Preferred Plan and the Upper Midwest Preferred Plan to provide comparable costs.

II. 2024-2040 UPPER MIDWEST INTEGRATED RESOURCE PLAN

While this filing presents our ND Resource Plan for the Commission's consideration, we describe the Upper Midwest Resource Plan that we recently proposed in Minnesota so that the Commission can understand how they align, and how they differ.

Our planning process places a critical emphasis on ensuring that we maintain a reliable system and that we have the resources needed to serve all of our customers. As the Commission is aware, the Company is planning to close all of its coal facilities by 2030. In addition, we also have around 2,000 MWs of power purchase agreements (PPAs) with other capacity resources set to expire between 2025 and 2028. In response to these changes, our Upper Midwest Resource Plan is increasingly focused on ensuring that our system remains reliable, so that we can deliver the power our customers' demand at all times and responsibly meet the Company's and other jurisdictions' carbon reduction goals. This need to ensure an adequate power supply during this transition drives several of the additions we proposed in the Upper Midwest Resource Plan, many of which are consistent with our ND Resource Plan.

Our Upper Midwest Resource Plan proposes two broad steps to maintain an adequate supply of generation resources. First, we plan to extend the lives of several existing facilities. Specifically, we plan to extend the lives of both of our nuclear plants into the early 2050s to match 20-year life-extensions we are working to obtain from the Nuclear Regulatory Commission. This will ensure that the Company continues to have available more than 1,700 MWs of carbon-free baseload power into the foreseeable future. We are also planning to extend the lives of our Company owned Refuse Derived Fuel (RDF) waste to energy generating facilities. These will provide additional dispatchable capability for our customers.

Second, the Company plans to add a robust set of cost-effective resources to provide additional capacity and energy. Our five-year action plan found in the Upper Midwest Preferred Plan is expected to see 3,200 MWs of wind resources added to our system and over 1,000 MWs of distributed solar and community solar gardens, consistent with newly-passed Minnesota state law. We will have new opportunities to maximize the value of these and other intermittent resources as we project adding 600 MWs of stand-alone storage during this time. These resources will be supported by 2,200 MWs of firm peaking capacity to be added during our five-year action plan. These firm peaking resources can be operated when needed to support the reliability of our system during periods of high load and low renewable generation.

Collectively, these changes will result in a resource mix that continues to be diverse but that will rely much more heavily on carbon-free resources going forward, as shown in Figures 1-1 and 1-2 below.

Figure 1-1: NSP System 2024 and 2040 Upper Midwest Preferred Plan Capacity Mix

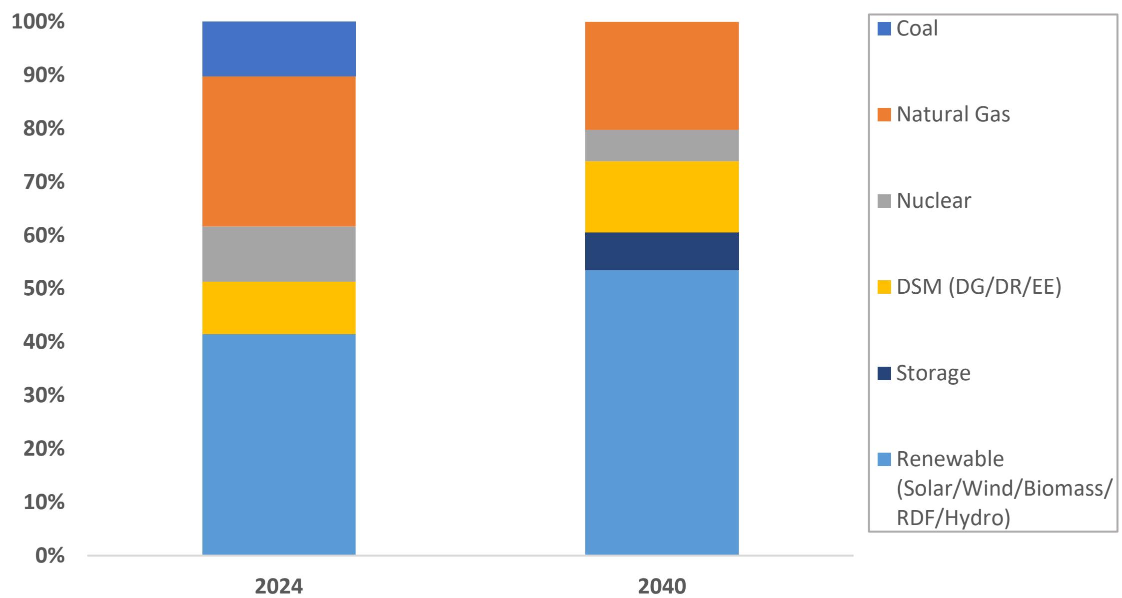
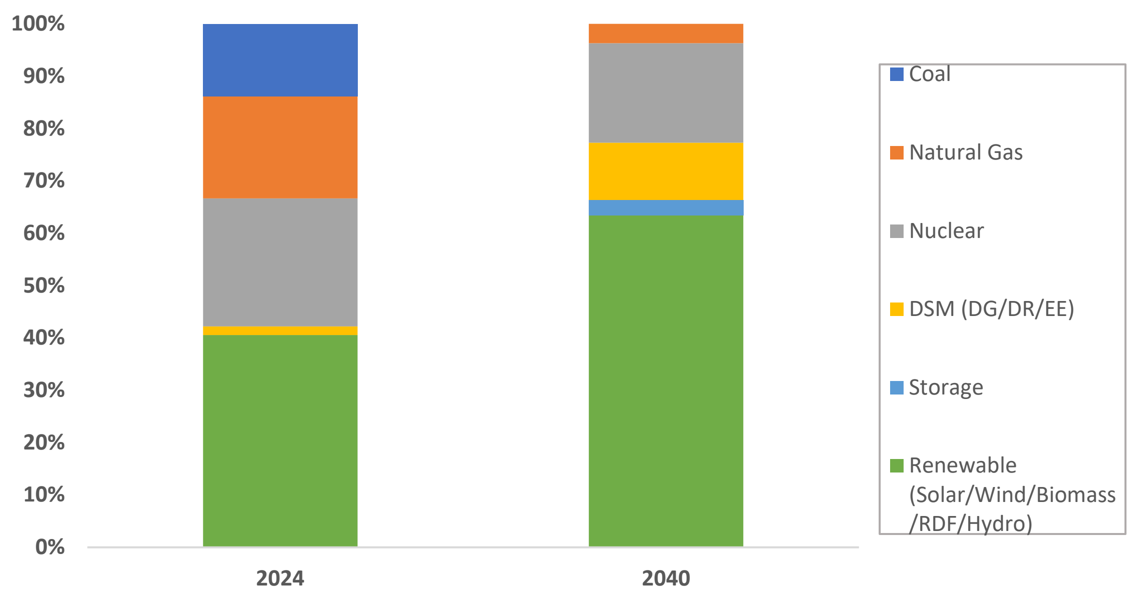


Figure 1-2: NSP System 2024 and 2040 Upper Midwest Preferred Plan Energy Mix[7]



[7] These results are based on the modeled dispatch of resources added pursuant to our Upper Midwest Preferred Plan. We note that the market dispatch of resources will ultimately determine the energy mix of the Preferred Plan. Storage represents the dispatch of energy from storage resources. Storage does not generate energy.

Our 2024 Upper Midwest Plan is also impacted by and consistent with Minnesota and federal energy policy, which is increasingly incentivizing utilities to accelerate their carbon-reduction strategies. As referred to above, this past year, the State of Minnesota passed the "100 x 2040" law, which requires that, by 2040, utilities generate or procure an amount of carbon-free energy equivalent to their Minnesota load. Likewise, Minnesota also passed a new law requiring that at least three percent of the Company's retail sales be generated by new distributed solar generating systems. As discussed in greater detail in the 2024 Upper Midwest Plan, we developed our Upper Midwest Preferred Plan to ensure compliance with these and other applicable laws.

Changes in federal policy also make increasing investments in renewable resources more cost effective, and our 2024 Upper Midwest Plan reflects this change. The Inflation Reduction Act (IRA) provides for enhanced tax incentives for new clean energy projects, making our planned renewable additions more cost effective for our customers. In addition, the EPA's proposed "Good Neighbor Plan" would increase the per mega-watt hour (MWh) cost of operating carbon-emitting resources. The combination of these policies, in addition to the new Minnesota statutes reflected above, support a more rapid transition of our system.

III. NORTH DAKOTA PREFERRED PLAN

This ND Resource Plan focuses on ensuring a reliable and least-cost resource mix for our customers consistent with North Dakota energy policy. Below, we discuss the least-cost resource mix and the reliability metrics we analyzed in developing the ND Preferred Plan.

A. Least-Cost Resource Mix

The new resource planning legislation and rules re-emphasizes that a North Dakota preferred resource plan may not select resources based on externalities representing environmental costs or future environmental laws or regulations that have not yet been enacted. The preferred plan must instead describe and select resources representing the least-cost plan for providing reliable service to ratepayers, consistent with North Dakota energy policy.

A comparison between the ND Preferred Plan and the Upper Midwest Preferred Plan is set forth in Tables 1-2 and 1-3 below.

Table 1-2: 2024-2040 ND Preferred Plan Resource Additions (MW)

North Dakota Plan(MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Cumulative Exp 2027-2040
Standalone Storage	480	-	120	-	180	120	240	-	-	-	-	120	360	-	1,620
Wind	400	400	1,200	-	1,000	400	1,200	-	200	200	600	200	600	200	6,600
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm Peaking	748	748	-	748	-	599	-	-	374	-	748	-	374	-	4,340
Total	**1,628**	**1,148**	**1,320**	**748**	**1,180**	**1,119**	**1,440**	**-**	**574**	**200**	**1,348**	**320**	**1,334**	**200**	**12,560**

Table 1-3: 2024-2040 Upper Midwest Preferred Plan Resource Additions (MW)

Minnesota Plan (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Cumulative Exp 2027-2040
Standalone Storage	480	-	120	-	240	360	60	60	-	60	360	240	120	-	2,100
Wind	400	2,000	800	-	800	600	600	400	200	400	400	400	400	1,000	8,400
Solar	-	-	-	400	300	200	600	-	-	-	-	-	-	-	1,500
Firm Peaking	748	748	-	748	-	225	-	-	-	374	374	-	374	-	3,592
Total	**1,628**	**2,748**	**920**	**1,148**	**1,340**	**1,385**	**1,260**	**460**	**200**	**834**	**1,134**	**640**	**894**	**1,000**	**15,592**

First, our ND Preferred Plan reflects the need for substantial wind additions—an incremental 2,000 MWs of wind capacity by 2030 and 6,600 MWs through 2040. This is consistent with our 2024 Upper Midwest Plan and represents a substantial increase from the amount of wind additions that the Company had projected in our previous resource plans. There are two main drivers of these additions. First, the change to the MISO seasonal construct has resulted in varying capacity accreditation across seasons. This makes wind resources more valuable relative to the annual construct, which relied on the summer accreditation. Second, the production tax credits included in the newly enacted IRA have lowered the levelized cost of energy from wind resources. Under the ND Preferred Plan the significant additions of wind are dependent on the ability to procure wind resources consistent with our base assumptions. If wind resources are higher cost, fewer additions of wind will be cost effective. Because emission costs are considered when developing our Upper Midwest Preferred Plan, higher cost renewable resource may result in greater differences between the ND Preferred Plan and the Upper Midwest Preferred Plan.

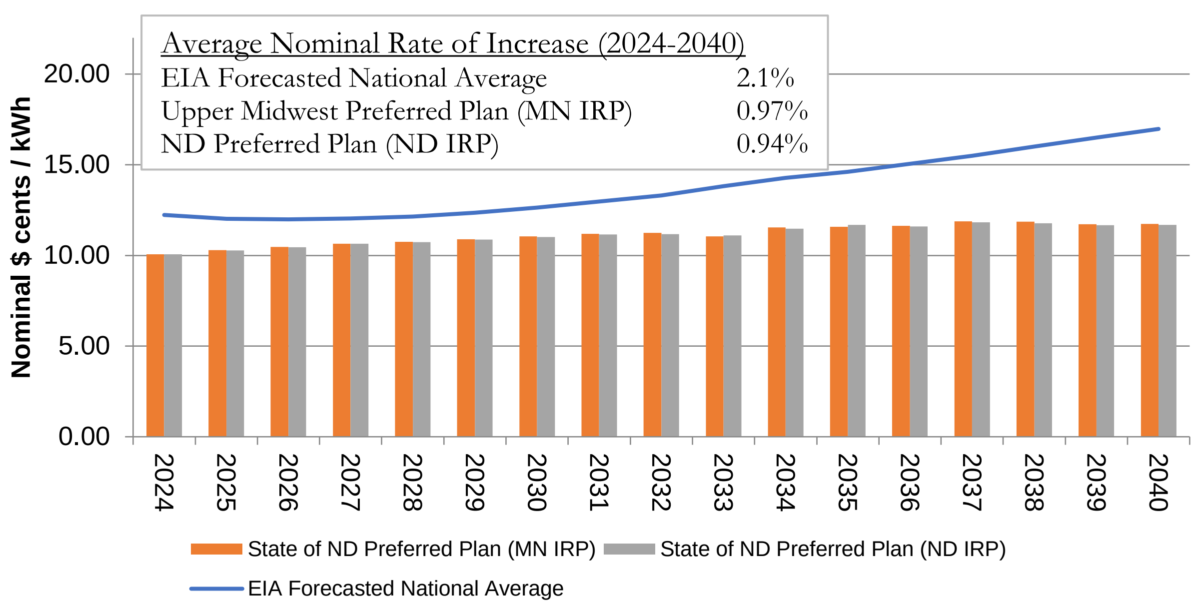
Second, like our Upper Midwest Preferred Plan, our ND Preferred Plan also proposes the extension of both Prairie Island and Monticello Nuclear Generating Plants into the 2050's. Notably, this extension is cost-effective across plans and scenarios. By continuing the operation of these plants to at least 2050, customers will continue to benefit from the baseload power that our nuclear fleet provides, while helping to keep costs low as we leverage these existing, reliable resources on our system.

Finally, our modeling shows that replacing our retiring baseload coal units will require us to add a substantial amount of firm dispatchable capacity and standalone storage over the life of our plan. The amount of these resources needed in our ND Preferred Plan by 2030 are identical to the amount needed in our Upper Midwest Preferred Plan. In both cases, these resources will provide low-cost energy and capacity, and complement the additions of new renewable resources in a way that will ensure reliability for our customers. We have modeled these firm dispatchable additions as combustion turbine resources that are relatively low-cost to build.

Overall, our ND Preferred Plan results in an estimated annual rate increase of 0.94 percent for North Dakota customers, which is less than the expected national average increase of 2.1 percent for electricity prices and slightly less than the estimated annual rate increase of 0.97 percent in the Upper Midwest Plan Preferred Plan.

Figure 1-3 below shows the relative cost growth of the Upper Midwest Preferred Plan and the ND Preferred Plan in comparison to the national average:

Figure 1-3: Preferred Plan Average Rate Impact for the NSP System Average Nominal Cost Comparison State of North Dakota Upper Midwest vs. North Dakota Resource Plans



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2023, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[8] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

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[8] *See* U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. The EIA's Annual Energy Outlook was published in 2023.

We note the impacts shown here do not include revenues for sales of excess energy. We have taken this approach to provide a conservative estimate of rate impacts. Because our Upper Midwest Preferred Plan and our ND Preferred Plan includes resources that are expected to produce energy in excess of our load serving needs, the value of this excess energy has the potential to impact the respective costs of the plans.

We believe that both the ND Preferred Plan and the Upper Midwest Preferred Plan keep customers' bills and rates as lows as practicable. While the ND Preferred was optimized without costs of constraints for emissions, the resulting cost impacts are similar, though slightly lower, than the expected impacts of our Upper Midwest Plan Preferred Plan. Importantly, this conclusion is based on numerous assumptions, including the costs of new resources, that could impact this result. We are optimistic that this analysis shows that the differences between the jurisdictions we serve can be addressed while maintaining the benefits of our integrated Upper Midwest System.

B. Reliability

The foundational service we provide to our customers is safe and reliable electricity, and we must be prepared to meet our customers' energy demands 24 hours a day, 365 days a year. The closing of our (and other utilities') baseload coal units and the substantial additions of intermittent renewable resources means that we must develop our plans thoughtfully to ensure that we continue to have the resources to meet our customers' needs at all times.

As the resource mix in the region has changed, there is also less excess capacity in the MISO footprint. In fact, MISO's 2022-23 Planning Resource Auction (PRA) resulted in a capacity shortfall for the MISO North/Central Regions, leading to the price of capacity clearing at the Cost of New Entry (CONE). As a result of these developments, among other things, MISO has changed its reliability construct to a seasonal Resource Adequacy (RA) construct with capacity requirements for each season. This new seasonal RA construct establishes planning reserve margin (PRM) and resource capacity contributions for each season (spring, summer, fall, winter).

Additional changes to the RA construct are also under consideration and will impact the resources needed in the MISO region to meet reliability requirements. These changes are intended to ensure that MISO's members maintain adequate supplies of generation at all times. This is especially important for us, since our Upper Midwest system constitutes approximately half of the load in MISO Zone 1 and approximately seven percent of the load in the entire MISO footprint from Manitoba to Louisiana, making our system a major part of the broader MISO market.

The planning process we used to develop our least-cost ND Preferred Plan reflects and responds to these changes and the need for additional focus on ensuring an adequate resource mix. In past resource plans, our modeling analysis allowed a portion of our resource needs to be fulfilled by the MISO market. When we performed the same analysis for the ND Preferred Plan and our Upper Midwest Preferred Plan, however, the models produced an expansion plan that would be unable to serve our load during a significant number of hours each year. This reflects the changing resource mix on our system.

To address this risk while continuing to optimize the cost-effectiveness of our fleet, we used a modified analysis to develop our ND Preferred Plan compared to previous resource plans, and we did not allow our model to rely on the MISO market when optimizing our capacity expansion plan.

We did, however, set those capacity obligations using MISO's coincident peak and PRM. By continuing to plan to MISO's coincident peak and PRM, our analytical approach ensures that we are not adding resources that are unnecessary to meet our customers' needs.

In addition to planning our resource additions to limit reliance on MISO market purchases and sales, we have taken steps to further refine our energy adequacy analysis. We conducted an energy adequacy back casting analysis to ensure our system had the reliable energy it needs to serve all customers at every hour of every day. We used historical data on scenarios, including the ND Preferred Plan and Market Access Optimization sensitivity, which was developed assuming 2,300 MW of hourly market access.[9] The analysis allowed us to assess the capacity and energy adequacy of our plans. We evaluated these plans on six different core measures, plus additional metrics in Attachment 2:

1. Native Capacity Shortfall: Hours of insufficient system capacity in each year.
2. Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
3. Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.

[9] As discussed in Appendix D: Energy Adequacy Analysis, which also analyzed the ND Reference Case.

4. Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
5. MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

The ND Preferred Plan performs well across all of these energy adequacy metrics, with no significant difference from the Upper Midwest Preferred Plan. For 2030, there are only eight hours of native capacity shortfall across the seven historic years tested and applied to our ND Preferred Plan, resulting in limited dependence on the market. There are also only nine hours across the seven historical test years where the ND Preferred Plan requires market purchases in order to meet load serving needs. In contrast, the Market Access Optimization sensitivity showed significant vulnerabilities across the energy adequacy metrics, supporting our approach in the ND Preferred Plan to ensuring reliability.

IV. CONCLUSION

We are pleased to present this 2024 North Dakota Resource Plan complete with a ND Preferred Plan that has selected resources representing the least-cost plan for providing reliable service to ratepayers, consistent with North Dakota energy policy. With formal resource plans and corresponding outcomes, we will now be able to identify where there are divergences between North Dakota and our other jurisdictions, and seek to reconcile differences when possible.

As discussed in Section III above and Chapter 4 of this ND Resource Plan, the resource additions in both the North Dakota Preferred Plan and the Upper Midwest Preferred Plan largely align through 2030, and the extension of our two nuclear plants into the 2050's is cost-effective across plans and scenarios. As a result, we believe that we have a path forward in the near-term to implement a plan that is consistent with all of our jurisdictions. We therefore ask the Commission to approve the extension of the Prairie Island and Monticello Nuclear Generating Plants into the 2050's and approve the ND Preferred Plan resource acquisitions proposed through 2030.

CHAPTER 2 – PLANNING LANDSCAPE

I. INTRODUCTION

In this Chapter, we discuss some of the key internal and external market contexts that affect how we have developed, and plan to execute on, our North Dakota (ND) Resource Plan. Specifically in this section we examine:

- Market Constructs & Renewable Integration
- Jurisdictional Updates
- Federal Incentives & Environmental Regulations
- Supply & Technology Trends

Each of these factors affected how we developed our ND Resource Plan. However, a few factors stand out above others as being particularly influential in this current Plan cycle, namely: market constructs and state and federal policy. Our regional system operator's new seasonal construct allows for more precise planning and resource allocation based on each season. It also introduces new levels of complexity and concern about reliability that our ND Resource Plan is tailored to address. Federal policy has also changed significantly since 2019—creating both significant financial incentives for renewables along with new areas of uncertainty related to the Clean Air Act.

These and other factors all affect how we developed the ND Resource Plan presented in this filing—and the issues we anticipate encountering while ensuring reliable and affordable grid services.

II. MARKET CONSTRUCTS AND RENEWABLE INTEGRATION

The Company's Upper Midwest system is part of the Midcontinent Independent System Operator (MISO) market. MISO's primary responsibilities are overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). MISO's operations therefore affect how we conduct resource planning. Here we focus on system reliability constructs and renewable integration challenges and their impacts on our ND Resource Plan.

A. New Resource Adequacy Construct

MISO's resource adequacy construct has historically been centered on an annual planning reserve margin (PRM) based on a summer peak. This approach was based on the assumption that resource needs and availability were relatively stable throughout the year, and consistently peaking in the early evening in summer months when air conditioning use is highest. However, recognizing the increasing variability in reliability needs and resource availability throughout the year, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to move to seasonal resource adequacy requirements. This new MISO construct began with the 2023 – 2024 planning year, which spans from June 1, 2023, through May 31, 2024, and will also be in place for subsequent planning years. The planned seasons are: (1) Summer: June through August; (2) Fall: September through November; (3) Winter: December through February; and (4) Spring: March through May.

This new construct is designed to address increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, seasonal variations, outages resulting from extreme weather events, and declining excess reserve margins. By planning for resource adequacy on a seasonal basis, utilities can better prepare for seasonal variations in demand and supply, leading to improved reliability of the power system.

Our ND Resource Plan has incorporated the seasonal construct into the planning process and modeling, allowing for more precise planning and resource allocation based on the specific needs and resource availability of each season. Modeling tools have been adjusted, and our models have become more complex because they now have to ensure sufficient capacity across all four seasons as opposed to a single year. We have also adjusted our long-term planning assumptions because our models use trends or averages from several years of data in order to accurately predict what will happen in the future. However, due to the amount of time it takes to build and conduct our modeling, we had only one year of historical data for existing generation assets under the seasonal construct available to determine how much capacity we will need for each season. Attachment 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs discusses our short- and long-term capacity accreditation assumptions in more detail.

Overall, MISO's seasonal resource adequacy construct adds complexity to resource modeling but also provides a more detailed and potentially more reliable approach to ensuring grid reliability throughout the year.

B. MISO Reforms on the Horizon

MISO is actively engaged in developing and refining additional reforms to improve resource adequacy and reliability of the electric power grid. Two reforms of note—Reliability-Based Demand Curve (RBDC) and Direct Loss-of-Load (DLOL) methodology —aim to better align the value of reliability, provide investment signals for future resource needs and ensure stability in resource adequacy modeling, while considering the impacts on load serving entities and various resource classes.

1. DLOL

Due to the growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, MISO determined that its existing accreditation methods for resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during periods of highest reliability risk and, based on stakeholder input, to ensure that there is a consistent, "non-discriminatory" framework for all resource classes.[1] In response, MISO has developed a proposal that contains a new two-step process for accreditation, characterizing it as an approximation of the Effective Load Carrying Capability (ELCC) of resources "adjusted by Resource Adequacy (RA)." At a high level, this proposal calculates accreditation based on both future modeled (ELCC approximation) and historical performance of resources (Schedule 53/RA) during tight margin hours.

More specifically, the first step in the process determines how resources receive unforced capacity (UCAP) credit at a class level and the second step contains a process for class-level UCAP megawatts to be allocated amongst specific resources. The class-level step utilizes a Direct Loss-of-Load (DLOL) method which averages the availability of each resource during loss-of-load hours within the Loss-of-Load Expectation model and aggregates by resource class. The second step of the proposed process allocates the resource class level megawatts from the first step among the individual resources in the class using what MISO characterizes as a Resource Adequacy adjustment, namely the individual resources' performance during tight margin hours based on the prior three years of operational experience.

[1] In its February 2024 Accreditation Design Whitepaper, MISO shows the current accreditation methodologies for different resource classes and indicates that "the DLOL approach will bring all non-emergency resources under one umbrella regarding accreditation." Available at: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202630728.pdf,

MISO's proposal would add significant complexity to the resource adequacy construct. Based on initial information provided by MISO in public Resource Adequacy Subcommittee (RASC) meetings, the proposed approach is likely to decrease the accreditation granted to resource types relative to the accreditation methodologies MISO has in place today, but may also decrease the reserve margin in certain seasons.

MISO and stakeholders have continued to discuss in the RASC details related to MISO's proposal as well as information that will be needed to integrate MISO's proposed changes into member resource planning processes. MISO filed their proposal with FERC on March 28, 2024. As of the February 2024 MISO RASC meeting, MISO has discussed proposing implementation in the 2028/2029 Planning Year with a three-year transition period. During this transition, indicative results for existing resources from the new DLOL methodology will be calculated and shared with the LSEs for informational purposes. However, existing accreditation methodologies will continue to be used on an interim basis for actual market participation.

Additionally, MISO has already shared earlier indicative results upon request from each LSE. These results illustrate the potential outcomes for the Company's resources and PRMR if the proposed DLOL methodology had been implemented during MISO PY 2023/2024. In reviewing the information provided by MISO, it appears that several of the Company's modeling construct decisions are appropriate, given that the filed and approved DLOL method is still pending with FERC. Namely, the most impactful decisions appear to be the Company's choice to 1) reduce the level of market dependence in its modeling methodology for this ND Resource Plan; and 2) use MISO RRA's long term ELCC assumptions to inform the accreditation assumptions for future generic solar, storage, and wind resources, instead of simply extending the MISO PY 2023/2024 assumptions.

2. RBDC

The RBDC is a proposed design for MISO's Planning Resource Auction (PRA). It aims to reflect the reliability value of capacity and produce more efficient and stable capacity prices. Historically, the MISO region has maintained reserves significantly exceeding the required reserve margins. However, as experienced in the 2022-2023 PRA, excess reserves can no longer be expected. MISO's proposed RBDC endeavors to address the limitations associated with the use of a vertical demand curve to clear the PRA. The RBDC proposal is currently under consideration by FERC. Pending FERC approval, the RBDC reform is expected to be implemented in PY 2025-2026.

The RBDC has not been approved by FERC and the proposed DLOL accreditation reform has not been filed with FERC. Chapter 5: Economic Modeling Framework, discusses a special reliability study evaluating a higher PRM as an RBDC opt-out proxy and Attachment 3 (ND Appendix F): Encompass Modeling Assumptions and Inputs includes the assumptions used in our analysis for future capacity accreditation.

C. Renewable Integration Challenges

The challenges of integrating new clean generation into the system continue due to delayed interconnection studies and limited open transmission availability. The MISO Generator Interconnection Process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has seen significant delays.

Delay impacts are particularly evident in the Definitive Planning Process, where MISO undertakes generation interconnection studies. Current studies are several months to years behind due to the considerable number of projects in the queue, and due to a generator interconnection process that allows late withdrawals from the queue. With the intention of addressing some limitations in processing generation interconnection queues, FERC issued Order 2023 in July of 2023,[2] which is discussed in more detail in Appendix L: System Planning Integration in the 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan).[3]

In response to direction from FERC and in recognition of the challenges described above, MISO is beginning to undertake several actions that could serve to mitigate challenges to bringing new, clean resources online. Appendix L in the 2024 Upper Midwest Plan discusses these potentially helpful initiatives in more detail, which could allow generation owners to leverage existing interconnection agreements to maximize utilization and fit lower cost, IRA-eligible renewable or storage additions into the existing open spaces on the grid. As such, the Company is engaging in Long Range Transmission Projects and looking for ways to preserve and reutilize interconnection rights we already have, which influenced the location, size, and type of resources proposed in our ND Resource Plan. For example, the Company has initiated proceedings in Minnesota to construct transmission lines for the replacement generation at both Sherco (the Sherco Gen-Tie) and King (the King Gen-Tie),

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[2] https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements.
[3] Filed with the Minnesota Public Utilities Commission (MPUC) on February 1, 2024.

which will allow for the cost-effective integration of thousands of megawatts of additional renewable resources on our existing system.

III. JURISDICTIONAL UPDATES

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. We have historically planned this system as an integrated whole. Each resource on the Upper Midwest bulk energy system—whether generation or transmission—is developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. In the next section, we explain how differing policies in our multi-state service territories are impacting our resource planning process.

A. New Carbon-Free Energy Requirements

In December 2018, the Company announced our goal to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels companywide, and to serve customers with 100 percent carbon-free electricity by 2050. Since the Company made this announcement, we have seen multiple states across our Upper Midwest service territory adopt similar carbon free goals.

In particular, in 2023, the Minnesota Legislature amended the requirements set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (see Minn. Laws 2023, chp. 7). The new legislation requires utilities to generate or procure carbon-free energy equivalent to 100 percent of their Minnesota retail sales by 2040. The law also requires utilities to achieve interim carbon-free energy standards of 80 percent by 2030 and 90 percent by 2035, and a renewable energy standard of 55 percent by 2035.

As discussed further below, this move towards carbon-free energy requirements is not exclusive to Minnesota; other states we serve are moving towards similar goals. We will continue to track and evaluate the impacts of those developments in our system plans.

B. North Dakota

As part of the 2021 North Dakota legislative session, the North Dakota Legislature enacted Senate Bill (SB) No. 2313, which added new sections regarding integrated resource planning to Chapter 49-05 of the North Dakota Century Code (NDCC).

To further guide the process of resource planning and provide clarification on the implementation of SB 2313, Section 69-09-12 of the North Dakota Administrative Code was enacted effective January 1, 2023. With this new legislation and administrative rules, the Commission has new oversight into utility resource planning; historically, the Commission did not have a formal vehicle to review resource acquisitions outside an advance determination of prudence (ADP) proceeding.

The new resource planning legislation and rules re-emphasizes that a North Dakota preferred resource plan may not select resources based on externalities representing environmental costs or future environmental laws or regulations that have not yet been enacted. The preferred plan must instead describe and select resources representing the least-cost plan for providing reliable service to ratepayers, consistent with North Dakota energy policy. Additional rules regarding resource plan filings are found at 69-09-12 of the North Dakota Administrative Code, which requires that:

- The resource plan must provide a North Dakota preferred plan,
- Except as otherwise required by law or by order of the commission, the North Dakota preferred plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities,
- The resource plan must include reliability and resource adequacy assessments using quantitative metrics, and
- The resource plan must include information on how the electric public utility intends to reconcile potential jurisdictional differences in resource selection.

We plan on filing this ND Resource Plan with the Minnesota Public Utilities Commission and providing updates on how this proceeding progresses.

C. Minnesota

In addition to the new carbon-free goal, Minnesota has seen other significant legislative developments since our last resource plan, the 2020-2034 Upper Midwest Integrated Resource Plan (2019 Plan), that impact how we conduct our resource planning, such as the updated cost of carbon and how Distributed Energy Resources (DER) are addressed.

1. *Cost of Carbon*

A recent MPUC Order Addressing Environmental and Regulatory Costs (Environmental and Regulatory Costs Order)[4] requires utilities to continue to analyze potential resources under a range of assumptions about environmental values and future regulatory costs, including the five modeling scenarios previously outlined in 2020, and altered the cost range utilities must apply to any fossil generation resource. Additionally, pursuant to Minn. Stat. § 216B.2422, Subd. 3, the MPUC provisionally adopted and applied the cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's (EPA) November 2023 Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advance.[5] Consistent with the Commission's Order, our 2024 Upper Midwest Plan includes sensitivities addressing these valuations. Our ND Resource Plan does not include Environmental and Regulatory Costs.

2. *Distributed Energy Resources*

In another recent development, Minnesota's distributed solar energy standard was amended at subdivision 2h of Minn. Stat. § 216B.1691. This amendment mandates that at least three percent of the Company's retail electric sales in Minnesota be generated from qualifying solar energy generating systems. To be counted towards this standard, the solar generating system must have a capacity of 10 megawatts or less, be connected to the distribution system, be located in our Minnesota service territory, and be constructed or procured after August 1, 2023. Additionally, subdivision 7 now sets an annual capacity limit on community solar gardens, which decreases over time, from 100 megawatts in 2024, 2025, and 2026, to 60 megawatts in 2031 and each year thereafter. To-date, community solar gardens still make up the clear majority of the DER on our system in the Upper Midwest. DERs are also coming onto our grid, in the form of electric transportation options—enabling not only flexible load opportunities but also broader economy-wide emissions reduction.

D. Wisconsin

In Wisconsin, the Company is subject to a Renewable Portfolio Standard (RPS) equal to 12.89 percent of its three-year average in-state retail energy sales. In 2022, excluding renewable energy used for voluntary renewable programs, NSPW provided

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[4] Order in MPUC Docket Nos. E-999CI-07-1199, E-999/DI-22-236, E-999/CI-14-463, December 19, 2023, Order Point 2.
[5] Available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

44.05 percent of its retail energy sales from RPS-eligible renewable-based energy sources, therefore exceeding the state's 2022 RPS requirements.[6]

In May 2023, the State's Governor issued a Clean Energy Plan that includes a 100 percent carbon reduction goal for the state's electric sector that is broadly consistent with our objectives to reduce emissions 80 percent from 2005 levels by 2030, and 100 percent by 2050. Therefore, the Clean Energy Plan should not impact our ND Resource Plan. The Governor's climate goals have not yet resulted in additional mandates for the electric sector. Similarly, the Company continues to engage with Public Service Commission of Wisconsin (PSCW) staff and interested stakeholder as several investigatory proceedings move forward. For instance, the PSCW has opened investigation to evaluate the impact of MISO's proposed reliability-based demand curve and capacity accreditation reforms (Docket 5-EI-161), a Roadmap to Zero Carbon (Docket 5-EI-158), and an evaluation of net energy metering programs (Docket 5-EI-157). None of these proceedings have resulted in Commission orders requiring utility action as of January 2024.

E. Michigan

In Michigan, the Company is subject to a Renewable Energy Standard (RES) equal to 15 percent of retail sales through 2029, pursuant to Michigan Public Act 235 of 2023.[7] The new legislation increased the RES to 50 percent for the period 2030-2034 and 60 percent for 2035 and beyond. In addition, the legislation establishes a Clean Energy Standard (CES) requiring 80 percent of retail electricity from qualifying resources during the period 2035-2039 and 100 percent in 2040 and beyond.

F. South Dakota

In South Dakota, the Company faces challenges to its decarbonization goals. For example, it has historically faced challenges in cost recovery for certain resources. The South Dakota Public Utilities Commission (SDPUC) suspended the fuel clause adjustment in 2016 to investigate disputed resource costs. A Settlement Stipulation approved in 2017 resolved the recovery of cost associated with the Aurora solar resource and several biomass resources. The Settlement required proxy prices for the remaining disputed resources, including the Marshall and North Star solar Power

[6] *See* Docket 5-RF-*NSPW Renewable Portfolio Compliance Plan for CY 2022. Northern States Power Company, a Wisconsin Corporation.*

[7] Act No. 235. Public Acts of 2023. Enrolled Senate Bill No. 271. Available at: https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf.

Purchase Agreements (PPAs), C-BED PPAs, and Renewable Development Fund PPAs. The Company currently recovers costs associated with these resources based on a proxy price.[8]

More recently, the SDPUC disagreed with the Company's plans to retire the King and Sherco 3 units in 2028 and 2030, respectively. In June of 2023, the SDPUC approved a rate case settlement that assumes the current depreciable lives of King and Sherco 3 in June 2037 and December 2034. In opposing the Company's request for accelerated depreciation of those units, Commission Staff specifically cited the impact those retirements would have on MISO's seasonal resource adequacy construct and the Company's ability to provide reliable electricity.[9] The SDPUC reiterated its reliability concerns over early plant closures in a January 4, 2024 letter to the Company.

IV. FEDERAL INCENTIVES AND ENVIRONMENTAL REGULATIONS

In addition to state policy, federal incentives, such as the Inflation Reduction Act (IRA), and environmental regulations, such as the EPA's New Source Performance Standards 111(b) and (d) and Good Neighbor Plan, are impacting utility resource planning by incentivizing clean energy and increasing the cost of emitting resources. As described below, the IRA, with its substantial funding for clean energy, is accelerating the transition towards renewable power generation and advancing policy goals such as decreasing energy burdens for low-income consumers. EPA 111(b) and (d), and the Good Neighbor Plan, on the other hand will potentially increase the cost of operating emitting resources, thereby incentivizing the shift towards cleaner energy sources.

A. Inflation Reduction Act

The IRA was signed into law on August 16, 2022, and includes an estimated $369 billion in energy and climate spending. The IRA puts the United States on track to reduce emissions 32-42 percent below 2005 levels by 2030 through grant and loan programs, tax credits and emissions fees that touch nearly every corner of the economy. Notably, the IRA contains roughly $161 billion in clean electricity tax credits, $37 billion in clean fuel and vehicle tax credits, and $27 billion in building efficiency, electrification, transmission, and Department of Energy (DOE) grants and loans.

[8] Docket EL18-004. https://puc.sd.gov/Dockets/Electric/2018/EL18-004.aspx.
[9] Docket EL22-017. https://puc.sd.gov/Dockets/Electric/2022/EL22-017.aspx.

The IRA provides the opportunity to transfer production tax credits (PTCs) and investment tax credits (ITCs) to unrelated taxpayers for cash. Eligible credits include clean energy PTCs and ITCs earned after 2022, including PTCs from projects placed in service before 2022. However, tax credits carrying forward from years prior to 2022 are not eligible for transferability. Consideration paid in exchange for transferred tax credits cannot be included in gross income and is not deductible by the transferee. In addition to transferability, the IRA expands the availability of tax incentives across a wider variety of technologies.

Our generic wind, solar, and storage resource cost assumptions are discussed in more detail in Attachment 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs. The "Markets + Policies" scenario in the NREL ATB 2023 assumptions was used to develop these resource cost assumptions; this scenario assumes the PTCs and ITCs are available to resources through 2038, in part due to safe harbor provisions that allow the credits to be realized by projects that ultimately attain a commercial operation date (COD) after 2032.[10]

B. EPA New Source Performance Standards (NSPS) 111(b) and (d)

On May 11, 2023, the EPA released a four-part proposal under their Clean Air Act's authority to regulate CO_2 emissions from the power sector. The proposal included:

1) Repeal of the Affordable Clean Energy rule;
2) Regulations for new natural gas generating units pursuant to Clean Air Act section 111(b), hereafter referred to as 111(b);
3) Regulations for existing natural gas generation pursuant to Clean Air Act section 111(d), hereafter referred to as 111(d);[11] and
4) Regulations for existing coal generation pursuant to section 111(d).

Since the rule is in a proposed state and has not yet been finalized, it is uncertain how the rule will ultimately impact operation of our facilities.

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[10] NREL Annual Technology Baseline: The 2023 Electricity Update (Slide 23). Available at: https://www.nrel.gov/docs/fy23osti/86419.pdf.

[11] The EPA recently announced it will withdraw greenhouse gas emission limits for existing gas-fired power plants from this proposed rulemaking and will develop standards in an upcoming rule-making process. *See* Ethan Howland, "EPA pulls existing gas plants from proposed power plant carbon reduction rules," Utility Dive (March 4, 2024), available at https://www.utilitydive.com/news/epa-existing-gas-power-plant-carbon-ghg-coal/709081/.

C. Good Neighbor Plan

The "Good Neighbor" provision of the Clean Air Act for the 2015 Ozone National Ambient Air Quality Standards (NAAQS) addresses the interstate transport of air pollution, ensuring that one state's pollution does not interfere with the air quality in other, downwind states.

On February 13, 2023, the EPA finalized a rule that partially approved and partially disapproved the State Implementation (SIP) submissions from Minnesota and Wisconsin. This led to the creation of a Federal Implementation Plan (FIP), which included Minnesota and Wisconsin in the Group 3 ozone nitrogen oxides (NOx) allowance trading program, starting with the 2023 Ozone NOx season (May-September 2023). On April 14, 2023, an industry coalition, including Northern States Power-MN, filed a petition for review of the partial disapproval of Minnesota's SIP. On July 5, 2023, the 8th Circuit granted a Stay of the SIP Disapproval for Minnesota, which effectively stayed the Good Neighbor Plan requirements. This means that the Good Neighbor Plan is not in effect for Minnesota during the litigation and its future depends on the outcome.

In Wisconsin, the Good Neighbor Plan applied to sources from August 4 – September 30, 2023, and will apply in future ozone seasons. NSPW will comply through operational changes and the potential purchase of allowances.

V. SUPPLY AND TECHNOLOGY TRENDS

Trends around the supply of equipment for generation and energy storage needed to fulfill our ND Resource Plan have had a significant impact on the mix and timing of our resource acquisition proposals.

Wind, solar, and battery energy storage systems technology costs are expected to continue to improve. While photovoltaic (PV) module costs did increase as a result of the AD/CVD and UFLPA policies that were put in place in 2021 and 2022 among other factors, they are trending downward again.[12] Overall, however, commercial solar in particular has experienced significant cost declines, with median installed costs falling over 78 percent since 2010.[13] Consistent with past years, our ND Resource Plan assumes that wind and solar capital costs will continue to decline, although at

[12] Domestic PV supply is constrained into 2027, but many suppliers have indicated plans to pursue US based production. The AD/CVD and UFLPA policies have resulted in greater risk of modules not being admitted into the US, resulting in the need to take great care in completing detailed due diligence of module suppliers supply chain to understand risk profiles.
[13] Bolinger, Mark and Seel, Joachim. *Utility Scale Solar, 2023 Edition*. Lawrence Berkeley National Laboratory October 2023. Available at: https://emp.lbl.gov/utility-scale-solar/.

perhaps a slower pace as these technologies advance on their respective maturity curves and as the industry continues to be challenged with supply chain constraints. We also expect technological advancements to continue to improve capacity factors, as tracking and PV module technologies have continued to improve and inverter loading ratios have increased with falling capital costs. These factors continue to improve the cost competitiveness of wind and solar resources in real terms–changes to incentive policies notwithstanding—relative to the other resource options we considered.

We also continue to examine the role energy storage can play in meeting our system needs. Technologically, we expect grid-scale energy storage will support our clean energy goals in the future, by helping us maintain grid stability and supporting peak management while integrating the higher quantities of intermittent renewable generation we envision on our system. From a cost perspective, battery energy storage systems have experienced significant improvements over the last few years, and we expect costs to further decline going forward.

VI. CONCLUSION

We will continue to consider key internal and external market conditions in our resource planning process. This ND Resource Plan focuses on reliable and cost-effective service for our customers.

CHAPTER 3 – MINIMUM SYSTEM NEEDS

I. INTRODUCTION

In this chapter, we describe in more detail how we arrived at the minimum number of resources our system will need through the planning period. The system needs and existing resources evaluated here formulate the baseline upon which we have developed the Reference Case, our modeling scenarios, and ultimately our North Dakota (ND) Preferred Plan.

We have made the following changes to aspects of our Minimum System Needs approach with this Resource Plan:

- *MISO Seasonal Resource Adequacy Requirements*. In the ND Resource Plan, we are incorporating a seasonal Planning Reserve Margin to align with the approach recently adopted by MISO. Further, we are applying seasonal accredited capacity (SAC) values for each resource option. These adjustments align with MISO's ongoing effort to address the increasing variability in reliability needs and resource availability across all four seasons.

- *Market Reliance Risk*. We have optimized resource additions in the EnCompass model to ensure that the portfolio of resources developed can serve customer load across all hours by limiting access to the MISO market. The limited access is only applied to the resource optimization to avoid over reliance on MISO market purchases for reliability. We allow the model to access the MISO market to dispatch resource and take advantage of the access to economic resource in the larger MISO market.

II. MEETING CUSTOMER NEEDS

Forecasting customers' needs for electricity is a key component of any resource plan and provides the foundation for determining the type and amount of resources that will be needed over the 15-year planning period. The first step is forecasting the amount of electricity our customers will need over the planning period. To do this, we add a reserve margin that is prescribed by MISO for each season. We then subtract the resources we already have or expect to have (with some adjustments), to determine our net surplus or need.

We illustrate this concept in Figure 3-1 and discuss each of the components below.

Figure 3-1: Seasonal Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by seasonal accredited capacity)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

A. Customer Needs Forecast

Forecasting our customers' energy needs starts with a capacity, or peak demand, assessment, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. In previous resource plans, planning centered on meeting the highest demand hour of a given year, which for NSP occurs in the summer. The introduction of MISO's seasonal construct shifts the focus to planning for the highest demand hour in each season.

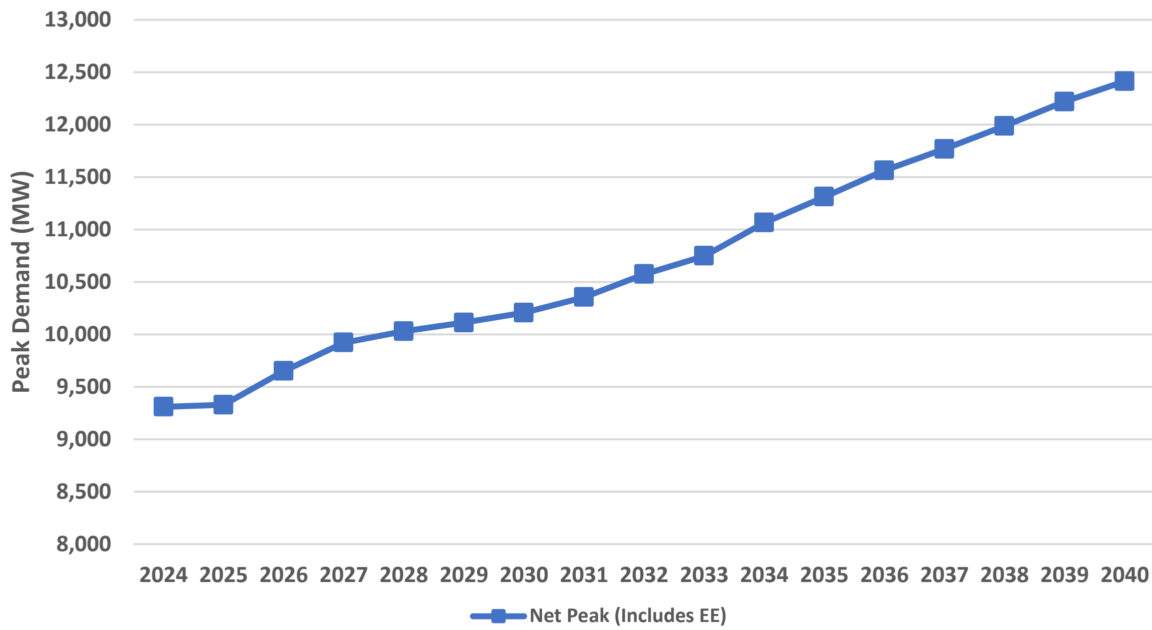
We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

1. Peak Demand Requirements

We use econometric analysis and historical actual coincident net peak demand data to determine system capacity requirements for each year. We provide a detailed discussion about our peak demand forecasting methodology in Appendix E: Load and Distributed Energy Resource Forecasting in the 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan).

During the 2024 – 2040 planning period, the base case peak forecast increases at an average annual growth rate of 1.8 percent. As demonstrated in Figure 3-2 below, annual peak demand increases at an average of 194 MW each year, starting with 9,309 MWs in 2024 to 12,414 MWs in 2040.

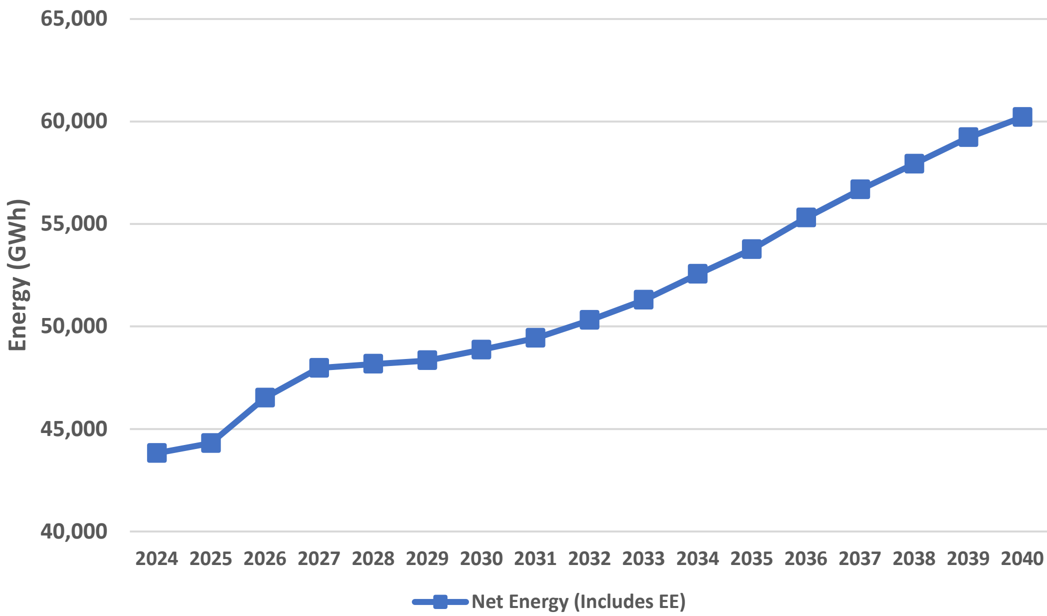
Figure 3-2: NSP System Median Base Summer Peak Demand (MW) (Includes Modeled EE Adjustment)



Additionally, the base energy forecast increases at an average annual growth rate of two percent over the 2024 – 2040 planning period, net of modeled energy savings, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements[1] are expected to increase at an annual average of 1,025 gigawatt-hours (GWh), starting with 43,823 GWhs in 2024 to 60,215 GWhs in 2040. See Figure 3-3 below.

[1] Gross of rooftop solar generation. Solar generation was modeled as a resource instead of netting against energy requirements.

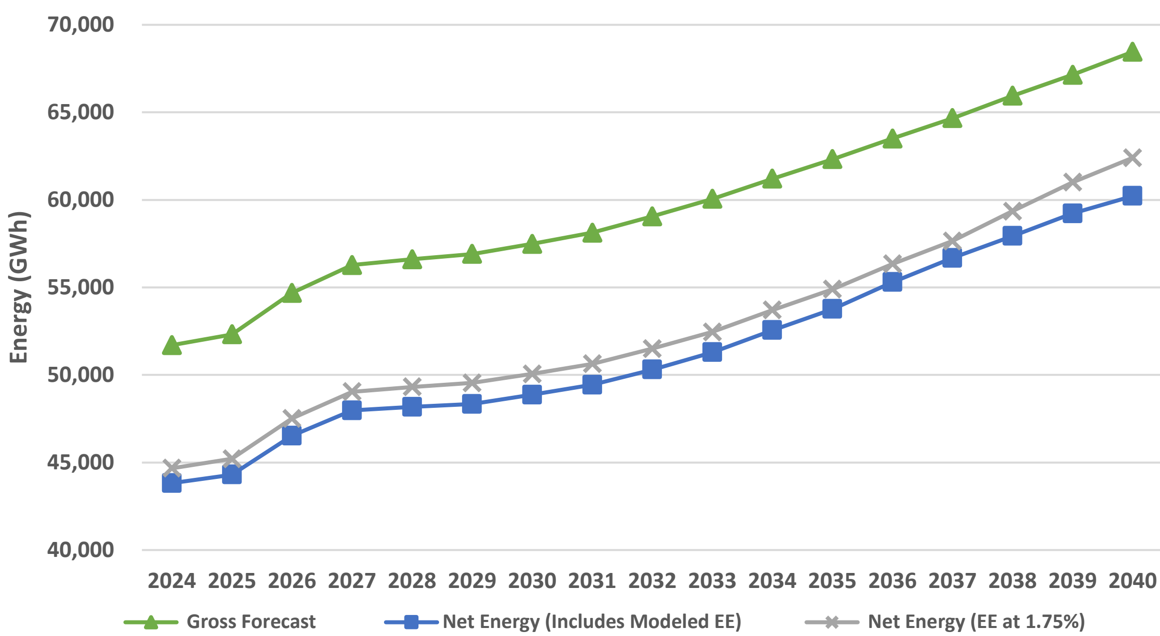
Figure 3-3: NSP System Total Median Net Energy (GWh)
(Includes Modeled EE Adjustment)



The projected two percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years due, primarily, to forecasted large new data center loads and acceleration in adoption of Electric Vehicles. After adjusting for unusual weather, electric energy requirements increased at an average annual rate of 0.2 percent from 2019 to 2022.

To be consistent with the modeling approach for Energy Efficiency (EE) in our 2020-2034 Upper Midwest Integrated Resource Plan (2019 Plan), we continue to model EE as a supply-side resource. In a separate process, we formulated annual EE savings amounts into "Bundles" that we made available in the EnCompass model along with other supply-side resources. This required that we adjust the base energy forecast to remove the embedded EE adjustment that projects the effects of energy savings to the end of the planning period. This resulted in an NSP System Gross Energy Requirements forecast. These adjustments are shown in Figure 3-4 below.

Figure 3-4: Gross Energy Requirements Forecast Compared to Net Energy Requirements Forecast

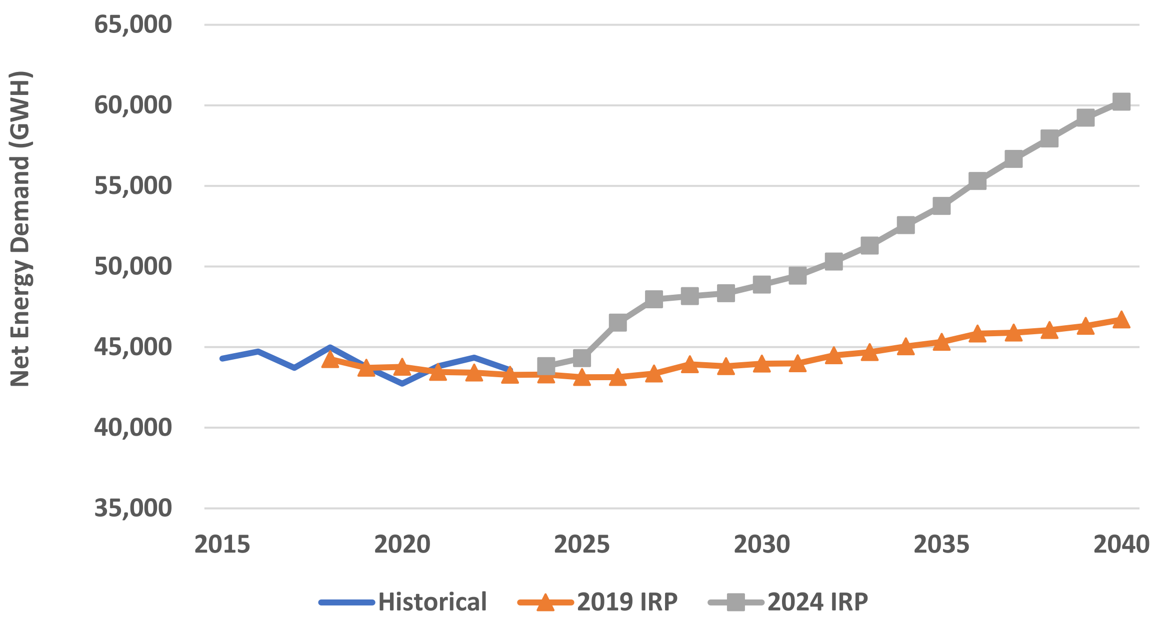


We discuss the EE Bundle modeling further in Appendix E, Appendix F: EnCompass Modeling Assumptions and Inputs, Appendix H: Resource Options in the 2024 Upper Midwest Plan. Appendix J: Distributed Energy Resources in the 2024 Upper Midwest Plan contains detail on how the EE bundles were developed.

2. *Energy Requirements*

We forecast an approximate 35 percent increase in energy requirements over the 2024-2040 planning period, after accounting for EE included in the Base Case. As discussed above, the inclusion of two incremental EE Bundles reflects achievement of approximately 2.2 percent EE, which leaves our Net Demand substantially higher than forecast in our 2019 Plan. Figure 3-5 below compares our estimated net energy demand adjusted by the two EE Bundles, to the energy forecast in our 2019 Plan approved by the Minnesota Public Utilities Commission.

Figure 3-5: Forecasted Net Energy Requirements, After Energy Efficiency Adjustments[2] (GWh)



3. *Forecast Adjustments*

After determining the base peak capacity and energy demand forecasts, we make certain forecast adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. We summarize our key adjustments below:

Demand Side Management (DSM). Prior to our 2019 Plan, the load forecasts used in our modeling were adjusted for the expected effects of existing DSM programs. As with our 2019 Plan, in this ND Resource Plan, incremental EE beyond that classified as naturally-occurring is no longer embedded in the load forecast; rather, EE is treated as a potential supply-side resource in our modeling, like Demand Response (DR). We further discuss the EE and DR (collectively, DSM) in the context of our resource planning process in Appendix J in the 2024 Upper Midwest Plan.

Rooftop solar. Projected rooftop solar is handled similarly to Energy Efficiency and is modeled as a supply-side resource in EnCompass, and is not netted from energy and peak forecasts.

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[2] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a demand reduction from gross demand for purposes of the chart above.

Expected Customer Changes. We make adjustments to account for known and expected changes in load on our system. These typically reflect expected changes in specific large customers' electricity usage, either because of increased behind the meter energy generation, increased production activities by existing customers, or additional demand from new customers. This adjustment only applies to the Large Commercial/Industrial (CI) class.

Electric Vehicle Adoption. We adjust our energy and peak demand forecasts to account for increasing use of plug-in electric vehicle charging. These forecasts are based on estimates of current EV usage and future adoption (including the effect of financial incentives to facilitate adoption), and the expected electricity consumption per vehicle.

Beneficial Electrification. Residential and Commercial/Industrial energy as well as our peak demand outlooks are adjusted to account for growth in beneficial electrification from converted space and water heating.

We discuss our forecasting process, inputs, assumptions, adjustments, and results in more detail in Appendix E in the 2024 Upper Midwest Plan.

III. MISO RESOURCE ADEQUACY REQUIREMENTS

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSE) like the Company to maintain resources or secure capacity to cover their level of demand by a specific margin (planning reserve margin or PRM) to cover potential uncertainty in the availability of resources or level of demand.[3] The RA requirements are fundamental to the resource planning process and inform the level of capacity we need in our portfolio to adequately serve customers.

MISO's resource adequacy construct has historically been centered on an annual PRM. However, recognizing the increasing variability in reliability needs and resource availability throughout the year, MISO has implemented a seasonal RA construct beginning with the 2023 – 2024 planning year (PY), which spans June 1, 2023 through May 31, 2024 (and will be in place for subsequent PYs). The planning seasons are delineated as follows:

- Summer: June through August
- Fall: September through November
- Winter: December through February
- Spring: March through May

[3] The factors affecting availability and demand include: planned maintenance, unplanned or forced outages of generating facilities, deratings in resource capabilities, variations in weather, and load forecasting uncertainty.

We describe the various aspects of the seasonal PRM calculation and note that the seasonal MISO PRM and average NSP Coincidence Factor[4] in Table 3-1 below.

Table 3-1: MISO Seasonal Planning Reserve Margin and Average NSP Coincidence Factor[5]

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY 2024/2025	9.00%	14.20%	27.40%	26.70%
Average NSP Coincidence Factor	92.24%	92.67%	97.09%	95.61%

Prior to each planning year, MISO determines two different sets of capacity obligations for each LSE; one for the entire MISO footprint as a whole, and one for the Local Resource Zone (LRZ or Zone) where the LSE has load.[6]

A. MISO Footprint Capacity Obligation

By November 1 prior to a planning period, MISO issues the finalized seasonal PRM applicable to all LSEs within its footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM for each season needed to achieve a Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2024 through May 31, 2025 the overall MISO seasonal PRM on an installed capacity (ICAP)[7] basis and on an unforced capacity rating (UCAP) basis[8] are shown in Table 3-2 below.

[4] NSP Coincidence Factor refers to the NSP demand at the time of the MISO footprint peak demand.
[5] The values in Table 4-1 are not static and represent a snapshot in time.
[6] Almost all of the NSP system load is located within LRZ 1, which includes almost all of Minnesota, western Wisconsin, and the Dakotas. Approximately 7 MW of load along the Minnesota-Iowa border is located in LRZ 3.
[7] ICAP refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.
[8] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "MISO Planning Year 2024-2025 Loss of Load Expectation Study Report." Available at: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

Table 3-2: MISO Footprint PY 2024-2025 Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO PRM ICAP	17.7%	25.2%	49.4%	40.8%
MISO PRM UCAP	9.0%	14.2%	27.4%	26.7%

Over the planning period MISO examined in the 2023-2024 LOLE study,[9] the summer UCAP PRM increased from 7.4 percent in 2023 to 11.2 percent in 2032. The fall UCAP PRM remained relatively constant between 14.9-16.3 percent. The winter and spring UCAP PRMs also remained relatively constant between 23.7 and 25.5 percent between 2024-2033.[10,11]

Each LSE is required to have resources sufficient to meet the forecasted demand at the time of MISO's peak demand, plus its PRM. MISO's tariff acknowledges a state regulatory body's authority to establish a PRM for LSEs within its jurisdiction, which would override the PRM otherwise determined by MISO. None of the NSP System states have established a PRM that would override the MISO PRM.

B. Zonal Capacity Obligation

Additionally, MISO makes an annual determination regarding the amount of capacity required within each of MISO's Zones, called the Local Clearing Requirement (LCR) for each season. The LCR is determined as a function of each Zone's Local Reliability Requirement (LRR) and its Capacity Import Limit (CIL) for each season. The LRR represents the necessary resource requirement in order for a Zone to achieve a LOLE of 0.1 day per year, without relying on resources outside of the Zone. Each Zone, having a smaller footprint than the overall MISO footprint does not benefit from the same level of peak load diversity as does the larger, more diverse MISO footprint. If a Zone within which the Company operates has import capacity, however, the resulting LCR is reduced from the LRR to recognize the transmission system's ability to deliver outside resources into that Zone. Accordingly, the Company plans its minimum system needs based on the MISO-wide PRM while also ensuring zonal requirement are satisfied.

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[9] *See* "MISO Planning Year 2023-2024 Loss of Load Expectation Study Report." Available at: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

[10] We note these values vary slightly from the those presented in Table 4-2, which originate from the MISO PY 2024-2025 LOLE Study. This study has not yet been updated to incorporate the analyses of outyear PRMs.

[11] These PRMs were formulated without the assumption of a Direct Loss of Load methodology, which MISO intends to file in 2024. This change will impact the PRM.

For the 2024-2025 planning year, Zone 1 was determined to require an LRR of 18.9 GW to achieve the LOLE reliability requirement of 0.1 days per year. After accounting for Zone 1's summer CIL of 5.3 GW, Zone 1's summer LCR is reduced to 13.6 GW. Among the several LSEs in LRZ 1, the Company must meet its load share of LRZ 1's LCR as identified in Table 3-3 below.

Table 3-3: MISO PY 2024-2025 Seasonal Local Reliability Requirement

Local Resource Zone 1	Summer	Fall	Winter	Spring	Formula Key
LRZ 1 LRR (GW)	18.9	15.6	22.1	19.1	[A]
LRZ 1 Capacity Import Limit (CIL) (GW)	5.3	6.5	4.9	6.2	[B]
LRZ 1 LCR (GW)	13.6	9.1	17.2	12.9	[A] - [B]
NSP's Share of LRZ 1 LCR (GW)	6.7325	5.8556	7.1288	6.3785	

C. Capacity Obligations Derived from Forecasted Demands

After MISO determines seasonal PRM and zonal LRRs, each LSE's MISO-wide and zonal capacity obligation are derived for each season from its forecast of peak demand (peak load). While LSEs typically forecast the peak demand for their individual system, the resource adequacy process requires the LSE to also forecast:

- The LSE's demand at the time of the MISO footprint's peak demand (MISO Coincident Peak Demand, or MISO CPD); and
- The LSE's demand at the time of the LRZ's peak demand (Zonal Coincident Peak Demand, or Zonal CPD).

Because each LRZ footprint is smaller than the MISO footprint, the LRZ's load diversity is lower than the load diversity of the MISO system, and an LSE's Zonal CPD is typically greater than its MISO CPD.

The NSP System CPD factor measures how closely our system peak matches the MISO system peak. A coincidence factor of 95 percent indicates that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. In other words, the timing of our peak and the MISO peak does not match exactly, so we are able to reduce the amount of reserves we are required to carry.

Our estimated obligation for all planning period years can be found in the Load and Resources table in Section VI below.

D. Capacity Accreditation of Resources

After these obligation levels have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements. MISO has recently made changes to its resource accreditation process, moving from an annual accreditation to a seasonal accreditation capacity (SAC). This change is intended to align resource accreditation with availability in the highest risk periods. Under the new system, MISO accredits resources on their SAC, which is determined by the resource's availability during seasonal RA hours and non-RA hours. MISO conducts independent auctions for all seasons in the spring to clear capacity for LSEs that are short of meeting their seasonal resource adequacy requirements.

Resources used to achieve MISO's RA requirements are referred to as "Planning Resources." Planning Resources include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e., physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO's resource accreditation represents a measure of a resource's reliable contribution to the system's resource adequacy needs. MISO's SAC value for each resource, in megawatts, accounts for various factors such as plant availability and outages during tight system margins and performance during peak hours. Therefore, instead of using installed or nameplate capacity (i.e. ICAP), MISO calculates the SAC value for each resource to determine its expected contribution to RA. These are calculated differently depending on the resource's dispatchability or variability:

- *Dispatchable thermal resources* – MISO determines the SAC value for dispatchable thermal resources pursuant to Schedule 53. The SAC calculation for these resources is primarily based on the availability of offered resources, mostly during RA hours.

- *DR and EE resources* – MISO assigns capacity accreditation for DR and EE resources based on modeled forecasts.
- *Intermittent Generation and Dispatchable Intermittent resources* – The SAC value for intermittent generation resources or dispatchable intermittent resources is determined by MISO based on historical performance, availability, and type and volume of interconnection service. For wind resources, MISO determines SAC values based on interconnection service volumes and their respective wind capacity credit established through a seasonal Effective Load Carrying Capacity (ELCC) study. Wind capacity credits are determined for individual wind resources based on their average capacity factor during MISO's top eight coincident peaks that occurred during the season for the previous three years.

  The SAC value for non-wind intermittent generation and dispatchable intermittent resources (e.g., run-of-river hydro, solar) is a function of the individual unit's historical performance during the peak hours for each season of the planning period. Specifically, these units are measured on historical performance during the operating hours of 1500 to 1700 during the Summer, Fall and Springs seasons; and the hours of 0800, 0900, 1900 and 2000 in the Winter season over the three-year most recent period.
- *Energy storage resources* – The SAC value for energy storage resources is determined by MISO based on the total net energy during a test of at least one hour, deliverability, and the historical forced outage rate of the resource.

Our modeling selects resources based on their SAC values from MISO PY 2023/2024 with a long-term trend to ELCC values for wind and solar resources, to ensure we maintain adequate capacity on our system over the planning period.

IV. DEMAND SIDE MANAGEMENT

DSM programs offer our customers opportunities to lower their energy use and manage their peak demand, in particular through energy efficiency (EE) and demand response (DR) programs. The Company has several customer programs throughout our service territory in Minnesota, North Dakota, South Dakota and Wisconsin. Our largest programs are included in our Minnesota Energy Conservation and Optimization (ECO) Triennial Plan. In North Dakota, the Company has DR programs plus energy efficiency programs impacting our natural gas resources, but no specific energy efficiency programs for electric. We base our forecasts and potential incremental additions on historic achievements through our existing Minnesota programs, as well as external studies about expected and potentially achievable adoption rates.

As previously discussed, we adjusted the customer capacity and energy forecasts in the Upper Midwest Plan[12] to distinguish incremental EE from the load forecast. We modeled incremental DR and EE achievements as "Bundles" to be evaluated alongside other resource options. Each Bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost.

For EE, these Bundles include measures that work to reduce a customer's overall energy usage throughout the year. The Minnesota Commission's Order in Docket No. E002/RP-19-368, on June 14, 2022, requires the Company to save, on average, at least 780 gigawatt-hours via energy efficiency each year through 2034. To demonstrate compliance with that target in this Resource Plan, the Company has bifurcated naturally occurring EE[13] from energy savings claimed through our Minnesota ECO programs. We included three EE Bundles in our modeling for both the ND Reference Case and Preferred Plan. The Company developed the EE bundles based on the filed 2024-2026 Minnesota ECO Triennial.[14]

The DR Bundles, on the other hand, reflect a customer's commitment to discrete reductions in demand (e.g., on a day when peak load is expected to be high otherwise). These actions are expected to reduce the anticipated annual system peak demand, as well as smooth demand on specific days when weather or other conditions lead to high demand at a certain point in time. In the Order approving our 2019 Plan,[15] the Minnesota Commission directed that the Company "shall continue to acquire no less than 400 MWs of incremental demand response by 2023 as ordered in the Company's last Resource Plan." We included six DR Bundles in our modeling for both the ND Reference Case and Preferred Plan.

We discuss the development of the bundles, our expected EE and DR levels, our analysis, and the changing DSM landscape in more detail in Appendix J: Distributed Energy Resources in the 2024 Upper Midwest Plan.

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[12] The same forecast is used in the ND Resource Plan.
[13] Naturally Occurring energy efficiency includes customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by energy efficiency programs, but in the future world would not be part of an energy efficiency program because an efficient technology is required to meet code or has become common practice.
[14] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.
[15] *See* E002/RP-19-368 Order Approving Plan with Modifications and Establishing Requirements for Future Filings (April 15, 2022), Order Point 2.A.2.

V. EXISTING AND APPROVED RESOURCES

Our current generating resources[16] comprise a diverse portfolio including nuclear, coal, wind, biomass, solar, hydro, natural gas, and oil-fueled facilities. Physical generating assets owned by the Company have a net capacity of approximately 9,500 MWs. In addition to these assets, we purchase power from additional physical generating assets representing a capacity of approximately 5,600 MWs.[17] Together, these provide approximately 15,000 MWs of generation resources, of which approximately 7,700 MWs[18] is supplied by renewables. In addition to the physical assets above, customer-owned distributed solar, demand response, and energy efficiency provide additional portfolio diversity. Counting these additional customer-facing resource types, as well as the Company's nuclear units, more than 11,400 MWs of resources[19] supply carbon-free energy for our system.

A. Renewable Resources

In total, we currently have approximately 7,700 MWs of renewable capacity serving the NSP System, including:[20]

- 4,500 MWs of wind resources;
- 2,300 MWs of solar, including community solar programs and grid-scale solar;[21]
- 800 MWs of hydroelectric power;[22] and
- 130 MWs of biomass and landfill gas.

B. Nuclear

Our Monticello and Prairie Island nuclear plants provide a total net capacity of approximately 1,650 MWs of clean energy. These units operate at high-capacity factors and provide nearly 30 percent of the total electric energy and approximately 40 percent of the carbon-free energy our customers consume. Between 2019 and 2023, we have consistently maintained production costs at approximately $31.25 per megawatt-hour (MWh) or less, which is a decrease of more than 20 percent when compared to 2013 production costs.

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[16] Includes these resources: Sherco Solar 1, 2, and 3; Louise, Fillmore and Apple River solar.
[17] This total excludes the Company's current diversity exchange contract with Manitoba Hydro.
[18] *Id.*
[19] *Id.*
[20] Note: these values are approximate.
[21] Includes solar projects anticipated to be operational in 2024.
[22] Excluding capacity associated with diversity agreement contracts with Manitoba Hydro.

C. Coal

Our coal fleet includes our Sherburne County Generating Station (Sherco) Units 1 and 3 in Becker, Minnesota, and the Allen S. King plant[23] in Oak Park Heights, Minnesota. This coal fleet provides almost 1,700 MW of baseload and cycling generating capacity and supports system reliability. The Minnesota Commission approved our proposal to retire Sherco Coal Units 1 and 2 in 2026 and 2023, respectively, in its Order in Docket No. E-002/RP-15-21(January 11, 2017). Sherco Unit 2 was retired on December 31, 2023, resulting in a loss of 682 MW of firm dispatchable generation from the NSP system. In the 2019 Plan, the Minnesota Commission approved our proposal to retire the Allen S. King Generating Station in 2028 and Sherco Unit 3 in 2030.[24] These retirements are reflected in our ND Reference Case.

D. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of both intermediate and peaking generation. We have three owned and three contracted intermediate-type generating assets that provide over 2,000 MWs of capacity. We have peaking-type resources located at seven sites, providing nearly another 2,000 MWs of capacity. Combined, these facilities provide valuable load following capabilities for our system, cycling as necessary to provide important flexibility to our generation operations and support to our growing renewable resources.

VI. NET RESOURCE SURPLUS/DEFICIT

As described above, our forecast of customers' peak demand and MISO RA requirements are used to determine our overall total generating capacity obligation. From this we deduct our expected load management achievements and accredited capacity of the various resources we have included in our ND Reference Case to determine our net generation capacity surplus or deficit. We anticipate a net surplus through 2026 and a deficit thereafter, starting first in the spring and summer of 2027. ND Reference Case Load and Resources tables for each season are in Tables 3-4 through 3-7 below.

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[23] Asset is in seasonal operation. The identified capacity represents its maximum capacity offered during the winter season.

[24] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy,* Docket No. E002/RP-19-368, Order (April 15, 2022), at Order Point 2.A.4.

Table 3-4: ND Reference Case Load and Resources, 2024-2040 Planning Period, Summer Season[25]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Summer																	
Forecasted gross load	10,735	10,769	11,087	11,361	11,468	11,489	11,550	11,518	11,621	11,671	11,757	11,817	11,920	11,954	12,047	12,148	12,226
Adjustment to Load from non-bundled Energy Efficiency	(1,347)	(1,277)	(1,195)	(1,132)	(1,072)	(1,004)	(927)	(839)	(772)	(718)	(623)	(524)	(482)	(461)	(482)	(513)	(602)
Adjustment to Load from EVs and Beneficial Electrification	20	35	54	81	115	158	213	361	482	620	768	919	1,058	1,193	1,324	1,453	1,578
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Coincident Load	8,678	8,787	9,174	9,511	9,695	9,817	9,994	10,183	10,452	10,675	10,979	11,264	11,526	11,702	11,890	12,073	12,178
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
NSP Obligation (Summer)	**9,459**	**9,578**	**10,000**	**10,367**	**10,568**	**10,700**	**10,894**	**11,100**	**11,393**	**11,636**	**11,967**	**12,278**	**12,564**	**12,755**	**12,960**	**13,159**	**13,274**
ND Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response, Existing	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997	993	989	985	982	978
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,206	649	649	649	649	649	649
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,445	3,117	2,843	2,727	2,433	2,433	2,433	2,433	2,433	2,433	2,433	2,119	2,119
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38	38	38	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	170	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	785	780	744	743	737	706	704	683	674	585	573	566	564	507	502	496	473
Solar (Utility-Scale System Resources)	147	259	464	396	362	329	296	262	256	249	242	236	226	201	195	189	183
Solar (Legacy CSGs)	438	367	341	233	214	195	176	157	153	150	147	143	170	165	160	155	150
Solar (Net Metered as of 2024)	121	84	57	52	47	40	36	33	33	32	29	28	27	28	27	26	24
Existing Resources	**10,855**	**9,678**	**10,039**	**9,268**	**8,687**	**7,845**	**7,509**	**6,852**	**6,465**	**6,358**	**5,771**	**5,169**	**5,173**	**5,081**	**5,029**	**4,694**	**4,655**
Summer Net Resource (Need)/Surplus After Existing & Approved Resources	**1,396**	**100**	**39**	**(1,099)**	**(1,881)**	**(2,855)**	**(3,385)**	**(4,248)**	**(4,927)**	**(5,277)**	**(6,195)**	**(7,109)**	**(7,391)**	**(7,674)**	**(7,930)**	**(8,465)**	**(8,619)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response - Created by 400 MW Order	177	178	179	179	179	178	177	175	174	172	171	169	168	166	165	163	162
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	8	40	74	102	118	130	137	140	150	159	168	176	183	190	196	201	206
Solar (Net Metered Installed after 2024)	0	18	25	33	41	49	53	56	63	71	81	88	93	97	102	107	115
Solar (3% Distributed Solar Energy Standard)	0	0	0	21	78	107	128	114	114	114	114	113	113	112	112	111	110
Incremental Distributed Resources Brought Forth in This Plan	**299**	**451**	**598**	**761**	**944**	**1,092**	**1,208**	**1,285**	**1,383**	**1,479**	**1,580**	**1,671**	**1,651**	**1,643**	**1,634**	**1,605**	**1,581**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**1,695**	**551**	**637**	**(338)**	**(937)**	**(1,763)**	**(2,177)**	**(2,963)**	**(3,544)**	**(3,798)**	**(4,615)**	**(5,438)**	**(5,740)**	**(6,031)**	**(6,296)**	**(6,860)**	**(7,038)**

[25] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case. This includes new resources at the Wheaton Generating Station, which are currently before the Public Service Commission of Wisconsin.

Table 3-5: ND Reference Case Load and Resources, 2024-2040 Planning Period, Fall Season[26]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Fall																	
Forecasted gross load	8,809	8,820	9,085	9,300	9,328	9,338	9,357	9,370	9,286	9,310	9,343	9,386	9,402	9,435	9,478	9,515	9,295
Adjustment to Load from non-bundled Energy Efficiency	(1,302)	(1,226)	(1,156)	(1,089)	(1,027)	(965)	(892)	(818)	(736)	(673)	(581)	(501)	(458)	(442)	(461)	(482)	(562)
Adjustment to Load from EVs and Beneficial Electrification	21	39	58	87	121	168	224	298	509	648	802	951	1,089	1,225	1,356	1,485	1,882
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%
Coincident Load	6,976	7,073	7,401	7,690	7,805	7,914	8,053	8,201	8,396	8,605	8,863	9,115	9,298	9,469	9,612	9,747	9,838
MISO Planning Reserve Margin (UCAP)	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
NSP Obligation (Fall)	**7,967**	**8,078**	**8,452**	**8,782**	**8,914**	**9,038**	**9,196**	**9,365**	**9,588**	**9,826**	**10,121**	**10,410**	**10,618**	**10,814**	**10,977**	**11,131**	**11,235**
ND Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response, Existing	759	762	764	766	766	765	763	760	757	754	752	749	746	744	741	739	736
Coal	1,505	1,505	1,505	872	872	455	455	0	0	0	0	0	0	0	0	0	0
Nuclear	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,219	668	668	668	668	668	668
Natural Gas/Oil	3,810	3,726	3,726	3,726	2,938	2,938	2,644	2,533	2,235	2,235	2,235	2,235	2,235	2,235	2,235	1,953	1,953
Biomass/RDF	90	57	57	57	57	57	57	57	57	57	57	37	37	37	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	169	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	989	971	918	904	888	841	825	796	793	698	691	691	654	633	633	633	611
Solar (Utility-Scale System Resources)	66	137	262	251	239	228	217	205	207	208	210	211	209	193	194	195	196
Solar (Legacy CSGs)	194	172	154	148	141	135	129	123	124	125	127	128	158	158	159	160	161
Solar (Net Metered as of 2024)	90	56	34	33	31	28	26	25	26	26	25	25	25	26	27	27	25
Existing Resources	**10,299**	**9,352**	**9,385**	**8,721**	**7,898**	**7,413**	**7,081**	**6,464**	**6,095**	**5,997**	**5,395**	**4,823**	**4,805**	**4,764**	**4,734**	**4,451**	**4,427**
Fall Net Resource (Need)/Surplus After Existing & Approved Resources	**2,332**	**1,274**	**933**	**(62)**	**(1,015)**	**(1,625)**	**(2,115)**	**(2,902)**	**(3,493)**	**(3,830)**	**(4,726)**	**(5,586)**	**(5,814)**	**(6,050)**	**(6,243)**	**(6,679)**	**(6,808)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response - Created by 400 MW Order	97	97	97	98	97	97	96	95	94	93	92	91	90	89	88	87	86
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	4	23	45	65	78	90	101	110	121	133	145	157	169	182	195	207	220
Solar (Net Metered Installed after 2024)	0	12	15	21	27	34	39	43	50	59	69	77	84	92	98	109	120
Solar (3% Distributed Solar Energy Standard)	0	0	0	13	52	74	94	89	92	95	98	101	105	108	111	115	118
Incremental Distributed Resources Brought Forth in This Plan	**217**	**351**	**483**	**628**	**790**	**932**	**1,052**	**1,149**	**1,252**	**1,356**	**1,465**	**1,566**	**1,556**	**1,561**	**1,565**	**1,553**	**1,545**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,549**	**1,625**	**1,416**	**566**	**(225)**	**(693)**	**(1,063)**	**(1,753)**	**(2,241)**	**(2,473)**	**(3,260)**	**(4,020)**	**(4,257)**	**(4,488)**	**(4,678)**	**(5,126)**	**(5,263)**

[26] *Id.*

Table 3-6: ND Reference Case Load and Resources, 2024-2040 Planning Period, Winter Season[27]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Winter																	
Forecasted gross load	7,660	7,791	8,047	8,156	8,177	8,208	8,243	8,275	8,252	8,308	8,101	8,126	8,129	8,427	8,464	8,534	8,256
Adjustment to Load from non-bundled Energy Efficiency	(1,067)	(958)	(903)	(880)	(805)	(782)	(727)	(671)	(599)	(541)	(446)	(383)	(350)	(360)	(380)	(388)	(439)
Adjustment to Load from EVs and Beneficial Electrification	20	56	81	101	154	171	234	309	493	661	986	1,156	1,315	1,325	1,480	1,640	1,912
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%
Coincident Load	6,420	6,689	7,015	7,163	7,307	7,375	7,524	7,683	7,909	8,183	8,390	8,640	8,829	9,119	9,286	9,501	9,445
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Winter)	**8,179**	**8,522**	**8,937**	**9,125**	**9,309**	**9,396**	**9,586**	**9,788**	**10,076**	**10,425**	**10,689**	**11,007**	**11,249**	**11,617**	**11,831**	**12,105**	**12,033**
ND Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response, Existing	441	443	445	447	447	447	447	447	447	447	447	447	447	446	446	446	446
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,250	665	665	665	665	665	665
Natural Gas/Oil	4,372	4,372	4,204	4,204	3,997	3,255	3,255	2,753	2,753	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,131
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29	29	29	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	268	268	169	169	169	169	169	169	100	100	80	80	72	72	70	70	70
Wind	2,146	1,723	1,690	1,596	1,582	1,507	1,472	1,442	1,392	1,193	1,157	1,109	1,073	954	923	892	831
Solar (Utility-Scale System Resources)	1	32	58	50	42	34	27	19	11	23	34	45	56	60	70	80	89
Solar (Legacy CSGs)	5	41	34	29	25	20	16	11	7	14	20	27	34	50	57	65	73
Solar (Net Metered as of 2024)	0	52	6	7	6	5	4	3	2	3	5	7	8	10	11	13	14
Existing Resources	**10,717**	**10,372**	**10,046**	**9,318**	**9,083**	**7,785**	**7,736**	**6,722**	**6,589**	**6,137**	**5,524**	**4,888**	**4,864**	**4,766**	**4,729**	**4,717**	**4,327**
Winter Net Resource (Need)/Surplus After Existing & Approved Resources	**2,538**	**1,850**	**1,110**	**193**	**(225)**	**(1,610)**	**(1,850)**	**(3,066)**	**(3,487)**	**(4,288)**	**(5,164)**	**(6,119)**	**(6,384)**	**(6,852)**	**(7,101)**	**(7,387)**	**(7,706)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response - Created by 400 MW Order	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	6	10	13	14	14	12	10	7	14	23	33	45	57	70	85	100
Solar (Net Metered Installed after 2024)	0	11	3	5	5	6	6	5	3	7	14	21	28	35	43	53	71
Solar (3% Distributed Solar Energy Standard)	0	0	0	3	9	11	12	8	5	10	16	22	28	34	40	47	54
Incremental Distributed Resources Brought Forth in This Plan	**130**	**260**	**375**	**503**	**625**	**741**	**835**	**927**	**1,012**	**1,119**	**1,232**	**1,341**	**1,331**	**1,337**	**1,344**	**1,335**	**1,335**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,668**	**2,111**	**1,485**	**696**	**400**	**(869)**	**(1,014)**	**(2,139)**	**(2,475)**	**(3,168)**	**(3,932)**	**(4,778)**	**(5,054)**	**(5,515)**	**(5,757)**	**(6,053)**	**(6,371)**

[27] *Id.*

Table 3-7: ND Reference Case Load and Resources, 2024-2040 Planning Period, Spring Season [28]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Spring																	
Forecasted gross load	8,137	8,181	8,473	8,699	8,809	8,712	8,697	8,737	8,786	8,789	8,840	8,699	8,753	8,785	8,801	8,839	8,843
Adjustment to Load from non-bundled Energy Efficiency	(1,108)	(1,062)	(1,012)	(949)	(961)	(808)	(738)	(687)	(635)	(569)	(488)	(401)	(375)	(366)	(385)	(394)	(459)
Adjustment to Load from EVs and Beneficial Electrification	14	24	39	57	107	113	200	265	353	459	571	887	1,026	1,158	1,287	1,412	1,534
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%
Coincident Load	6,733	6,830	7,171	7,465	7,606	7,666	7,800	7,949	8,131	8,298	8,531	8,782	8,991	9,157	9,277	9,425	9,483
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Spring)	**8,531**	**8,653**	**9,085**	**9,459**	**9,637**	**9,712**	**9,883**	**10,072**	**10,302**	**10,514**	**10,809**	**11,127**	**11,392**	**11,601**	**11,754**	**11,941**	**12,015**
ND Reference Case Existing & Approved Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response, Existing	811	815	819	821	822	821	820	818	816	814	813	811	809	808	806	804	803
Coal	1,229	1,229	1,229	669	669	276	276	0	0	0	0	0	0	0	0	0	0
Nuclear	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,247	664	664	664	664	664	664
Natural Gas/Oil	4,003	4,003	3,919	3,919	3,710	3,130	3,130	2,702	2,702	2,430	2,430	2,430	2,430	2,430	2,430	2,430	2,169
Biomass/RDF	87	53	53	53	53	53	53	53	53	53	53	36	36	36	8	8	8
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	1,001	169	169	169	169	169	169	100	100	80	78	72	70	70	70	70
Wind	1,106	934	868	777	717	632	578	510	457	399	395	395	395	362	362	362	349
Solar (Utility-Scale System Resources)	157	90	180	182	185	187	189	191	193	186	178	171	163	141	134	127	121
Solar (Legacy CSGs)	483	112	106	107	109	111	112	114	116	112	108	104	100	116	110	105	99
Solar (Net Metered as of 2024)	119	131	53	26	25	25	25	26	27	25	24	23	21	21	21	19	17
Existing Resources	**10,818**	**10,189**	**9,218**	**8,545**	**8,281**	**7,226**	**7,174**	**6,405**	**6,285**	**5,941**	**5,328**	**4,712**	**4,692**	**4,648**	**4,605**	**4,590**	**4,300**
Spring Net Resource (Need)/Surplus After Existing & Approved Resources	**2,287**	**1,536**	**132**	**(914)**	**(1,356)**	**(2,486)**	**(2,708)**	**(3,667)**	**(4,016)**	**(4,573)**	**(5,482)**	**(6,415)**	**(6,700)**	**(6,954)**	**(7,150)**	**(7,352)**	**(7,715)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response - Created by 400 MW Order	109	109	110	110	110	110	109	109	108	107	107	106	105	105	104	104	103
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	3	15	31	47	60	74	88	102	113	119	123	127	130	133	134	135	136
Solar (Net Metered Installed after 2024)	0	29	24	17	22	31	38	45	53	58	68	71	74	75	78	79	85
Solar (3% Distributed Solar Energy Standard)	0	0	0	10	40	61	82	83	86	85	84	82	80	79	77	75	73
Incremental Distributed Resources Brought Forth in This Plan	**236**	**386**	**513**	**646**	**806**	**957**	**1,091**	**1,208**	**1,319**	**1,415**	**1,518**	**1,608**	**1,578**	**1,562**	**1,544**	**1,504**	**1,470**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,523**	**1,923**	**645**	**(268)**	**(550)**	**(1,529)**	**(1,618)**	**(2,459)**	**(2,697)**	**(3,158)**	**(3,963)**	**(4,807)**	**(5,121)**	**(5,392)**	**(5,605)**	**(5,848)**	**(6,245)**

[28] *Id.*

VII. REFERENCE CASE

We incorporate all the aforementioned elements into the EnCompass modeling tool, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plan through sensitivity analysis and special studies by individually changing key assumptions and re-running the plans under these changed assumptions. Our analysis resulted in the following Reference Case Expansion Plan, depicted in Tables 3-8 through 3-12 below.

Table 3-8: ND Reference Case Annual Expansion Plan, Summer Season UCAP[29]

Reference Case Resource Additions (Seasonal Accredited Capacity, Summer)																	
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	88	0	0	0	0	0	0	0
Storage	0	0	425	0	102	0	148	50	103	0	0	0	167	284	174	0	0
Firm Dispatchable	0	0	0	629	629	0	629	0	629	0	314	629	314	314	0	417	0
Wind	0	0	0	72	36	216	0	216	36	282	139	172	0	101	33	131	0
Distributed Resources																	
Demand Response	177	182	182	181	179	177	173	171	170	168	167	165	164	163	161	160	158
Energy Efficiency (EE) Bundles	114	101	106	105	102	100	84	88	83	80	84	78	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	8	50	41	58	81	49	33	0	17	17	19	14	12	11	10	9	12
Total Annual Resource Additions, Summer Accredited Capacity	**299**	**333**	**754**	**1,045**	**1,129**	**542**	**1,066**	**526**	**1,036**	**635**	**723**	**1,058**	**657**	**872**	**378**	**717**	**170**

[29] Note: This table includes EE, DR, and Distributed Solar resources that are also reflected in the Load and Resources Table.

Table 3-9: ND Reference Case Annual Expansion Plan, Fall Season UCAP[30]

Reference Case Resource Additions (Seasonal Accredited Capacity, Fall)																	
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	74	0	0	0	0	0	0	0
Storage	0	0	391	0	90	0	122	43	89	0	0	0	157	271	168	0	0
Firm Dispatchable	0	0	0	628	628	0	628	0	628	0	314	628	314	314	0	406	0
Wind	0	0	0	88	44	258	0	252	42	336	168	210	0	126	42	168	0
Distributed Resources																	
Demand Response	97	100	100	99	98	96	93	92	91	90	89	88	88	87	86	85	84
Energy Efficiency (EE) Bundles	116	102	107	107	103	101	86	89	84	81	84	78	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	4	31	24	39	58	41	35	8	21	24	26	23	23	23	23	26	28
Total Annual Resource Additions, Fall Accredited Capacity	**217**	**233**	**623**	**960**	**1,020**	**497**	**964**	**485**	**955**	**605**	**681**	**1,028**	**581**	**821**	**319**	**685**	**112**

[30] *Id.*

Table 3-10: ND Reference Case Annual Expansion Plan, Winter Season UCAP[31]

Reference Case Resource Additions (Seasonal Accredited Capacity, Winter)																	
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0
Storage	0	0	433	0	104	0	151	49	100	0	0	0	161	273	167	0	0
Firm Dispatchable	0	0	0	598	598	0	598	0	598	0	299	598	299	299	0	386	0
Wind	0	0	0	156	77	459	0	449	74	574	278	337	0	189	61	234	0
Distributed Resources																	
Demand Response	0	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency (EE) Bundles	130	114	119	119	115	113	95	99	93	90	92	86	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	0	17	0	8	8	3	0	0	0	17	21	22	25	25	28	32	40
Total Annual Resource Additions, Winter Accredited Capacity	**130**	**133**	**554**	**883**	**903**	**574**	**844**	**597**	**865**	**690**	**691**	**1,044**	**485**	**786**	**255**	**652**	**40**

[31] *Id.*

Table 3-11: ND Reference Case Annual Expansion Plan, Spring Season UCAP[32]

Reference Case Resource Additions (Seasonal Accredited Capacity, Spring)																	
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0
Storage	0	0	422	0	100	0	141	46	90	0	0	0	126	206	122	0	0
Firm Dispatchable	0	0	0	702	702	0	702	0	702	0	351	702	351	351	0	453	0
Wind	0	0	0	76	35	194	0	161	24	192	96	120	0	72	24	96	0
Distributed Resources																	
Demand Response	109	113	113	112	111	109	108	107	106	106	105	104	104	103	103	102	101
Energy Efficiency (EE) Bundles	124	109	115	114	111	108	92	96	90	87	91	85	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	3	41	11	19	49	43	42	22	22	9	13	6	4	2	3	0	4
Total Annual Resource Additions, Spring Accredited Capacity	**236**	**263**	**661**	**1,022**	**1,108**	**455**	**1,084**	**431**	**1,034**	**459**	**656**	**1,016**	**585**	**735**	**251**	**651**	**105**

[32] *Id.*

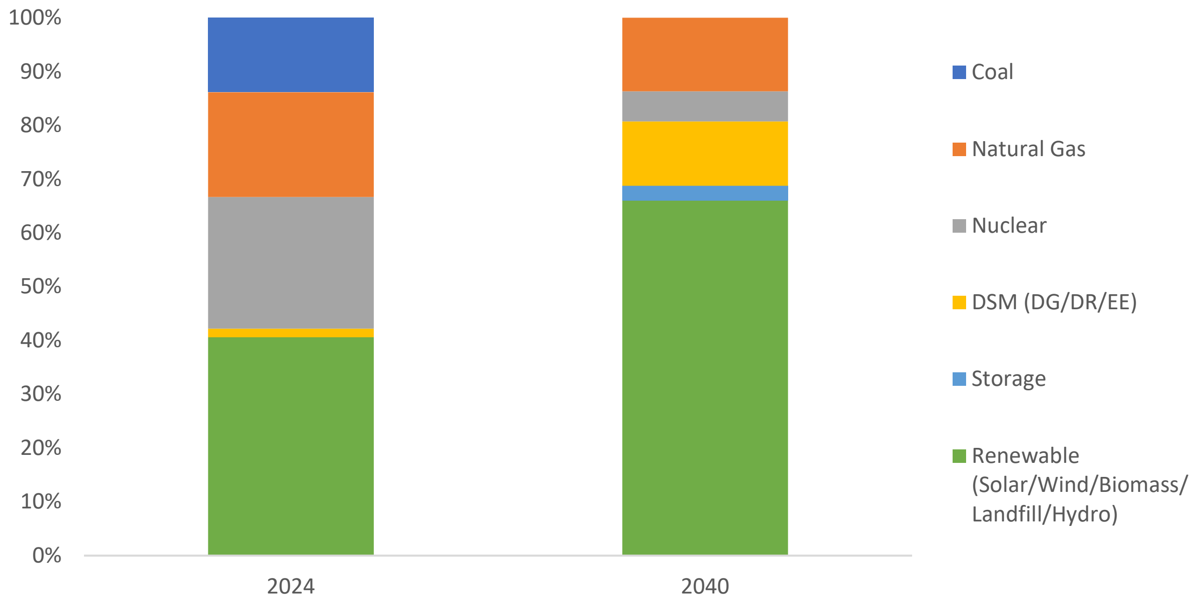
Table 3-12: ND Reference Case Annual Expansion Plan, ICAP[33]

Reference Case Resource Additions (Installed Capacity)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Generic Units																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	400	0	0	0	0	0	0	0
Storage	0	0	0	480	0	120	0	180	60	120	0	0	0	180	300	180	0
Firm Dispatchable	0	0	0	662	662	0	662	0	662	0	331	662	331	331	0	439	0
Wind	0	0	0	400	200	1,200	0	1,200	200	1,600	800	1,000	0	600	200	800	0
Distributed Resources																	
Demand Response	300	306	309	306	303	302	298	298	298	297	297	296	296	296	296	295	295
Energy Efficiency (EE) Bundles	124	109	115	114	111	108	92	96	90	87	91	85	0	0	0	0	0
Solar (Net Metered After 2024, 3% DSES, & Non-Legacy CSGs)	18	119	138	194	306	263	245	109	107	117	169	110	114	80	96	124	186
Total Annual Resource Additions, Installed Capacity	**443**	**535**	**561**	**2,155**	**1,582**	**1,993**	**1,297**	**1,883**	**1,416**	**2,621**	**1,688**	**2,153**	**741**	**1,487**	**891**	**1,838**	**481**

[33] *Id.*

The Reference Case presented here would result in the following energy mix depicted in Figure 3-6 below.

Figure 3-6: NSP System ND Reference Case Energy Mix in 2024 and 2040[34]



In Chapter 4, we detail our Preferred Plan. In Chapter 5: Economic Modeling Framework, we outline and discuss the starting assumptions, scenarios, and sensitivities that formed our EnCompass modeling analysis, and resulted in our Preferred Plan.

VIII. CONCLUSION

Our ND Resource Plan focuses on ensuring reliable and affordable service to our customers. The minimum number of resources required for the planning period is determined based on system needs and existing resources. The ND Reference Case, modeling scenarios, and ND Preferred Plan are developed based on this baseline. In our ND Resource Plan, our minimum system needs are informed by the seasonal resource adequacy construct recently implemented by MISO and our energy adequacy analysis. These changes are intended to address the increasing variability in reliability needs and resource availability throughout the year and align resource accreditation with availability.

[34] Storage represents the dispatch of energy from storage resources. Storage does not generate energy.

CHAPTER 4 – PREFERRED PLAN

I. INTRODUCTION

The North Dakota (ND) Preferred Plan we propose here continues to deliver on our obligations to provide safe, reliable, and affordable service to our customers. The key components of our ND Preferred Plan include:

- Adding thousands of megawatts of additional renewable resources to our system;
- Integrating and investing in energy storage systems, including adding short-duration storage systems to our fleet;
- Extending the life of our nuclear fleet;
- Ensuring reliability through additional firm dispatchable generation; and
- Continuing to increase Energy Efficiency and Demand Response resources to help reduce overall system demand.

Our ND Preferred Plan leverages existing grid connections and proven technologies, while using emerging technologies like battery storage to provide a balanced mix of resources, at an estimated average annual increase in retail rates of less than one percent, all while preserving our fundamental commitment to reliability.

Our planning objectives center on load growth while maintaining reliability and the cost effectiveness of our ND Preferred Plan. Importantly, we understand and have considered the impact that our ND Preferred Plan will have on our customers. Our strategy reflects our commitment to providing safe, reliable, and affordable energy to our customers.

II. ND PREFERRED PLAN

Our ND Preferred Plan is designed to maintain a safe, reliable, and affordable system for our customers and communities. Figure 4-1 below outlines our ND Preferred Plan's modeled resource additions over the 2024–2040 planning period, with new resource additions considered beginning in 2027.

Figure 4-1: ND Preferred Plan Resource Additions (MW)

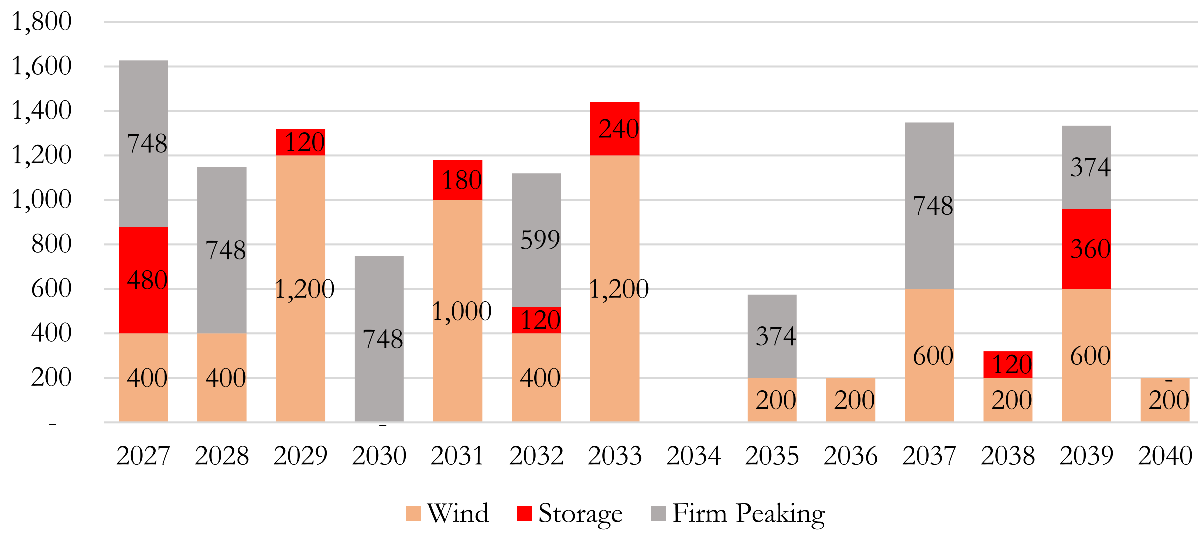
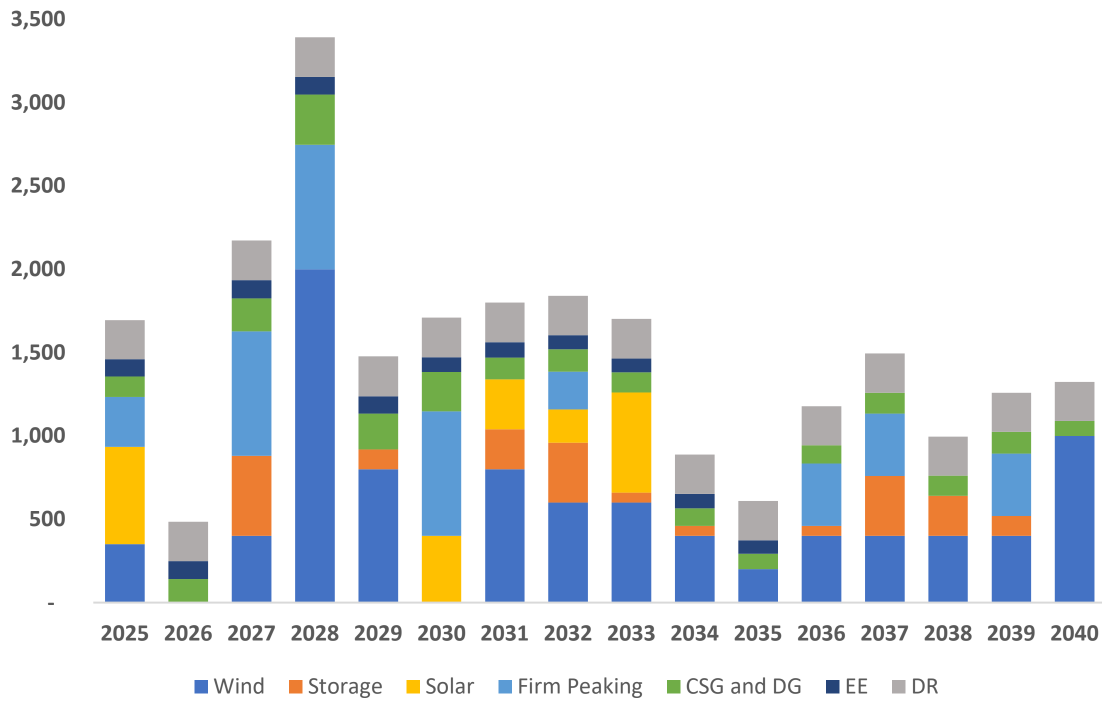


Figure 4-1 above illustrates our ND Preferred Plan's aim to maximize cost-effective resources. In doing that, the ND Preferred Plan relies on a diverse mix of renewable and firm dispatchable resources to reduce market exposure and risk while ensuring that the Company has the resources needed to continue to provide reliable service. This plan also retains the flexibility to consider the economics of new resources as our baseload plants retire. Further, the ND Preferred Plan reutilizes our valuable interconnection rights at Sherco, allowing for cost-effective integration of resources on our system through the Sherco gen-tie line.

As a point of comparison, Figure 4-2 below outlines our 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan) modeled resource additions over the 2024–2040 planning period.[1] Resource additions in 2025 include the approved Sherco Solar resources expected to achieve commercial operations in 2025, the Apple River solar resource, and the investments at our Wheaton and Blue Lake facilities.[2] The Community Solar Gardens (CSG) and Distributed Solar (DG) shown in Figure 4-2 below are also included in the baseline modeling conducted for the ND Preferred Plan.[3] The Energy Efficiency (EE) and Demand Response (DR) resources were also selected in the ND Preferred Plan.

[1] Filed with the Minnesota Public Utilities Commission on February 1, 2024.
[2] The Wheaton repowering is currently under review by the Wisconsin Public Service Commission.
[3] These resources are expected to be added to our Upper Midwest System and are therefore included as planned resources. However, the full cost of these resources is not allocated to North Dakota customers.

Figure 4-2: 2024 Upper Midwest Preferred Plan Resource Additions (MW)



2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
350	0	400	2,000	800	0	800	600	600	400	200	400	400	400	400	1,000
0	0	480	0	120	0	240	360	60	60	0	60	360	240	120	0
585	0	0	0	0	400	300	200	600	0	0	0	0	0	0	0
298	0	748	748	0	748	0	225	0	0	0	374	374	0	374	0
124	140	198	301	215	237	131	134	123	106	94	110	125	121	130	90
103	108	108	105	103	87	91	85	82	86	80	0	0	0	0	0
234	237	238	239	239	239	238	237	237	236	236	235	235	235	234	234

Despite the differences in these plans, the resource additions in both the North Dakota and Minnesota jurisdictions largely align in the near-term. This is shown in Table 4-1 below. In particular, both Preferred Plans select the same firm capacity additions of 2,244 MW and standalone storage of 600 MW. Additionally, both plans include substantial wind resource additions through 2030: 2,000 MW in North Dakota and 3,200 MW in the Upper Midwest.

Table 4-1: Near-Term ND and Upper Midwest Preferred Plan Resource Additions (MW)

North Dakota	2027	2028	2029	2030	Total
Standalone Storage	480	-	120	-	600
Wind	400	400	1,200	-	2,000
Solar	-	-	-	-	0
Firm Peaking	748	748	-	748	2,244
Upper Midwest (Minnesota)	**2027**	**2028**	**2029**	**2030**	**Total**
Standalone Storage	480	-	120	-	600
Wind	400	2,000	800	-	3,200
Solar	-	-	-	400	400
Firm Peaking	748	748	-	748	2,244

When projected out to 2024, our ND Preferred Plan will result in a diverse set of resources that can cost-effectively provide safe and reliable service to our customers. Our projected capacity and energy mix for 2040 under our ND Preferred Plan can be seen in Figures 4-3 and 4-4 below.

Figure 4-3: NSP System 2024 and 2040 ND Preferred Plan Capacity Mix

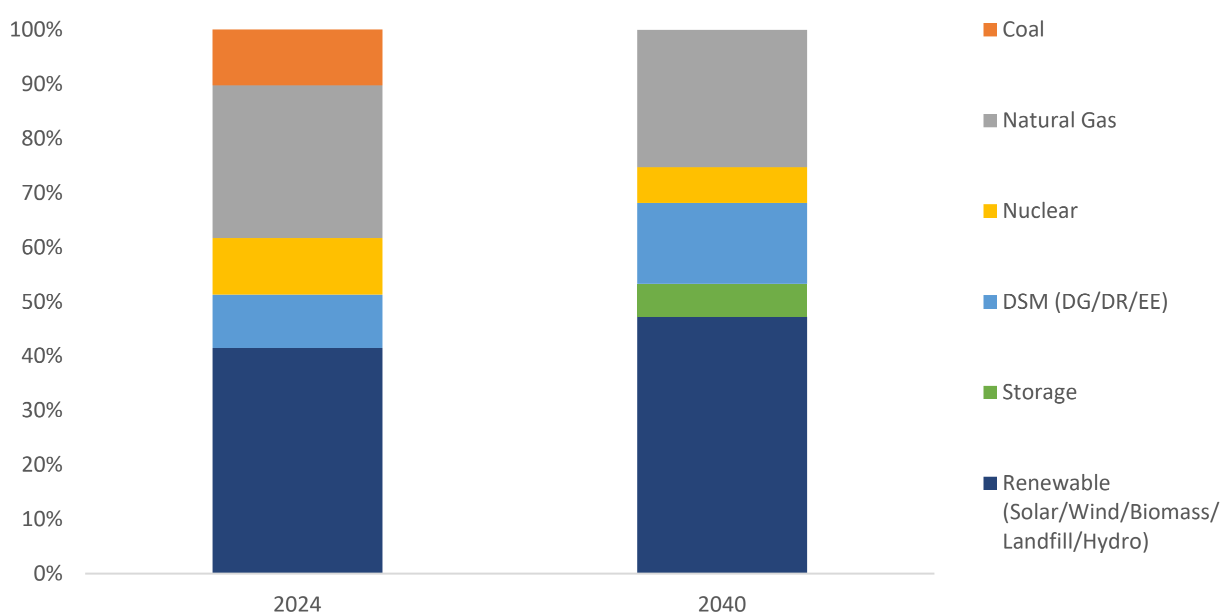
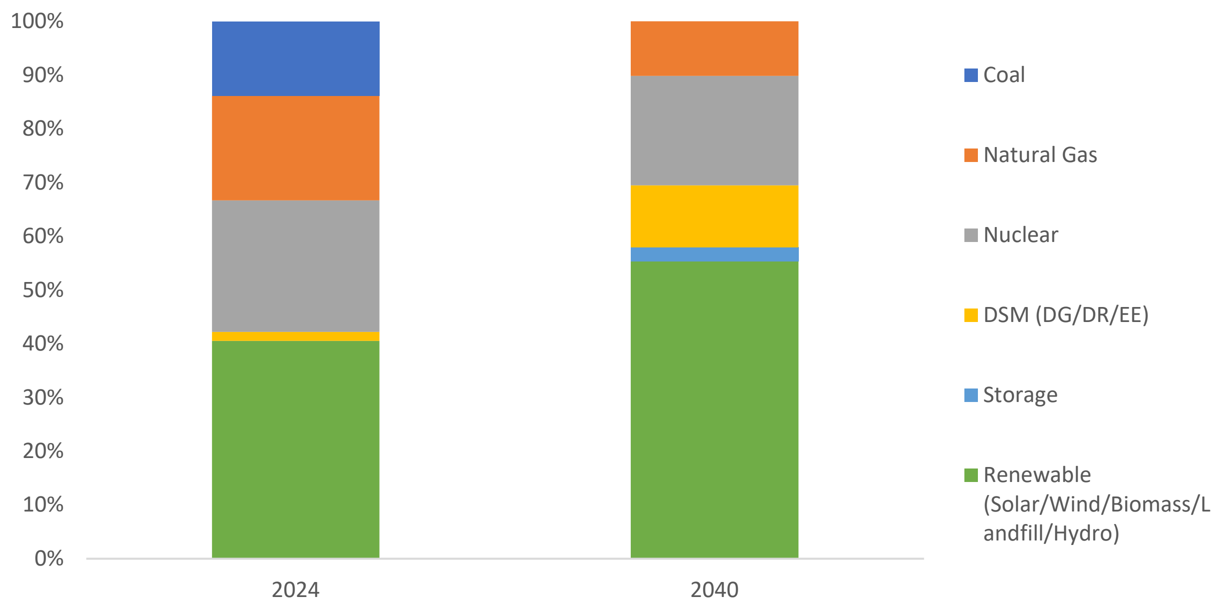


Figure 4-4: NSP System 2024 and 2040 ND Preferred Plan Energy Mix[4]



Below, we discuss the generation resources in our ND Preferred Plan in more detail.

A. Coal Resources

Our ND Preferred Plan continues along the path set in our 2019 Plan to close all of our coal units by 2030. We retired Sherco Unit 2 at the end of 2023, removing approximately 700 MWs of baseload coal from our fleet. We continue to plan for retiring Sherco Unit 1 in 2026, King in 2028, and Sherco Unit 3 in 2030, bringing our total coal reductions to 2,400 MWs.[5]

Closing our coal units makes economic sense due to changes in federal policy that makes replacing coal generation with cleaner energy sources more cost-effective. Regardless, these coal units have been a cornerstone of our fleet for decades, operating at high load-factors to provide reliable power to our customers. We therefore need to retire these resources responsibly by giving ourselves sufficient time to build the necessary replacement resources, help transition our workforce, and maintain a reliable system. Our ND Preferred Plan is designed to allow us to do just that.

[4] Storage represents the dispatch of energy from storage resources. Storage does not generate energy.
[5] The Minnesota Public Utilities Commission approved our proposal to retire Sherco Coal Units 1 and 2 in 2026 and 2023, respectively, in its Order in Docket No. E002/RP-15-21 (January 11, 2017). Additionally, our proposal to retire the Allen S. King Generating Station in 2028 and Sherco Unit 3 in 2030, respectively, was approved in its Order in Docket No. E002/RP-19-368 (April 15, 2022).

B. Renewable Resources

We have long been one of the nation's leading providers of wind energy and expect this to continue. Our ND Preferred Plan reflects the need for an incremental 6,600 MWs of wind capacity through 2040. This is a substantial increase from the amount of wind additions projected in our 2019 plan. There are two main drivers of this change. First, the change to the MISO seasonal construct has resulted in a higher accreditation during our summer peak, and in some other seasons, than the annual accreditation assumed in the 2019 Plan. This makes wind resources more valuable to our customers. Second, the production tax credits included in the newly enacted IRA have lowered the levelized cost of energy from wind resources. Further, wind resources do not have any fuel costs and act to insulate the Company against rising fuel prices. The wind additions included in the ND Preferred Plan are highly dependent on the underlying cost assumptions. Under scenarios with higher cost assumptions, significantly less wind is added.

C. Firm and Dispatchable Resources

We plan to add essential firm dispatchable capacity to our resource mix. As we transition our system, we remain committed to ensuring that we can still meet our customers' energy demands at all times. This reliability is a fundamental obligation of our service and one that our customers expect. Unlike intermittent renewable resources, firm dispatchable resources can be relied on to deliver power on-demand for extended periods of time due to their primary characteristics: dispatchability and consistent fuel supply. Our focus on reliability is particularly important because at the same time we are planning to retire our entire coal fleet (approximately 2,400 MWs of baseload generation), we also have nearly 1,700 MWs of power purchase agreements (PPAs) with other capacity resources set to expire between 2025 and 2028.

As shown in our energy adequacy analysis in Attachment 2 (ND Appendix D): Energy Adequacy Analysis, additional firm dispatchable resources help maintain reliability amid retiring base load generation. Our ND Resource Plan therefore includes the addition of approximately 4,300 MW of cumulative firm dispatchable resources between 2027 and 2040 to ensure long-duration, affordable energy when our intermittent renewables are not able to fully meet our customers' needs.

D. Battery Energy Storage Systems

We plan to add Battery Energy Storage Systems (BESS) to help meet some of our dispatchable needs. In addition to firm dispatchable resources, our modeling shows an incremental need for approximately 1,620 MW of storage between 2027 and 2040. The BESS modeled as part of our ND Resource Plan are short-duration storage systems. Although valuable, short-duration BESS cannot currently meet the longer duration dispatch needed from firm dispatchable resources.[6] Instead, the primary value to our system that short-duration BESS provides is in aiding renewable integration, providing grid support, deferring some, but not all, traditional grid investments, and improving power quality. We provide additional information on the uses of BESS, and its limitations, as part of the Appendix I: Minnesota Energy Storage Systems Assessment in the 2024 Upper Midwest Plan.

E. Nuclear Resources

We plan to extend operations at both of our nuclear plants. Combined, this will provide approximately 1,650 MW of net dispatchable generation. We propose to extend operation of the two Prairie Island Nuclear Generating Plant units for 20 years past the current license expirations, to 2053/2054, and to extend operation of the Monticello Nuclear Generating Plant by 10 years to 2050, which aligns with our Subsequent License Renewal application for Monticello pending review by the Nuclear Regulatory Commission.

To accommodate more intermittent renewable resources on the grid, we work with the MISO Day-Ahead market to allow for flexible power operation capabilities at all three nuclear units. Our nuclear plants can safely and efficiently ramp up or down to accommodate power changes of approximately 280 MW—or over 15 percent—of our nuclear capacity in response to the market. Our nuclear fleet is also a critical component of our reliability and stability strategy, particularly during the winter months when MISO's seasonal resource adequacy construct reduces the accredited capacity of renewables. We discuss the benefits of nuclear, as well as the performance of our nuclear fleet, in greater detail in Appendix M: Nuclear in the 2024 Upper Midwest Plan.

By continuing the operation of these plants to at least 2050, customers will continue to benefit from the baseload power that our nuclear fleet provides, while helping to keep costs low as we leverage these existing, reliable resources on our system. Nuclear is central to maintaining reliability as we transition our system.

[6] Recently, we partnered with Form Energy to deploy and test a multi-day, iron-air battery system at the Sherco site, but the project is a pilot, to allow for further study. We anticipate that advancements in long-duration storage and grid-forming technologies will continue, and that long-duration storage, together with other grid investments to ensure system stability, will have the potential to address firm dispatchable needs in the future.

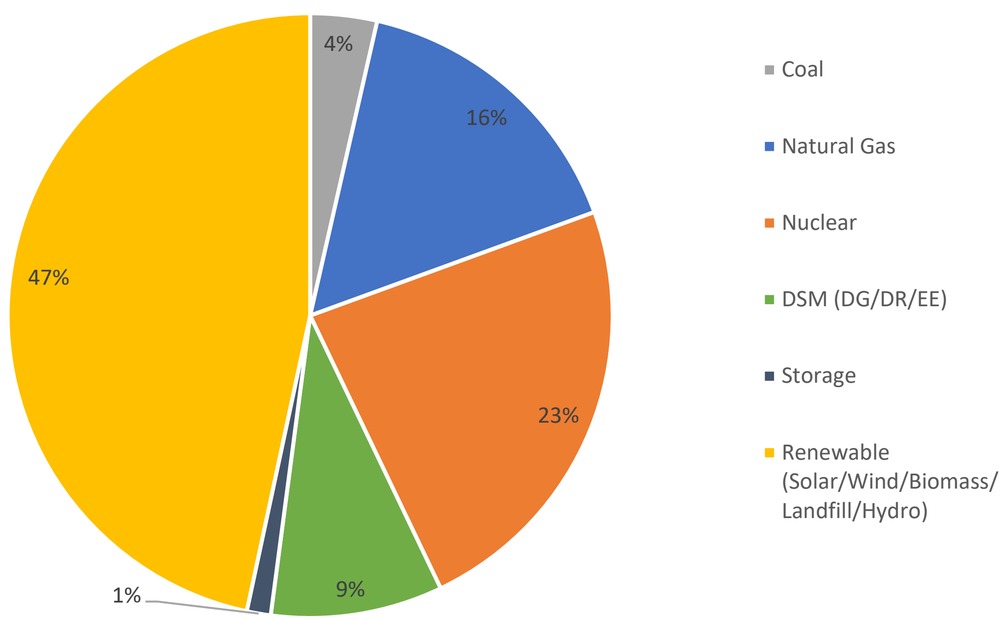
III. FIVE AND FIFTEEN YEAR PLANS

A. Five-Year Plan (2024-2030)

Our ND Preferred Plan does not identify any incremental capacity needs until 2027. However, from 2027 through 2030, our ND Preferred Plan contemplates adding over 4,800 MWs of incremental generation. Below, we discuss the near-term actions by resource type that underly our long-term plan, recognizing that the resource additions may need to be smoothed during the implementation process to create a portfolio of projects that can be constructed effectively within the constraints of the market for equipment and labor.

With our ND Preferred Plan, we are taking steps to transform our energy resource portfolio to include a robust mix of resources. We anticipate that by 2030 our forecasted energy mix would match that displayed in Figure 4-5 below.

Figure 4-5: NSP System 2030 ND Preferred Plan Energy Mix[7]



The details of this near-term resource mix and related plan are provided below.

[7] Storage represents the dispatch of energy from storage resources. Storage does not generate energy.

1. Wind

Our ND Preferred Plan proposes to add 2,000 MWs of wind additions through 2030. We are currently pursuing development transfer wind projects to utilize the interconnection at Sherco. We expect to begin further procurement activities in the next year to ensure we have the necessary wind generation online before the capacity is needed. To the extent we encounter opportunities to economically repower existing resources or if specific customer programs require specific procurements, we expect to pursue them and submit the plans for approval in separate proceedings.

2. Solar

Our ND Preferred Plan does not include any new utility scale solar projects between 2024 through 2030, other than those already approved by the Minnesota Public Utilities Commission and included in our Base Case. We acknowledge that the North Dakota Commission did not approve the Sherco Solar addition; however the Sherco Solar resource is included in our Base Case because it will be constructed and will be available to serve our customers across our Upper Midwest System.

3. Firm Dispatchable

Our ND Preferred Plan calls for 2,244 MWs of firm dispatchable resources by 2030. These resources are split between 748 MWs in 2027, 748 MWs in 2028, and 748 MWs in 2030. Approximately 374 MWs of the 2028 need is located on our re-optimized Sherco Generation tie line and is pending regulatory approvals from the Minnesota Commission. The rest of the firm dispatchable additions are not location specific and could include extension of existing resources.

We have already opened a proceeding before the Minnesota Commission to consider up to 800 MWs of firm dispatchable resources.[8] The 800 MWs are included in the 2,244 MWs proposed in our ND Preferred Plan. However, our modeling for our ND Preferred Plan confirms a need exceeding 800 MWs of firm dispatchable resources. As part of the 800 MW proceeding, the Company has submitted three proposals totaling in excess of 800 MWs. This includes the Bison Generating Station in Cass County, North Dakota, which consists of two natural gas-fired, simple cycle, 210 MW combustion turbine (CT) generators and three, nine MW Reciprocating Internal Combustion Engines (RICE), resulting in a total capacity of 447 MWs. Third-party providers have also submitted their own proposals.

[8] Docket No. E002/CN-23-212

4. Battery Energy Storage Systems

We plan to add approximately 600 MWs of BESS by 2030. The 600 MWs of BESS is comprised of a modeled 480 MWs of generic storage in 2027, and 120 MWs as part of our re-optimized Sherco Generation tie line in 2029. We expect to solicit these resources as part of a future request for proposals.

5. Nuclear Extension

In order to support our nuclear extensions to at least 2050, steps will need to be taken in the near future. In February of 2024, the Company filed a Certificate of Need with the Minnesota Commission for additional dry fuel storage to support continued operation of the Prairie Island Nuclear Generating Plant through 2053/2054. The concrete pad construction would occur over a 9- to 12-month period between 2027 and 2029 to support license extension and future dry fuel storage needs. By the end of 2026, we anticipate submitting our application for license renewal with the Nuclear Regulatory Commission to extend the Prairie Island plant operating license from 2033/2034 to 2053/2054.

With respect to the Monticello Nuclear Generating Plant, the Minnesota Commission recently approved dry fuel storage expansion in support of a Subsequent License Renewal, which is currently pending review by the Nuclear Regulatory Commission. The concrete pad construction at Monticello would occur in 2026 over a 9- to 12-month duration with spent fuel loading occurring in 2028 to support license extension and future dry fuel storage needs. Shortly after a Minnesota Commission decision on our 2024 Upper Midwest Plan, we will also seek another Certificate of Need to support the additional 10-year life extension of the Monticello plant.

6. Refuse Derived Fuel Waste to Energy Extension

Finally, all three of our renewable Refuse Derived Fuel (RDF) waste to energy generating plants are slated for retirement in 2027, and we plan to extend the life and operations of our Red Wing, Mankato, and French Island RDF plants to 2037, 2037, and 2040 respectively. These plants add significant value to our system and provide value to the local communities they serve. More about these plants, and the value they provide to their community, is included in Appendix W: RDF Plants in the 2024 Upper Midwest Plan.

B. Long-Term Plan

In addition to our immediate five-year plan, our long-term ND Preferred Plan relies on model-selected resources in the 2031-2040 planning period that we envision could be part of our energy future including:

- Adding an additional 4,600 MWs of incremental wind and repowering existing wind resources when economical;
- Adding an additional 1,020 MWs of incremental Battery Energy Storage Systems;
- Adding approximately 2,096 MWs of incremental firm dispatchable resources;
- Developing additional regional transmission infrastructure;
- Growing our DR portfolio to approximately 1,385 MW by 2040; and
- Continuing plans to achieve average annual energy savings, through our energy efficiency programs between 2031-2040.

IV. PUBLIC INTEREST ANALYSIS

As set forth in more detail below, we believe our ND Preferred Plan is in the public interest and merits Commission approval. We believe it best balances our goals to ensure reliability and maintain reasonable costs to customers.

A. Reliability

The ND Preferred Plan aims to provide safe and reliable service amidst the retirement of baseload units. Challenges in planning for reliability are presented by the new seasonal MISO Resource Adequacy construct, the increase in intermittent resources, and the uncertainty in future capacity accreditation and Planning Reserve Margins. The future accreditation of resources, crucial for investments in solar and storage resources, is particularly challenging due to its dependence on the installed capacity of all resource types across the MISO system.

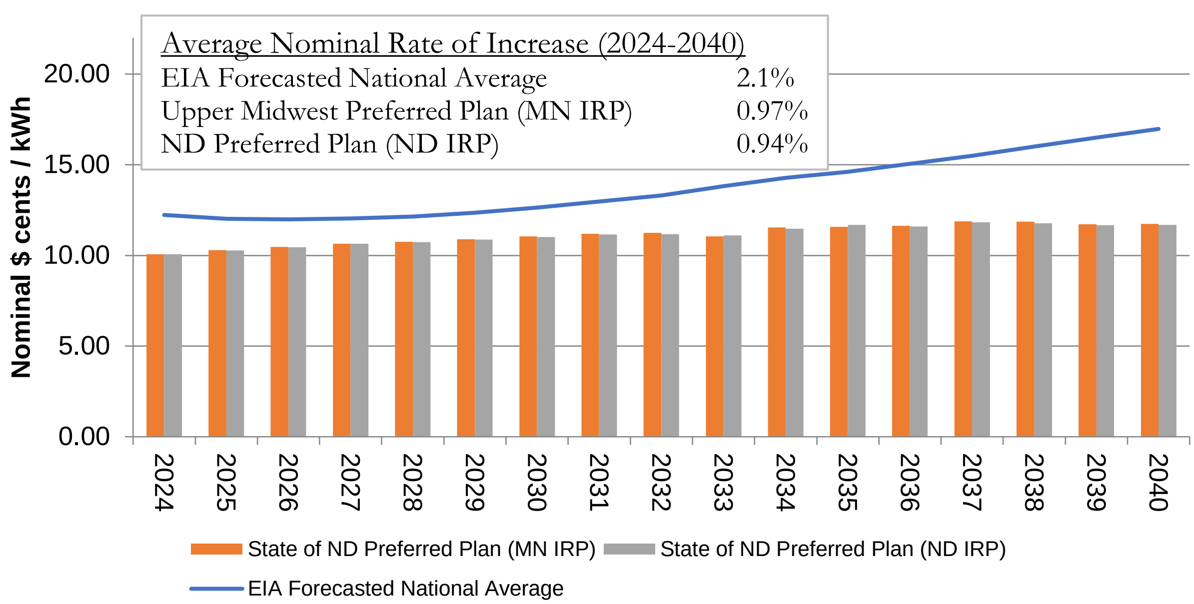
In this ND Resource Plan, we used an updated analytical approach to design a plan that addresses these challenges. It both ensures we have sufficient resources to meet our customers' needs and positions us to be able to comply with future changes to the MISO Resource Adequacy construct. We plan to meet customer needs with very limited reliance on neighboring systems and the broader MISO market. At the same time, we benefit from participation in the MISO market by incorporating the current planning assumptions and allowing for the economic dispatch of our resources within the broader region. As a result, our ND Preferred Plan is robust under changing assumptions and provides a path to transition our system while maintaining the reliable system our customers expect. For further detail on our reliability stress tests, see Attachment 2 (ND Appendix D): Energy Adequacy Analysis.

B. Impact to Customer Bills

The resources included in the ND Preferred Plan were selected without the consideration of externality costs or CO_2 constraints. Therefore, optimized resource planning for the ND Preferred Plan results in lower costs without the consideration of market interactions. As discussed further in Chapter 6, the ND Preferred Plan results in lower costs without the inclusion of revenue from the sale of excess generation. The Preferred Plan submitted to the Minnesota Commission includes significant generation in excess of native load serving needs. Therefore, the value of that excess generation in the market impacts the overall cost comparison of the plans.

Figure 4-6 below shows the relative cost growth of our ND Preferred Plan in comparison to our Upper Midwest Plan and the national average.

Figure 4-6: Average Nominal Cost Comparison State of ND Upper Midwest (MN) vs. ND Resource Plans



While there is a cost to add the resources the Company needs over the next 15 years to continue providing safe and reliable service and to address plant retirements and PPA expirations, the cost is modest and appropriate in light of the benefits.

For further details about the rate impact analysis, please see Chapter 6: Customer Rate and Cost Impacts.

C. Flexibility to Respond to Change

Our ND Preferred Plan positions the Company to meet near-term needs and create flexibility for the future. Planning constructs, federal and state policy changes, and technology development, cost, and adoption all create uncertainty, which led us to prioritize strategic flexibility in our ND Preferred Plan. With this diverse mix of resources, our system will not be overly reliant on any one fuel source, and we will continue to ensure reliability, while retaining the flexibility to consider the economics of new resources as our baseload plants retire. For example, we have left open our firm and dispatchable capacity needs in our long-term plan, recognizing that the technology landscape is rapidly changing, and new options may be more economically favorable than natural gas at that time. This flexibility enhances our ability to respond to changes in our planning landscape that could affect our operations during the planning period and preserves some agility for us to respond and adapt.

D. Limiting Risks

The ND Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The Plan incorporates significant capacity additions to replace retiring resources and expiring PPAs, consisting of a diverse portfolio of DSM, nuclear and RDF extension, wind, and firm dispatchable resource additions. Under the ND Plan, whether future wind additions will be cost-effective is dependent on the actual costs of wind resource available, but low-cost wind additions could reduce cost and provide a hedge against fuel prices ensuring we do not become too dependent on a single fuel source which mitigates risk.

We also have evaluated factors such as energy market exposure and portfolio length. All of our baseload scenarios show high levels of market interaction but are not overly reliant on the market to serve customer load.

V. CONCLUSION

Our ND Preferred Plan provides a least-cost resource mix that will allow the Company to continue providing safe and reliable service. It is consistent with the Company' 2019 Plan and aligns with the 2024 Upper Midwest Preferred Plan in the near-term. The plan proposes a diverse set of resources that work together to maintain reliability and keep costs low. These resources include significant additions of renewable generation, investments in energy storage systems, extension of our nuclear fleet's life, and the addition of firm dispatchable resources to balance the system and maintain reliability. By leveraging existing grid connections, proven technologies, and emerging technologies like battery storage, we aim to provide a balanced mix of resources.

Our planning objectives are consistent with North Dakota energy policy, centered on balancing service reliability and affordability. The ND Preferred Plan allows for the identification of divergences between North Dakota and our other jurisdictions. We believe that the ND Plan provides a path forward to reconcile differences when possible and maintain our integrated system.

Table 4-2: ND Preferred Plan Seasonal Accredited Capacity (SAC) Load and Resources 2024-2040 Planning Period, Summer Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Summer																	
Forecasted gross load	10,735	10,769	11,087	11,361	11,468	11,489	11,550	11,518	11,621	11,671	11,757	11,817	11,920	11,954	12,047	12,148	12,226
Adjustment to Load from non-bundled Energy Efficiency	(1,347)	(1,277)	(1,195)	(1,132)	(1,072)	(1,004)	(927)	(839)	(772)	(718)	(623)	(524)	(482)	(461)	(482)	(513)	(602)
Adjustment to Load from EVs and Beneficial Electrification	20	35	54	81	115	158	213	361	482	620	768	919	1,058	1,193	1,324	1,453	1,578
Forecasted Net Load	9,408	9,526	9,946	10,311	10,511	10,643	10,835	11,040	11,331	11,573	11,902	12,212	12,496	12,686	12,890	13,088	13,202
MISO System Coincidence	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Coincident Load	8,678	8,787	9,174	9,511	9,695	9,817	9,994	10,183	10,452	10,675	10,979	11,264	11,526	11,702	11,890	12,073	12,178
MISO Planning Reserve Margin (UCAP)	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
NSP Obligation (Summer)	**9,459**	**9,578**	**10,000**	**10,367**	**10,568**	**10,700**	**10,894**	**11,100**	**11,393**	**11,636**	**11,967**	**12,278**	**12,564**	**12,755**	**12,960**	**13,159**	**13,274**
ND Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response, Existing	1,011	1,015	1,019	1,021	1,021	1,020	1,016	1,012	1,008	1,004	1,001	997	993	989	985	982	978
Coal	1,475	1,475	1,475	883	883	461	461	0	0	0	0	0	0	0	0	0	0
Nuclear	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747
Natural Gas/Oil	4,020	3,719	3,962	3,962	3,445	3,117	2,843	2,727	2,433	2,433	2,433	2,433	2,433	2,433	2,433	2,119	2,119
Biomass/RDF	110	61	61	61	61	61	61	61	61	61	61	38	38	38	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	170	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	785	743	744	743	737	706	700	683	674	585	573	566	564	507	502	496	473
Solar (Utility-Scale System Resources)	147	259	464	396	362	329	296	262	256	249	242	236	226	201	195	189	183
Solar (Legacy CSGs)	438	367	341	233	214	195	176	157	153	150	147	143	170	165	160	155	150
Solar (Net Metered as of 2024)	121	84	57	52	47	40	36	33	33	32	29	28	27	28	27	26	24
Existing Resources	**10,855**	**9,641**	**10,039**	**9,268**	**8,687**	**7,845**	**7,505**	**6,852**	**6,465**	**6,358**	**6,313**	**6,267**	**6,271**	**6,179**	**6,127**	**5,792**	**5,753**
Summer Net Resource (Need)/Surplus After Existing & Approved Resources	**1,396**	**64**	**39**	**(1,099)**	**(1,881)**	**(2,855)**	**(3,388)**	**(4,248)**	**(4,927)**	**(5,277)**	**(5,654)**	**(6,011)**	**(6,293)**	**(6,576)**	**(6,832)**	**(7,367)**	**(7,521)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Summer)																	
Demand Response - Created by 400 MW Order	244	232	232	231	230	229	227	225	223	221	219	217	215	213	211	209	207
Energy Efficiency (EE) Bundles	114	215	321	426	528	628	712	801	883	963	1,047	1,125	1,094	1,077	1,060	1,023	988
Solar (Non-Legacy CSGs)	8	40	74	102	118	130	137	140	150	159	168	176	183	190	196	201	206
Solar (Net Metered Installed after 2024)	0	18	25	33	41	49	53	56	63	71	81	88	93	97	102	107	115
Solar (3% Distributed Solar Energy Standard)	0	0	0	21	78	107	128	114	114	114	114	113	113	112	112	111	110
Incremental Distributed Resources Brought Forth in This Plan	**366**	**505**	**651**	**813**	**995**	**1,143**	**1,258**	**1,335**	**1,433**	**1,528**	**1,629**	**1,719**	**1,698**	**1,690**	**1,680**	**1,651**	**1,626**
Summer Net Resource (Need)/Surplus Even After Additional Distributed Resources	**1,762**	**569**	**690**	**(286)**	**(885)**	**(1,712)**	**(2,130)**	**(2,913)**	**(3,494)**	**(3,749)**	**(4,025)**	**(4,293)**	**(4,595)**	**(4,886)**	**(5,152)**	**(5,716)**	**(5,895)**
ND Preferred Plan Resource Additions (Seasonal Accredited Capacity, Summer)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	425	417	512	502	640	754	976	996	1,017	1,037	1,058	1,192	1,562	1,591
Firm Dispatchable	0	0	0	629	1,257	1,257	1,886	1,886	2,400	2,400	2,400	2,714	2,714	3,343	3,343	3,657	3,657
Wind	0	0	0	72	144	360	360	540	605	810	800	826	850	941	963	1,050	1,069
Additions	**0**	**0**	**0**	**1,126**	**1,819**	**2,129**	**2,748**	**3,065**	**3,760**	**4,186**	**4,197**	**4,557**	**4,602**	**5,342**	**5,498**	**6,269**	**6,317**
Projected Net Position (Need)/Surplus	**1,762**	**569**	**690**	**840**	**933**	**417**	**618**	**153**	**265**	**436**	**171**	**264**	**7**	**455**	**346**	**552**	**422**

Table 4-3: ND Preferred Plan Seasonal Accredited Capacity (SAC) Load and Resources 2024-2040 Planning Period, Fall Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Fall																	
Forecasted gross load	8,809	8,820	9,085	9,300	9,328	9,338	9,357	9,370	9,286	9,310	9,343	9,386	9,402	9,435	9,478	9,515	9,295
Adjustment to Load from non-bundled Energy Efficiency	(1,302)	(1,226)	(1,156)	(1,089)	(1,027)	(965)	(892)	(818)	(736)	(673)	(581)	(501)	(458)	(442)	(461)	(482)	(562)
Adjustment to Load from EVs and Beneficial Electrification	21	39	58	87	121	168	224	298	509	648	802	951	1,089	1,225	1,356	1,485	1,882
Forecasted Net Load	7,528	7,633	7,987	8,299	8,423	8,540	8,689	8,850	9,060	9,285	9,564	9,836	10,034	10,218	10,373	10,517	10,616
MISO System Coincidence	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%
Coincident Load	6,976	7,073	7,401	7,690	7,805	7,914	8,053	8,201	8,396	8,605	8,863	9,115	9,298	9,469	9,612	9,747	9,838
MISO Planning Reserve Margin (UCAP)	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
NSP Obligation (Fall)	**7,967**	**8,078**	**8,452**	**8,782**	**8,914**	**9,038**	**9,196**	**9,365**	**9,588**	**9,826**	**10,121**	**10,410**	**10,618**	**10,814**	**10,977**	**11,131**	**11,235**
ND Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response, Existing	759	762	764	766	766	765	763	760	757	754	752	749	746	744	741	739	736
Coal	1,505	1,505	1,505	872	872	455	455	0	0	0	0	0	0	0	0	0	0
Nuclear	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796
Natural Gas/Oil	3,810	3,726	3,726	3,726	2,938	2,938	2,644	2,533	2,235	2,235	2,235	2,235	2,235	2,235	2,235	1,953	1,953
Biomass/RDF	90	57	57	57	57	57	57	57	57	57	57	37	37	37	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	169	169	169	169	169	169	169	100	97	80	78	72	70	70	70	70
Wind	989	925	918	904	888	841	825	794	751	698	691	649	654	633	633	633	611
Solar (Utility-Scale System Resources)	66	137	262	251	239	228	216	205	207	208	210	211	209	193	194	195	196
Solar (Legacy CSGs)	194	172	154	148	141	135	129	123	124	125	127	128	158	158	159	160	161
Solar (Net Metered as of 2024)	90	56	34	33	31	28	26	25	26	26	25	25	25	26	27	27	25
Existing Resources	**10,299**	**9,306**	**9,385**	**8,721**	**7,898**	**7,413**	**7,081**	**6,461**	**6,053**	**5,997**	**5,972**	**5,908**	**5,932**	**5,892**	**5,862**	**5,579**	**5,555**
Fall Net Resource (Need)/Surplus After Existing & Approved Resources	**2,332**	**1,228**	**933**	**(62)**	**(1,016)**	**(1,625)**	**(2,115)**	**(2,904)**	**(3,535)**	**(3,830)**	**(4,150)**	**(4,501)**	**(4,686)**	**(4,922)**	**(5,116)**	**(5,552)**	**(5,680)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Fall)																	
Demand Response - Created by 400 MW Order	162	151	149	149	148	147	145	144	142	141	139	138	136	135	133	132	130
Energy Efficiency (EE) Bundles	116	218	325	432	536	637	723	812	895	976	1,061	1,139	1,108	1,091	1,073	1,036	1,000
Solar (Non-Legacy CSGs)	4	23	45	65	78	90	101	110	121	133	145	157	169	182	195	207	220
Solar (Net Metered Installed after 2024)	0	12	15	21	27	34	39	43	50	59	69	77	84	92	98	109	120
Solar (3% Distributed Solar Energy Standard)	0	0	0	13	52	74	94	89	92	95	98	101	105	108	111	115	118
Incremental Distributed Resources Brought Forth in This Plan	**283**	**404**	**535**	**679**	**841**	**982**	**1,101**	**1,198**	**1,301**	**1,404**	**1,512**	**1,612**	**1,602**	**1,607**	**1,610**	**1,598**	**1,589**
Fall Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,614**	**1,633**	**1,468**	**618**	**(175)**	**(643)**	**(1,014)**	**(1,706)**	**(2,234)**	**(2,426)**	**(2,637)**	**(2,889)**	**(3,084)**	**(3,315)**	**(3,506)**	**(3,954)**	**(4,091)**
ND Preferred Plan Resource Additions (Seasonal Accredited Capacity, Fall)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	391	375	448	428	530	641	848	885	921	958	994	1,139	1,516	1,568
Firm Dispatchable	0	0	0	628	1,255	1,255	1,883	1,883	2,388	2,388	2,388	2,702	2,702	3,330	3,330	3,644	3,644
Wind	0	0	0	88	174	430	425	630	714	966	966	1,008	1,050	1,176	1,218	1,344	1,386
Additions	**0**	**0**	**0**	**1,107**	**1,805**	**2,134**	**2,737**	**3,043**	**3,743**	**4,203**	**4,239**	**4,631**	**4,710**	**5,500**	**5,687**	**6,504**	**6,598**
Projected Net Position (Need)/Surplus	**2,614**	**1,633**	**1,468**	**1,725**	**1,630**	**1,491**	**1,722**	**1,337**	**1,509**	**1,777**	**1,602**	**1,743**	**1,626**	**2,185**	**2,181**	**2,550**	**2,507**

Table 4-4: ND Preferred Plan Seasonal Accredited Capacity (SAC) Load and Resources 2024-2040 Planning Period, Winter Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Winter																	
Forecasted gross load	7,660	7,791	8,047	8,156	8,177	8,208	8,243	8,275	8,252	8,308	8,101	8,126	8,129	8,427	8,464	8,534	8,256
Adjustment to Load from non-bundled Energy Efficiency	(1,067)	(958)	(903)	(880)	(805)	(782)	(727)	(671)	(599)	(541)	(446)	(383)	(350)	(360)	(380)	(388)	(439)
Adjustment to Load from EVs and Beneficial Electrification	20	56	81	101	154	171	234	309	493	661	986	1,156	1,315	1,325	1,480	1,640	1,912
Forecasted Net Load	6,612	6,889	7,225	7,377	7,526	7,596	7,750	7,913	8,146	8,428	8,641	8,899	9,094	9,392	9,565	9,786	9,728
MISO System Coincidence	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%
Coincident Load	6,420	6,689	7,015	7,163	7,307	7,375	7,524	7,683	7,909	8,183	8,390	8,640	8,829	9,119	9,286	9,501	9,445
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Winter)	**8,179**	**8,522**	**8,937**	**9,125**	**9,309**	**9,396**	**9,586**	**9,788**	**10,076**	**10,425**	**10,689**	**11,007**	**11,249**	**11,617**	**11,831**	**12,105**	**12,033**
ND Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response, Existing	441	443	445	447	447	447	447	447	447	447	447	447	447	446	446	446	446
Coal	1,562	1,562	1,562	938	938	469	469	0	0	0	0	0	0	0	0	0	0
Nuclear	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826
Natural Gas/Oil	4,372	4,372	4,204	4,204	3,997	3,255	3,255	2,753	2,753	2,480	2,480	2,480	2,480	2,480	2,480	2,480	2,131
Biomass/RDF	96	52	52	52	52	52	52	52	52	52	52	29	29	29	7	7	7
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	268	268	169	169	169	169	169	169	100	100	80	80	72	72	70	70	70
Wind	2,146	1,641	1,685	1,596	1,573	1,488	1,470	1,426	1,392	1,193	1,157	1,109	1,073	954	923	892	831
Solar (Utility-Scale System Resources)	1	28	58	50	42	34	27	19	11	23	34	45	56	60	70	80	89
Solar (Legacy CSGs)	5	41	34	29	25	20	16	11	7	14	20	27	34	50	57	65	73
Solar (Net Metered as of 2024)	0	52	6	7	6	5	4	3	2	3	5	7	8	10	11	13	14
Existing Resources	**10,717**	**10,285**	**10,041**	**9,318**	**9,075**	**7,766**	**7,734**	**6,706**	**6,589**	**6,137**	**6,100**	**6,049**	**6,025**	**5,926**	**5,890**	**5,878**	**5,487**
Winter Net Resource (Need)/Surplus After Existing & Approved Resources	**2,538**	**1,764**	**1,104**	**193**	**(234)**	**(1,630)**	**(1,851)**	**(3,082)**	**(3,487)**	**(4,288)**	**(4,588)**	**(4,958)**	**(5,224)**	**(5,691)**	**(5,941)**	**(6,227)**	**(6,546)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Winter)																	
Demand Response - Created by 400 MW Order	62	50	48	47	46	45	45	44	43	43	42	41	41	40	40	39	38
Energy Efficiency (EE) Bundles	130	243	363	482	597	710	805	904	997	1,087	1,179	1,265	1,230	1,211	1,191	1,150	1,110
Solar (Non-Legacy CSGs)	0	6	10	13	14	14	12	10	7	14	23	33	45	57	70	85	100
Solar (Net Metered Installed after 2024)	0	11	3	5	5	6	6	5	3	7	14	21	28	35	43	53	71
Solar (3% Distributed Solar Energy Standard)	0	0	0	3	9	11	12	8	5	10	16	22	28	34	40	47	54
Incremental Distributed Resources Brought Forth in This Plan	**191**	**310**	**424**	**549**	**671**	**786**	**880**	**971**	**1,055**	**1,162**	**1,274**	**1,382**	**1,372**	**1,377**	**1,384**	**1,374**	**1,373**
Winter Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,729**	**2,074**	**1,528**	**742**	**438**	**(843)**	**(971)**	**(2,111)**	**(2,432)**	**(3,126)**	**(3,314)**	**(3,576)**	**(3,852)**	**(4,314)**	**(4,557)**	**(4,853)**	**(5,172)**
ND Preferred Plan Resource Additions (Seasonal Accredited Capacity, Winter)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	433	425	521	512	652	738	952	969	986	1,003	1,020	1,147	1,499	1,523
Firm Dispatchable	0	0	0	598	1,197	1,197	1,795	1,795	2,275	2,275	2,275	2,574	2,574	3,172	3,172	3,472	3,472
Wind	0	0	0	156	309	765	757	1,122	1,258	1,651	1,601	1,618	1,630	1,764	1,763	1,875	1,861
Additions	**0**	**0**	**0**	**1,187**	**1,931**	**2,483**	**3,063**	**3,570**	**4,271**	**4,878**	**4,845**	**5,178**	**5,207**	**5,957**	**6,082**	**6,845**	**6,856**
Projected Net Position (Need)/Surplus	**2,729**	**2,074**	**1,528**	**1,930**	**2,368**	**1,639**	**2,092**	**1,459**	**1,839**	**1,752**	**1,531**	**1,602**	**1,355**	**1,643**	**1,526**	**1,992**	**1,683**

Table 4-5: ND Preferred Plan Seasonal Accredited Capacity (SAC) Load and Resources 2024-2040 Planning Period, Spring Season

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Needs: Spring																	
Forecasted gross load	8,137	8,181	8,473	8,699	8,809	8,712	8,697	8,737	8,786	8,789	8,840	8,699	8,753	8,785	8,801	8,839	8,843
Adjustment to Load from non-bundled Energy Efficiency	(1,108)	(1,062)	(1,012)	(949)	(961)	(808)	(738)	(687)	(635)	(569)	(488)	(401)	(375)	(366)	(385)	(394)	(459)
Adjustment to Load from EVs and Beneficial Electrification	14	24	39	57	107	113	200	265	353	459	571	887	1,026	1,158	1,287	1,412	1,534
Forecasted Net Load	7,043	7,143	7,500	7,808	7,955	8,018	8,158	8,314	8,504	8,679	8,923	9,185	9,404	9,577	9,703	9,858	9,918
MISO System Coincidence	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%
Coincident Load	6,733	6,830	7,171	7,465	7,606	7,666	7,800	7,949	8,131	8,298	8,531	8,782	8,991	9,157	9,277	9,425	9,483
MISO Planning Reserve Margin (UCAP)	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
NSP Obligation (Spring)	**8,531**	**8,653**	**9,085**	**9,459**	**9,637**	**9,712**	**9,883**	**10,072**	**10,302**	**10,514**	**10,809**	**11,127**	**11,392**	**11,601**	**11,754**	**11,941**	**12,015**
ND Preferred Plan Existing & Approved Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response, Existing	811	815	819	821	822	821	820	818	816	814	813	811	809	808	806	804	803
Coal	1,229	1,229	1,229	669	669	276	276	0	0	0	0	0	0	0	0	0	0
Nuclear	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821	1,821
Natural Gas/Oil	4,003	4,003	3,919	3,919	3,710	3,130	3,130	2,702	2,702	2,430	2,430	2,430	2,430	2,430	2,430	2,430	2,169
Biomass/RDF	87	53	53	53	53	53	53	53	53	53	53	36	36	36	8	8	8
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	1,001	1,001	169	169	169	169	169	169	100	100	80	78	72	70	70	70	70
Wind	1,106	890	835	777	715	632	578	510	457	399	395	395	395	362	362	362	349
Solar (Utility-Scale System Resources)	157	90	180	182	185	187	189	191	193	186	178	171	163	141	134	127	121
Solar (Legacy CSGs)	483	112	106	107	109	111	112	114	116	112	108	104	100	116	110	105	99
Solar (Net Metered as of 2024)	119	131	53	26	25	25	25	26	27	25	24	23	21	21	21	19	17
Existing Resources	**10,818**	**10,146**	**9,185**	**8,545**	**8,279**	**7,226**	**7,174**	**6,405**	**6,285**	**5,941**	**5,902**	**5,869**	**5,849**	**5,805**	**5,762**	**5,747**	**5,457**
Spring Net Resource (Need)/Surplus After Existing & Approved Resources	**2,287**	**1,492**	**100**	**(914)**	**(1,357)**	**(2,486)**	**(2,708)**	**(3,667)**	**(4,016)**	**(4,573)**	**(4,907)**	**(5,258)**	**(5,543)**	**(5,797)**	**(5,993)**	**(6,195)**	**(6,558)**
ND Preferred Plan Incremental Distributed Resources (Seasonal Accredited Capacity, Spring)																	
Demand Response - Created by 400 MW Order	175	163	162	161	161	160	159	157	156	155	153	152	151	150	148	147	146
Energy Efficiency (EE) Bundles	124	233	348	462	573	682	773	870	959	1,046	1,137	1,222	1,189	1,170	1,151	1,111	1,074
Solar (Non-Legacy CSGs)	3	15	31	47	60	74	88	102	113	119	123	127	130	133	134	135	136
Solar (Net Metered Installed after 2024)	0	29	24	17	22	31	38	45	53	58	68	71	74	75	78	79	85
Solar (3% Distributed Solar Energy Standard)	0	0	0	10	40	61	82	83	86	85	84	82	80	79	77	75	73
Incremental Distributed Resources Brought Forth in This Plan	**302**	**441**	**565**	**697**	**856**	**1,007**	**1,140**	**1,256**	**1,367**	**1,462**	**1,565**	**1,654**	**1,624**	**1,606**	**1,589**	**1,548**	**1,513**
Spring Net Resource (Need)/Surplus Even After Additional Distributed Resources	**2,589**	**1,933**	**665**	**(216)**	**(501)**	**(1,479)**	**(1,568)**	**(2,411)**	**(2,649)**	**(3,111)**	**(3,342)**	**(3,604)**	**(3,919)**	**(4,190)**	**(4,404)**	**(4,647)**	**(5,045)**
ND Preferred Plan Resource Additions (Seasonal Accredited Capacity, Spring)																	
Solar (Utility-Scale System Resources)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	422	410	499	485	611	684	853	839	825	812	798	867	1,095	1,076
Firm Dispatchable	0	0	0	702	1,403	1,403	2,105	2,105	2,669	2,669	2,669	3,020	3,020	3,722	3,722	4,072	4,072
Wind	0	0	0	76	140	323	295	401	408	552	552	576	600	672	696	768	792
Additions	**0**	**0**	**0**	**1,199**	**1,953**	**2,224**	**2,884**	**3,117**	**3,761**	**4,074**	**4,060**	**4,422**	**4,432**	**5,192**	**5,285**	**5,936**	**5,940**
Projected Net Position (Need)/Surplus	**2,589**	**1,933**	**665**	**982**	**1,452**	**745**	**1,316**	**706**	**1,112**	**963**	**718**	**818**	**513**	**1,002**	**880**	**1,289**	**895**

CHAPTER 5 – ECONOMIC MODELING FRAMEWORK

I. INTRODUCTION

We have used the EnCompass Resource Planning model to perform our economic analysis since 2020. We use EnCompass as our primary resource planning software to estimate the costs of various resource expansion plan options, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. EnCompass results are a decision support tool to guide development and selection of a Preferred Plan and test the robustness of the plan under a variety of assumptions and sensitivities.

To ultimately identify and refine our North Dakota (ND) Preferred Plan presented in Chapter 4, we created three scenarios that examined different combinations and timing of baseload nuclear unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs. We refer to these scenarios as "baseload study scenarios." After this analysis was completed, we used the outcomes and sensitivity tests to select and refine a ND Preferred Plan. Finally, we conducted special studies on the ND Preferred Plan for a more thorough examination of specific issues not fully covered in the plan.

We discuss our assumptions, scenarios, sensitivities and how these inputs guided selection of our ND Preferred Plan in more detail below. This comprehensive analysis ultimately aligns with and reinforces our ND Preferred Plan.

II. BASE ASSUMPTIONS IN THE REFERENCE CASE

There are several assumptions included in our baseline data inputs that are common across all scenarios studied. These factors may, in some cases, be varied within sensitivities, but are largely kept constant across the default study of each scenario.

As discussed in Chapter 2: Planning Landscape, in 2023, Minnesota's distributed solar energy standard (DSES) was amended at subdivision 2h of Minn. Stat. § 216B.1691. This amendment mandates that at least three percent of the Company's retail electric sales in Minnesota be generated from solar energy generating systems that meet certain eligibility criteria by 2030. While we did not include constraints to meet the required renewable energy standard, solar energy standard, or carbon-free standard, we did include resources in the model to comply with the three percent DSES by 2030.

Other important starting assumptions in our analysis include:

Load Forecast. The Company used discrete changes in assumptions for electric vehicles, large commercial and industrial customers, beneficial electrification, and rooftop solar to determine our load and energy forecasts under two alternatives to the base forecast, which is our most probable forecast of future load changes: the High and Low load sensitivities. We provide detailed descriptions of our load forecasting methodology and assumptions under each of our sensitivities in Appendix E: Load and Distributed Energy Resource Forecasting in the 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan).

We also incorporated a seasonal planning reserve margin, per MISO requirements, as shown in Table 5-1. The modeled Planning Reserve Margin is based on the MISO Planning Year 2024-2025 assumptions, adjusted for the average coincidence factors in MISO Planning Year 2024-2025 and Planning Year 2023-2024. EnCompass determines an effective reserve margin based on our MISO coincident factor assumption. For summer 2024, the coincidence factor results in a reduction to net load of 730 MW.

Table 5-1: Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY24/25	9.00%	14.20%	27.40%	26.70%
Average Coincidence Factor	92.24%	92.67%	97.09%	95.61%

Existing Fleet. We develop forecasts to model our existing fleet's cost and performance assumptions (such as variable O&M, heat rate, forced outage rate, maintenance requirements, etc.) based on historical data, with adjustments for known future changes where applicable. Additional operational and performance assumptions include:

- Retirements of Sherburne County Generating Station (Sherco) Units 1 and 3 in 2026 and 2030, respectively, and retirement of the Allen S. King plant in 2028, as approved by the Minnesota Public Utilities Commission (MPUC or Minnesota Commission) in our last resource plan, 2020-2034 Upper Midwest Integrated Resource Plan (2019 Plan);[1]

[1] Sherco Unit 2 was retired on December 31, 2023.

- Sherco Units 1 and King are dispatched economically through their respective retirement dates. Sherco 3 is jointly owned with Southern Municipal Power Agency (SMMPA). We are currently offering Sherco 3 as a must-run under our operating agreement with SMMPA. We will continue to work with SMMPA to identify opportunities to operate Sherco 3 more flexibly as the plant nears its end of life. Therefore, in the modeling, we have assumed Sherco 3 is offered as must-run through 2029 and offered on an economic basis in 2030.
- Retirement of all other facilities at their current expected end of life, if that is planned to occur within the resource planning period, unless we have specifically included costs of life extension (e.g. for nuclear units in scenarios that include life extension);
- Short-term PPA extensions for Mankato Energy Center and Cannon Falls, consistent with recently-executed agreements;
- Sherco and King generation tie lines reoptimized with a Combustion Turbine (CT), solar, storage, and wind allowed for selection on the Sherco generation tie-line; and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Major PPA expirations include:

- Manitoba Hydro: 835 MW in 2025
- Cottage Grove: 226 MW in 2027
- Mankato Energy Center: 314 MW in 2028
- Cannon Falls: 317 MW in 2028.

Additional cost–related assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Costs associated with re-licensing the nuclear plants were developed for use in the Baseload Study modeling.

Renewable Energy. The addition of Sherco Solar 1, 2, and 3, Apple River Solar, and the Louise and Fillmore solar projects are included in our baseline assumptions. We also included small solar resources in our baseline assumptions.

In addition, we have assumed:

- Accreditation of new and existing wind, solar and battery resources based on the 2023-2024 MISO Planning Year seasonal accredited capacity. For years beyond 2024, the seasonal accredited capacity trends over multiple years to meet the assumptions in MISO's November 2022 Regional Resource Assessment (RRA).
- The costs used for wind, solar, and storage assets fully incorporate the Production Tax Credit (PTC) or Investment Tax Credit (ITC) in the Inflation Reduction Act (IRA). The IRA allows the transferability of tax credits, allows utilities to elect out from normalization for storage facilities, and allows owners of solar facilities to claim a PTC in lieu of the ITC, which is subject to normalization.
- The resources on the generation tie-lines to Sherco and King were allowed to re-optimize—meaning the model selected from an updated resource mix based on updated assumptions to maximize customer and system benefits. Wind, Solar, storage, and a firm dispatchable resource were available for selection on the Sherco tie-line. Solar additions were available for selection on the King tie-line, but no solar additions were selected in the North Dakota Preferred Plan.

Markets. We have optimized resource additions in the EnCompass model to ensure that the portfolio of resources developed is capable of serving customer load across all hours by limiting access to the MISO market. The limited access is applied to the resource optimization to avoid over reliance on MISO market purchases for reliability or sales for wholesale revenues. We conduct analysis that allows the model to access the MISO market to dispatch resources and take advantage of the access to economic resources in the larger MISO market, but this analysis does not impact the expansion plan.

Wholesale electricity price forecasts. To derive the forecast of monthly On and Off-peak electricity prices, the Company uses a simple average of On and Off-peak power price forecasts provided by external analysts Wood Mackenzie and S&P Global. To generate hourly market prices, the Company uses the hourly energy price forecast from the Horizons Energy EnCompass National Database, specifically the energy prices at the MISO-ND-MN node and scales it to match the monthly On and Off-peak price forecasts.

Purchase and sales limits. In our EnCompass model, when we allow access to the MISO market in the dispatch, we include a limit on the amount of energy that we can either purchase from or sell to the MISO market. This limit was established in our 2019 Plan based on PROMOD modeling and historical transfer data. For the ND Resource Plan, we have continued to assume a market interaction limit of 2,300 MWs over the 2024-2040 planning period. Further, we include a cap on market sales of no more than 25 percent of retail sales consistent with the assumption used in our 2019 Plan. While significant transmission expansion projects are at various stages of development, as discussed in Attachment 5 (ND Appendix T): MISO Grid Congestion, we believe it is prudent to limit market exposure during this period of rapid energy transition as further discussed below and have conducted analysis that does not include market sales in the dispatch which we rely on for the rate impact analysis, as discussed further in Chapter 6.

Generic Resources. EnCompass uses generically defined resources to meet future demand when our already existing and approved resources are not sufficient in a given year. Generic resources are modeled as incremental units of a certain installed capacity size. The ICAP values are provided below, and the UCAP, representing the MISO seasonal accredited capacity value the units would yield, is factored into the EnCompass modeling process. For example, although the generic unit size for solar is 100 MW installed capacity, the resource adequacy or MISO capacity credit value we would expect to receive for a plant of that size is as little as 6.3 MWs in the winter for Planning Year 2023-2024.

Generic units ICAP values included in modeling are as follows:[2]

- 374 MW gas-fired CT unit
- 225 MW gas-fired CT unit
- 108 MW reciprocating engine peaking unit (RICE)
- 60 MW utility scale battery
- 200 MW wind project
- 100 MWdc utility scale solar, and
- 130 MWdc solar + 60 MWac battery, 100 MWac inverter.

Attachment 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs, provides more detail on modeling assumptions. Please see Appendix H: Resource

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[2] The cost and performance data for these units are based on consultant's estimates, publicly available third-party data, and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction.

Options in the 2024 Upper Midwest Plan for additional discussion on supply-side resource options included in the analysis.

Customer Programs. Incremental customer programs for Demand Response (DR) and Energy Efficiency (EE) were included as potential resources in the EnCompass model. The derivation of these six DR and three EE "Bundles" is described in Appendix J: Distributed Energy Resources in the 2024 Upper Midwest Plan. It is important to note that these Bundles represent generic Demand-Side Management (DSM) additions and therefore may not perfectly align with the size and timing of actual DR or EE additions to the system in the future.

III. SCENARIOS

We created three scenarios to examine combinations and timing of baseload nuclear unit retirements (our only remaining baseload units after Sherco and King retire by the end of this decade), and the resulting size, type, and timing of new resources we would need to add to continue meeting customers' needs. We describe key parameters of these scenarios below.

A. Reference Case Scenario

We describe the development of our Reference Case in Chapter 3: Minimum System Needs. The Reference Case (Scenario 1) is an extension of our approved 2019 Plan,[3] in that all of the baseload units retire at their currently scheduled retirement dates, and it serves as our starting point. The Reference Case includes the following underlying assumptions:

- Approved or planned resources, including: Sherco Solar 1, 2, and 3; Apple River, Louise and Fillmore solar projects; Wheaton Repower[4]
- Extension of our Refuse Derived Fuel Waste to Energy Generating Plants
- Short-term PPA extensions include: Mankato Energy Center and Cannon Falls
- Sherco and King Tie-Line reoptimized
- CT allowed for selection on Sherco Tie-Line
- Optimized without market purchases/sales.

[3] July 25, 2021 Reply Comments, MPUC Docket No. E002/RP-19-368.
[4] Wheaton Repower is subject to approval by the Public Service Commission of Wisconsin.

Additional resource options are evaluated and optimized in the modeling and added when economic. These resource options include wind, solar, storage, combustion turbines, and reciprocating engines, as described in Attachment 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs.

To determine the optimal strategy regarding the future of the baseload nuclear fleet, we developed two additional scenarios with varying combinations of nuclear retirement dates. The resulting system needs were then met with an EnCompass model-optimized portfolio of new resources. Internal finance, energy supply, and nuclear subject matter experts worked to develop a robust set of assumptions and potential retirement dates for the nuclear retirements. These input assumptions include: ongoing capital expenditures, O&M expenses, and decommissioning and/or life extension costs. We also incorporated planning level estimates from a "leave behind" study conducted by the Company to determine the transmission system impacts of the nuclear plants' retirement to inform our ND Preferred Plan.

B. Prairie Island Extension Scenario

For the Prairie Island Nuclear Generating Plant extension scenario (Scenario 2), the Prairie Island 1 and 2 retirement date extends from 2033/2034 to 2053/2054. The Monticello Nuclear Generating Plant retirement date is unchanged. This scenario is designed to test the economics of re-licensing Prairie Island and extending the operational life by 20 years.

C. Extend All Nuclear Scenario

For the "extend all nuclear" scenario (Scenario 3), the Prairie Island 1 and 2 retirement date extends from 2033/2034 to 2053/2054, and the Monticello retirement date extends from 2040 to 2050. This scenario is designed to test the economics of re-licensing both Prairie Island 1 and 2 and Monticello, extending the operational life of Prairie Island by 20 years and Monticello by 10 years.[5]

IV. MARKET ACCESS AND RELIABILITY

While reliability has always been a critical objective of resource planning, there has been increased focus on regional reliability in the past several years as utilities and

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[5] The Company has assumed operation of the Monticello Plant until 2040 in its Reference Case because that is consistent with our last resource plan. The Company also received a Certificate of Need from the Minnesota Commission to obtain the additional cask storage needed to operate the plant until 2040. The Company has requested an Advance Determination of Prudence from the North Dakota Commission to extend the life of Monticello. That request is pending at the time of this filing.

other generation owners across the country retire significant dispatchable capacity, replacing it with significant amounts of variable renewable generation. In 2022, the North American Reliability Corporation (NERC) concluded that the MISO region was at risk of insufficient electricity supplies during peak winter conditions.[6] MISO's 2022-2023 Planning Resource Auction (PRA) resulted in a capacity shortfall for the MISO North/Central Regions resulting in the price of capacity clearing at the Cost of New Entry (CONE). More recently, NERC concluded that the supply of electricity in the MISO region "is more likely to be insufficient in the forecast period and that more firm resources are needed."[7]

Recognizing the evolving reliability challenges, MISO has proposed changes to its resource adequacy (RA) construct. The seasonal RA construct was implemented last year and provided reserve margin and resource capacity contributions tailored to each season (spring, summer, fall, winter). Additional changes to the RA construct – namely the Reliability-Based Demand Curve and the Direct Loss-of-Load (DLOL) accreditation methodology – are also under consideration[8] and will impact the resources needed in the MISO region to meet reliability requirements.

The evolving MISO RA construct creates a challenge to resource planning. Ensuring resource and energy adequacy to all our customers across our Upper Midwest System is a foundational duty of our business. The challenges facing resource planning include the change to a seasonal RA construct, a transition to a higher percentage of intermittent resources across the region, and uncertainty in accredited capacity and future Planning Reserve Margins (PRM). The future accreditation of resources presents a particularly difficult challenge for planners. Investments in solar and storage resources, like other resources, depend on the capacity value of the resources over the life of the assets, which is dependent upon the installed capacity of all resource types in the MISO system.

In this ND Resource Plan, the Company used an analytical approach to develop a plan that ensures we have sufficient resources to meet our customers' needs at all times and positions us to be able to comply with future changes to the MISO RA construct, while retaining the economic benefits of participation in the MISO market. Our ND Resource Plan adds resources to be able to meet customer needs with very

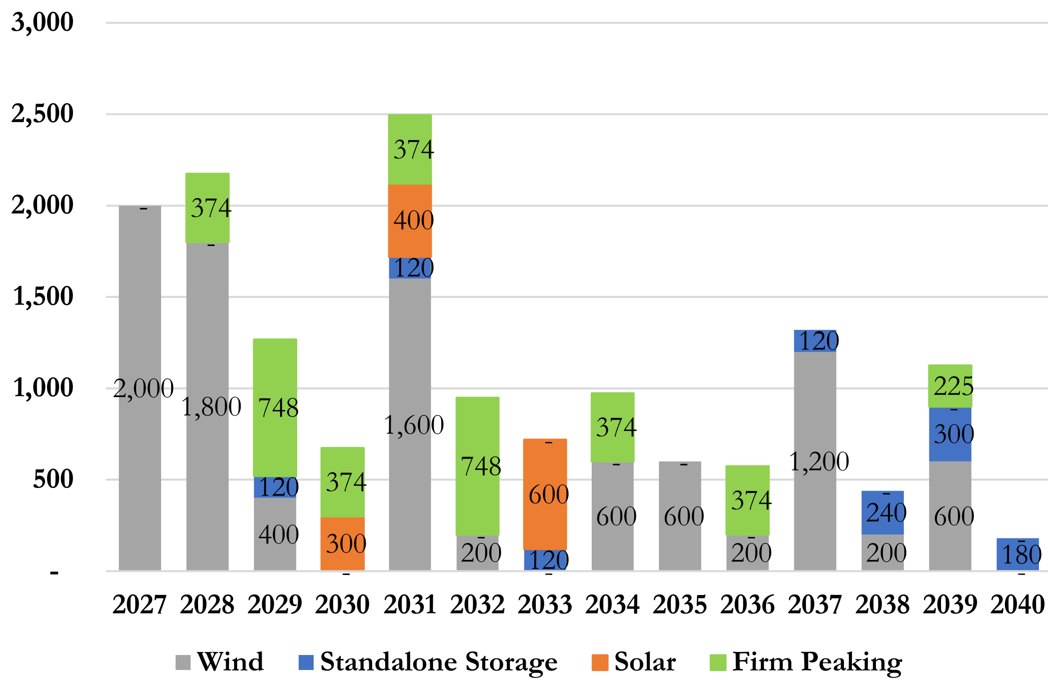
[6] 2022-2023 NERC Winter Reliability Assessment (November 2022) at p. 4. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.
[7] 2023 NERC Long-Term Reliability Assessment (Dec. 2023) at p. 7. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf
[8] FERC is considering MISO's Reliability-Based Demand Curve proposal and is expected to make a decision by June 2024. In late March 2024, MISO filed the proposed DLOL methodology with FERC.

limited reliance on neighboring systems and the broader MISO market. At the same time, our ND Resource Plan retains the benefits of participation in the MISO market by incorporating the current planning assumptions and including analysis that allows for the economic dispatch of our resources within the broader region. We have tested our ND Preferred Plan using historical data to analyze variations in load and renewable production. Our ND Resource Plan is robust under changing assumptions and provides a path to maintain the reliable system our customers expect.

In our 2019 Plan, we allowed access to the MISO market, subject to an hourly limit on the amount of energy that we could buy or sell to the MISO market. This limit was developed for our 2019 Plan based on PROMOD modeling and historical transfers. We also imposed a limit on market sales of no more than 25 percent of retail sales, consistent with the assumption used in our last 2019 Plan. Given the scale and pace of change in the market at that time, this approach was reasonable for that plan.

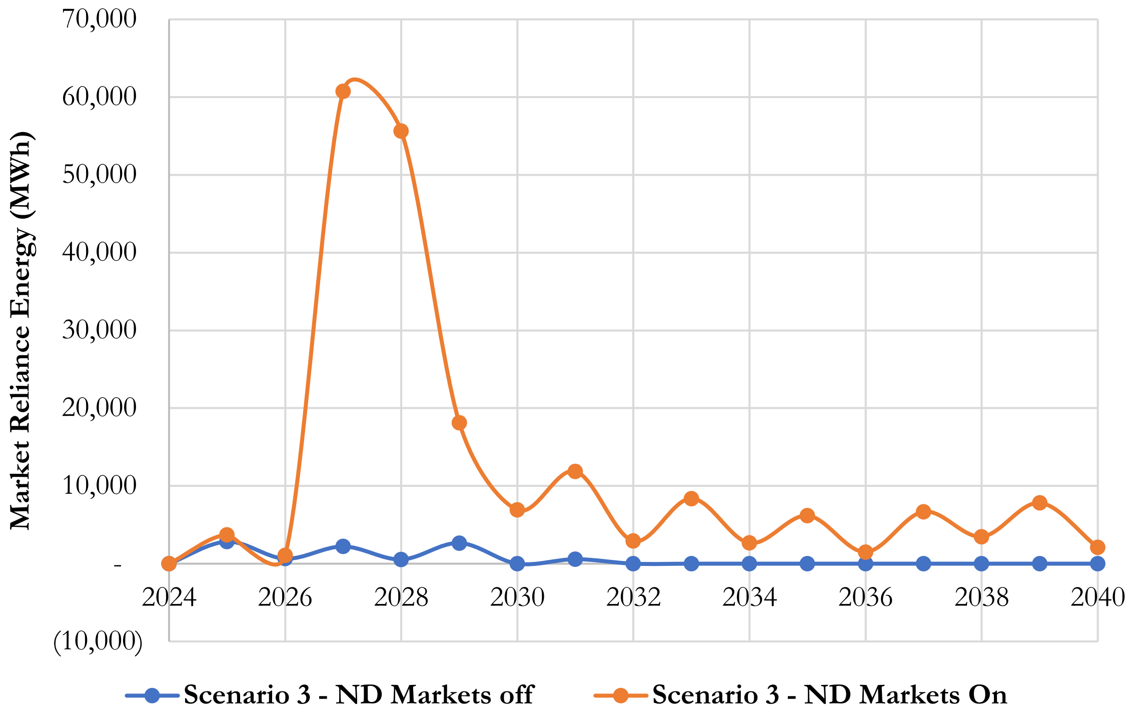
Using the same market access assumptions as those applied in the 2019 Plan now, however, results in a plan with substantial market exposure. In other words, when we allow EnCompass to optimize the resource expansion with the ability to rely on the market, the resources included in the expansion plan rely on market revenues or are unable to serve our load in a significant number of hours. The Market Access Optimization expansion plan, which represents Scenario 3 with 2,300 MW of hourly market access, is shown below in Figure 5-1.

Figure 5-1: ND Market Access Optimization Expansion Plan (MW)



The model makes large wind resource additions in 2027, 2028, and beyond (adding over 9,000 MW of wind alone during the planning period) to fulfill capacity needs based on accreditation assumptions and current market conditions. The model assumes excess energy is sold into the market, and the resulting wholesale revenue would make these significant wind resource additions cost-effective. The model does not select firm dispatchable resources until 2028. To assess the market exposure of this plan, we modeled a dispatch run on the expansion plan without market access. This dispatch run provides the number of hours our system relies on market purchases to serve load. The expected market reliance energy shown in Figure 5-2 below is the total megawatt-hours (MWh) in each year in which the expansion plan resources are unable to serve our load and must rely on market purchases.

Figure 5-2: ND Market Access Optimization - Expected Market Reliance



The significant amount of market reliance results when the plan is optimized with market access. This level of market exposure would be risky for multiple reasons. For instance, during the times when our system is reliant on the market for purchases, Locational Marginal Prices (LMPs) may be higher than those assumed in our model, or worse, resources may simply not be available. During times when our resources are selling into the market, LMPs could be lower than assumed in our model. If the difference is substantial, the resources added by the Company may not be cost-effective, since they would generate less revenue from market sales than anticipated by the model. In addition, the resources may not be able to comply with future changes to the MISO reliability construct if, for instance, there are significant changes to capacity accreditation in the future.

Moreover, historically, we have planned to have enough resources to meet our load serving needs. In the past, when our system relied on fewer renewable resources, this meant ensuring we had sufficient resources to meet our annual planning reserve margin. In general, having sufficient capacity to meet our annual peak resulted in sufficient capacity to meet our needs year-round. As more variable resources have been added to our system, it has become necessary to consider more hours of the year. The change to a seasonal RA construct and the use of the chronological hourly modeling tool, EnCompass, were both motivated by the changing resource mix.

While we have optimized our portfolio without access to the market, we will continue to benefit from the access to the MISO market as we have in the past. We will continue to dispatch our resources on an economic basis. We will purchase from the market when market purchases are lower cost than using our own resources, and we will sell excess generation into the market to benefit our customers. While we optimized the capacity expansion additions without market reliance, we conduct a dispatch run in the EnCompass model with and without market access to analyze these potential benefits. Furthermore, as noted above, we plan for our peak needs coincident with the MISO peak. The coincidence factor allows us to procure less capacity than we would otherwise need. In addition, we plan to the MISO PRM, which is developed considering the broader MISO footprint.

By optimizing the resource expansion plan without access to the market, we ensure that our ND Resource Plan can serve our customers' needs across all hours of the year and positions us to be able to comply with future changes to the MISO RA construct. Our ND Resource Plan adds resources to be able to meet customer needs with very limited reliance on neighboring systems and the broader MISO market for reliability. At the same time, our ND Resource Plan retains the benefits of participation in the MISO market by incorporating the current planning assumptions and we will continue to economically dispatch our resources within the broader region. We have tested our ND Preferred Plan using historical data to analyze variations in load and renewable production. Our ND Resource Plan is robust under changing assumptions as further described in Attachment 2 (ND Appendix D): Energy Adequacy Analysis and provides a path to transition our system while maintaining the reliable system our customers expect.

V. SENSITIVITIES

To determine how changes in our assumptions impact the costs or characteristics of the baseload study plans, we examine them under a number of sensitivities. This testing provides insights on potential plan performance and helps us assess the "robustness" of each scenario in the face of future uncertainty, meaning that we want to test how resilient the scenario is to changes in one or more key assumptions. Generally, if a given plan is extremely sensitive to changes in assumptions, it would not represent a prudent course of action for the Company to pursue, because it would subject our customers to excessive risk. A summary of sensitivities is presented in Table 5-2 below with additional discussion below.

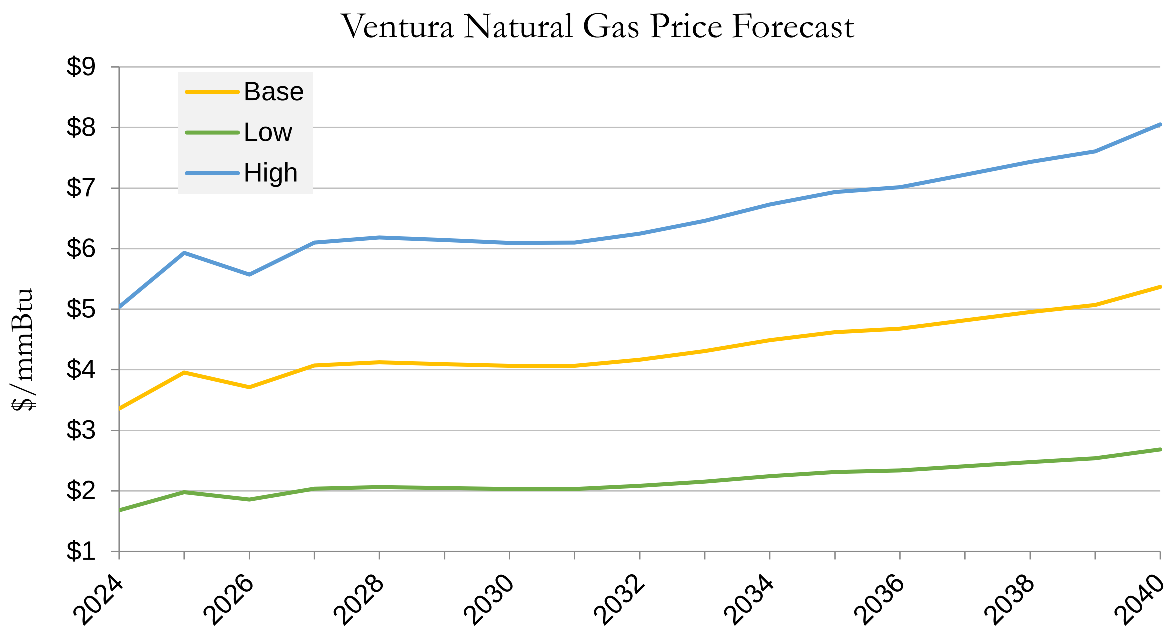
Table 5-2: Sensitivities and Special Studies

Category	Scenario Descriptions
Standard	PVRR – Base, i.e. no carbon cost and environmental externality
Sensitivities on All Three Nuclear Scenarios	
Fuel prices	High Fuel/Market Price
	Low Fuel/Market Price
Load	High Load
	Low Load
Technology cost	High Tech Cost
	Low Tech Cost
	Edison MISO Market Prices with NREL ATB Trend for wind and solar
	Edison MISO Market Prices as starting point and converge to NREL ATB forecast in 2030 for wind and solar
Integration Cost	Apply $500/kW transmission integration cost to generic wind, solar, battery and CT starting in 2029
Market Access	Market access off in dispatch runs
Special Studies on the ND Preferred Plan	
Resource Adequacy	Higher PRM (RBDC opt-out proxy)
	25% Battery ELCC
	Market Access 2,300 MW
Data Center Load	Data Center Load
Energy Adequacy Analysis	Scenario 3 with market access off
	Scenario 1 with market access off
	Market access 2,300 MW re-optimization for Scenario 3
*Note: shaded scenarios require reoptimization of the expansion plans and redispatch of the resulting expansion plans.	

Special studies on the ND Preferred Plan are discussed in Section VIII. A summary of the PVRR for each sensitivity can be found in Attachment 4 (ND Appendix G): Scenario Sensitivity Analysis, and below we discuss additional detail for these sensitivities.

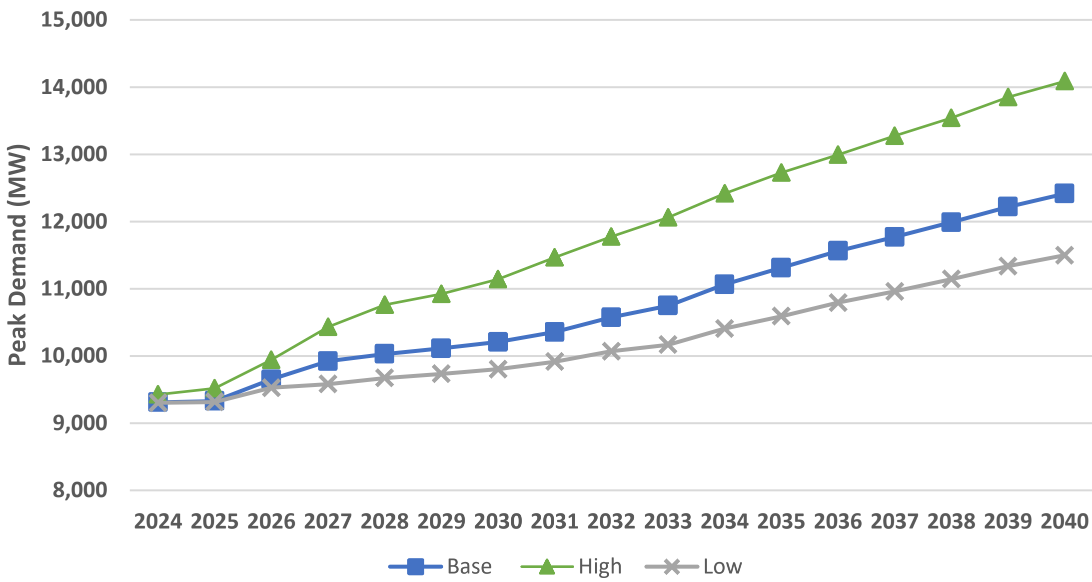
Fuel Price/Market Costs. High and low-price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast. Fuel price assumptions by base, low, and high sensitivities are depicted below in Figure 5-3.

Figure 5-3: Fuel Price Assumptions, by Base, Low, High Sensitivities



Load. The low load sensitivity includes high customer adoption-based Distributed Energy Resource (DER) growth, no beneficial electrification, slower adoption of electric vehicles (EV), and less new load from data centers. The high load sensitivity includes increased beneficial electrification, full achievement of Minnesota's "20 percent by 2030" goal for EV penetration with similar increases in EV adoption in other states served by NSP, and additional large data center loads located in Minnesota. Peak Demand, net of EE impacts, by Base, Low, and High sensitivity is shown in Figure 5-4 below.

Figure 5-4: Peak Demand, Net of EE Impacts, by Base, Low, High Sensitivities (MW)



Technology Costs. Wind, solar and battery costs, as well as battery operational characteristics such as cycle limit and Round-Trip Efficiency (RTE), are from National Renewable Energy Laboratory (NREL) 2023 *Annual Technology Baseline* (ATB) data. High and low technology cost sensitivities are created based on NREL ATB "Conservative" and "Advanced" forecasts. We also have a sensitivity where the wind and solar LCOEs prior to 2030 are adjusted to match the 2023 Q1-Q3 actual PPA prices in MISO, reported in the Edison Energy Global Renewable Market Update quarterly reports to align pricing with most recent market trends in MISO. Finally, we have a sensitivity where wind and solar LCOEs are adjusted to match PPA prices in MISO as previously described. However, in this sensitivity, the LCOEs remain elevated, trending in line with the NREL ATB forecast. We did not include any sensitivities adjusting capital costs for thermal resources such as the generic CTs or Reciprocating Engines, so all sensitivities include our base cost assumptions for those resources. New wind and solar resource cost assumptions and sensitivities are shown below in Figure 5-5, and new battery resource costs assumptions and sensitivities are shown below in Figure 5-6.

Figure 5-5: New Wind and Solar Resource Cost Assumptions with Transmission Cost ($/MWh)

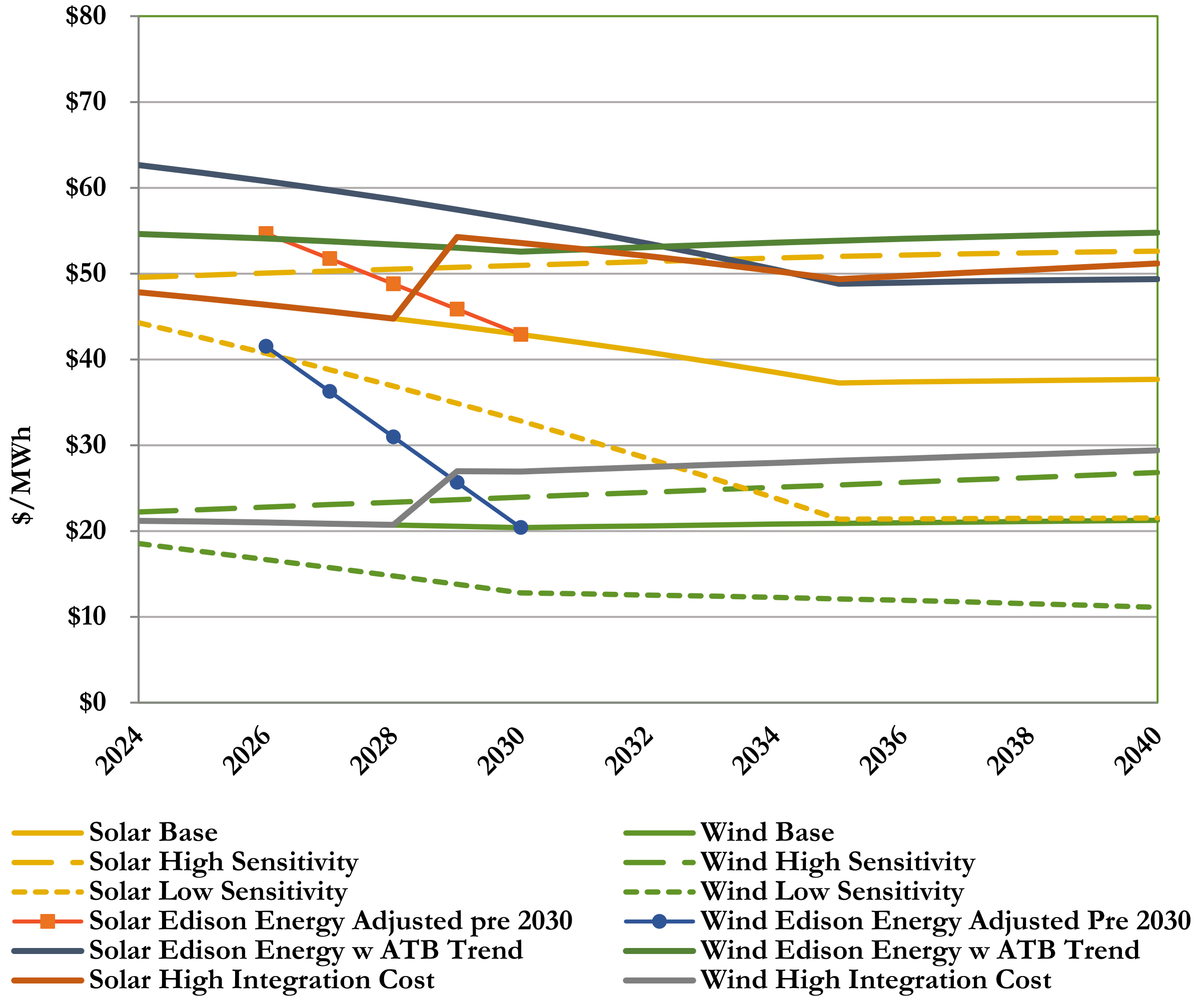
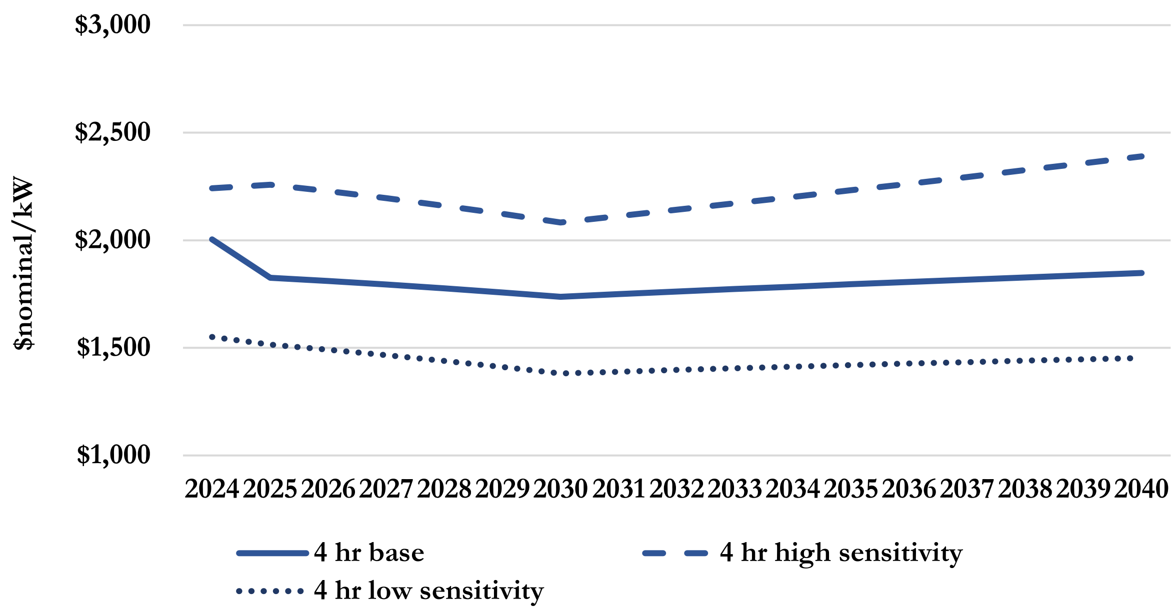


Figure 5-6: New Battery Resource Cost Assumptions with Transmission Cost (nominal $/kW)



Integration Cost. For this sensitivity, we apply a higher transmission integration cost of $500/kW to generic wind, solar, battery, and CT resources starting in 2029.

Market Access. The "all markets off" sensitivity represents a view in which we cannot access the market to sell energy outside our system.

It is important to note that these sensitivities are designed to test the performance of our baseload nuclear retirement decisions under plausible future conditions. These sensitivities are not, however, intended to test which future is overall least cost for our system. We do not have full control over the level of distributed solar or electrification growth on our system and have no control over variables such as fuel prices and new resource capital costs. However, as shown in Attachment 4 (ND Appendix G): Scenario Sensitivity Analysis: PVRR Summary, our ND Preferred Plan provides benefits under all sensitivities through 2040. As demonstrated in the next section, the sensitivities analysis shows that our ND Preferred Plan baseload nuclear decisions to extend Prairie Island 1 and 2 and Monticello are likely to yield customer benefits relative to the ND Reference Case, even in a future where multiple key assumptions change.

VI. ENCOMPASS ANALYSIS RESULTS AND SELECTING THE PREFERRED PLAN

After identifying the scenarios and sensitivities for analysis, we used EnCompass to identify the expansion plans for each of the three primary scenarios, and their resulting cost and emissions impacts.

A. EnCompass Model Optimization and Challenges

In the initial round of modeling, all generic technology alternatives (wind, solar, 4-hour and 10-hour batteries, solar + battery hybrid, CTs) were made available to the model, and we developed fully-optimized expansion plans using a typical on and off-peak day per month for the optimization horizon 2027-2055. However, due to the substantial number of these alternatives, initial runs took a significant amount of time to complete (or fail completely). Furthermore, the limited dispatch duration of the 4-hour generic batteries was not evaluated due to the typical on and off-peak setting in the expansion plan. As a result, the model yielded unreliable plans with prominent levels of unserved energy. This unserved energy occurs due to the production cost runs, which are used for more granular dispatch and system cost estimates and simulate the electric system on an hourly time basis, versus the simplified time periods used during capacity expansion modeling used to determine the best mix of resources to arrive at a least-cost portfolio for a planning period. If the production cost runs associated with certain portfolio yield unserved energy, it demonstrates that resource adequacy captured in the EnCompass modeling has not been achieved due to the disconnect between modeling steps. In this case, due to this set of initial runs reflecting unserved energy and therefore deemed unreliable, we needed to address several refinements in our modeling methodology.

1. Reduced Time Block Granularity

On average, initial runs took over 24 hours to process, and in several instances, EnCompass ran into memory issues and was unable to "solve" the problem. This is defined as the mixed integer programming ("MIP") Stop Basis tolerance defined within EnCompass never being reached and a portfolio never being presented in the modeling output. In order to address the solve time/feasibility issue, the number of daily intervals modeled was reduced to 11 total time blocks per day versus the 24 per day (i.e., every hour) initially used for the on-peak/off-peak optimization period. This additional aggregation of hours resulted in 264 (11*2*12) intervals being solved per year versus 576 (24*2*12) intervals. It should be noted that this aggregation of hours was only applied to capacity expansion modeling for selection of resources for the portfolios and not for the production costing used to estimate overall portfolio costs, which was done using the full 8,760 hours per year granularity. This aggregation was determined based on similar modeling run-time issues experienced in the Company's other jurisdictions and has been discussed/recommended by the software vendor for EnCompass, Anchor Power. They have confirmed that the aggregation proposed would not fundamentally alter the validity of the analysis results. The reason the capacity expansion process, versus production costing, requires this additional aggregation of hours is because of the much larger problem size EnCompass must solve when determining capacity selections.

2. *Addressing Battery Storage*

In addition to the time granularity issues discussed previously, modeling the different battery storage duration options (for example, 10-hour versus 4-hour) created additional complexities that were a challenge for the model to solve. To develop reliable portfolios which did not result in the modeling reflecting unserved energy, we first removed the 10-hour batteries and solar + battery hybrid resource options to reduce the problem size in the initial step of the capacity expansion plan optimization. We specifically removed these options because doing so was expected to have a minimal impact on any resulting expansion plan for two different reasons, namely MISO's current capacity accreditation methodology for Energy Storage Resources (ESRs) does not differentiate between ESRs of different durations. For instance, 10-hour batteries receive the same amount of capacity accreditation as 4-hour batteries. Should MISO provide updated guidance for ESR accreditation, we will incorporate it into our model to distinguish between short-duration and long-duration resources.

Second, since the battery portion of a solar + battery hybrid resource can only be charged by the paired solar instead of the grid, the solar + battery hybrid resources do not generate the same energy benefits to the system as standalone batteries. Therefore, they are unlikely to be selected over standalone solar resources or standalone batteries. Furthermore, the IRA allows standalone batteries to receive full ITC without pairing with solar, thereby removing most of the cost advantages of solar + battery hybrid. Moreover, to verify that this simplifying assumption did not result in the elimination of any 10-hour ESR or solar + storage additions, we conducted a special study in the 2024 Upper Midwest Integrated Resource Plan to allow the EnCompass model to consider these resource options. The special study confirmed that 10-hour ESR and solar + storage resources are not selected in the planning period when included as resource options. In the special study where we allow 10-hour batteries and hybrid options in the expansion plan, the 10-hour batteries are only selected in 2052 and the hybrid resource was not selected.

3. Expansion Plan Setup

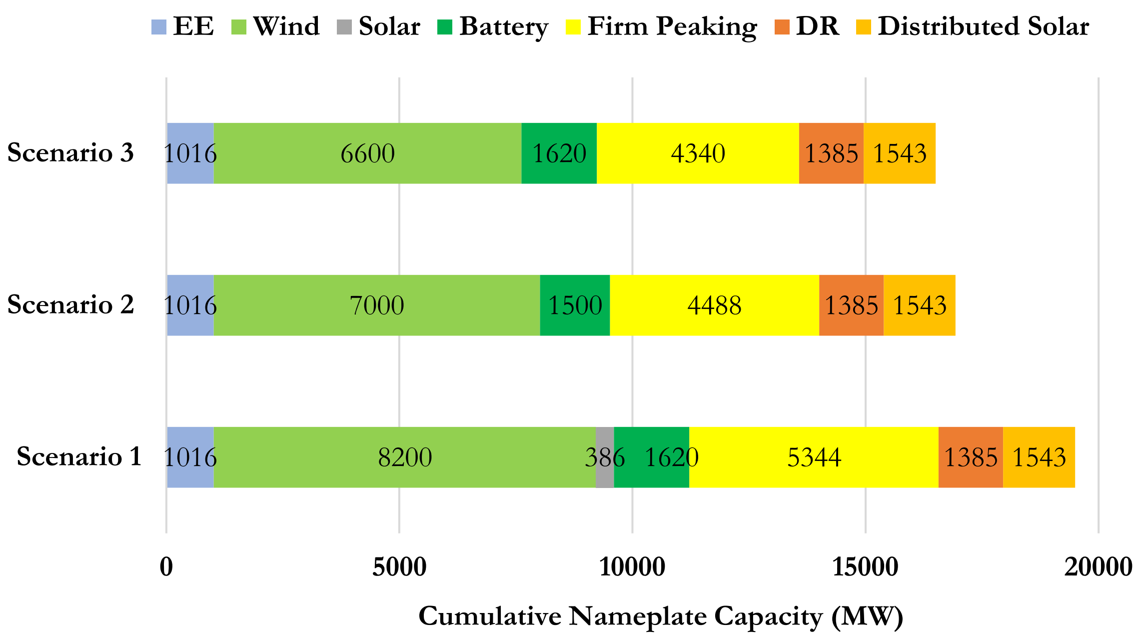
In order to address the unserved energy issue, we created expansion plan optimization with more granular time periods, which allowed EnCompass to better evaluate the energy adequacy of dispatchable resources (i.e. 4-hour batteries and CTs). Specifically, we used all calendar days instead of typical on- and off-peak days per month used in our previous expansion plan scenarios. With this increased optimization granularity, the problem size increased significantly. To allow the model to solve within a reasonable amount of time, we reduced the optimization horizon from the whole study period to every four years. Further, we used the CT capacity additions selected in the 2024 Upper Midwest Plan's capacity expansion plan as a floor for the CT needs. Additions of CT resources above the floor are considered in the expansion plan. This expansion plan setup allows EnCompass to capture most of the hourly granularity when evaluating resource options.

B. Modeling Results and Conclusions

Completing baseload scenario runs, as described above, allows us to examine scenario outcomes side-by-side, to evaluate their benefits and drawbacks. Among other factors, we examine the resource expansion profile and carbon emissions outcomes, present value costs, and several indicators of risk for each scenario.

The cumulative expansion plan additions through the planning period for the three scenarios are shown below in Figure 5-7.

Figure 5-7: ND Expansion Plans by Scenario (MW, Cumulative Nameplate Capacity Resource Additions by Resource Type, 2024-2040)



As shown above in Figure 5-7 above, Scenario 3 results in fewer additions of firm peaking and wind capacity relative to both Scenarios 1 and 2. The extension of the nuclear units offset additions of other resources needed for capacity and energy. Scenario 2 includes fewer additions of firm peaking and wind than Scenario 1, but more than Scenario 3. Moreover, the nuclear extensions provide a certain and stable source of energy to our system as we transition our generation fleet.

The cost impact of the three scenarios is shown below in Tables 5-3 and 5-4. The tables shows the net present value (NPV) delta of modeled costs compared to Scenario 1 (the Reference Scenario), with negative values representing customer savings relative to the Reference Scenario. Table 5-3 shows the impacts when market interactions are included in the dispatch allowing excess generation to be sold into the market and incorporating those revenues. Table 5-4 shows the impacts without market interactions.[9]

[9] The comparable PVRR costs for Scenario 3 when market interactions are not included for the Upper Midwest Preferred Plan filed in Minnesota are: $37,891,000 through 2040, $49,728,000 through 2047 and $54,318,000 through 2050. These PVRR costs can be compared to the PVRR costs of $37,640,000, $49,288,000 and $54,031,000, respectively, shown in Table 5-4.

Table 5-3: Scenario PVRR Deltas from Reference Case with Markets ($2024 millions)

PVRR Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
ND Scenario 1	$0	**$34,818**	$0	**$45,163**	$0	**$49,352**
ND Scenario 2	($248)	**$34,570**	$116	**$45,279**	$276	**$49,628**
ND Scenario 3	($505)	**$34,313**	($110)	**$45,053**	$69	**$49,421**

Table 5-4: Scenario PVRR Deltas from Reference Case without Markets ($2024 millions)

PVRR Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
ND Scenario 1 – Markets Off	$0	**$ 38,188**	$0	**$ 49,502**	$0	**$ 54,088**
ND Scenario 2 – Markets Off	($280)	**$ 37,908**	$42	**$ 49,544**	$190	**$ 54,278**
ND Scenario 3 – Markets Off	($548)	**$ 37,640**	($215)	**$ 49,288**	($57)	**$ 54,031**

The Scenario 3 plan was the lowest-cost plan through 2047 with and without market interactions. When market interactions are not included, Scenario 3 is lowest-cost through 2050. We note that the replacement capacity added at the end of the expansion plan to replace Prairie Island in Scenario 2 and Prairie Island and Monticello in Scenario 3, significantly impacts overall cost.

Given current technologies, the model makes significant additions of firm dispatchable resources in the late 2040s in anticipation of the retirement of the nuclear fleet. Under the PVRR assumptions, no cost is included on the emissions from these resource additions. We expect technological advancements will provide resource options that are not currently available when the plants near the end of their extended lives. Therefore, the significant firm dispatchable additions in the late 2040s may not provide a reliable indication of the costs that far out in time. As a result, we provide cost comparisons over three different time horizons. The most relevant of these horizons—through 2040, when resource and cost assumptions are most known—shows the extension of our nuclear fleet provides significant economic benefits.

VII. ND PREFERRED PLAN SELECTION AND ASSESSMENT

As described previously in this chapter and in Chapter 4: Preferred Plan, we evaluated the PVRR results of our three baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the ND Preferred Plan. Based on these outcomes, we selected baseload Scenario 3. Our ND Preferred Plan ensures reliability and affordability for our customers on a PVRR basis. The baseload aspects of this ND Preferred Plan include extension of our Monticello nuclear facility to 2050 and Prairie Island to 2053/2054. We discuss more detail regarding how we selected and evaluated our Preferred Plan below.

A. Extend All Nuclear

From a modeling perspective, the PVRR results are primary indicators of the various scenarios' economic favorability. Tables 5-3 and 5-4 above indicate that the Prairie Island and Monticello nuclear extension scenario, Scenario 3, yields the most attractive customer value relative to the Reference Case.. Maintaining nuclear generation in our resource portfolio provides fuel diversity and an ongoing source of baseload generation. From a reliability risk perspective, baseload nuclear adds value as we transition our generation fleet.

As demonstrated in our modeling analysis, the ND Preferred Plan achieves customer value on a PVRR basis.

In addition to the beneficial cost outcomes discussed above, the ND Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality, and effectively managing market exposure, as shown in the sensitivity analysis below. The ND Preferred Plan incorporates significant capacity additions to replace retiring resources, consisting of a diverse portfolio of DSM, nuclear extension, wind, and firm dispatchable resource additions. This approach mitigates the risk of becoming too dependent on a single fuel source.

B. Sensitivity Results

As previously discussed, a final step in our analysis process evaluated the performance of the baseload study plans under different sensitivities. As shown in Attachment 4 (ND Appendix G): Scenario Sensitivity Analysis–PVRR Summary, the summary of the PVRR for each sensitivity consistently shows the Preferred Plan, Scenario 3, as yielding the most customer benefits on a PVRR basis across all sensitivities through the 2024-2040 planning period. We address key sensitivity assumptions and insights below.

1. Fuel Prices

The ND Preferred Plan produces savings under both High and Low Fuel Price sensitivities through the 2024-2040 planning period as shown in Attachment 4. Our nuclear fleet provides an effective hedge against fuel price volatility through the planning period.

2. Load

Table 5-5 below provides a summary of the load sensitivity results under different planning periods. The ND Preferred Plan provides savings under both the high and low load sensitivities relative to the Reference Case through the 2024-2040 planning period, which suggests that the Preferred Plan is robust under a range of potential future conditions through the planning period.

Table 5-5: ND Preferred Plan NPV Savings Under Different Load Scenarios and Planning Periods ($2024 millions)

	Base PVRR	High Load PVRR	Low Load PVRR
2024-2040 NPV Delta	($505)	($472)	($474)
2024-2047 NPV Delta	($110)	$90	$153
2024-2050 NPV Delta	$69	$298	$323

3. Technology Cost

The ND Preferred Plan provides savings through the 2024-2040 planning period under the High Tech, Low Tech, Edison MISO Market Prices sensitivities conducted. Further impacts of technology costs on the ND Preferred Plan are discussed below.

4. Market Access

As discussed above, our analysis includes EnCompass dispatch runs that allow for purchases of market energy and energy sales to market. The ND Preferred Plan shows significant benefits with and without market access as illustrated in Tables 5-3 and 5-4 above.

C. ND Preferred Plan and Future Renewable Cost Uncertainty

We anticipate steady wind and declining solar resource costs as shown in the base wind and solar cost assumptions in Figure 5-5 above. Given that there is uncertainty in any long-term resource cost forecast, primarily around the potential for technological advancements, policy and regulation changes, market dynamics and competition, grid integration and infrastructure costs, commodity pricing, etc., we developed wind and solar resource cost sensitivities that adjusted the base outlook using discrete adjustments for these assumptions as described in Section V and shown in Figure 5-5 above. The Edison Energy Pricing with ATB Trend Assumptions assumes higher renewable pricing throughout the planning period. As shown in Table 5-6 below, if future renewable pricing is higher, the benefits of nuclear extension under the ND Preferred Plan significantly increase.

Table 5-6: NPV Savings under Base Renewable Pricing and Edison Energy with NREL ATB Trend Renewable Pricing ($2024 millions)

	Scenario 1	Scenario 2	Scenario 3
Delta in NPV ($m) 2024-2040 Base PVRR	$0	($248)	($505)
Delta in NPV ($m) 2024-2040 Edison Energy Pricing with ATB Trend PVRR	$0	($527)	($681)
Delta in NPV ($m) 2024-2047 Base Load PVRR	$0	$116	($110)
Delta in NPV ($m) 2024-2047 Edison Energy Pricing with ATB Trend PVRR	$0	($408)	($664)
Delta in NPV ($m) 2024-2050 Base Load PVRR	$0	$276	$69
Delta in NPV ($m) 2024-2050 Edison Energy Pricing with ATB Trend PVRR	$0	($382)	($677)

As demonstrated above, the Preferred Plan offers benefits across a range of potential future wind and solar resource cost scenarios. Additional analysis focused on the Preferred Plan is discussed below.

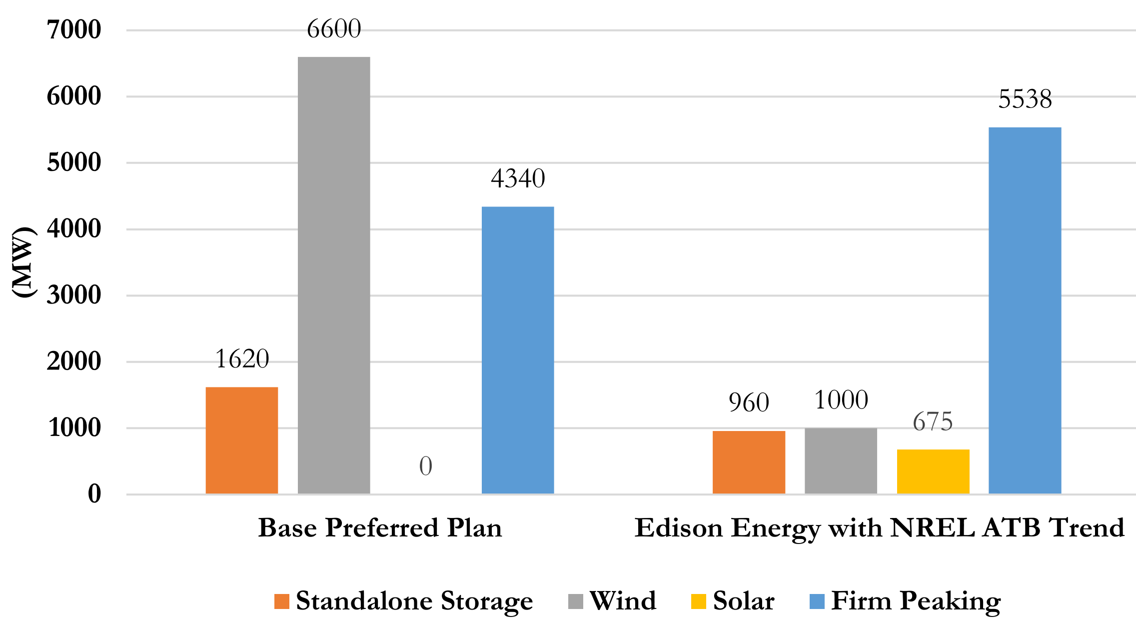
The detailed expansion plan for the 2027-2030 ND Preferred Plan is provided in Table 5-7 below.

Table 5-7: ND Preferred Plan Expansion Plan (2027-2030) (MW)

	2027	2028	2029	2030
Standalone Storage	480	0	120	0
Wind	400	400	1200	0
Solar	0	0	0	0
Firm Peaking	748	748	0	748
Total	1,628	1,148	1,320	748

Relative to the ND Preferred Plan, the high wind and solar resource cost sensitivity (Edison Energy with NREL ATB Trend) results in significantly less wind resource additions over the planning period. For simplicity, Figure 5-8 below shows cumulative expansion plan additions by resource type for the ND Preferred Plan and the high wind and solar resource cost sensitivity.

Figure 5-8: ND Cumulative 2024-2040 Additions by Resource Type and Sensitivity (MW)



D. ND Preferred Plan Benefits

We believe our analysis supports selection of Scenario 3, extension of the Prairie Island nuclear facility to 2053/2054 and the Monticello nuclear facility to 2050, as our ND Preferred Plan. The cost and risks of Scenario 3 are discussed further below.

1. Cost

As demonstrated in our modeling analysis, the ND Preferred Plan achieves customer value under a wide variety of future conditions. The ND Preferred Plan achieves savings under all PVRR analysis through the 2024-2040 planning period. Further, from a customer rate impact perspective, the ND Preferred Plan, based on the assumptions as modeled, results in annual rate increases of approximately 0.9 percent, which is below the rate of inflation.[10] Altogether, we believe the ND Preferred Plan delivers tangible customer savings.

2. Risk

In addition to beneficial cost outcomes, the ND Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The ND Plan incorporates significant capacity additions to replace retiring resources and expiring PPAs, consisting of a diverse portfolio of DSM, nuclear extension, wind, storage, and firm dispatchable resource additions. Further, ensuring we do not become too dependent on a single fuel source mitigates risk.

We also evaluate factors such as energy market exposure and portfolio length. Our ND Preferred Plan limits our exposure to market risk and ensures we have the resources needed to serve our customers. As discussed below, we conducted extensive analysis to confirm the energy adequacy of our plan. Further, our ND Preferred Plan results in a portfolio length of at least 569 MWs through the next five years. A plan that includes portfolio length is warranted at this time, and creates an effective hedge for our customers against two key risk factors:

Capital Investment Wind Down at Retiring Plants. The retirement of our remaining coal assets, in addition to the expiration of other resources by 2030 exposes our customers to some risk as we wind down operations and reduce capital spend at these plants. In the event of an early outage, excess capacity will give us the option to adjust resource

[10] As noted in Chapter 4: Preferred Plan and discussed further in Chapter 6: Customer Rate and Cost Impacts these impacts to not include the potential revenues from market sales of excess generation.

procurements as needed if we find that a capital investment needed to continue operation of a retiring plant is not in our customers' best interests at that time.

Capacity Accreditation. We expect further changes to the accreditation of resources in MISO as discussed Chapter 2: Planning Landscape. MISO's Direct Loss of Load (DLOL) proposal, filed in late March 2024, calculates accreditation based on modeled and historical performance of resources during critical hours. Our ND Preferred Plan additions position us to be able to manage the uncertainty of further changes to resource accreditation.

VIII. SPECIAL STUDIES ON THE ND PREFERRED PLAN

Special studies in resource planning allow for a more thorough examination of specific issues not fully covered in the general resource plan. In this ND Resource Plan, we conducted special studies on the ND Preferred Plan to assess resource adequacy (higher PRM/RBDC opt-out, 25 percent battery ELCC, 2,300 MW market access), and data center load. We also conducted an energy adequacy analysis. For each of these studies, the additional resource options are evaluated and optimized in the modeling and added when economic. The study assumptions and findings are described below. A cost analysis for these studies is not included below because the assumptions are insufficiently developed, and the purpose of the studies is to evaluate the robustness of the preferred capacity expansion plan under these additional scenarios.

A. Resource Adequacy

1. Resource Adequacy Studies

To assess resource adequacy, we conducted three special studies as further described below: (1) higher planning reserve margin (RBDC Opt-Out), (2) 25 percent battery ELCC, and (3) 2,300 MW Market Access. The resulting capacity expansion plan for each resource adequacy study is shown in Table 5-8 and discussed below.

Table 5-8: ND Cumulative 2024-2040 Additions by Resource Type for Each Resource Adequacy Study

Resource Type	Base Preferred Plan	RBDC Opt-Out	25% Battery ELCC	2,300 MW Market Access
Standalone Storage	1,620	1,680	720	1,200
Wind	6,600	6,400	7,400	9,400
Solar	-	400	200	1,300
Firm Peaking	4,340	4,191	5,313	3,592
Total	12,560	12,671	13,633	15,492

a. Higher Planning Reserve Margin (RBDC Opt-Out)

As discussed in Chapter 2: Planning Landscape, the Reliability Based Demand Curve (RBDC) is a proposed design for MISO's Planning Resource Auction that aims to reflect the value of capacity in excess of the MISO PRM and produce more efficient and stable capacity prices. The RBDC opt-out proxy represents the additional capacity necessary to opt-out of the RBDC. By opting out of the RBDC, we can avoid costs that would otherwise be assessed to compensate other generators in MISO. This sensitivity assesses the cost of securing the excess generation needed to opt-out.
As shown in Table 5-8 above, this study results indicate that the ND Preferred Plan capacity additions are nearly sufficient to meet the higher planning reserve margin in most years.

b. 25 Percent Battery Effective Load Carrying Capability (ELCC)

The 25 percent battery ELCC special study evaluates the impact of a lower ELCC for battery storage, instead of the 95 percent accreditation battery storage received in the current planning year. As shown in Table 5-8 above, in this study, standalone storage resources additions are reduced by 900 MW over the planning period while over 1,973 MW of additional capacity is added from the other resource options beyond the capacity in the base plan. In the near term, by 2030, there is no change in firm peaking capacity additions.

c. 2,300 MW Market Access

For this study, we allow hourly market access of 2,300 MW when optimizing resource additions. As thoroughly discussed in Section IV, the model adds over 9,000 MW of wind alone during this planning period and results in a significant market exposure.

2. *Data Center Load Study*

For the data center load special study, we have assumed load growth surpassing the traditional high load sensitivity to accommodate the accelerated load growth stemming from data centers. The demand for data centers has recently surged notably due to the expansion of machine learning/artificial intelligence technologies, which are more energy-intensive than traditional data processing methods. The Company is actively engaged with several hyperscale and colocation data centers, with transmission interconnection studies underway for several requests. These entities are largely seeking renewable/carbon-free energy options and are interested in forming partnerships.

The results in Table 5-9 below show the impact of an increased data center load on the capacity expansion plan.

Table 5-9: ND Cumulative 2024-2040 Additions by Resource Type Comparison

Resource Type	Base Preferred Plan	Data Center Load
Standalone Storage	1,620	1,500
Wind	6,600	10,200
Solar	0	300
Firm Peaking	4,340	6,584
Total	12,560	18,584

3. *Energy Adequacy Analysis*

We conducted a special study to test the energy adequacy of our plans. As discussed in more detail in Attachment 2 (ND Appendix D): Energy Adequacy Analysis, we used historical data on three plans including our ND Preferred Plan and the ND Market Access Optimization, which was developed assuming 2,300 MW of hourly market access.[11] This analysis allows us to assess the capacity and energy adequacy of our plans. We evaluated these three plans on six core measures:

- Native Capacity Shortfall: Hours of insufficient system capacity availability in each year.

[11] As discussed in Attachment 2 (ND Appendix D), which also analyzed the ND Reference Case.

- Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
- Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.
- Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
- MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
- MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

In addition to these core metrics, we also provide a number of additional metrics and reliability analyses in Attachment 2.

A summary of the results for the ND Preferred Plan and the ND Market Access Optimization in 2030 and 2040 is shown in Table 5-10 below, with additional results in Attachment 2.

Table 5-10: Summary of 2030 ND Energy Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2030**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
ND Preferred Plan (Scenario 3)	**2016 Historical**	3	93	2	123	3	280
	2017 Historical	0	0	0	0	0	0
	2018 Historical	0	0	0	0	0	0
	2019 Historical	1	85	1	85	1	85
	2020 Historical	2	235	2	300	3	1,075
	2021 Historical	2	543	2	695	2	1,085
	2022 Historical	0	0	0	0	0	0
Market Access Optimization (ND Scenario 3 Market On Expansion Plan)	**2016 Historical**	28	484	5	1,222	34	14,827
	2017 Historical	17	200	4	488	26	6,619
	2018 Historical	20	329	5	947	41	9,487
	2019 Historical	43	359	4	962	51	19,147
	2020 Historical	41	397	4	1,378	53	22,065
	2021 Historical	17	250	2	622	40	10,574
	2022 Historical	6	359	3	836	8	2,680
	**** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)**						

As shown in Table 5-10 above, the ND Preferred Plan performs well across energy adequacy metrics. There are only 8 hours of native capacity shortfalls when seven historical test years are applied to the 2030 year of our ND Preferred Plan, resulting in limited dependence on the market. There are less than 10 hours across the seven historical test years where the ND Preferred Plan requires market purchases to meet load serving needs.

In contrast, under the Market Access Optimization, assumes market access of 2,300 MW in all hours of the year, the results plan exposes our customers to excessive risk. There are 172 hours across the seven historic years where the plan has insufficient capacity available to meet needs. This results in 258 hours where the plan cannot meet load serving needs and must rely on market purchases of over 85,000 MWh of energy.

IX. CONCLUSION

Considering the above, we believe our modeling and analysis supports the ND Preferred Plan and strikes a strong balance in meeting our planning objectives, in service of our customers' needs. In the near term, our ND Preferred Plan shows similar resource additions to the Upper Midwest Preferred Plan. Under the ND Preferred Plan the significant additions of wind are dependent on the ability to procure wind resources consistent with our base assumptions. If wind resources are higher cost, fewer additions of wind will be cost effective, likely resulting in greater differences between the ND Preferred Plan and our Upper Midwest Preferred Plan. The extension of our nuclear fleet, both Prairie Island and Monticello, is cost-effective across plans and scenarios.

CHAPTER 6 – CUSTOMER RATE AND COST IMPACTS

I. INTRODUCTION

In this chapter we present rate and bill impacts of our ND Preferred Plan for our Residential, Commercial, and Industrial customer classes. We also present impacts of our Upper Midwest Plan filed in Minnesota on our North Dakota customers. Overall, our ND Preferred Plan results in an estimated annual rate increase of 0.9 percent for North Dakota customers, which is less than the expected national average increase of 2.1 percent for electricity prices and slightly less than our Upper Midwest Plan submitted in Minnesota.

Producing a detailed analysis of rate impacts in a resource planning process with long time horizons is challenging due to the potential changes in our rates and resource needs over time. Factors that can impact the estimated rate impacts in the planning period include generation ownership structure, tax treatment, regulatory decisions, large customer load additions, changes in customer class allocations, and others. The simplifying assumptions made in both the calculation methodology and the input variables mean that these estimated impacts may not align with the actual rates set by the Commission for various customer classes in the future. We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing.

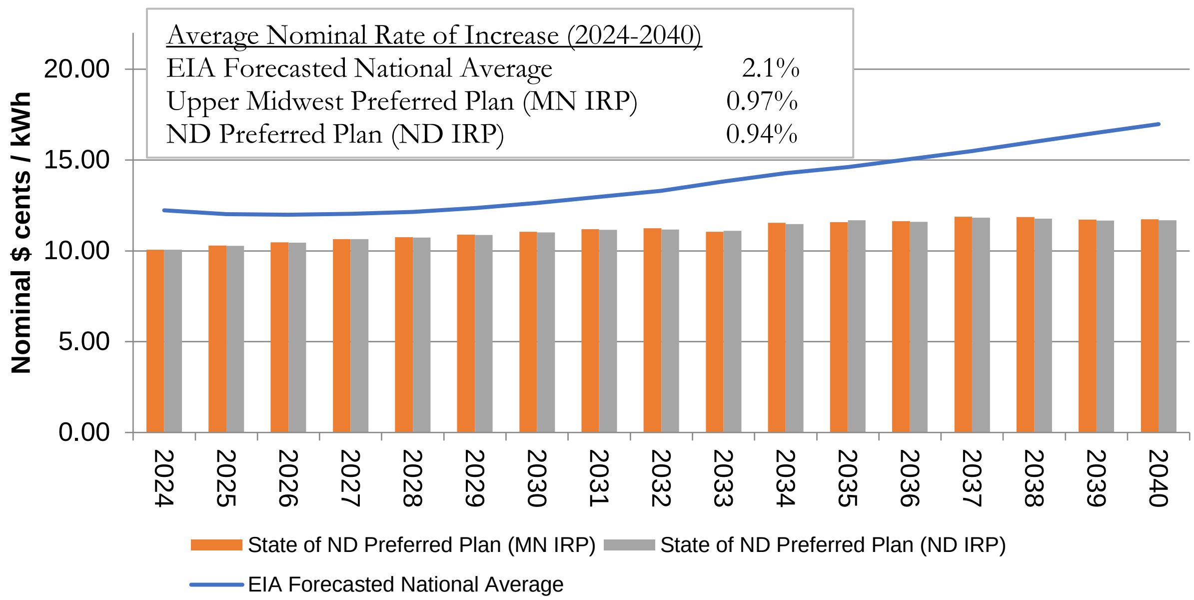
Our customer cost impact analysis shows that the ND Preferred Plan does not materially increase costs for our customers. The ND Preferred Plan results in an estimated average annual increase in retail rates of 0.9 percent across our system, compared to the EIA forecasted national average electricity rate increase of 2.1 percent and slightly below our Upper Midwest Preferred Plan submitted in Minnesota. We note the impacts shown here do not include revenues for sales of excess energy. We acknowledge that future revenues from market sales are uncertain, but any revenues received would be passed on to our customers and reduce impacts. We have taken this approach to provide a conservative estimate of rate impacts. Because our Upper Midwest Preferred Plan submitted in Minnesota and our ND Preferred Plan include resources that are expected to produce energy in excess of our load serving needs, the value of this excess energy has the potential to impact the respective costs of the plans.[1] We provide further analysis of our ND Preferred Plan and Upper Midwest Preferred Plan below

[1] The Preferred Plan submitted in Minnesota included revenues from the sale of excess energy.

A. Preferred Plan Average Nominal Cost Comparison to National Average

We begin by comparing, for the years 2024-2040, the cost impact on North Dakota customers of our Upper Midwest Integrated Resource Plan filed in Minnesota[2] and our North Dakota Resource Plan as compared to the national average as forecasted by the Energy Information Administration. To show the cost impact of our proposal over the long term, we provide a compound average growth rate (CAGR) comparison of our Preferred Plans in North Dakota and Minnesota in Figure 6-1 below. As illustrated in Figure 6-1, both Preferred Plans remain lower than the national average.

Figure 6-1: Average Nominal Cost Comparison State of ND Upper Midwest (MN) vs. ND Resource Plans



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2023, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[3] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

The results above indicate that the 2024-2040 CAGR for average rates is expected to be slightly higher for the Upper Midwest Preferred Plan filed in Minnesota compared to the ND Preferred Plan. This is due to lower overall revenue requirement of the ND Preferred Plan through 2040.

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[2] See *In the Matter of the 2024-2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. E002/RP-24-67.
[3] *See* U.S. Energy Information Administration - EIA - Independent Statistics and Analysis The EIA's Annual Energy Outlook was published in 2023.

II. REVENUE REQUIREMENTS FORECAST METHODOLOGY

To calculate the long-term rate impacts of the North Dakota Preferred Plan as compared to the Upper Midwest (Minnesota) Preferred Plan, we first developed a forecast of revenue requirements for the Reference Case. This forecast leverages retail revenue requirements from the Company's most recent rate case test years approved by each Commission in our five jurisdictions: Minnesota,[4] North Dakota,[5] South Dakota,[6] Wisconsin,[7] and Michigan[8] to create an NSP System revenue requirement for 2024. We identified annual costs through the end of the planning period (2040) using the CAGR of generation and fuel costs from the EnCompass model Reference Case. This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the EnCompass model to create a "business as usual" long term rate projection.

To determine the revenue requirement impact for each Preferred Plan, we identified the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case Encompass model results. This annual differential was added to the annual Reference Case revenue requirements to create the Preferred Plan annual revenue requirements.

Table 6-1 and Figure 6-2 below illustrate the estimated revenue requirement impacts for North Dakota of both the ND Preferred Plan and Upper Midwest (Minnesota) Preferred Plan compared to the Reference Cases over the planning period

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[4] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. E002/GR-21-630 (July 17, 2023).

[5] *Northern States Power Company 2021 Electric Rate Increase Application*, Order on Settlement, Case No. PU-20-441 (August 18, 2021).

[6] *In the Matter of the Application of Northern States Power DBA Xcel Energy for Authority to Increase Its Electric Rates*, Order Granting Joint Motion for Approval of Settlement Stipulation; Order Approving Refund Plan, Docket No. EL22-017 (June 8, 2023).

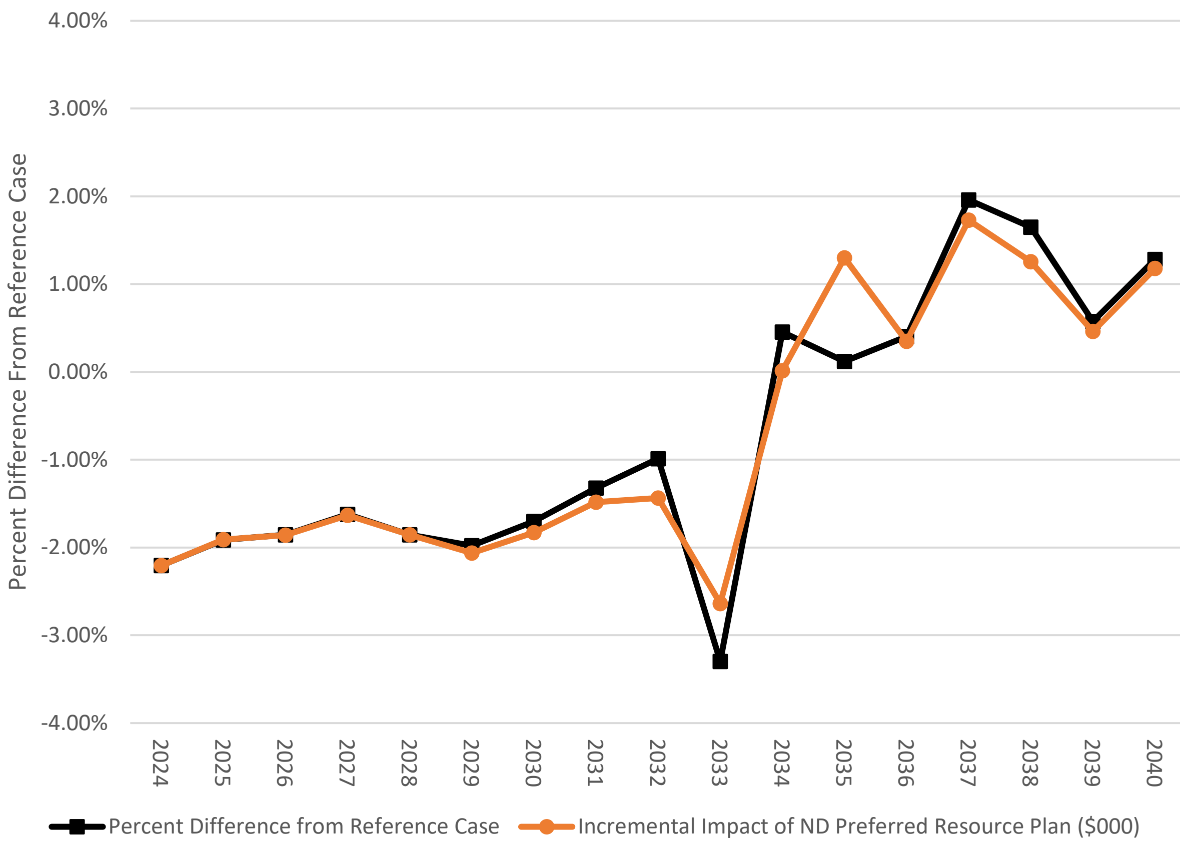
[7] *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates,* Final Decision, 4220-UR-126 (December 20, 2023).

[8] *Id.*

Table 6-1: Estimated Incremental Impact of Preferred Plan Upper Midwest (MN) IRP vs. ND Resource Plan

Year	State of ND Total Revenue Req ($000) - MN IRP	Incremental Impact of MN Preferred Resource Plan ($000)	Percent Difference from Reference Case	State of ND Total Revenue Req ($000) - ND IRP	Incremental Impact of ND Preferred Resource Plan ($000)	Incremental Impact of ND Preferred Resource Plan ($000)
2024	$224,379	($4,950)	-2.21%	$224,260	($4,944)	-2.20%
2025	$228,147	($4,363)	-1.91%	$227,987	($4,355)	-1.91%
2026	$231,979	($4,305)	-1.86%	$231,775	($4,304)	-1.86%
2027	$235,876	($3,825)	-1.62%	$235,627	($3,849)	-1.63%
2028	$239,837	($4,450)	-1.86%	$239,542	($4,446)	-1.86%
2029	$243,866	($4,820)	-1.98%	$243,523	($5,021)	-2.06%
2030	$247,962	($4,216)	-1.70%	$247,569	($4,531)	-1.83%
2031	$252,127	($3,337)	-1.32%	$251,683	($3,728)	-1.48%
2032	$256,361	($2,536)	-0.99%	$255,866	($3,670)	-1.43%
2033	$260,667	($8,592)	-3.30%	$260,117	($6,859)	-2.64%
2034	$265,045	$1,209	0.46%	$264,440	$38	0.01%
2035	$269,497	$321	0.12%	$268,834	$3,493	1.30%
2036	$274,024	$1,107	0.40%	$273,301	$955	0.35%
2037	$278,626	$5,462	1.96%	$277,843	$4,805	1.73%
2038	$283,306	$4,669	1.65%	$282,460	$3,550	1.26%
2039	$288,064	$1,660	0.58%	$287,154	$1,323	0.46%
2040	$292,903	$3,754	1.28%	$291,925	$3,440	1.18%

Figure 6-2: Annual Percent Change in Revenue Requirements (2024-2040)
Upper Midwest (MN) IRP vs. ND Resource Plan – State of ND



III. KEY DRIVERS

The major inflection points in the delta of revenue requirements (and rates) are driven by the differences in the set of resources that comprise both Preferred Plans and each Reference Case; these points coincide with differences in the retirement dates for Prairie Island. Compared to the Reference Case, the Preferred Plan results in lower cost through 2033 due to the extension of Prairie Island and corresponding reduction in depreciation expense. The Prairie Island extension results in fewer resources added in 2033, including the offset of a firm dispatchable addition, compared to the Reference Case, and therefore lower costs reflected in the downward spike in 2033 reflected in Figure 6-2 above. The slightly higher costs in 2034 and beyond reflect the relative costs associated with the Prairie Island extension and the costs of resources added in the Reference Case after Prairie Island retires based on our assumptions for generic resource additions. The generic resource additions are modeled assuming a levelized cost over the life of the asset.

IV. ESTIMATED ANNUAL RATE IMPACTS

After determining the revenue requirement of the Reference Case and the incremental impacts from the ND Preferred Plan, we determined customer class revenue requirement impacts using cost allocation principles described below. We calculated rate impacts in $ per kWh by dividing each customer class's revenue requirement in each year by the annual forecasted sales.

Figures 6-3 and 6-4 below provide the incremental rate impacts of the Preferred Plan for retail customers and by customer class, respectively.

Figure 6-3: Incremental Rate Impact of Preferred Plan
State of ND – All Customers

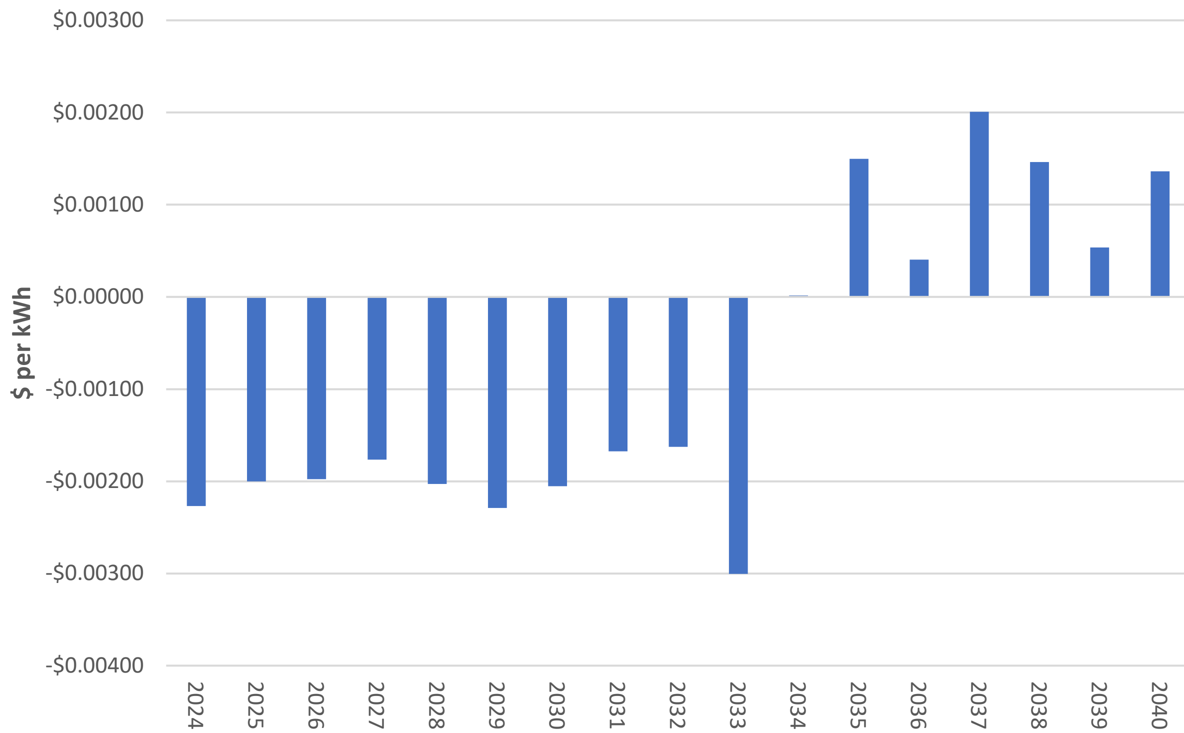
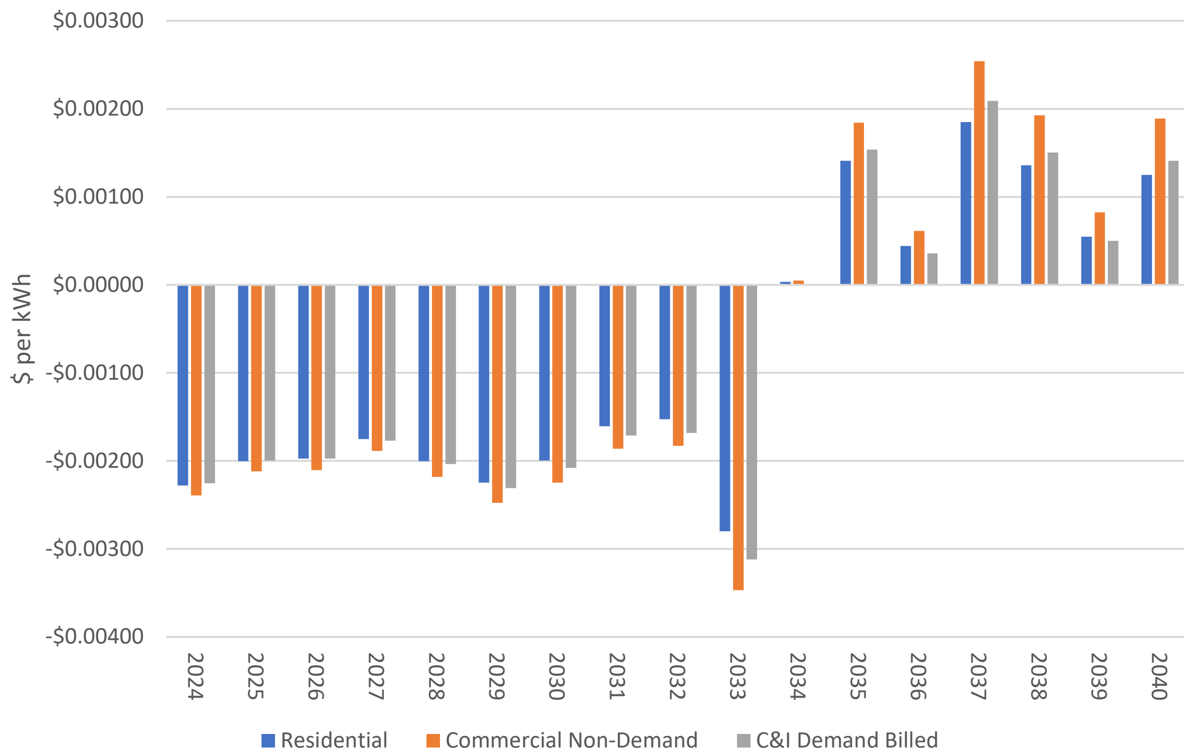


Figure 6-4: Incremental Rate Impact of ND Preferred Plan by Customer Class – State of ND



As noted above, we determine customer class revenue requirement impacts of the ND Preferred Plan by allocating incremental costs to customer classes for each year in the planning period (2024-2040). To do this, we apply ratemaking treatments to expense items for each generation resource type that is impacted by the 2024 Plan. Items include fuel costs and purchased energy, fixed O&M, variable O&M, and the revenue requirement associated with capital investments.

Costs for fuel, purchased energy, and variable O&M are allocated to customer classes using the E8760 energy allocator approved in our most recent North Dakota rate case, as provided in Table 6-2 below.[9]

[9] See Case No. PU-20-441, Northern States Power Company 2021 Electric Rate Increase Application, Order on Settlement, (August 18, 2021).

Table 6-2: E8760 Energy Allocator

ND	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	36.91%	4.93%	57.50%	0.66%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

Fixed O&M and the revenue requirement related to capital investments are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent North Dakota rate case.[10] We provide the plant stratification analysis for each plant type below:

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$942	$942 / $942	100.0%	0.0%
Fossil	$2,387	$942 / $2,387	39.5%	60.5%
Nuclear	$4,952	$942 / $4,952	19.0%	81.0%
Combined Cycle	$1,429	$942 / $1,429	65.9%	34.1%
Wind	$14,024	$942 / $14,024	6.7%	93.3%
Solar	$3,736	$942 / $3,736	25.2%	74.8%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, nuclear, etc.) to the replacement cost of a Combustion Turbine (CT). CTs are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After fixed O&M costs and the capital-related revenue requirement originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to customer class using the E8760 energy allocator provided in *part 1* above.

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[10] *Id.*

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator utilized in our most recent rate case.[11] The D10S allocator is simply each customer class's load that is coincident with the NSP system peak load. We provide the D10S customer class allocator percentages in Table 6-4 below:

Table 6-4: D10S Capacity Allocator

ND	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	35.60%	4.71%	59.12%	0.57%

V. ESTIMATED NEAR-TERM RATE IMPACTS

Table 6-5 below provides a more detailed view of near-term estimated rate impacts for North Dakota customer classes.

Table 6-5: Preferred Plan ND Estimated Rate Impacts by Customer Class per Year

Rate Class Impacts		2024	2025	2026	2027	2028	2029	2030	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)		11.444¢	11.235¢	11.383¢	11.521¢	11.559¢	11.645¢	11.687¢	N/A
Cumul Increase (¢/kWh)			-0.210	-0.061	0.076	0.114	0.201	0.243	N/A
Cumulative Increase (%)			-1.83%	-0.54%	0.67%	1.00%	1.75%	2.12%	0.35%
$ Impact/Month, @	650 kWh		($1.36)	($0.40)	$0.50	$0.74	$1.30	$1.58	N/A
Sm Non-Dmd (avg rate, ¢/kWh)		11.868¢	11.727¢	11.981¢	12.255¢	12.429¢	12.694¢	12.991¢	N/A
Cumul Increase (¢/kWh)			-0.141	0.113	0.387	0.561	0.826	1.123	N/A
Cumulative Increase (%)			-1.19%	0.95%	3.26%	4.73%	6.96%	9.46%	1.52%
$ Impact/Month, @	1,000 kWh		($1.41)	$1.13	$3.87	$5.61	$8.26	$11.23	N/A
Demand (avg rate, ¢/kWh)		9.392¢	9.225¢	9.400¢	9.590¢	9.701¢	9.862¢	10.054¢	N/A
Cumul Increase (¢/kWh)			-0.166	0.008	0.198	0.309	0.470	0.662	N/A
Cumulative Increase (%)			-1.77%	0.09%	2.11%	3.29%	5.00%	7.05%	1.14%
$ Impact/Month, @	37,500 kWh		($62.38)	$3.09	$74.26	$115.79	$176.24	$248.21	N/A
Street Ltg (avg rate, ¢/kWh)		13.864¢	13.677¢	13.895¢	14.190¢	14.424¢	14.627¢	14.876¢	N/A
Cumul Increase (¢/kWh)			-0.187	0.031	0.326	0.561	0.763	1.012	N/A
Cumulative Increase (%)			-1.35%	0.22%	2.35%	4.04%	5.50%	7.30%	1.18%
$ Impact/Month, @	60 kWh		($0.11)	$0.02	$0.20	$0.34	$0.46	$0.61	N/A

[11] *Id.*

Using the methodologies described above, the incremental costs in the last year of the period (2030) for the Preferred Plan would be expected to have the following impacts:

- Residential rate increases by about 0.35 percent on a compounded annual basis through 2030, equivalent to a total increase of $1.58 per month above the current rate level;
- Commercial rate increases by about 1.52 percent on a compounded annual basis through 2030, equivalent to a total increase of $11.23 per month above the current rate level; and
- Industrial rate increases by about 1.14 percent on a compounded annual basis through 2030, equivalent to a total decrease of $248.21 per month below the current rate level.

As noted above, this is not intended to be a prediction of what rate or bill increases will actually be over this time (which will be impacted by numerous factors, including, among other things, the specific costs of actual generation additions rather than generic assumptions used here, non-generation related costs, actual sales growth, and cost allocation decisions). Instead, this is intended to serve as an indicative look at the incremental rate and monthly bill impacts of the modeling results for the Preferred Plan.

VI. CONCLUSION

Based on the totality of these metrics, we believe that both the ND Preferred Plan and the Upper Midwest Plan as filed in Minnesota keep customers' bills and rates as lows as practicable. While the ND Preferred Plan was optimized without costs of constraints for emissions, the resulting cost impacts are similar, though slightly lower than the expected impacts of our Upper Midwest Plan. Importantly, this conclusion is based on numerous assumptions, including the costs of new resources, that could impact this result. We are optimistic that our analysis shows that differences between the jurisdictions we serve can be addressed while maintaining the benefits of our integrated Upper Midwest System.

ATTACHMENT 1 – COMPLIANCE MATRIX

Xcel Energy is committed to complying fully with all applicable statutes, rules and orders. We believe our 2024-2040 North Dakota Resource Plan reflects appropriate implementation of all related requirements. The matrix below reflects our inventory of requirements to be met in the North Dakota Resource Plan and cross-references to the portions of the Resource Plan that fulfill each compliance item. Where required information is provided in the 2024-2040 Upper Midwest Integrated Resource Plan filed with the Minnesota Public Utilities Commission on February 1, 2024 in Docket No. E002/RP-24-67 (copy provided), it is so noted.

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute, Rule or Order	2024-2040 Resource Plan Location of Required Content
ND Administrative Code Chapter 69-09-12 (Effective 01/01/23) Resource Plans and Cybersecurity			
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 1	A resource plan must identify the resources needed to meet forecasted capacity and energy needs, including a reserve requirement, subject to various objectives, including reliability, planning, operational, and regulatory requirements. The resource plan must provide a North Dakota preferred plan.	Cht 3: Minimum System Needs, Cht. 4: Preferred Plan
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 2	If an electric public utility's existing resources are inadequate to meet forecasted capacity and energy requirements, the utility shall identify in the resource plan the proposed actions to meet current and future electric capacity and energy needs, including generating facility additions of various types, sizes, fuel types, any known new transmission facilities, life extensions of existing generation facilities, load-modifying equipment, sponsored conservation programs, market purchases, power purchases from other utilities, and contracted capacity.	Cht. 4: Preferred Plan
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 4	The resource plan must have a planning horizon of at least fifteen years detailing both supply side and demand-side resources.	Cht 4: Preferred Plan; MN Appendix H: Resource Options
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 5	The resource plan must describe how the electric public utility intends to meet the forecasted capacity and energy needs within the next five years, along with construction and in-service timelines for generation and associated interconnection and network upgrade and new transmission facilities. The resource plan also must describe how the electric public utility intends to meet the forecasted energy and capacity needs for at least a fifteen-year planning horizon.	Cht. 4: Preferred Plan; MN Appendix H: Resource Options

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute, Rule or Order	2024-2040 Resource Plan Location of Required Content
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 6	Except as otherwise required by law or by order of the commission, the North Dakota preferred plan may not select resources based on a carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goal, or other externalities.	Cht. 4: Preferred Plan; Cht. 5: Economic Modeling Framework
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 7	The electric public utility may provide alternative scenarios with sensitivities based on proposed and current federal, state, and utility goals and mandates relating to carbon cost, emissions goal, or other externalities.	Cht. 4: Preferred Plan; Cht. 5: Economic Modeling Framework; Att. 4 (ND Appendix G): Scenario Sensitivity Analysis--PVRR Summary
N.D.C.C. § 69-09-12-03 Resource Plan Attributes	Subsection 8	The electric public utility shall describe how scenarios and sensitivities influenced the selection of the North Dakota preferred plan. The scenarios and sensitivities must be evaluated on a consistent and comparable basis, and the utility shall identify and assess the risks of each scenario and sensitivity.	Cht. 4: Preferred Plan; Cht. 5: Economic Modeling Framework; Att. 4 (ND Appendix G): Scenario Sensitivity Analysis--PVRR Summary
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 1.a.	The resource plan must describe the: a. Key data, assumptions, model inputs, information used in producing forecasts and models, and how uncertainties in assumptions were incorporated into the analysis;	Cht. 5: Economic Modeling Framework; Att. 3 (ND Appendix F): Encompass Modeling Assumptions and Inputs; MN Appendix H: Resource Options
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 1.b.	b. Type, cost, and relevant operating characteristics of demand-side and supply-side resources considered and a description of the type and cost of additional transmission facilities necessitated by the resources;	Att. 3 (ND Appendix F): Encompass Modeling Assumptions and Inputs; MN Appendix H: Resource Options; MN Appendix J: Distributed Energy Resource
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 1.c.	c. Modeling and methodological approach to load forecasting, an assessment of load forecast uncertainty, and the cost and effectiveness of existing and future utility and state-sponsored conservation and load management efforts;	MN Appendix E: Load and DER Forecasting; MN Appendix J: Distributed Energy Resources
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 1.d.	d. Projected load for the electric public utility over the planning horizon and the underlying assumptions for the projection. The information must be as geographically specific as possible and describe how the electric public utility will meet the projected load; and	MN Appendix E: Load and DER forecasting; Att. 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 1.e.	e. Criteria used in determining the appropriate level of reliability, including any required reserve or capacity margin seasonal accreditation levels and how the determinations influenced the resource plan.	Cht. 3: Minimum System Needs; Att. 2 (ND Appendix D): Energy Adequacy Analysis

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute, Rule or Order	2024-2040 Resource Plan Location of Required Content
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.a.	The resource plan must include: a. A robust set of scenarios and sensitivities, including changes to the resource mix, fuel prices, load, resource costs, inflation, operating and maintenance costs, capital costs, transmission interconnection and network upgrade costs, congestion costs, renewable integration costs, and resource accreditation.	Cht 5, Economic Modeling; Att. 4 (ND Appendix G): Scenario Sensitivity Analysis--PVRR Summary
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.b.	b. Reliability and resource adequacy assessments using quantitative metrics capturing the size, frequency, duration, and timing during extreme weather events and normal weather conditions for the fifth, tenth, and final year of the planning horizon. The assessment should include the annual expected unserved energy, the annual expected cost of unserved energy, peak seasonal capacity shortfall in megawatts, number of negative capacity shortfalls, average capacity shortfall in megawatts, longest hourly capacity shortfall, and number of hours requiring the utility to use the maximum available energy imports during a capacity shortfall.	Att. 2 (ND Appendix D): Energy Adequacy Analysis
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.c.	c. Reliability and resource adequacy assessments using quantitative metrics, including expected unserved energy during correlated natural gas-fired generation fuel delivery outages for the fifth, tenth, and final year of the planning horizon.	Att. 2 (ND Appendix D): Energy Adequacy Analysis
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.d.	d. A description of energy conversion facilities and associated interconnection and network upgrade and new transmission facilities the electric public utility intends to own and operate, or from which the utility intends to purchase energy output during the ensuing planning horizon, and the energy conversion facilities to be removed from service over the planning horizon.	Cht. 3: Minimum System Needs; Cht. 4: Preferred Plan; Cht. 5: Economic Modeling Framework; MN Appendix H: Resource Options; Att. 4 (ND Appendix T): MISO Grid Congestion
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.e.	e. Plans for energy conversion facility retirements, asset extensions, derates, market purchases and sales, and how scenarios affect cost, affordability, reliability, and resiliency.	Cht. 4: Preferred Plan; Cht. 5: Economic Modeling; Att. 4 (ND Appendix G): Scenario Sensitivity Analysis--PVRR Summary; MN Appendix H: Resource Options; MN Appendix M: Nuclear; MN Appendix W: RDF Plants
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.f.	f. To the extent possible, qualitative benefits and quantitative value of baseload and load following generation resources and the value of proximity of such resources to load.	Cht. 5: Economic Framework; Att. 2 (ND Appendix D): Energy Adequacy Analysis; MN Appendix M: Nuclear; Att. 5 (ND Appendix T): MISO Grid Congestion

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute, Rule or Order	2024-2040 Resource Plan Location of Required Content
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.g.	g. The estimated annual and total revenue requirement broken out by new and existing resources by cost category, such as generation, transmission, fuel, and energy efficiency.	Cht. 6: Customer Rate and Cost Impacts
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 2.h.	h. Any other information as may be requested by the commission.	N/A
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.a.	The resource plan must include information on: a. Expansion of, improvements to, and more efficient use of existing electric public utility generation, distribution, and transmission facilities;	Cht. 4: Preferred Plan; Cht. 5: Economic Framework; MN Appendix L: System Planning Integration; Att. 5 (ND Appendix T): MISO Grid Congestion
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.b.	b. Opportunities for energy conversion facilities, including economic opportunities to partner with other utilities in constructing and operating new facilities and extending the useful lives of existing facilities;	Cht. 4: Preferred Plan; Cht. 5: Economic Framework; MN Appendix H: Resource Options; MN Appendix M: Nuclear; MN Appendix W: RDF Plants
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.c.	c. Opportunities to pursue power purchase agreements with or develop baseload and load following generation within the state;	Cht. 4: Preferred Plan
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.d.	d. Opportunities to pursue power purchase agreements, demand- or supply-side resources, or develop generation;	Cht. 4: Preferred Plan
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.e.	e. Distributed generation, including generating capacity provided by cogeneration technologies relying on renewable resources, nonutility generation, and other sources;	Cht. 4: Preferred Plan; MN Appendix E: Load and DER Forecasting
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.f.	f. Recent or expected changes to generation dispatch across all generation technologies;	Cht. 2: Planning Landscape; Cht. 3: Minimum System Needs; Cht. 5: Economic Modeling Framework; Att. 3 (ND Appendix F): EnCompass Modeling Assumptions and Inputs; MN Appendix K: Environmental Regulations
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.g.	g. Opportunities for existing and planned transmission facilities to reduce congestion, transmission line losses, energy costs, and to increase export or import capability;	Att. 5 (ND Appendix T): MISO Grid Congestion
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.h.	h. The accuracy of the peak demand and energy forecasts compared to the previous integrated resource plan forecasts and an explanation for the causes of any deviation from the previous integrated resource plan forecasts;	MN Appendix E: Load and DER Forecasting
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.i.	i. The risk of fuel supply disruption due to extreme weather or market events; and	Att. 2 (ND Appendix D): Energy Adequacy Analysis
N.D.C.C. § 69-09-12-04 Filing Requirements	Subsection 3.j.	j. How the electric public utility intends to reconcile potential jurisdictional differences in resource selection.	Cht. 2: Planning Landscape; Cht 4: Preferred Plan; Cht. 5: Economic Modeling Framework; Cht. 6: Customer Rate and Cost Impacts

ATTACHMENT 2 (ND APPENDIX D) – ENERGY ADEQUACY ANALYSIS

I. INTRODUCTION

The electric grid is undergoing a significant transformation, moving away from traditional thermal baseload sources to more variable energy sources like wind, solar, and battery energy storage. This shift brings new challenges and complexities in maintaining grid resilience and reliability.

We are increasingly focused on ensuring that our system remains reliable, so that we can continue to deliver the power our customers demand. Our focus on reliability is particularly important because, as we are planning to retire our coal fleet (approximately 2,400 MWs of baseload generation), we have around 2,000 MWs of power purchase agreements (PPAs) set to expire between 2025 and 2028. At the same time, our neighbors are also retiring firm capacity, which makes relying on the market more difficult. Given these challenges, traditional reserve margins and capacity-based estimates are no longer sufficient to ensure our system is prepared for the challenges of extreme weather and changing grid dynamics. To ensure reliability, enhanced planning and energy adequacy assessments are necessary.

In addition to planning to meet our planning obligations without reliance on MISO, we have taken steps to further refine our energy adequacy analysis. We conducted energy adequacy back casting analysis to ensure our system has the reliable energy it needs to serve all customers at every hour of every day. We also examined the inertial floor of our system to assess how the grid would perform in the absence of traditional baseload generation. Our studies go beyond traditional EnCompass modeling to verify the need for firm dispatchable resources and inertia to ensure reliable service for our customers.

II. UTILITY PLANNING FOR SYSTEM NEEDS

Historically, we planned to have enough resources to meet our load serving needs. Though MISO plays a critical role in ensuring the reliable and efficient operation of the electric grid in the Midwest region of the United States by managing the grid and determining the availability and need for capacity, energy, and ancillary services, we cannot simply rely on MISO to address our capacity needs and ensure the reliability of our system.

MISO's Resource Adequacy (RA) construct will not necessarily ensure there is sufficient firm capacity online to cover the needs of load serving entities. The MISO region relies on Load Serving Entities (LSEs) and market participants to supply the generation resources needed to serve load. MISO also oversees a market to ensure the resources that are available are used efficiently to serve load across the MISO footprint. While MISO can manage the distribution of resources, it cannot ensure that there is enough power generation to meet demand and does not guarantee that there will be enough firm capacity to meet the needs of LSEs.

MISO's role in generation planning is limited. Generation planning is reserved for the states. MISO has the ability to set a reserve margin but not the ability to determine what resources will be procured to meet it. While we utilize MISO market energy purchases when they are more cost-effective than our own resources, these purchases are non-firm and do not contribute to our capacity for meeting our seasonal Planning Reserve Margin Requirements (PRMR) obligations as a MISO market participant. Compliance with PRMR obligations is for single-year periods, and the acquisition of new generation capacity often spans multiple years. Our most cost-effective and responsible strategy is to plan for the acquisition of generation capacity several years in advance.

Relying on the MISO Planning Resource Auction (PRA) for securing capacity for single-year periods is not a viable resource planning option. Therefore, it is crucial that we continue to plan for a system with sufficient capacity to meet our customer's energy needs.

A. Navigating the Challenges of Changing Energy Landscapes and Extreme Weather Conditions

The challenges and considerations for maintaining reliability in the face of changing energy landscapes and extreme weather conditions underscores the importance of long-term planning and the integration of new technologies and resources into the grid. Utilities are facing mounting pressure to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.[1] Extreme weather events continue to pose the greatest risk to its reliability and stability. The North American Reliability Corporation (NERC) concluded that much of North America is again at an elevated risk of having insufficient energy supplies to meet

[1] 2023 Long-Term Reliability Assessment (LTRA): North American Electric Reliability Corporation, 2023 Long-Term Reliability Assessment (2023). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_Infographic_2023.pdf.

demand in extreme operating conditions.[2] As the resource mix on the grid continues to evolve, the risk associated with continuity of energy supply must be managed.

For many years, the regional energy supply has relied on large generators located near large load centers. However, in recent years, there has been a marked shift toward renewable and distributed resources that may be distant from major load centers or may provide variable production profiles. This transition toward more variable resources located far away from load has only increased in recent years.

Consistent with our 2020-2034 Upper Midwest Integrated Resource Plan approved by the Minnesota Public Utilities Commission (2019 Plan), we recently retired Sherco Unit 2, and will retire Sherco Unit 1 in 2026, King in 2028, and Sherco 3 in 2030. Ultimately, the retirements of all the Sherco and King units will remove a total of 2,400 MWs from our system by 2030. Others are also removing base load from their system. For example, according to the most recent MISO Regional Resource Assessment (RRA)[3] in LRZ1, coal generation is expected to decline by more than 3,200 MWs from 2027 to 2037. This generation is being replaced by less than 1.5 GWs of dispatchable generation. While a substantial amount of non-dispatchable resources is also replacing this retiring generation, MISO is still forecasting a one GW reduction in accredited capacity from 2027-2032 for LRZ1. These forecasted replacements create a systemic risk that the market for capacity and energy in MISO LRZ1 will not be enough to serve the load in LRZ1—including that of Xcel Energy—under certain weather conditions. This situation could lead to an energy shortfall, disrupting the supply to consumers and potentially causing widespread outages. Moreover, similar risk extends to areas immediately adjacent to LRZ1 – LRZ2 and LRZ3 – as shown in Figure D-1 below.

[2] 2023–2024 Winter Reliability Assessment: North American Electric Reliability Corporation, 2023-2024 Winter Energy Market and Electric Reliability Assessment (2023), https://www.nerc.com/news/Pages/Generator-Fuel-Supplies,-Power-Plant-Winterization,-Load-Forecasting-Complexity-Increase-Reliability-Risk-in-North-America-.aspx

[3] 2023 Regional Resource Assessment, MISO. (November 2023). RAN Reliability Requirements and Sub-annual Construct (misoenergy.org)

Figure D-1: Local Resource Zones[4]

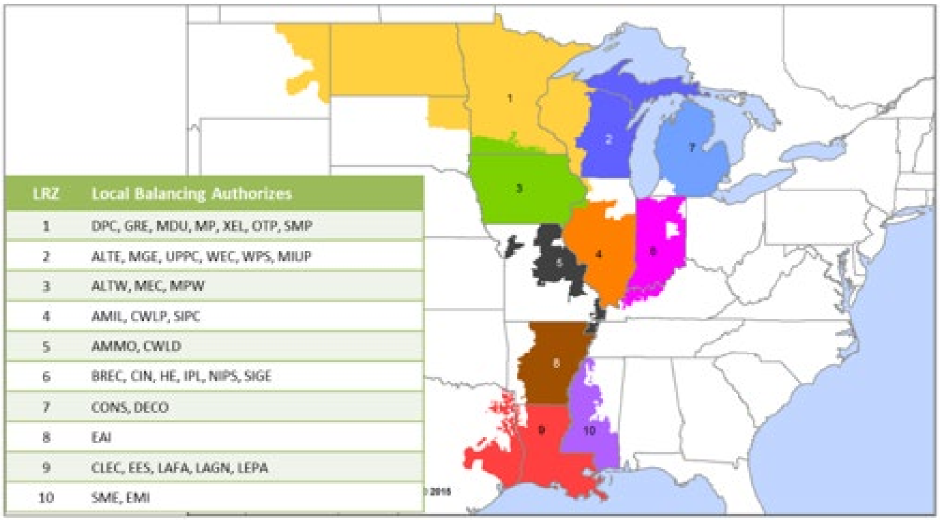


Table D-1 below shows RRA projections of no excess capacity in LRZ3 and an even larger capacity shortfall than LRZ1 in the same period. These adjacent LRZs are critical for the Company's market interactions and reduction of available capacity in these locations further threatens the reliability of the energy supply for LRZ1, as it suggests they may not always be able to provide support to LRZ1 if needed. This scenario underscores the need for strategic planning and robust risk management measures to ensure the uninterrupted operation of the energy market.

Table D-1: Estimated Net Change in Resource Type for Surrounding Load Balancing Authorities

	2027 GW Surplus or (Gap) in Accredited Capacity	2032 GW Surplus or (Gap)
LRZ 1 (Company's LRZ)	**1.0**	**(1.0)**
LRZ 2	**(1.0)**	**(3.0)**
LRZ 3	**1.0**	**0.0**

In the face of these challenges, it is imperative that we explore and implement solutions that can effectively mitigate these risks. The amount of dispatchable capacity that is scheduled to retire from our system in the next several years requires that we earnestly analyze the reliability of our system to ensure that we can continue to be resilient and that our customers continue to experience the high levels of reliability they expect. It is

[4] Source, MTEP18 Book 2 Resource Adequacy264875.pdf (misoenergy.org).

important that we plan to meet our energy and capacity obligations without over-reliance on the market or exposing our customers to excessive risk.

III. ENERGY AND CAPACITY ADEQUACY ANALYSIS

To ensure we would have sufficient capacity available on our system to meet our customers' needs across hours of the year (capacity adequacy) and that this capacity can provide enough energy during all hours of the year (energy adequacy), we stress-tested our ND Preferred Plan against historical hourly load and renewable production data using Encompass modeling software. In particular, as use-limited resources such as storage become more prevalent in future plans, evaluating both capacity and energy adequacy in a plan becomes critical because, as discussed further below, these types of adequacy are seen differently by EnCompass. For example, suppose the Company has a 200 MW storage asset in its plan. For a given hour, the 200 MW storage asset will show as "available capacity" for that hour in the model. This means it is a resource that is online for that given hour and can be considered by the model as one of the many resource options that EnCompass can choose to dispatch during that time. The availability of this battery helps avoid capacity shortfalls as measured in Tables D-2 through D-4 below, and as evaluated in the Company's prior resource plans. However, if the storage resource begins the hour only partially charged, it will not be able to provide 200 MWH during that hour. This limitation on the amount of energy is not reflected in the "capacity shortfall" metrics; rather it must be captured by additional energy adequacy analysis.

The Encompass modeling reflects actual system and market conditions and hourly production cost analysis. We use the model's full chronological modeling capabilities to run dispatch and cost analyses for the years required for compliance with the North Dakota Resource Plan: 2029, 2034, and the last year of the planning period (2040). Chapter 5 also includes 2030 results to allow for a comparison with 2030 results in the Company's 2024-2040 Upper Midwest Integrated Resource Plan (2024 Upper Midwest Plan).

Using each historical year from 2016 to 2022, we developed an 8,760-hour historical demand shape, along with monthly peak and energy forecasts, to calculate the future system level demand and shape to use in the Encompass model. All existing wind and solar resources were dispatched based on their actual historical 8,760-hour production profiles or an 8,760-hour profile from a nearby facility. Generic facilities were given a random 8,760-hour profile. Using this historical data, we conducted multiple types of special studies on three plans to ensure we would have sufficient capacity on our system to meet our customers' needs under varying weather conditions:

(1) North Dakota Reference Case (Scenario 1),
(2) North Dakota Preferred Plan (Scenario 3),
(3) Market Access Optimization (Scenario 3 optimized with 2,300 MW of hourly market access).

This analysis allows us to assess the capacity and energy adequacy of our plans. We evaluated these plans on six different measures, plus additional metrics discussed in the narrative:

1. Native Capacity Shortfall: Hours of insufficient system capacity in each year.
2. Average Shortfall Intensity: Average Shortfall in MW during the shortfall events in each year.
3. Longest Shortfall Event: Longest duration in hours of the shortfall events in each year.
4. Peak Capacity Shortfall: Peak capacity shortfall in MW of the capacity shortfall events in each year.
5. MISO Market Reliance Hours: Total number of hours the plan is reliant on the market to serve load.
6. MISO Market Reliance Energy: Total amount of MWh the plan is reliant on the market to serve load.

The results for each scenario in 2029, 2034, and 2040 are shown below in Tables D-2 through D-4:

Table D-2: Summary of 2029 Energy and Capacity Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2029**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
ND Reference Case (Scenario 1)	**2016 Historical**	**11**	**284**	**3**	**464**	**11**	**3,219**
	2017 Historical	**1**	**4**	**1**	**4**	**9**	**2,855**
	2018 Historical	**1**	**319**	**1**	**319**	**3**	**429**
	2019 Historical	**7**	**196**	**2**	**365**	**7**	**1,370**

		Capacity Adequacy Metrics				**Energy Adequacy Metrics****	
Plan	**Historical Year - Hourly Conditions in 2029**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
	2020 Historical	**10**	**125**	**2**	**394**	**18**	**3,063**
	2021 Historical	**7**	**459**	**4**	**1,188**	**11**	**3,963**
	2022 Historical	**1**	**182**	**1**	**182**	**1**	**182**
ND Preferred Plan (Scenario 3)Scenario 3	**2016 Historical**	**11**	**268**	**3**	**447**	**14**	**3,711**
	2017 Historical	**0**	**0**	**0**	**0**	**8**	**2,848**
	2018 Historical	**1**	**301**	**1**	**301**	**2**	**342**
	2019 Historical	**7**	**171**	**2**	**365**	**14**	**2,739**
	2020 Historical	**10**	**104**	**2**	**391**	**19**	**2,828**
	2021 Historical	**7**	**352**	**4**	**1,002**	**13**	**4,164**
	2022 Historical	**1**	**163**	**1**	**163**	**1**	**163**
Market Access Optimization (Scenario 3 Market On Expansion Plan)	**2016 Historical**	**41**	**449**	**6**	**1,267**	**56**	**25,389**
	2017 Historical	**22**	**292**	**4**	**868**	**41**	**15,990**
	2018 Historical	**55**	**266**	**6**	**959**	**93**	**29,929**
	2019 Historical	**68**	**298**	**6**	**1,026**	**87**	**31,808**
	2020 Historical	**57**	**367**	**5**	**1,088**	**88**	**35,910**
	2021 Historical	**44**	**384**	**13**	**1,075**	**67**	**27,674**
	2022 Historical	**8**	**324**	**2**	**804**	**12**	**4,746**
	** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)						

As shown in Table D-2 above, the ND Preferred Plan performs well across energy and capacity adequacy metrics. There are less than 40 hours of native capacity shortfall across the seven historic years tested, resulting in limited dependence on the market. There are 71 hours across the seven historical test years – less than 0.1 percent of all hours tested - where the ND Preferred Plan requires market purchases in order to meet load serving needs. The ND Reference Case scenario also results in limited market dependence.

In contrast, under the Market Access Optimization, which allows the capacity expansion to optimize assuming market access of 2,300 MWs in all hours of the year, the results show that the plan exposes our customers to excessive risk. There are 295 hours across the seven historic years where the plan has insufficient capacity to meet needs. This results in 444 hours where the plan cannot meet load serving needs and must rely on market purchases of nearly 172,000 MWhs of energy.

Our analyses of 2034 and 2040, below, shows similar results as displayed in Tables D-3 and D-4 below:

Table D-3: Summary of 2034 Energy and Capacity Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	Historical Year - Hourly Conditions in 2034	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliance Hours	MISO Market Reliance (MWh)
ND Reference Case (Scenario 1)	2016 Historical	9	538	3	772	9	5,073
	2017 Historical	0	0	0	0	0	0
	2018 Historical	5	252	3	608	5	1,616
	2019 Historical	7	286	2	692	8	2,019
	2020 Historical	5	231	3	419	5	1,153
	2021 Historical	3	188	2	234	7	2,085
	2022 Historical	1	533	1	533	1	533
ND Preferred Plan (Scenario 3)Scenario 3	2016 Historical	9	372	3	622	9	3,497
	2017 Historical	0	0	0	0	0	0
	2018 Historical	2	246	1	367	4	767
	2019 Historical	5	191	2	516	5	954
	2020 Historical	2	166	1	189	3	351

<table>
<tr><th></th><th></th><th colspan="4">Capacity Adequacy Metrics</th><th colspan="2">Energy Adequacy Metrics**</th></tr>
<tr><th>Plan</th><th>Historical Year - Hourly Conditions in 2034</th><th>Native Capacity Shortfall (Hrs.)</th><th>Average Shortfall Intensity (MW)</th><th>Longest Shortfall Event (Hrs.)</th><th>Peak Capacity Shortfall (MW)</th><th>MISO Market Reliance Hours</th><th>MISO Market Reliance (MWh)</th></tr>
<tr><td rowspan="2"></td><td>2021 Historical</td><td>4</td><td>97</td><td>2</td><td>212</td><td>5</td><td>2,136</td></tr>
<tr><td>2022 Historical</td><td>1</td><td>283</td><td>1</td><td>283</td><td>1</td><td>283</td></tr>
<tr><td rowspan="7">Market Access Optimization (Scenario 3 Market On Expansion Plan)</td><td>2016 Historical</td><td>16</td><td>649</td><td>4</td><td>1,285</td><td>18</td><td>10,559</td></tr>
<tr><td>2017 Historical</td><td>3</td><td>204</td><td>2</td><td>288</td><td>6</td><td>1,342</td></tr>
<tr><td>2018 Historical</td><td>12</td><td>320</td><td>3</td><td>985</td><td>15</td><td>4,161</td></tr>
<tr><td>2019 Historical</td><td>21</td><td>319</td><td>3</td><td>795</td><td>25</td><td>7,508</td></tr>
<tr><td>2020 Historical</td><td>18</td><td>315</td><td>3</td><td>893</td><td>22</td><td>7,283</td></tr>
<tr><td>2021 Historical</td><td>9</td><td>356</td><td>3</td><td>731</td><td>13</td><td>4,534</td></tr>
<tr><td>2022 Historical</td><td>3</td><td>451</td><td>1</td><td>917</td><td>3</td><td>1,353</td></tr>
<tr><td></td><td colspan="7">** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)</td></tr>
</table>

Similar to the results for 2029, the ND Preferred Plan performs well across energy adequacy metrics in 2034. There are only 23 hours of native capacity shortfall across the seven historic years tested, resulting in limited dependence on the market. There are 27 hours across the seven historical test years where the ND Preferred Plan requires market purchases in order to meet load serving needs. The Reference Case scenarios also result in limited market dependence.

In contrast, under the Market Access Optimization, which allows the capacity expansion to optimize assuming market access of 2,300 MWs in all hours of the year, the results expose our customers to excessive risk. There are 82 hours across the seven historic years where the plan has insufficient capacity to meet needs. In addition to capacity shortfalls, there are 102 hours where the plan cannot meet load serving needs and must rely on market purchases of over 36,740 MWhs of energy.

Table D-4: Summary of 2040 Energy and Capacity Adequacy Special Study Scenario

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	Historical Year - Hourly Conditions in 2040	Native Capacity Shortfall (Hrs.)	Average Shortfall Intensity (MW)	Longest Shortfall Event (Hrs.)	Peak Capacity Shortfall (MW)	MISO Market Reliance Hours	MISO Market Reliance (MWh)
ND Reference Case (Scenario 1)	2016 Historical	8	135	3	354	13	2,638
	2017 Historical	0	0	0	0	0	0
	2018 Historical	1	236	1	236	3	559
	2019 Historical	1	16	1	16	1	16
	2020 Historical	0	0	0	0	0	0
	2021 Historical	1	479	1	479	14	5,113
	2022 Historical	0	0	0	0	0	0
ND Preferred Plan (Scenario 3)Scenario 3	2016 Historical	7	140	3	322	7	983
	2017 Historical	0	0	0	0	0	0
	2018 Historical	1	163	1	163	1	163
	2019 Historical	0	0	0	0	0	0
	2020 Historical	0	0	0	0	0	0
	2021 Historical	2	132	1	214	5	1,640
	2022 Historical	0	0	0	0	0	0
ND Market Access Optimization (Scenario 3 Market On Expansion Plan)	2016 Historical	23	601	4	1,357	30	20,728
	2017 Historical	2	130	1	191	3	352
	2018 Historical	14	347	3	1,115	27	11,060
	2019 Historical	19	402	3	886	38	13,178
	2020 Historical	18	178	3	466	41	13,151
	2021 Historical	22	356	6	1,279	44	23,368
	2022 Historical	3	541	1	818	3	1,624

		Capacity Adequacy Metrics				Energy Adequacy Metrics**	
Plan	**Historical Year - Hourly Conditions in 2040**	**Native Capacity Shortfall (Hrs.)**	**Average Shortfall Intensity (MW)**	**Longest Shortfall Event (Hrs.)**	**Peak Capacity Shortfall (MW)**	**MISO Market Reliance Hours**	**MISO Market Reliance (MWh)**
	** LOLH is higher than capacity shortfall due to batteries having available capacity, but no stored energy (MWh)						

Finally, like the results for 2034, the ND Preferred Plan performs well across energy adequacy metrics in 2040. There are only 10 hours of native capacity shortfall across the seven historic years tested, resulting in limited dependence on the market. There are 13 hours across the seven historical test years where the ND Preferred Plan requires market purchases to meet load serving needs. The Reference Case scenarios also result in limited market dependence.

In contrast, under the Market Access Optimization, which allows the capacity expansion to optimize assuming market access of 2,300 MWs in all hours of the year, the results expose our customers to excessive risk. There are 101 hours across the seven historic years where the plan has insufficient capacity to meet needs. In addition to capacity shortfalls, there are 186 hours where the plan cannot meet load serving needs and must rely on market purchases of over 83,400 MWhs of energy.

A. Additional Market Dependence Metrics and Outage Scenarios North Dakota Resource Plan

Limiting market dependence is important for both cost and reliability. During hours when system resources cannot meet load serving needs, purchases from the market are needed. During these hours, we are exposed to the prevailing Locational Marginal Energy Prices (LMPs) at load. If LMPs are high, those high costs will increase customer bills, especially if we need a large volume of purchases during those high-cost hours. If LMPs are high over multiple hours, those impacts could be significant. More importantly, if resources are not available in the market, customers may be subjected to reliability impacts. As one of the largest utilities in MISO Zone 1, the potential for reliability impacts in the region are greater if we have insufficient resources to meet our load serving needs.

In looking at the Peak Capacity Shortfall columns in Tables D-2 through D-4 above, none of the plans had any hours where the Company would have been required to use the maximum available energy imports (2,300 MW).

Additionally, the results shown in Tables D-2 through D-4 above are single-year production cost runs without market access. This methodological change is new since the conclusion of the 2019 Plan and allows for a more granular set of reliability results regarding both capacity and energy adequacy. Our EnCompass modeling assumes a cost of $1,000,000/MWH for unserved energy. In this analysis, the "MISO Market Reliance" columns show the unserved energy when no access to market energy is assumed. Therefore, this analysis may not be overly meaningful as estimators of the actual cost or amount of unserved energy since these production costs runs were not allowed to access market energy, but rather is designed to analyze market exposure.

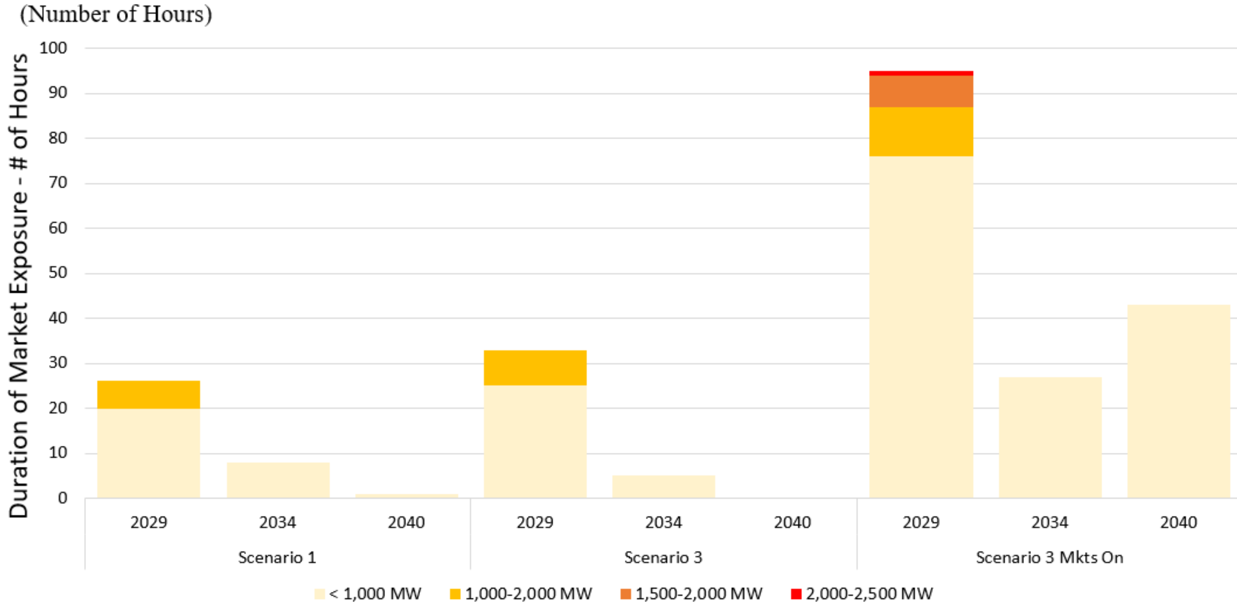
1. *Correlated Gas Outages and Fuel Risk*

In addition to the energy adequacy testing above, Figure D-2 below shows a special set of additional test results for a correlated gas outage stress test scenario. In this case, using the 2019 weather year, all of the Company's natural gas generation located in the Minneapolis – St. Paul vicinity was made unavailable during the same time period as the polar vortex (January 29-31). The Company believes that this scenario – a high level gas supply event that effectively cuts off gas service to all Twin Cities area plants for a multiday period – would be highly improbable under normal circumstances given optionality for the bi-directional flow of gas.[5] However, it is a suitable scenario in terms of an "extreme" stress-test comparison between plans.

Figure D-2 below shows the results for these runs – the ND Reference Case, the ND Preferred Plan, and the Market Access Optimization plans were all tested with this scenario.

[5] The Company believes a more plausible outage would likely be a localized pressure event where 2-3 plants in a region are unable to run on gas Such events could vary in length for a few hours (from something like a compressor issue) to a day (a more extreme event like a rupture).

Figure D-2: Market Exposure Quantities and Durations if Correlated Gas Outages Also Occurred During 2019 Polar Vortex



The results show that the Market Optimization plan, with its reliance on market access, is far more vulnerable to impacts from a correlated gas outage than the ND Preferred Plan or ND Reference Case.

In terms of general fuel supply risk, this type of risk is challenging to incorporate directly into modeling in a separate fashion, as not all upstream or general fuel supply access events in the Upper Midwest will necessarily impact the Company's generation. To mitigate potential disruptions from fuel supply, the Company first holds firm transportation on connecting inter and intrastate pipelines for gas fired generation that serves our native load. This provides access to liquid gas supply markets via firm transportation. The interstate pipelines providing service for our gas generation have access, through liquid market hubs, to gas supplies from several gas basins, so that in the event of a significant disruption, such as freeze offs in one source, can be offset by additional supplies from elsewhere. Similarly, in the event of a disruption to the pipeline itself, interstate pipeline operators, such as Northern Natural Gas (NNG), are able to flow bi-directionally in most situations, and could maintain levels of flow from alternate interconnections of direction.

In addition, many of the Company's generation sites have dual fuel capability, which allows for fuel switching when gas supplies are unavailable, or when daily prices reach un-economic levels. Both dual fuel capability and firm fuel supply access help mitigate the risk of our generation being significantly affected by a regional or upstream fuel supply issues as well.

While MISO's currently proposed DLOL methodology does not propose separate resource classes for those physical fuel resources that have firm fuel supply or onsite storage versus those that do not, it does weight the performance of generation units during critical hours – both historically tight margin hours and future projected Loss-of-Load (LOL) hours. The Company's steps to secure firm fuel supply or dual fuel capability in many of its gas-fired generation units helps ensure these resources stay online during these resource adequacy hours, which in turn helps keep resource accreditation higher.

2. *Additional Market Dependence Metrics*

Figures D-3 through D-5 below provide additional insight into the energy adequacy of the three plans analyzed.

Figure D-3: ND Reference Case (Scenario 1)

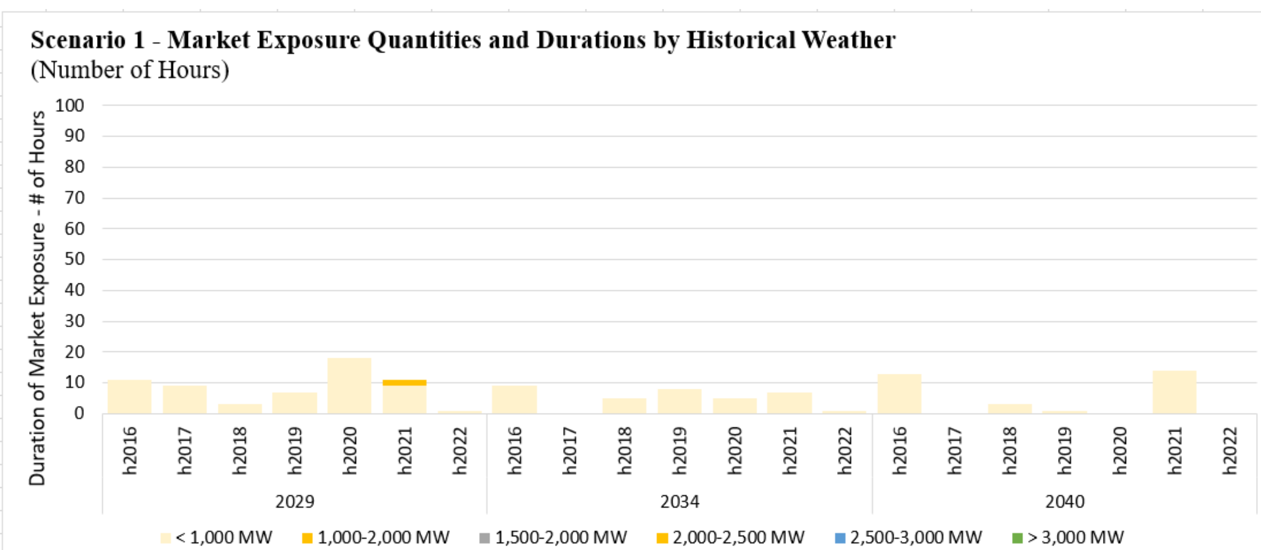


Figure D-4: ND Preferred Plan (Scenario 3)

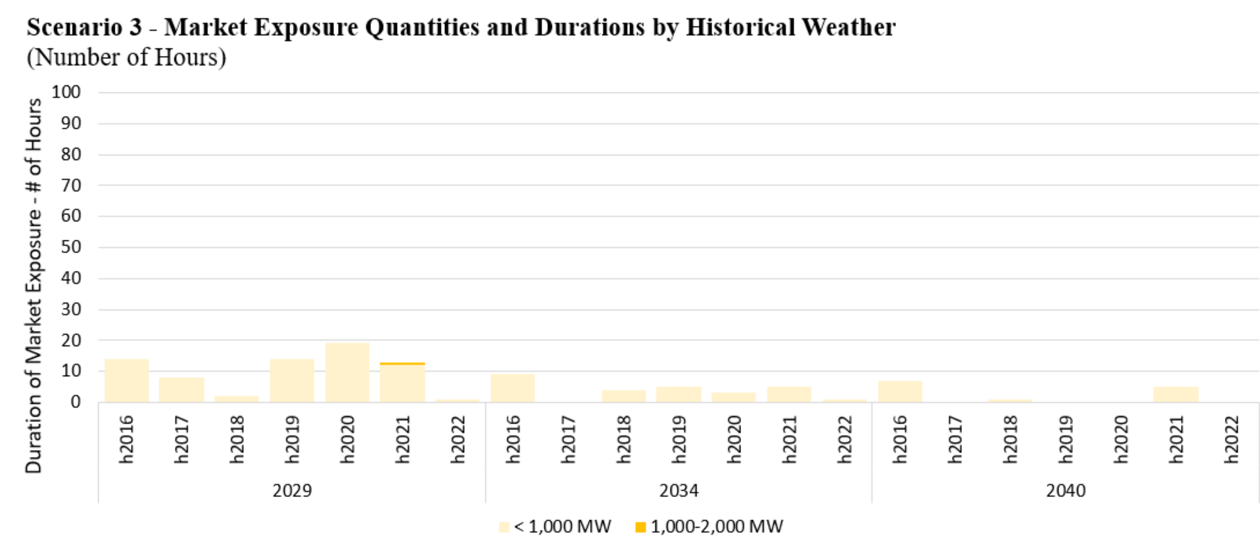
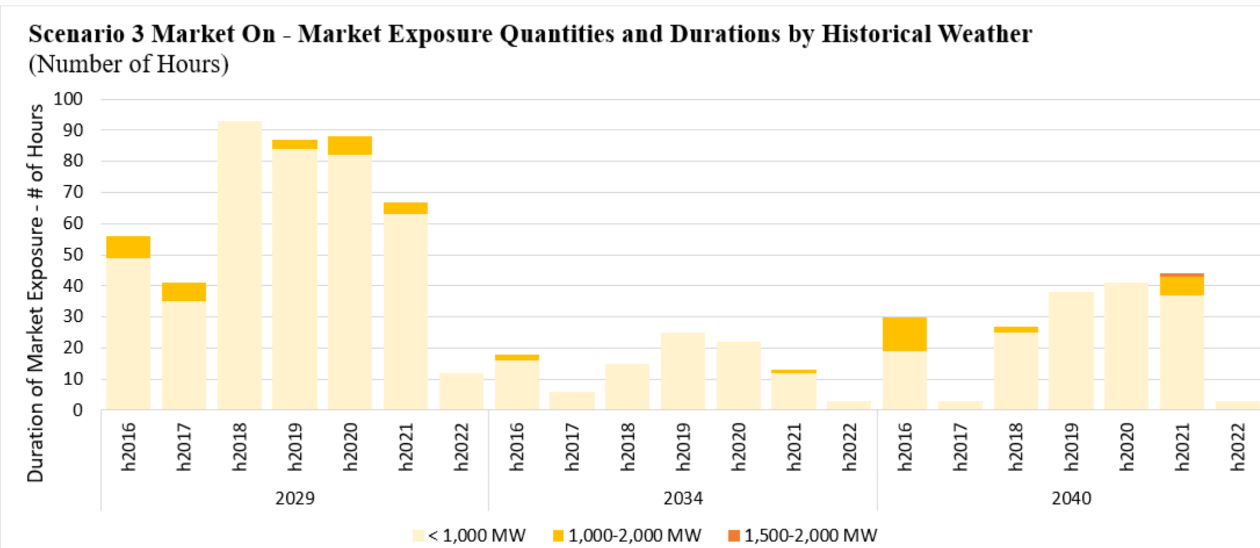


Figure D-5: Market Access Optimization (Scenario 3 Optimized with 2,300 MW of Hourly Market Access)



The figures above show the market dependence of each scenario analyzed. The bar for each historic year shows the impact in 2029, 2034, and 2040 both in terms of the number of hours of market dependence and the magnitude of those hours. The darkest colors show hours where the system must rely on the market for more MW of purchases to serve load. Consistent with the results above, the ND Preferred Plan and ND Reference Case scenarios also result in limited market dependence. In contrast, the Market Optimization analysis shows significant market dependence, both in terms of increased hours and in terms of the larger amounts, in MW, of market dependence.

The tests and metrics above focus on limiting market dependence. There are many reasons market exposure can occur, including fluctuations in pricing, weather, load, or generation outages that last for a few acute hours or for 1–2 day periods. However, in addition to limiting market dependence across all events, different plans can also differ starkly in terms of how they weather a longer period – 4 days – of lower than expected solar and wind generation.

The need for our resources to be able to cover energy needs over an elongated period of time is important because we have seen such periods historically, and we project instances of low renewable output that could impact reliability without sufficient firm capacity to cover energy needs. For instance, recently customers in Oahu were asked to reduce use of electricity to avoid rolling blackouts across Oahu due to a shortage of reserve generation capacity.[6] Two large generating units at Waiau Power Plant went offline, and repairs were not expected to be completed by the end of the day. Heavy cloud cover and rainy conditions reduced the production from solar energy systems and prevented battery energy storage systems from charging to full capacity. As a result, Hawaiian Electric began load shedding in various areas around the island to avoid a more widespread outage or damage to the electric system from an imbalance of demand versus available generation.

Further, the Moon Shoot study[7] by GridLab, emphasized the importance of firm dispatchable generation to support a clean energy policy. The study noted that short storage duration batteries (typically 4 to 10 hours) can provide a significant amount of capacity for reliability, but they cannot be the only capacity resource on the system (unless systems are upsized in terms of solar and wind resources, or capacity expansions are planned through a regional optimization approach). There may be long periods—potentially spanning multiple days—where solar and wind are unavailable, requiring other resources (such as hydrogen capacity) to be available in these times. During this time, even relatively long, 10-hour duration battery storage does not bridge the gap between periods of renewable production and demand.

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[6] https://www.hawaiianelectric.com/update-rolling-oahu-outages-initiated-customers-asked-to-reduce-use-of-electricity.[7] The Moonshot 100 percent clean electricity study:
[7] The Moonshot 100 percent clean electricity study:
Assessing the tradeoffs among clean portfolios with a PNM case study, Grid Lab
https://gridlab.org/moonshot-study/.

In conclusion, energy and capacity adequacy analysis is a critical tool in resource planning. It helps ensure that we have a diverse and resilient energy portfolio capable of meeting demand.

IV. THE IMPORTANCE OF FIRM DISPATCHABLE RESOURCES IN OUR ND PREFERRED PLAN

Our ND Preferred Plan modeling indicates the need for the addition of approximately 4,340 MWs of cumulative firm dispatchable resources between 2027 and 2040 to ensure long-duration, affordable energy when our intermittent renewables are not able to fully meet our customers' needs. Of this modeled need, 2,244 MWs of firm dispatchable resources are needed by 2030. These resources are split between 748 MWs in 2027, 748 MWs in 2028, and 748 MWs in 2030. Approximately 374 MWs of the 2028 need is located on our re-optimized Sherco Generation tie line.

We note that the Minnesota Commission is considering firm dispatchable resources additions in MPUC Docket No. E002/CN-23-212. Additional firm dispatchable resources above 800 MWs have bid into the acquisition proceeding to serve our up to 800 MW need identified in our 2019 Plan. As noted here, firm dispatchable resources provide numerous benefits, including near-instant availability, making them ideal for peak power supply and when intermittent wind and solar generation are not producing energy.

The value of firm dispatchable resources and fuel diversity becomes evident during periods of extreme weather. During the 2019 Plan, it was observed that firm dispatchable resources were crucial during severe cold spells when wind resources underperformed. Even with a hypothetical doubling of wind output, there were periods of low renewable output. Hence, having diverse resources is essential to meet customer needs during such events. A diverse mix of firm dispatchable resources ensures our ability to provide reliable electric service under all conditions. With the increasing frequency of extreme weather events, it is crucial to manage the transformation of our generation portfolio while preserving system reliability and stability. Though our nuclear units remain a major source of reliable, carbon-free generation for our system, our modeling shows a need for additional firm dispatchable generation.

Extreme events can span all or nearly all of MISO's footprint, limiting the ability to rely on the broader MISO system in times of need. To meet the shortfall in the output of variable resources; at such times, we may have to rely on our resource diversity and our dispatchable generation, including units fueled by natural gas and fuel oil. With the increasing frequency of extreme weather events, such as the 2019 polar vortex and Winter Storm Uri in 2021, it is crucial to manage the transformation of our generation portfolio while preserving system reliability and stability. Any disruption in electric service during similar future events could have serious impacts on our customers, public safety and to overall grid operations.

In sum, from a high-level capacity and reliability standpoint, the importance of firm, dispatchable resources in our energy strategy is undeniable. As we transition towards a more sustainable energy future, these resources provide the reliability and stability necessary to ensure uninterrupted service under all conditions. While advancements in transmission technologies, renewable energy sources, and energy storage resources are promising, they cannot at this time fully replace the need for firm dispatchable resources due to their current technological maturity, regulatory complexities, and the challenges in large-scale deployment. Therefore, a balanced approach that includes a diverse mix of firm, dispatchable resources, is crucial in meeting the growing energy demand while also progressing towards decarbonization.

V. INERTIAL FLOOR STUDY

In addition to considering the value of various resources from a high-level capacity and reliability view, the Company is assessing the electrical engineering impacts of moving from a system built around large, centrally located baseload units to one based more on remotely located renewable generators. Studies that the Company and others have conducted show that the inertia historically provided by these baseload units is crucial to help the system oscillations dampen out. To help inform decisions for future generation transformation from traditional coal-based generation, the Company's Transmission Planning engineers performed a study to evaluate the NSP system's transient stability response with all of the baseload coal generation in the region offline and replaced by renewable generation (wind and solar) and other thermal generation. Unlike traditional MISO generator replacement studies, this study considers not only what happens to our system as we retire Company-owned coal generation but also potential retirements of neighboring coal generation. At this time, MISO only studies system impacts of unit retirements based on unit-specific requests made by the owners of such units. However, we understand that the vast majority of utilities within MISO are considering similar renewable initiatives to the Company. Therefore, while MISO's studies currently reflect the transmission system as being reliable and stable, they do not provide a forward-looking regional assessment of stability as coal retirements continue.

Our NSP Power System Inertial Floor Study Report, showing how the grid would perform in the absence of traditional baseload generation, mainly coal and nuclear, is included as Appendix D1 in the 2024 Upper Midwest Plan. This Inertial Floor study is run annually to update the analysis and evaluate the impacts to our system reliability, system stability, angular stability and inertia. This analysis allows us to determine the necessary levels of spinning mass and/or dispatchable generation necessary to keep the system stable and reliable to serve our customers.

Our study shows that inertia is crucial to help the system remain stable, and as we and other owners of baseload generation in the region retire those units, we begin to see regional stability issues. This demonstrates that it will be critical that we acquire resources capable of providing inertia as we retire our coal-fleet.

VI. CONCLUSION

Preparation and planning are key to delivering reliable power to our customers. As a Company, we take this responsibility seriously. Recent events have shown that it is important to plan for how we can provide electricity to our customers under all conditions. In addition to planning to meet our planning obligations without reliance on MISO, we have taken steps to further refine our energy adequacy analysis. We conducted an energy adequacy back casting analysis to ensure our system has the reliable energy it needs to serve all customers at every hour of every day. We also examined the inertial floor of our system to assess how the grid would perform in the absence of traditional baseload generation. Our studies go beyond traditional EnCompass modeling to verify the need for firm dispatchable resources and inertia to ensure reliable service for our customers. Our ND Preferred Plan and Upper Midwest Preferred Plans will provide for the reliability our system needs to adequately ensure continued service to our customers.

ATTACHMENT 3 (ND APPENDIX F) – ENCOMPASS MODELING ASSUMPTIONS AND INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and determining the present value of modeled costs is 6.39 percent. The rates shown below were calculated by taking a weighted average of the most recent electric retail rate case in each NSP jurisdiction.

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.83%	4.34%	2.03%	1.47%
Common Equity	52.48%	9.35%	4.91%	4.91%
Short-Term Debt	0.68%	3.18%	0.02%	0.02%
Total			**6.96%**	**6.39%**

B. Inflation Rate

The inflation rate is applied to existing resources, generic resources, and other costs associated with general inflationary trends in the modeling. For long term capacity expansion planning purposes, we used the two percent long-term inflation rate inflation target established by the Federal Reserve.

C. Reserve Margin

The modeled Planning Reserve Margin is based on the MISO Planning Year 2024-2025 assumptions, adjusted for the average coincidence factors in MISO Planning Year 2024-2025 and Planning Year 2023-2024.

Table F-1: Seasonal Planning Reserve Margin

	Summer	Fall	Winter	Spring
MISO Planning Reserve Margin (PRM) PY24/25	9.00%	14.20%	27.40%	26.70%
Average Coincidence Factor	92.24%	92.67%	97.09%	95.61%

The higher Planning Reserve Margin or MISO Reliability Based Demand Curve[1] (RBDC) Opt-Out sensitivity represents the additional capacity necessary to opt out of the RBDC and assumes the effective reserve margin as shown in Table F-2 below.

Table F-2: Reliability-Based Demand Curve Sensitivity

	Summer	Fall	Winter	Spring
Reliability-Based Demand Curve Opt Out[2]	3.1%	3.4%	2.7%	1.7%

D. Energy Efficiency (EE) Bundles

The Company based our EE bundles on our proposed 2024-2026 ECO Triennial Plan.[3] Three bundles of EE were developed: (1) a low-achievement bundle based on minimum statutory requirements in Minn. Stat. § 216B.241, (2) a mid-achievement bundle based on estimated savings derived from our 2024-2026 ECO Triennial, and (3) a high-achievement bundle based on the "Optimized Bundle" as part of the 2020-2034 IRP which took into account the most recent state potential analysis.[4] Internal experts provided estimated costs, and energy and demand avoidance characteristics for the programs. Multiple sources were considered for the different bundles including the 2018 *Minnesota Energy Efficiency Potential Study* findings, the Company's ECO Triennial Plan, and IRA policies and funding. In addition to the bundles, naturally occurring EE is embedded in the load forecast.

Each bundle is modeled in Encompass in the same manner as a supply side resource. The first two bundles are forced into the model and are not selectable as they represent our planned program achievement for EE. The High Achievement Bundle (Bundle 3) was offered as a selectable resource by the EnCompass model as part of the optimization process. Bundle 3 was developed by the Company, drawing on the Optimal Bundle in the 2019 IRP.

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[1] The RBDC proposal, currently under consideration by FERC, is a proposed design for MISO's Planning Resource Auction that aims to reflect the reliability value of capacity and produce more efficient and stable capacity prices. Pending FERC approval, the RBDC reform is expected to be implemented in PY 2025-2026.
[2] Reliability Requirement Representations in the Planning Resource Auction: Consideration of a Reliability-Based Demand Curve (August 22, 2023). Available at: https://cdn.misoenergy.org/20230822-23%20RASC%20Item%2006a%20Reliability%20Based%20Demand%20Curves%20Presentation%20(RASC-2019-8)629946.pdf
[3] 2024-2026 ECO Triennial Plan, as filed, Docket No. G,E002/CIP-23-92, June 29, 2023.
[4] Upper Midwest Integrated Resource Plan 2020-2034, Xcel Energy, Docket No. E002/RP-19-368, 2019.

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Table F-3: Energy Efficiency Bundles

	Energy (GWh)			Demand (MW)			Cost ($000)		
Year	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High
2024	477	138	159	91	26	30	$ 86,040	$ 47,971	$ 79,937
2025	887	256	310	169	49	59	$ 86,202	$ 54,143	$ 81,246
2026	1,298	400	460	247	76	88	$ 82,934	$ 62,811	$ 79,928
2027	1,691	531	654	322	101	124	$ 82,108	$ 57,926	$ 108,775
2028	2,075	659	864	395	125	164	$ 82,108	$ 57,926	$ 123,859
2029	2,455	785	1,023	467	149	195	$ 82,108	$ 57,926	$ 97,752
2030	2,832	835	1,268	539	159	241	$ 92,536	$ 31,685	$ 152,953
2031	3,204	893	1,498	610	170	285	$ 92,536	$ 31,685	$ 152,953
2032	3,565	948	1,725	678	180	328	$ 92,536	$ 31,685	$ 152,953
2033	3,908	1,010	1,947	744	192	371	$ 89,458	$ 34,764	$ 152,953
2034	4,234	1,066	2,161	806	203	411	$ 89,458	$ 34,764	$ 152,953
2035	4,554	1,121	2,327	867	213	443	$ 89,458	$ 34,764	$ 125,340
2036	4,419	1,089	2,259	841	207	430		$ -	
2037	4,347	1,069	2,222	827	203	423		$ -	
2038	4,270	1,049	2,181	813	200	415		$ -	
2039	4,113	1,007	2,116	783	192	403		$ -	
2040	3,963	969	2,050	754	184	390		$ -	
2041	3,807	925	1,980	725	176	377		$ -	
2042	3,591	863	1,882	683	164	358		$ -	
2043	3,379	802	1,779	643	153	339		$ -	
2044	3,012	692	1,635	573	132	311		$ -	
2045	2,655	599	1,470	505	114	280		$ -	
2046	2,316	501	1,312	441	95	250		$ -	
2047	1,986	409	1,144	378	78	218		$ -	
2048	1,658	324	957	315	62	182		$ -	
2049	1,330	241	787	253	46	150		$ -	
2050	1,009	184	599	192	35	114		$ -	
2051	774	143	455	147	27	87		$ -	
2052	541	103	314	103	20	60		$ -	
2053	321	61	183	61	12	35		$ -	
2054	160	30	84	30	6	16		$ -	
2055	-	-	-	-	-	-		$ -	

E. Demand Response Forecast

Like the process for EE, the Company created six bundles for demand response based on level of achievement and technology so that DR could be modeled in Encompass in the same manner as a supply-side resource. These bundles included: (1) Base DR, Saver's Switch, (2) Base DR, Other DR, (3) Incremental DR, Saver's Switch, (4) Incremental DR, Other DR, (5) High Potential, Saver's Switch, and (6) High Potential, Other DR.

Consistent with past practice, the Company developed a Base DR Forecast from existing programs at historical growth rates, which was included in all baseline resource modeling as the first level of DR achievement. The Company then developed two levels of DR achievement incremental to the Base DR Forecast. The second level of DR achievement represents a higher level of growth rate necessary to achieve the required 400 MW of incremental DR by the end of 2023,[5] and a continuation of that level of achievement beyond 2023. This level of achievement, represented by bundles 1 through 4, is included in the Encompass model as required resources as ordered by the Commission. The third level of DR achievement, represented by bundles 5 and 6, is based on the Brattle DR Potential Study included in the 2019 IRP. This level of achievement exceeds the achievement of the ordered 400 MW by 2023 at a higher cost. These bundles are included in the Encompass model as selectable resources to determine the cost-effective level of future DR achievement.

Within each level of achievement, the costs and impacts of the Saver's Switch program and all other DR programs were modeled separately. This was done as the Saver's Switch program controls air-conditioning,[6] resulting in load reductions that differ significantly from the load reductions from all other DR programs which control a wide variety of loads. This results in a total of six bundles modeled bundles as described above (each level broken into specific technology and control characteristics). Similar to EE, each level of achievement represents an incremental amount of DR and is dependent on the preceding level of achievement being selected (i.e., third level of achievement for the Saver's Switch program cannot be selected unless the second level of achievement is selected).

[5] *See Order Approving Plan with Modifications and Establishing Requirements For Future Filings*, Docket No. E002/RP-19-368, April 15, 2022 at Order Point 2.A.2.

[6] Saver's Switch was used as a proxy for characterization of the resource, other programs such as AC Rewards also hold these characteristics.

Table F-4: Demand Response Forecast

	Incremental Demand (MW)						Incremental Costs ($000's $2023)					
Year	Bundle 1	Bundle 2	Bundle 3	Bundle 4	Bundle 5	Bundle 6	Bundle 1	Bundle 2	Bundle 3	Bundle 4	Bundle 5	Bundle 6
2024	686	339	176	56	24	70	29,538	20,204	13,834	4,362	3,490	10,068
2025	689	350	177	57	27	59	29,665	20,894	13,893	4,511	3,877	8,482
2026	691	362	178	59	28	59	29,756	21,584	13,936	4,660	4,057	8,500
2027	692	369	178	61	30	59	29,790	22,025	13,952	4,756	4,273	8,518
2028	692	375	178	61	31	59	29,732	22,357	13,924	4,827	4,522	8,537
2029	691	380	177	62	33	59	29,657	22,656	13,889	4,892	4,806	8,555
2030	687	385	176	63	36	60	29,367	22,960	13,753	4,957	5,124	8,573
2031	683	390	174	64	38	60	29,079	23,268	13,619	5,024	5,463	8,592
2032	679	395	173	65	40	60	28,795	23,580	13,486	5,091	5,825	8,610
2033	675	401	171	66	43	60	28,513	23,896	13,354	5,160	6,211	8,628
2034	671	406	170	67	46	60	28,234	24,216	13,223	5,229	6,622	8,647
2035	667	412	168	67	49	60	27,958	24,541	13,094	5,299	7,060	8,665
2036	663	417	167	68	52	60	27,684	24,870	12,966	5,370	7,527	8,684
2037	660	423	166	69	56	60	27,413	25,203	12,839	5,442	8,026	8,702
2038	657	428	164	70	59	61	27,145	25,541	12,713	5,515	8,557	8,721
2039	654	434	163	71	63	61	26,880	25,883	12,589	5,589	9,123	8,739
2040	650	440	162	72	68	61	26,617	26,230	12,465	5,664	9,727	8,758
2041	647	446	161	73	72	61	26,356	26,582	12,343	5,740	10,371	8,777
2042	644	452	160	74	77	61	26,098	26,938	12,223	5,816	11,058	8,795
2043	641	458	158	75	82	61	25,843	27,300	12,103	5,894	11,790	8,814
2044	638	464	157	76	87	61	25,590	27,666	11,985	5,973	12,570	8,833
2045	635	470	156	77	93	61	25,340	28,036	11,867	6,054	13,402	8,852
2046	632	477	155	78	99	62	25,092	28,412	11,751	6,135	14,290	8,871
2047	629	483	154	79	106	62	24,846	28,793	11,636	6,217	15,236	8,890
2048	626	489	153	80	113	62	24,603	29,179	11,522	6,300	16,244	8,909
2049	623	496	152	81	120	62	24,362	29,570	11,410	6,385	17,319	8,928
2050	620	503	150	82	128	62	24,124	29,967	11,298	6,470	18,466	8,947
2051	617	509	149	83	137	62	23,888	30,368	11,187	6,557	19,688	8,966
2052	615	516	148	85	146	62	23,654	30,776	11,078	6,645	20,992	8,985
2053	612	523	147	86	156	62	23,423	31,188	10,970	6,734	22,381	9,004
2054	609	530	146	87	166	63	23,193	31,606	10,862	6,824	23,863	9,023
2055	606	537	145	88	177	63	22,966	32,030	10,756	6,916	25,443	9,043

F. Demand and Energy Forecast

The Company's Fall 2023 load forecast is used as the base assumption in this Resource Plan. The forecast assumes adoption of Electric Vehicle (EV), new Large Commercial & Industrial (C&I) customer additions, Beneficial Electrification (BE), and demographic/economic growth. These load increases are netted against reductions in consumption resulting from Energy Efficiency to result in an overall energy requirements outlook that increases two percent per year in the 2024-2040 timeframe. Table F-5 below shows the demand and energy forecasts used.
The forecasts shown do not include the impact of DG solar.

Table F-5: Demand and Energy Forecast

Seasonal Peak Demand and Energy Forecast										
Year	Peak Seasonal Demand (MW) without required MN EE Bundles				Peak Seasonal Demand (MW) with required MN EE Bundles				Energy (GWh)	
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Forecast without required MN EE Bundles	Forecast with required MN EE Bundles
2024	9,408	7,528	6,612	7,043	9,309	7,433	6,525	6,949	44,439	43,823
2025	9,526	7,633	6,715	7,143	9,328	7,438	6,551	6,975	45,459	44,308
2026	9,946	7,987	7,036	7,500	9,650	7,697	6,798	7,249	48,238	46,524
2027	10,311	8,299	7,377	7,808	9,922	7,919	7,060	7,479	50,235	47,973
2028	10,511	8,423	7,526	7,955	10,029	7,954	7,138	7,560	50,971	48,170
2029	10,643	8,540	7,596	8,018	10,112	8,030	7,124	7,541	51,661	48,339
2030	10,835	8,689	7,750	8,158	10,207	8,060	7,215	7,632	52,630	48,866
2031	11,040	8,850	7,913	8,314	10,354	8,155	7,304	7,723	53,659	49,436
2032	11,331	9,060	8,146	8,504	10,574	8,308	7,495	7,852	54,974	50,305
2033	11,573	9,285	8,428	8,679	10,748	8,466	7,724	7,968	56,363	51,291
2034	11,902	9,564	8,574	8,923	11,065	8,769	7,794	8,193	58,051	52,555
2035	12,212	9,836	8,851	9,185	11,312	8,984	8,021	8,407	59,665	53,763
2036	12,496	10,034	9,080	9,404	11,563	9,111	8,277	8,626	61,053	55,302
2037	12,686	10,218	9,392	9,577	11,768	9,311	8,599	8,811	62,319	56,674
2038	12,890	10,373	9,565	9,703	11,987	9,500	8,785	8,950	63,482	57,934
2039	13,088	10,517	9,786	9,858	12,218	9,696	9,046	9,131	64,569	59,222
2040	13,202	10,616	9,681	9,918	12,414	9,901	8,958	9,238	65,390	60,215
2041	13,296	10,691	9,807	9,989	12,489	9,942	9,190	9,317	66,124	61,161
2042	13,389	10,757	9,966	10,061	12,628	10,050	9,639	9,446	66,861	62,174
2043	13,461	10,807	10,401	10,119	12,743	10,142	10,093	9,554	67,480	63,066
2044	13,542	10,859	10,436	10,258	12,903	10,277	10,160	10,016	68,166	64,220
2045	13,594	10,890	11,361	10,809	13,058	10,408	11,102	10,558	68,749	65,264
2046	13,642	11,095	11,848	11,245	13,173	10,883	11,622	11,026	69,373	66,338
2047	13,676	11,500	12,318	11,657	13,251	11,311	12,133	11,475	69,885	67,276
2048	13,703	11,885	12,302	12,041	13,345	11,725	12,147	11,887	70,391	68,194
2049	13,712	12,324	13,307	12,509	13,423	12,194	13,180	12,383	70,830	69,056
2050	13,775	12,608	13,675	12,823	13,555	12,503	13,574	12,723	71,343	69,951
2051	13,990	12,868	13,970	13,142	13,915	12,790	13,884	13,056	71,715	70,602
2052	14,247	13,158	13,676	13,514	14,190	13,099	13,609	13,447	72,164	71,321
2053	14,462	13,398	14,548	13,640	14,426	13,351	14,504	13,595	72,532	71,958
2054	14,683	13,656	14,833	13,954	14,660	13,623	14,802	13,922	73,096	72,715
2055	14,916	13,949	15,125	14,265	14,907	13,929	15,107	14,246	73,717	73,528

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

High and low load sensitivity assumptions are summarized below in Table F-6. Our high load forecast sensitivity assumes increased BE, full achievement of Minnesota's "20% by 2030" goal for EV penetration with similar increases in EV adoption in other states served by NSP, and additional large data center loads locating in Minnesota. All other assumptions are held the same as in the base case outlook. The resulting high load forecast is shown below in Table F-7. The low load sensitivity assumes increased adoption of rooftop solar generation, no beneficial electrification, slower adoption of EVs, and less new load from data centers than was assumed in the Base Case. The resulting low load forecast is show below in Table F-8.

Table F-6: High and Low Load Sensitivity Assumptions

Component	High Load Case	Low Load Case
Base Load	Base Case	Base Case
Solar	Base Case	High Solar
Demand-Side Management	Base Case	Base Case
Beneficial Electrification	High BE	No BE
Electric Vehicles	Full Achievement	Low Achievement
Large Commercial & Industrial Customers	High LCI	Low LCI

Table F-7: High Load Sensitivity

High Load Sensitivity					
	Peak Seasonal Demand (MW)				Energy (GWh)
Year	Summer	Fall	Winter	Spring	
2024	9,524	7,653	6,730	7,125	45,219
2025	9,716	7,844	6,884	7,282	46,739
2026	10,236	8,300	7,362	7,721	50,174
2027	10,823	8,823	7,857	8,202	53,786
2028	11,240	9,160	8,316	8,649	56,033
2029	11,454	9,368	8,345	8,708	57,219
2030	11,772	9,642	8,545	8,902	58,866
2031	12,152	9,979	8,876	9,229	61,193
2032	12,529	10,294	9,374	9,568	63,514
2033	12,884	10,620	9,902	9,919	65,948
2034	13,255	10,975	10,144	10,244	68,159
2035	13,626	11,339	10,582	10,576	70,377
2036	13,927	11,567	10,732	10,816	72,105
2037	14,191	11,856	11,224	11,098	74,060
2038	14,445	12,084	11,501	11,302	75,783
2039	14,721	12,325	11,890	11,543	77,563
2040	14,876	12,488	11,897	11,660	78,837
2041	15,002	12,594	12,700	12,070	79,976
2042	15,092	12,644	13,224	12,485	80,871
2043	15,200	12,964	13,848	13,097	81,948
2044	15,364	13,608	14,061	13,836	83,367
2045	15,500	14,370	15,484	14,619	84,760
2046	15,830	15,069	16,233	15,407	85,957
2047	16,567	15,813	17,062	16,250	87,274
2048	16,975	16,323	17,032	16,783	87,984
2049	17,754	17,205	18,645	17,712	89,420
2050	18,239	17,670	19,252	18,264	90,570
2051	19,021	18,322	19,945	18,891	91,855
2052	19,427	18,756	19,618	19,433	92,801
2053	19,784	19,122	20,850	19,725	93,655
2054	20,153	19,539	21,295	20,208	94,703
2055	20,541	19,967	21,748	20,689	95,810

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

Table F-8: Low Load Sensitivity

Low Load Sensitivity					
	Peak Seasonal Demand (MW)				Energy (GWh)
Year	Summer	Fall	Winter	Spring	
2024	9,401	7,521	6,606	7,038	44,394
2025	9,513	7,618	6,702	7,134	45,146
2026	9,821	7,863	6,905	7,382	46,766
2027	9,970	7,963	7,029	7,476	47,359
2028	10,153	8,070	7,150	7,601	47,964
2029	10,264	8,165	7,213	7,659	48,502
2030	10,431	8,287	7,336	7,775	49,267
2031	10,602	8,412	7,464	7,893	50,036
2032	10,827	8,564	7,611	8,034	51,006
2033	10,993	8,713	7,813	8,162	52,005
2034	11,244	8,906	7,956	8,355	53,243
2035	11,490	9,110	8,168	8,545	54,419
2036	11,727	9,260	8,328	8,697	55,446
2037	11,878	9,406	8,526	8,810	56,408
2038	12,044	9,524	8,653	8,879	57,267
2039	12,207	9,633	8,820	8,995	58,042
2040	12,287	9,687	8,697	9,021	58,545
2041	12,350	9,714	8,752	9,062	58,984
2042	12,415	9,736	8,810	9,107	59,436
2043	12,463	9,750	8,957	9,137	59,795
2044	12,527	9,771	9,014	9,146	60,239
2045	12,565	9,773	9,109	9,170	60,609
2046	12,601	9,778	9,463	9,185	61,025
2047	12,626	9,767	9,805	9,374	61,348
2048	12,650	9,752	9,751	9,521	61,693
2049	12,661	9,799	10,567	9,884	62,015
2050	12,711	10,048	10,891	10,156	62,422
2051	12,744	10,272	11,146	10,511	62,698
2052	12,803	10,533	10,906	10,779	63,056
2053	12,017	10,748	11,647	10,874	63,341
2054	12,059	10,977	11,899	11,155	63,820
2055	12,207	11,243	12,158	11,435	64,358

*Winter peak does not include December because EnCompass model does not assume December as the peak month so that consecutive winter periods from one year to the next never occur.

G. Fuel and Market Price Forecasts

To derive the forecast of monthly delivered gas prices at Ventura Hub, the Company uses a combination of market indicators such as New York Mercantile Exchange (NYMEX) and long-term price forecasts published by highly respected, industry-leading sources such as Wood Mackenzie and S&P Global. The forecast is NYMEX-based for the first few years, and then it transitions into blending the NYMEX curve with the vendor forecasts to develop a composite forecast. The Company used the following weightings for each component at various time intervals:

Period	NYMEX	S&P Global	Wood Mackenzie
Balance of the year + 2 years	100%	0%	0%
Years 3 and Beyond	25%	37.5%	37.5%
	10 yr trendline extension		

The final years of the forecasts vary between sources; Wood Mackenzie and S&P Global provide data through 2050, and NYMEX through 2035. The Company uses linear extrapolation to extend the data of each forecast out to 2050 and beyond. The Ventura Hub is later adjusted for specific delivery costs at each generating unit to develop the final model inputs.

Coal price forecasts at mine mouth are based on a combination of the short-term spot market forecast from Coaldesk, LLC in the near term and a simple average of long-term coal price forecasts provided by Wood Mackenzie and S&P Global. Added to the coal price forecast at mine mouth, which is just for the coal commodity, are: transportation charges (rail and diesel fuel), SO_2 costs, freeze control, and dust suppressant, as required. Coal price forecasts are shown below in Table F-9.

Table F-9: Coal Price Forecasts

Coal Price Forecast		
Year	AS King (Delivered) $/mmBtu	Sherco (Delivered) $/mmBTU
2024	$2.62	$2.37
2025	$2.71	$2.52
2026	$2.78	$2.57
2027	$2.81	$2.60
2028	$2.89	$2.67
2029	$2.95	$2.72
2030	$3.01	$2.78

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. To derive the forecast of monthly On and Off-peak electricity prices, the Company uses a simple average of On and Off-peak power price forecasts provided by Wood Mackenzie and S&P Global. Table F-10 below shows the market prices under zero CO_2 cost assumptions. To generate the hourly market prices, the Company uses the hourly energy price forecasts from the Horizons Energy EnCompass National Database, specifically the energy prices at the MISO-ND-MN node and scales it to match the monthly On and Off-peak price forecasts in Table F-10.

High and low-price sensitivities were performed by adjusting the base forecast up and down by 50 percent.

Table F-10: Gas and Market Price Forecast

	Base Forecast			Low Forecast			High Forecast		
	Gas Price ($/mmBTu)	Market Price ($/MWh)		Gas Price ($/mmBTu)	Market Price ($/MWh)		Gas Price ($/mmBTu)	Market Price ($/MWh)	
Year	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2024	$3.36	$39.74	$30.58	$1.68	$19.87	$15.29	$5.04	$59.61	$45.88
2025	$3.95	$34.84	$26.39	$1.98	$17.42	$13.19	$5.93	$52.26	$39.58
2026	$3.71	$38.11	$28.81	$1.86	$19.05	$14.41	$5.57	$57.16	$43.22
2027	$4.07	$38.04	$29.23	$2.03	$19.02	$14.61	$6.10	$57.05	$43.84
2028	$4.12	$37.25	$29.02	$2.06	$18.62	$14.51	$6.18	$55.87	$43.53
2029	$4.09	$35.21	$28.30	$2.05	$17.60	$14.15	$6.14	$52.81	$42.45
2030	$4.06	$35.52	$29.11	$2.03	$17.76	$14.55	$6.09	$53.28	$43.66
2031	$4.07	$35.57	$30.60	$2.03	$17.78	$15.30	$6.10	$53.35	$45.90
2032	$4.16	$35.72	$31.58	$2.08	$17.86	$15.79	$6.24	$53.59	$47.37
2033	$4.31	$34.78	$31.79	$2.15	$17.39	$15.89	$6.46	$52.17	$47.68
2034	$4.49	$34.15	$32.02	$2.24	$17.08	$16.01	$6.73	$51.23	$48.02
2035	$4.62	$33.96	$32.59	$2.31	$16.98	$16.30	$6.93	$50.94	$48.89
2036	$4.68	$33.21	$32.58	$2.34	$16.60	$16.29	$7.01	$49.81	$48.87
2037	$4.81	$33.60	$32.86	$2.41	$16.80	$16.43	$7.22	$50.39	$49.30
2038	$4.95	$32.83	$33.05	$2.48	$16.41	$16.52	$7.43	$49.24	$49.57
2039	$5.07	$32.93	$33.28	$2.54	$16.47	$16.64	$7.61	$49.40	$49.91
2040	$5.37	$33.04	$35.28	$2.68	$16.52	$17.64	$8.05	$49.56	$52.92
2041	$5.53	$35.19	$37.40	$2.77	$17.59	$18.70	$8.30	$52.78	$56.10
2042	$5.62	$34.30	$36.76	$2.81	$17.15	$18.38	$8.44	$51.45	$55.14
2043	$5.86	$34.04	$37.19	$2.93	$17.02	$18.60	$8.79	$51.05	$55.79
2044	$6.19	$34.50	$37.35	$3.10	$17.25	$18.68	$9.29	$51.76	$56.03
2045	$6.48	$35.08	$41.40	$3.24	$17.54	$20.70	$9.72	$52.62	$62.10
2046	$6.61	$36.25	$40.19	$3.30	$18.12	$20.10	$9.91	$54.37	$60.29
2047	$6.77	$36.81	$42.23	$3.38	$18.40	$21.11	$10.15	$55.21	$63.34
2048	$6.92	$36.70	$43.07	$3.46	$18.35	$21.54	$10.37	$55.05	$64.61
2049	$7.19	$37.53	$44.27	$3.59	$18.77	$22.13	$10.78	$56.30	$66.40
2050	$7.54	$37.61	$46.10	$3.77	$18.81	$23.05	$11.31	$56.42	$69.16
2051	$7.68	$40.59	$47.30	$3.84	$20.29	$23.65	$11.51	$60.88	$70.95
2052	$7.89	$41.75	$48.64	$3.95	$20.87	$24.32	$11.84	$62.62	$72.97
2053	$8.11	$42.91	$49.99	$4.06	$21.45	$25.00	$12.17	$64.36	$74.99
2054	$8.33	$44.07	$51.36	$4.17	$22.03	$25.68	$12.50	$66.10	$77.04
2055	$8.55	$45.22	$52.72	$4.28	$22.61	$26.36	$12.83	$67.84	$79.08

H. Baseload Retirement "Leave Behind" Costs

The Company includes "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of baseload resource retirements. For the retiring coal units, these costs are largely attributed to synchronous condensers that will likely be needed to maintain grid stability. For the nuclear units, the Company conducted a "leave behind" study to determine the transmission system impacts of the nuclear plants' retirement. The reinforcement costs are included as capital expenditure based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated by the Company. We applied these costs in the modeling as soon as the resource is retired to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2023).

- King: $50 million
- Sherco 1: $50 million
- Sherco 2: $50 million
- Sherco 3: $50 million

Table F-11: Nuclear Leave Behind Costs

[PROTECTED DATA BEGINS

Baseload Scenario Name	Nuclear Unit	Retirement Date	Leave Behind Cost (2023$)	Year(s) when LBC incurs
Reference Case	Monticello	2040		2035-2040
	Prairie Island	2033/34		2028-2033
Prairie Island Extension	Monticello	2040		2036-2040
	Prairie Island	2053/54		N/A
Extend All Nuclear	Monticello	2050		2045-2050
	Prairie Island	2053/54		2048-2053

PROTECTED DATA ENDS]

I. Market Capacity Price

Surplus capacity up to 500 MW can receive surplus capacity credit and is priced at the avoided capacity cost of a generic greenfield H-Class combustion turbine on an economic carrying charge basis.

Table F-12: Market Capacity Price

Surplus Capacity Credit																
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
$/kw-mo	8.75	8.92	9.10	9.28	9.47	9.66	9.85	10.05	10.25	10.45	10.66	10.88	11.09	11.32	11.54	11.77
	2040	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**
$/kw-mo	12.01	12.25	12.49	12.74	13.00	13.26	13.52	13.79	14.07	14.35	14.64	14.93	15.23	15.53	15.84	16.16

J. Seasonal Accredited Capacity Assumptions for Wind, Solar, and Battery Resources

The seasonal accredited capacity (SAC) values for wind, solar, and battery resources vary according to whether a resource is already in existence or is a new resource option for the model. The Effective Load Carrying Capability (ELCC) for existing NSP wind and solar resources is based on the 2023-2024 MISO planning year seasonal accreditation capacity[7] with an annual degradation assumption for solar resources.[8] For years beyond 2024, the seasonal accredited capacity of existing wind, solar, and battery resources trends over multiple years so it meets the assumptions used in MISO's November 2022 Regional Resource Assessment (RRA) as depicted in Figures F-1, F-2, and F-3 below. As outlined by MISO, there was an unexpected deviation from the anticipated declining trend in ELCC when more of a resource type is added to the system. Specifically, the average solar ELCC for the winter season increased from one percent in 2031 to 11 percent in 2041. This increase can be attributed to the hour in which risk emerged during the winter months. In 2041, the evening risk materialized two hours earlier than it did in 2031. This change, attributed to low wind output, resulted in a ten percent change to the solar ELCC outcome when using the average ELCC methodology as described further below.[9]

[7] MISO Planning Year 2023-2034 Wind and Solar Capacity Credit Report (March 2023). Available at https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf.
[8] The seasonal accredited capacity percentages are applied to the installed capacity of each existing NSP resource. In the case of solar resources, the maximum capacity declines slightly each year, due to slight degradation in the installed solar modules. NSP incorporates a 0.5 percent decrease in existing solar resources' installed capacity to mimic this effect in addition to the ELCC assumptions described in this section.
[9] MISO Regional Resource Assessment (November 2022) at p. 45. Available at https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf.

Figure F-1: Average Seasonal ELCC for Existing Wind Resources[10]

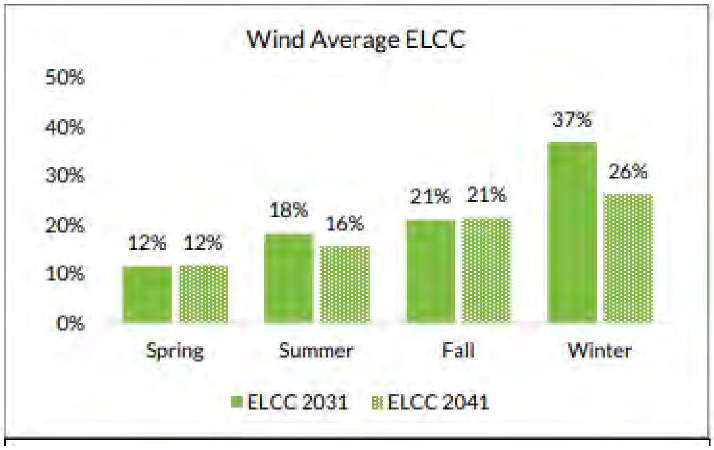
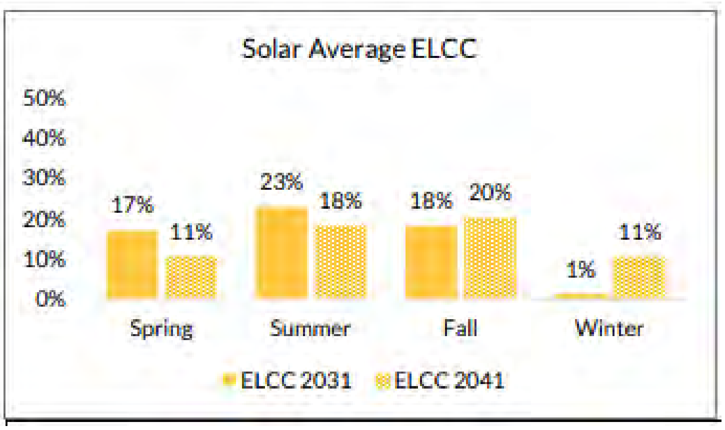
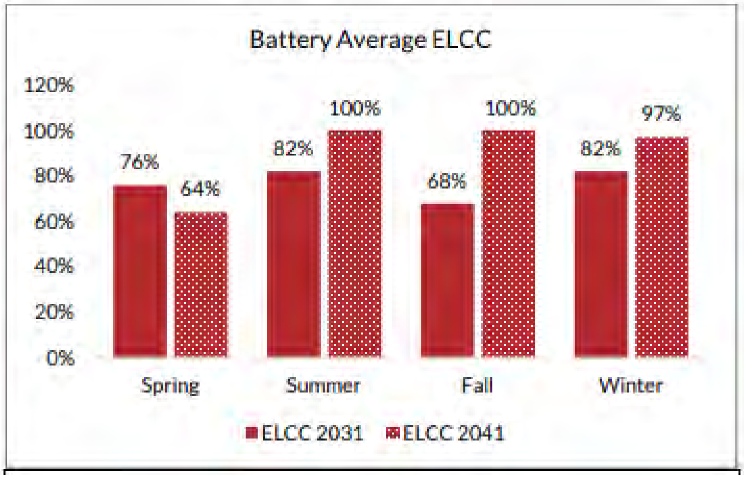


Figure F-2: Average Seasonal ELCC for Existing Solar Resources[11]



[10] *Id.* at p. 47.
[11] *Id.* at p. 45.

Figure F-3: Average Seasonal ELCC for Battery Resources[12]



The seasonal accreditation assumptions for generic wind, solar, battery, and solar + battery hybrid resources are shown on Table F-13 below. The seasonal accreditation assumptions for generic wind resources are based on values used in MISO's 2022 and 2023 Regional Resource Assessment (RRA); and stem from MISO's March 2023 Planning Year 2023-2024 Wind and Solar Capacity Credit Report.

The seasonal accreditation for generic solar resources starts with the values in the MISO 2023/2024 PY Planning Reserve Margin and Local Reliability Requirements. These values then trend to the long-term ELCC assumptions in the MISO November 2022 RRA.

The battery seasonal accreditation starts with the MISO October 2023 Resource Adequacy Business Practice Manual (BPM) section 4.2.9.4, which provides the five percent forced outage (95% accredited capacity assumptions) for new energy storage resources. The accreditation trends over several years from the 95% capacity accreditation to the long-term assumptions for battery storage resources in the MISO November 2022 RRA. The MISO battery accreditation is based on a four-hour battery. In the case of a 10-hour battery, we conservatively apply the same value since MISO does not provide an ELCC for a 10-hour duration.

The solar plus battery hybrid accreditation value is calculated using the methodology in the MISO October 2023 Resource Adequacy Business Practice Manual BPM,

[12] *Id.* at p. 51.

Section 4.2.11. This section details the Phase I "sum of parts" method for hybrid systems, applying it to the assumed generic solar and storage units in our model. For each year within the modeling horizon, the "sum of parts" methodology from the current MISO BPM is replicated. However, in this case, the components combined are the standalone storage and solar generic units, each component part – solar and storage – with accreditation assumptions that trend over time to align with the long-term November 2022 MISO RRA values for standalone storage and standalone solar.[13]

A key trend over time here is that many of the seasonal values for different generic resource types trend down from the single year MISO PY 2023/2034 to MISO PY 2031/2032 and then back up again by MISO PY 2041/2042. This occurs in part because the studies for MISO PY 2023/2024 assumptions differ from those for the later years and also because of the methodology and assumptions being used for PY 2031/2032 and PY 2041/2041.

In the case of MISO PY 2031/2032 and MISO PY 2041/2042 variations, ELCC assumptions for intermittent resources are affected by the system-wide generation resource mixes MISO projects for those years. Additionally, the average ELCC method MISO uses for this study heavily depends on projected resource output for a few key Loss of Load Probability (LOLP) hours each season. While MISO notes that average ELCC methodology "may not be adequate for a system with large amounts of intermittent generation" and that "changes to the accreditation methodology applied to non-thermal technologies are currently being considered by MISO's Resource Adequacy Subcommittee (RASC) stakeholders," in the absence of other long-term data, the Company has adopted these ELCC values for its long-term modeling purposes.

[13] The total resource accreditation for hybrid units used this method instead of matching to MISO 2022 RRA values for hybrids because the sizes of the solar and storage components relative to total asset size that MISO had used in their analysis were unknown and may have differed from the hybrid generic unit configuration used by the Company in IRP modeling.

Table F-13: Generic Wind, Solar, Battery, and Solar + Battery Hybrid Resource ELCC

PY 2023/2024				
Generic Resource Type	Summer	Fall	Winter	Spring
Wind[14]	18.1%	23.1%	40.3%	23.0%
Solar[15]	45.4%	25.3%	6.3%	15.0%
Battery	95.0%	95.0%	95.0%	95.0%
Solar + Battery Hybrid	52.6%	43.3%	33.3%	37.9%
PY 2031/2032				
Generic Resource Type	Summer	Fall	Winter	Spring
Wind	18.0%	21.0%	37.0%	12.0%
Solar	23.0%	18.0%	1.0%	17.0%
Battery	82.0%	68.0%	82.0%	76.0%
Solar + Battery Hybrid	38.0%	30.9%	26.4%	32.9%
PY 2041/2042				
Generic Resource Type	Summer	Fall	Winter	Spring
Wind	16.0%	21.0%	26.0%	12.0%
Solar	18.0%	20.0%	11.0%	11.0%
Battery	100.0%	100.0%	97.0%	64.0%
Solar + Battery Hybrid	41.1%	42.1%	36.4%	26.0%

K. Spinning Reserve Requirement

The total spinning requirement in the model consists of spinning reserve and supplemental reserve. Spinning reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. Supplemental reserve is the off-line capacity capable of quick start within 10 minutes. On an hourly basis, each ancillary type for NSP is calculated as the NSP load ratio of the published MISO System Wide Ancillary Requirements. The level of total spinning requirement modeled is 125.17 MW and is based on a 12-month historical average in 2022.

[14] MISO Planning Year 2023-2024 Wind and Solar Capacity Credit Report. (March 2023). Available at: https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf

[15] MISO 2023/24 PY Planning Reserve Margin and Local Reliability Requirements – Final Results. October 3, 2022. Available at: https://cdn.misoenergy.org/20221003%20LOLEWG%20Item%2003%20PY%202023-24%20Final%20LOLE%20Study%20Results626468.pdf.

L. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In EnCompass, we use the value of $1,000,000/MWh. Emergency energy is a "soft constraint" in EnCompass modeling that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small, required run time – are utilized before emergency energy.

M. Cost Assumptions for Transmission Tie Lines and New Resource Interconnections

Interconnection costs of $250/kw[16] are included in addition to the capital costs and operating expenses for utility-scale generic resource options.[17] These interconnection costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system and are the "behind the fence" costs associated with substation and representative gen-tie construction.

In this IRP, a new distribution-interconnected resource, solar used to comply with the 3 percent Distributed Solar Energy Storage (DSES) legislation, also includes an interconnection cost as part of its total modeled cost. Costs from our recently filed Integrated Distribution Plan (IDP) were used as shown below in Table F-14.[18]

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[16] The basis for this cost assumption is discussed in Appendix L: System Planning Integration.
[17] Generic resources interconnecting to the Sherco and King transmission tie-lines do not have this cost as part of their capital cost assumption since they will not need to have a new, dedicated Generator Interconnection Agreement (GIA) with MISO.
[18] *See* Integrated Distribution Plan, Appendix I: Distribution System Upgrades, November 1, 2023, Docket No. E002/M-23-452, for more information on the development of interconnection cost assumptions.

Table F-14: 3% DSES Interconnection Cost Assumptions

Years	3% Distributed Solar Energy Standard Interconnection Cost Assumption (Nominal $/kW)
2024-2029	$225
2030-2040	$184
2041-2055	$149

Regarding transmission tie-lines, in the Alternate Plan, we proposed to build transmission tie-lines from our Sherco and King sites that can interconnect incremental renewable and/or firm dispatchable resources. The total costs of the tie lines include capital costs plus VAR support, such as installing tie-line synchronous condensers and series compensation of the lines; while these are general cost estimates and subject to change during detailed project design, they are in line with the Company's experience on other projects. The total capacities of generator reuse are based on the existing interconnection rights at Sherco and King.

Table F-15: Sherco and King Gen-tie Assumptions

	Total Capital Costs (in 2023 Dollars)	Interconnection Rights
Sherco gen-tie	$1.139 billion	1996 MW
King gen-tie	$177 million	591 MW

Table F-16: Retiring Coal Units and Selection Windows for Gen-tie Resources

Retiring Unit	Open Interconnection	Replacement Resource Window	Replacement Resources Allowed
Sherco 2	710 MW	2024-2026	Solar[19]
Sherco 1	720 MW	2027-2029	Solar, and Wind + Batteries ~400 MW of CTs (2028-2029)
Sherco 3	566 MW	2031-2033	Solar + Wind +Batteries
AS King	591 MW	2028-2030	Solar only

[19] Collectively, the Sherco Solar 1, 2, and 3 projects reutilize the interconnection capacity made available with the retirement of Sherco Coal Unit 2.

N. Distributed Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts and an estimated ramp up of resources that comply with the Distributed Solar Energy Standard (DSES). Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a 25-year service life.

Table F-17: Distributed Solar Nameplate Capacity Forecast

Distributed Solar (Nameplate MWac)					
Year	CSG Legacy (2016-2024)	Non-Legacy CSGs	Customer Sited DG Solar	Distributed Solar Energy Standard (3%)	Total
2024	881	18	192		1,091
2025	877	100	239		1,215
2026	872	199	284		1,356
2027	868	298	325	62	1,553
2028	864	377	364	250	1,854
2029	859	455	382	373	2,069
2030	855	533	422	497	2,306
2031	851	610	481	494	2,436
2032	846	667	551	506	2,570
2033	842	724	610	517	2,693
2034	838	780	652	529	2,799
2035	834	836	683	540	2,893
2036	830	892	729	551	3,002
2037	825	948	792	562	3,127
2038	821	1,003	851	574	3,249
2039	817	1,058	919	585	3,379
2040	813	1,113	947	596	3,468
2041	841	1,167	993	607	3,608
2042	1,022	1,221	1,056	618	3,917
2043	1,246	1,275	1,167	629	4,316
2044	1,372	1,329	1,272	640	4,612
2045	1,478	1,382	1,353	650	4,864
2046	1,511	1,435	1,420	661	5,028
2047	1,534	1,488	1,540	672	5,233
2048	1,557	1,540	1,735	682	5,515
2049	1,554	1,609	1,906	693	5,762
2050	1,547	1,733	2,075	704	6,058
2051	1,539	1,872	2,210	714	6,335
2052	1,531	2,011	2,310	724	6,577
2053	1,524	2,132	2,520	735	6,911
2054	1,516	2,252	2,797	745	7,310
2055	1,508	2,371	3,051	755	7,686

*Customer sited DG solar capacity is reported as the max capacity of each year.

Table F-18: Distributed Solar Cost Forecast[20]

Distributed Solar ($nominal/MWh)				
Year	CSG Legacy (2016-2024)	Non-Legacy CSGs	Customer Sited DG Solar	Distributed Solar Energy Standard (3%)
2024	121.25	121.25	144.84	
2025	124.06	124.06	147.74	
2026	126.94	126.94	150.69	
2027	129.89	129.89	153.71	51.54
2028	132.90	132.90	156.78	50.79
2029	135.98	135.98	159.92	50.36
2030	139.14	139.14	163.11	49.33
2031	142.36	142.36	166.38	49.33
2032	145.67	145.67	169.70	49.20
2033	149.05	149.05	173.10	49.05
2034	152.51	152.51	176.56	48.88
2035	156.04	156.04	180.09	48.68
2036	159.66	159.66	183.69	48.49
2037	163.37	163.37	187.37	48.31
2038	167.16	167.16	191.11	48.14
2039	171.04	171.04	194.94	47.98
2040	175.00	175.00	198.83	47.82
2041	179.06	179.06	202.81	47.61
2042	183.22	183.22	206.87	47.41
2043	187.47	187.47	211.00	47.22
2044	191.82	191.82	215.22	47.12
2045	196.27	196.27	219.53	47.12
2046	200.82	200.82	223.92	47.29
2047	205.48	205.48	228.40	47.46
2048	210.25	210.25	232.97	47.62
2049	215.13	215.13	237.63	47.77
2050	220.12	220.12	242.38	47.93
2051	225.22	225.22	247.23	48.09
2052	230.45	230.45	252.17	48.27
2053	235.79	235.79	257.21	48.46
2054	241.27	241.27	262.36	48.66
2055	246.86	246.86	267.60	48.87

[20] Costs for each resource are derived from the following data sources: (1) CSG: Value of Solar Bill Credit Rates, (2) Customer Sited DG Solar: Xcel Energy A50 Rate Code, and (3) Distributed Solar Energy Standard (3 percent): combination of NREL ATB Utility-Scale Solar and Distributed Commercial PV resource types.

O. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Seasonal Accredited Capacity Ratings
d. Minimum Capacity Rating
e. Heat Rate Profiles
f. Variable O&M
g. Start up fuel usage and start up charge
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

P. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Accredited Capacity Ratings
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Start up fuel usage and start up charge
j. Maintenance Schedule
k. Forced Outage Rate
o. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter

l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Q. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Seasonal Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Whether curtailed energy is compensable or not

R. Park Potential profiles for modeling wind and solar generation on the NSP System

This section discusses the process used to create Park (i.e., wind or solar farm) Potential profiles of wind and solar generation for Xcel Energy's upper Midwest region.

1. *Annual Expected Park Potential*

The Company combined monthly generation and curtailment data to derive the monthly Park Potential for each renewable generation Commercial Pricing Node (CP Node) from January, 2018 through November, 2022. The monthly Park Potentials were summed on a rolling 12-month basis to derive 48 annual Park Potential values. The Company averaged the 48 annual values to determine the annual expected Park Potential value for each CP Node. For renewable generation without sufficient historic data, the most recent Energy Production Estimate (EPE) from pre-construction developer software or the Annual Committed Energy from the Purchase Power Agreement was used as the annual PP value.

2. *Monthly Allocation of Annual Park Potential*

For new wind plants, the pre-construction developer software uses 30 years' worth of meteorological weather reanalysis data to determine the expected monthly generation expressed as a percentage of the annual EPE. The Company used the average of the monthly percentages from new wind plants to allocate the CP Node annual Park Potential values to each calendar month. For solar plants, the Company calculated the ratio of monthly Park Potential relative to annual Park Potential for each month from the years 2018-2022. Table F-19 below shows the monthly allocations for wind and solar plants expressed as a percentage of the annual expected Park Potential.

Table F-19: Monthly Percentage of Annual Wind and Solar Plant Park Potential

Month	Wind Allocation (%)	Solar Allocation (%)
January	9.1	3.7
February	8.2	5.4
March	9.1	9.0
April	9.4	10.0
May	9.1	11.9
June	7.7	13.2
July	6.3	13.1
August	6.1	11.6
September	7.7	9.2
October	9.1	6.6
November	9.2	3.8
December	9.0	2.7

3. *Hourly Allocation of Monthly Park Potential*

For most wind plants, the Company has wind speed data measured at the turbine anemometers.[21] The Company gathered hourly averaged wind speed data from 2020 for each wind CP Node and used empirical power conversions specific to those CP Nodes to convert the hourly wind speed to hourly generation. The summed monthly generation for each CP Node was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. A constant wind speed adjustment was made to each hour so that the sum of the hourly generation based on the hourly wind speed data matched the monthly allocation of the annual Park Potential.

[21] The Company has turbine wind speed data for approximately 91% of Company-controlled wind generation capacity.

For wind generation at CP Nodes without wind speed data, the Company generated a single empirical power conversion derived from the simple average of all wind speed data for each hour in 2021 and the paired sum-of-generation from all CP Nodes without wind speed data. For each of these CP Nodes, the Company calculated the pro rata ratio of the CP Node annual Park Potential relative to the sum of annual Park Potentials for all CP Nodes without wind speed data. A constant wind speed adjustment was applied to the system average wind speed profile for each month so that the resulting generation profile matched the monthly allocation of the sum of annual Park Potentials for all CP Nodes without wind speed data. Each CP Node without wind speed data was assigned their pro-rata share of this hourly generation profile for each month.

For solar generation, the Company used hourly irradiance and generation data from 2020 for each solar plant and used empirical power conversions to convert the hourly irradiance to hourly generation. The summed monthly generation for each plant was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. An irradiance adjustment was made to each hour in a given month so that the sum of the hourly generation based on the hourly irradiance data matched the monthly allocation of the annual Park Potential.

For plants without historic irradiance or generation data, the Company used 2020 hourly irradiance data for each plant location sourced from the National Solar Radiation DataBase (NSRDB) maintained by the National Renewable Energy Laboratory (NREL). The same process was used to derive the hourly generation profiles for these solar plants as for the existing solar plants in the Company's portfolio of renewable generation.

S. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal assumptions are based on the Company's internal estimates informed by external consultants and original equipment manufacturers. Generic renewable and battery costs, as well as battery operational characteristics such as cycle limit and Round-Trip Efficiency (RTE) are from National Renewable Energy Laboratory (NREL) 2023 Annual Technology Baseline (ATB) data. High and low technology cost sensitivities are created based on NREL ATB "Conversative" and "Advanced" forecasts. We also have a sensitivity where the wind, solar and solar + battery hybrid LCOEs prior to 2030 are adjusted to match the 2023

Q1-Q3 actual PPA prices in MISO, reported in the Edison Energy Global Renewable Market Update quarterly reports. Utility-scale wind, solar, solar plus battery hybrid and battery costs, with and without interconnection costs for the base case and all sensitivities, are shown in Tables F-20 through F-39 below.

The costs used for wind, solar, and storage assets fully incorporate the Production Tax Credit (PTC) or Investment Tax Credit (ITC) in the Inflation Reduction Act (IRA). The costs of wind and solar resources selected to replace the interconnection capacity of Sherco and King are calculated without incremental transmission costs (as the gen-tie costs are already accounted for elsewhere in the model). In addition, we do not make cost adjustments to the Company's owned units selected to replace the retired coal capacities. The IRA allows the transferability of tax credits, allows utilities to elect out from normalization for storage facilities, and allows owners of solar facilities to claim a PTC in lieu of the ITC, which is subject to normalization. All of these combine to create a more level playing field for utilities to build/own solar and storage assets.

Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. Seasonal Accredited Capacity
d. Minimum Capacity Rating
e. Heat Rate Profiles
f. Variable O&M
g. Fixed O&M
h. Maintenance Schedule
i. Forced Outage Rate
j. Emission rates for SO_2, NO_x, CO_2, CO, CH_4, N_2O, Pb and particulate matter
k. Contribution to spinning reserve
l. Fuel prices
m. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity

c. Seasonal Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Whether curtailed energy is compensable or not

Table F-20: Thermal Generic Information (Costs in 2023 Dollars)

Thermal Generic Information			
Resource	**Generic CT**	**Generic CT**	**Reciprocating Engine**
Technology	7H DF	7F DF	Medium Speed reciprocating engine DF
Location Type	Greenfield	Greenfield	Greenfield
Cooling Type	Dry	Dry	Dry
On Site Fuel Storage Full Load Duration (hours)	48	48	50
Book life	40	40	40
Nameplate Capacity (MW)	374	225	108
Summer Peak Capacity (MW)	331	210	108
Minimum Emissions-Compliant Load Capacity (MW)	149	106	7.0
Capital Cost ($000) 2023$	$280,000	$215,000	$316,000
Capital Cost ($/kW) 2023$	$749	$954	$2,926
Ongoing Capital Expenditures ($000-yr) 2023$	$1,784	$1,320	$108
Ongoing Capital Expenditures ($/kW-yr) 2023$	$4.77	$5.86	$1.00
Fixed O&M Cost ($000/yr) 2023$	$1,524	$1,463	$1,277
Variable O&M Cost ($/MWh) 2023$	$1.20	$1.26	$6.30
Interruptible Gas Demand Cost ($/mmBTU) 2023$	$0.49	$0.49	$0.49
Startup Cost ($/start)	$5,809	$3,872	$0.00
Cold Startup Fuel Usage (mmBTU/start)	110	73	$0.00
Summer HHV Heat Rate 100% Loading (btu/kWh)	9,264	10,113	8,275
Summer HHV Heat Rate 75% Loading (btu/kWh) (70% loading for reciprocating engine)	9,738	10,567	8,739
Summer HHV Heat Rate 50% Loading (btu/kWh)	11,120	12,711	9,437
Summer HHV Heat Rate MECL Loading (btu/kWh)	11,558	12,592	9,979
Winter HHV Heat Rate 100% Loading (btu/kWh)	9,066	10,157	8,275
Winter HHV Heat Rate 75% Loading (btu/kWh) (70% loading for reciprocating engine)	9,647	10,952	8,739
Winter HHV Heat Rate 50% Loading (btu/kWh)	10,964	12,924	9,437
Winter HHV Heat Rate MECL Loading (btu/kWh)	11,443	12,837	9,979
Forced Outage Rate	3%	3%	3%
Maintenance (weeks/yr)	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118
CO Emissions (lbs/MWh)	0.14	0.15	0.12
SO2 Emissions (lbs/MWh)	0.00	0.02	0.09
NOx Emissions (lbs/MWh)	0.90	0.32	0.08
PM10 Emissions (lbs/MWh)	0.03	0.03	0.10
PM2.5 Emissions (lbs/MWh)	0.03	0.03	0.10

Notes:

1. Summer capacity and heat rate for generic 7H CT are based on an ambient temperature of 95 degrees F, 40% relative humidity.

2. Winter capacity and heat rate for generic 7H CT are based on an ambient temperature of -6 degrees F, 60% relative humidity.

3. Summery capacity and heat rate for generic 7F CT are based on an ambient temperature of 86.7 degrees F, 59.6% relative humidity.

4. Winter capacity and heat rate for generic 7F CT are based on an ambient temperature of 18 degrees F, 74.2% relative humidity.

5. Capacity and heat rate for generic reciprocating engine are based on an inlet air temperature of 86.7 degree F, 59.6% relative humidity.

Table F-21: Renewable and Battery Generic Information

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Utility Scale PV + Battery**	**Utility Scale Battery**
Representative Plan Size (MW)	200 MW	100 MWDC*	130 MWDC Solar + 60 MWAC Battery, 100 MWAC Inverter	60 MW
Capacity Factor	44.3%	23.0%	Subject to dispatch	Subject to dispatch
Book life (years)	30	30	30	15
PTC or ITC applied	PTC	PTC	ITC	ITC
Electric Transmission Delivery ($/kW)	250	250	250	250
Storage Characteristics	NA	NA	NA	1 cycle/day; 85% RTE

*Solar capacity assumes 0.5 percent annual degradation.

Table F-22: Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost				
Capex with TRX ($nominal/kW)			Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)	
Year	4 hr duration	10 hr duration	4 hr duration	10 hr duration
2024	$2,004.38	$4,101.77	$43.48	$95.91
2025	$1,825.17	$3,688.93	$38.86	$85.46
2026	$1,810.38	$3,632.95	$38.36	$83.92
2027	$1,794.27	$3,573.10	$37.82	$82.29
2028	$1,776.78	$3,509.23	$37.24	$80.55
2029	$1,757.86	$3,441.16	$36.62	$78.71
2030	$1,737.48	$3,368.73	$35.97	$76.75
2031	$1,749.60	$3,383.17	$36.12	$76.96
2032	$1,761.50	$3,396.87	$36.27	$77.15
2033	$1,773.19	$3,409.80	$36.40	$77.32
2034	$1,784.63	$3,421.91	$36.53	$77.46
2035	$1,795.83	$3,433.19	$36.65	$77.58
2036	$1,806.76	$3,443.58	$36.76	$77.68
2037	$1,817.42	$3,453.06	$36.86	$77.75
2038	$1,827.77	$3,461.58	$36.94	$77.79
2039	$1,837.82	$3,469.10	$37.02	$77.80
2040	$1,847.53	$3,475.59	$37.08	$77.78
2041	$1,856.90	$3,481.00	$37.14	$77.74
2042	$1,865.91	$3,485.29	$37.17	$77.66
2043	$1,874.54	$3,488.42	$37.20	$77.55
2044	$1,882.77	$3,490.34	$37.21	$77.40
2045	$1,890.58	$3,491.00	$37.21	$77.22
2046	$1,897.95	$3,490.37	$37.19	$77.01
2047	$1,904.86	$3,488.39	$37.16	$76.75
2048	$1,911.28	$3,485.02	$37.11	$76.46
2049	$1,917.21	$3,480.20	$37.05	$76.12
2050	$1,922.61	$3,473.88	$36.97	$75.75
2051	$1,961.06	$3,543.36	$37.71	$77.26
2052	$2,000.29	$3,614.23	$38.46	$78.81
2053	$2,040.29	$3,686.51	$39.23	$80.38
2054	$2,081.10	$3,760.24	$40.01	$81.99
2055	$2,122.72	$3,835.45	$40.81	$83.63

Table F-23: Storage Generic Information without Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost				
	Capex ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)	
Year	4 hr duration	10 hr duration	4 hr duration	10 hr duration
2024	$1,739.08	$3,836.46	$43.48	$95.91
2025	$1,554.56	$3,418.32	$38.86	$85.46
2026	$1,534.36	$3,356.93	$38.36	$83.92
2027	$1,512.72	$3,291.56	$37.82	$82.29
2028	$1,489.60	$3,222.06	$37.24	$80.55
2029	$1,464.95	$3,148.25	$36.62	$78.71
2030	$1,438.71	$3,069.96	$35.97	$76.75
2031	$1,444.85	$3,078.42	$36.12	$76.96
2032	$1,450.66	$3,086.03	$36.27	$77.15
2033	$1,456.13	$3,092.74	$36.40	$77.32
2034	$1,461.23	$3,098.51	$36.53	$77.46
2035	$1,465.96	$3,103.32	$36.65	$77.58
2036	$1,470.30	$3,107.11	$36.76	$77.68
2037	$1,474.22	$3,109.86	$36.86	$77.75
2038	$1,477.71	$3,111.52	$36.94	$77.79
2039	$1,480.75	$3,112.04	$37.02	$77.80
2040	$1,483.33	$3,111.38	$37.08	$77.78
2041	$1,485.42	$3,109.51	$37.14	$77.74
2042	$1,487.00	$3,106.37	$37.17	$77.66
2043	$1,488.04	$3,101.92	$37.20	$77.55
2044	$1,488.54	$3,096.11	$37.21	$77.40
2045	$1,488.47	$3,088.89	$37.21	$77.22
2046	$1,487.79	$3,080.22	$37.19	$77.01
2047	$1,486.50	$3,070.04	$37.16	$76.75
2048	$1,484.56	$3,058.29	$37.11	$76.46
2049	$1,481.95	$3,044.94	$37.05	$76.12
2050	$1,478.65	$3,029.92	$36.97	$75.75
2051	$1,508.22	$3,090.52	$37.71	$77.26
2052	$1,538.39	$3,152.33	$38.46	$78.81
2053	$1,569.16	$3,215.38	$39.23	$80.38
2054	$1,600.54	$3,279.68	$40.01	$81.99
2055	$1,632.55	$3,345.28	$40.81	$83.63

Table F-24: High Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost - high sensitivity		
Capex with TRX ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$2,242.64	$49.43
2025	$2,258.87	$49.71
2026	$2,228.10	$48.80
2027	$2,195.20	$47.84
2028	$2,160.08	$46.82
2029	$2,122.69	$45.74
2030	$2,082.94	$44.60
2031	$2,112.14	$45.18
2032	$2,141.67	$45.77
2033	$2,171.54	$46.36
2034	$2,201.75	$46.96
2035	$2,232.30	$47.56
2036	$2,263.19	$48.17
2037	$2,294.42	$48.78
2038	$2,325.99	$49.40
2039	$2,357.92	$50.02
2040	$2,390.18	$50.65
2041	$2,422.80	$51.28
2042	$2,455.76	$51.92
2043	$2,489.07	$52.56
2044	$2,522.74	$53.21
2045	$2,556.75	$53.87
2046	$2,591.12	$54.52
2047	$2,625.83	$55.19
2048	$2,660.90	$55.85
2049	$2,696.32	$56.53
2050	$2,732.10	$57.20
2051	$2,786.74	$58.35
2052	$2,842.48	$59.51
2053	$2,899.33	$60.70
2054	$2,957.31	$61.92
2055	$3,016.46	$63.16

Table F-25: High Storage Generic Information without Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost - high sensitivity		
	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,977.34	$49.43
2025	$1,988.27	$49.71
2026	$1,952.08	$48.80
2027	$1,913.66	$47.84
2028	$1,872.91	$46.82
2029	$1,829.78	$45.74
2030	$1,784.17	$44.60
2031	$1,807.39	$45.18
2032	$1,830.83	$45.77
2033	$1,854.48	$46.36
2034	$1,878.35	$46.96
2035	$1,902.43	$47.56
2036	$1,926.72	$48.17
2037	$1,951.22	$48.78
2038	$1,975.93	$49.40
2039	$2,000.85	$50.02
2040	$2,025.98	$50.65
2041	$2,051.31	$51.28
2042	$2,076.84	$51.92
2043	$2,102.58	$52.56
2044	$2,128.51	$53.21
2045	$2,154.64	$53.87
2046	$2,180.96	$54.52
2047	$2,207.48	$55.19
2048	$2,234.18	$55.85
2049	$2,261.07	$56.53
2050	$2,288.14	$57.20
2051	$2,333.90	$58.35
2052	$2,380.58	$59.51
2053	$2,428.19	$60.70
2054	$2,476.75	$61.92
2055	$2,526.29	$63.16

Table F-26: Low Storage Generic Information with Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *with* Transmission Cost - low sensitivity		
	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,550.82	$32.14
2025	$1,515.12	$31.11
2026	$1,491.54	$30.39
2027	$1,466.41	$29.62
2028	$1,439.68	$28.81
2029	$1,411.30	$27.96
2030	$1,381.22	$27.06
2031	$1,389.48	$27.12
2032	$1,397.53	$27.17
2033	$1,405.32	$27.21
2034	$1,412.88	$27.24
2035	$1,420.21	$27.26
2036	$1,427.22	$27.27
2037	$1,433.96	$27.27
2038	$1,440.40	$27.26
2039	$1,446.53	$27.24
2040	$1,452.30	$27.20
2041	$1,457.75	$27.16
2042	$1,462.86	$27.10
2043	$1,467.57	$27.03
2044	$1,471.85	$26.94
2045	$1,475.75	$26.84
2046	$1,479.21	$26.73
2047	$1,482.22	$26.60
2048	$1,484.73	$26.45
2049	$1,486.77	$26.29
2050	$1,488.34	$26.11
2051	$1,518.11	$26.63
2052	$1,548.47	$27.16
2053	$1,579.44	$27.71
2054	$1,611.03	$28.26
2055	$1,643.25	$28.83

Table F-27: Low Storage Generic Information without Transmission Cost Adder

Lithium-Ion Battery, 60 MW 85% RTE *without* Transmission Cost - low sensitivity		
Capex with TRX ($nominal/kW)		Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$1,285.51	$32.14
2025	$1,244.51	$31.11
2026	$1,215.52	$30.39
2027	$1,184.87	$29.62
2028	$1,152.51	$28.81
2029	$1,118.38	$27.96
2030	$1,082.45	$27.06
2031	$1,084.74	$27.12
2032	$1,086.68	$27.17
2033	$1,088.26	$27.21
2034	$1,089.48	$27.24
2035	$1,090.34	$27.26
2036	$1,090.75	$27.27
2037	$1,090.76	$27.27
2038	$1,090.34	$27.26
2039	$1,089.47	$27.24
2040	$1,088.10	$27.20
2041	$1,086.26	$27.16
2042	$1,083.95	$27.10
2043	$1,081.07	$27.03
2044	$1,077.63	$26.94
2045	$1,073.64	$26.84
2046	$1,069.06	$26.73
2047	$1,063.86	$26.60
2048	$1,058.01	$26.45
2049	$1,051.52	$26.29
2050	$1,044.38	$26.11
2051	$1,065.27	$26.63
2052	$1,086.57	$27.16
2053	$1,108.30	$27.71
2054	$1,130.47	$28.26
2055	$1,153.08	$28.83

Table F-28: Base Renewable Levelized Costs by In-Service Year with Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) with Transmission Cost			
Year	Wind	Utility Scale Solar	Battery + Solar Hybrid
2024	$21.19	$47.81	$92.69
2025	$21.09	$47.12	$90.02
2026	$20.98	$46.38	$89.54
2027	$20.86	$45.59	$89.01
2028	$20.72	$44.75	$88.42
2029	$20.56	$43.86	$87.77
2030	$20.39	$42.91	$87.06
2031	$20.50	$41.90	$86.75
2032	$20.60	$40.84	$86.39
2033	$20.70	$39.71	$85.98
2034	$20.80	$38.51	$85.53
2035	$20.89	$37.25	$85.02
2036	$20.97	$37.36	$85.90
2037	$21.05	$37.46	$86.79
2038	$21.12	$37.54	$87.67
2039	$21.19	$37.61	$88.56
2040	$21.25	$37.68	$89.45
2041	$21.30	$37.72	$90.33
2042	$21.35	$37.75	$91.22
2043	$21.39	$37.77	$92.11
2044	$27.41	$43.18	$98.53
2045	$33.29	$48.53	$104.67
2046	$43.64	$58.24	$115.14
2047	$44.12	$58.63	$116.09
2048	$44.60	$59.01	$117.04
2049	$45.08	$59.39	$117.97
2050	$45.57	$59.75	$118.90
2051	$46.48	$60.77	$121.28
2052	$47.41	$61.79	$123.70
2053	$48.36	$62.81	$126.18
2054	$49.32	$63.83	$128.70
2055	$50.31	$64.85	$131.28

Table F-29: Base Renewable Levelized Costs by In-Service Year without Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost			
Year	Wind	Utility Scale Solar	Battery + Solar Hybrid
2024	$15.53	$38.56	$82.45
2025	$15.29	$37.65	$88.34
2026	$15.04	$36.69	$88.90
2027	$14.77	$35.67	$91.50
2028	$14.48	$34.59	$88.54
2029	$14.17	$33.45	$87.89
2030	$13.84	$32.25	$87.18
2031	$13.80	$30.98	$86.41
2032	$13.76	$29.64	$85.57
2033	$13.71	$28.22	$84.67
2034	$13.65	$26.73	$84.18
2035	$13.58	$25.16	$83.64
2036	$13.50	$25.00	$83.05
2037	$13.42	$24.83	$82.40
2038	$13.32	$24.63	$81.69
2039	$13.22	$24.42	$82.46
2040	$13.10	$24.18	$83.23
2041	$12.98	$23.93	$83.99
2042	$12.84	$23.65	$84.75
2043	$12.69	$23.35	$85.51
2044	$19.01	$29.03	$86.26
2045	$25.20	$34.68	$87.01
2046	$36.44	$45.40	$87.75
2047	$36.78	$45.53	$93.33
2048	$37.11	$45.65	$98.62
2049	$37.44	$45.76	$107.62
2050	$37.78	$45.85	$108.34
2051	$38.53	$46.87	$110.50
2052	$39.30	$47.89	$112.71
2053	$40.09	$48.91	$114.97
2054	$40.89	$49.93	$117.27
2055	$41.71	$50.95	$119.61

Table F-30: Low Renewable Levelized Costs by In-Service Year with Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$18.54	$44.27
2025	$17.62	$42.51
2026	$16.68	$40.69
2027	$15.73	$38.81
2028	$14.76	$36.88
2029	$13.78	$34.88
2030	$12.79	$32.81
2031	$12.67	$30.67
2032	$12.54	$28.47
2033	$12.40	$26.18
2034	$12.25	$23.82
2035	$12.09	$21.38
2036	$11.92	$21.42
2037	$11.73	$21.45
2038	$11.54	$21.48
2039	$11.33	$21.50
2040	$11.10	$21.51
2041	$10.87	$21.52
2042	$10.62	$21.52
2043	$10.36	$21.51
2044	$16.49	$27.45
2045	$22.49	$33.35
2046	$33.47	$44.22
2047	$33.67	$44.64
2048	$33.86	$45.06
2049	$34.05	$45.48
2050	$34.23	$45.90
2051	$34.92	$46.92
2052	$35.62	$47.94
2053	$36.33	$48.96
2054	$37.06	$49.98
2055	$37.80	$51.00

Table F-31: Low Renewable Levelized Costs by In-Service Year without Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$13.15	$35.34
2025	$12.18	$33.43
2026	$11.19	$31.46
2027	$10.19	$29.43
2028	$9.17	$27.33
2029	$8.13	$25.16
2030	$7.08	$22.92
2031	$6.84	$20.60
2032	$6.58	$18.21
2033	$6.32	$15.74
2034	$6.04	$13.17
2035	$5.74	$10.52
2036	$5.43	$10.33
2037	$5.11	$10.14
2038	$4.77	$9.93
2039	$4.42	$9.71
2040	$4.05	$9.48
2041	$3.66	$9.23
2042	$3.26	$8.98
2043	$2.83	$8.70
2044	$9.23	$14.90
2045	$15.51	$21.07
2046	$27.26	$32.85
2047	$27.34	$33.06
2048	$27.41	$33.27
2049	$27.48	$33.47
2050	$27.53	$33.67
2051	$28.08	$34.69
2052	$28.65	$35.71
2053	$29.22	$36.73
2054	$29.80	$37.75
2055	$30.40	$38.77

Table F-32: High Renewable Levelized Costs by In-Service Year with Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$22.22	$49.56
2025	$22.50	$49.81
2026	$22.79	$50.05
2027	$23.07	$50.29
2028	$23.37	$50.52
2029	$23.66	$50.74
2030	$23.96	$50.96
2031	$24.24	$51.18
2032	$24.52	$51.39
2033	$24.81	$51.60
2034	$25.09	$51.81
2035	$25.37	$52.02
2036	$25.66	$52.17
2037	$25.95	$52.30
2038	$26.24	$52.43
2039	$26.53	$52.53
2040	$26.82	$52.61
2041	$27.11	$52.68
2042	$27.41	$52.73
2043	$27.70	$52.75
2044	$33.68	$57.64
2045	$39.51	$62.46
2046	$49.44	$71.05
2047	$50.15	$71.39
2048	$50.86	$71.72
2049	$51.58	$72.04
2050	$52.32	$72.34
2051	$53.36	$73.36
2052	$54.43	$74.38
2053	$55.52	$75.40
2054	$56.63	$76.42
2055	$57.76	$77.44

Table F-33: High Renewable Levelized Costs by In-Service Year without Transmission Cost Adder

Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$16.26	$39.47
2025	$16.35	$39.49
2026	$16.43	$39.50
2027	$16.52	$39.50
2028	$16.60	$39.49
2029	$16.68	$39.46
2030	$16.76	$39.42
2031	$16.83	$39.36
2032	$16.91	$39.30
2033	$16.98	$39.22
2034	$17.04	$39.12
2035	$17.11	$39.01
2036	$17.17	$38.60
2037	$17.22	$38.16
2038	$17.27	$37.70
2039	$17.32	$37.21
2040	$17.36	$36.70
2041	$17.40	$36.17
2042	$17.43	$35.61
2043	$17.46	$35.02
2044	$23.72	$39.99
2045	$29.86	$44.95
2046	$40.76	$54.56
2047	$41.26	$54.40
2048	$41.75	$54.22
2049	$42.26	$54.03
2050	$42.76	$53.81
2051	$43.62	$54.83
2052	$44.49	$55.85
2053	$45.38	$56.87
2054	$46.29	$57.89
2055	$47.21	$58.91

Table F-34: Wind, Solar, Battery + Solar Hybrid Edison Energy Market Forecast-Adjusted LCOE pre 2030 with Transmission Cost

Edison Energy Market Forecast Adjusted LCOE Pre 2030		
Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Solar
2026	$41.52	$54.67
2027	$36.24	$51.73
2028	$30.96	$48.79
2029	$25.68	$45.85
2030	$20.39	$42.91
2031	$20.50	$41.90
2032	$20.60	$40.84
2033	$20.70	$39.71
2034	$20.80	$38.51
2035	$20.89	$37.25
2036	$20.97	$37.36
2037	$21.05	$37.46
2038	$21.12	$37.54
2039	$21.19	$37.61
2040	$21.25	$37.68
2041	$21.30	$37.72
2042	$21.35	$37.75
2043	$21.39	$37.77
2044	$27.41	$43.18
2045	$33.29	$48.53
2046	$43.64	$58.24
2047	$44.12	$58.63
2048	$44.60	$59.01
2049	$45.08	$59.39
2050	$45.57	$59.75
2051	$46.48	$60.77
2052	$47.41	$61.79
2053	$48.36	$62.81
2054	$49.32	$63.83
2055	$50.31	$64.85

Table F-35: Wind, Solar, Battery + Solar Hybrid Market Forecast-Adjusted LCOE pre 2030 without Transmission Cost

Edison Energy Market Forecast Adjusted LCOE Pre 2030		
Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Solar
2028	$21.64	$37.71
2029	$17.69	$34.97
2030	$13.84	$32.25
2031	$13.80	$30.98
2032	$13.76	$29.64
2033	$13.71	$28.22

Table F-36: Wind, Solar, Edison Energy Market Forecast with NREL ATB Trend, with Transmission Cost

Edison Energy Market Forecast with NREL ATB Trend		
Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Solar
2024	$54.61	$62.64
2025	$54.36	$61.74
2026	$54.08	$60.77
2027	$53.76	$59.74
2028	$53.40	$58.64
2029	$53.00	$57.47
2030	$52.56	$56.22
2031	$52.83	$54.91
2032	$53.10	$53.51
2033	$53.35	$52.03
2034	$53.60	$50.47
2035	$53.83	$48.81
2036	$54.04	$48.95
2037	$54.25	$49.08
2038	$54.44	$49.19
2039	$54.61	$49.29
2040	$54.77	$49.37
2041	$54.91	$49.43
2042	$55.03	$49.47
2043	$55.13	$49.50
2044	$70.63	$56.58
2045	$85.78	$63.60
2046	$112.47	$76.32
2047	$113.70	$76.83
2048	$114.94	$77.33
2049	$116.19	$77.82
2050	$117.44	$78.30
2051	$119.79	$79.86
2052	$122.18	$81.46
2053	$124.63	$83.09
2054	$127.12	$84.75
2055	$129.66	$86.45

Table F-37: Wind, Solar, Edison Energy Market Forecast with NREL ATB Trend, without Transmission Cost

Levelized Costs by In-Service Year (30 year life) without Transmission Cost		
Year	Wind	Solar
2028	$37.32	$45.32
2029	$36.52	$43.83
2030	$35.67	$42.25
2031	$35.57	$40.59
2032	$35.46	$38.83
2033	$35.33	$36.98

Table F-38: Renewable Levelized Costs by In-Service Year with $500/kW Transmission Cost Starting in 2029[22]

High Integration Cost Sensitivity		
Levelized Costs by In-Service Year (30 year life) with Transmission Cost		
Year	Wind	Utility Scale Solar
2024	$21.19	$47.81
2025	$21.09	$47.12
2026	$20.98	$46.38
2027	$20.86	$45.59
2028	$20.72	$44.75
2029	$26.96	$54.26
2030	$26.95	$53.57
2031	$27.20	$52.83
2032	$27.45	$52.04
2033	$27.70	$51.19
2034	$27.94	$50.29
2035	$28.19	$49.34
2036	$28.44	$49.72
2037	$28.68	$50.09
2038	$28.92	$50.45
2039	$29.16	$50.81
2040	$29.40	$51.17
2041	$29.63	$51.51
2042	$29.87	$51.86
2043	$30.10	$52.19
2044	$35.81	$57.33
2045	$41.37	$62.39
2046	$50.84	$71.08
2047	$51.46	$71.73
2048	$52.09	$72.37
2049	$52.72	$73.01
2050	$53.36	$73.65
2051	$54.43	$75.12
2052	$55.51	$76.63
2053	$56.63	$78.16
2054	$57.76	$79.72
2055	$58.91	$81.32

[22] The generic CT cost assumption is not shown in this table because there is no levelized cost input in EnCompass; instead, the additional $500/kW is directly input into the EnCompass model as a nominal cost, starting in the year 2029.

Table F-39: Storage Generic Information with $500/kW Transmission Cost Starting in 2029

High Integration Cost		
	Capex with TRX ($nominal/kW)	Fixed Operation & Maintenance Cost (FOM) ($nominal/kW-yr)
Year	4 hr duration	4 hr duration
2024	$2,004.38	$43.48
2025	$1,825.17	$38.86
2026	$1,810.38	$38.36
2027	$1,794.27	$37.82
2028	$1,776.78	$37.24
2029	$2,050.78	$36.62
2030	$2,036.25	$35.97
2031	$2,054.34	$36.12
2032	$2,072.35	$36.27
2033	$2,090.25	$36.40
2034	$2,108.04	$36.53
2035	$2,125.70	$36.65
2036	$2,143.23	$36.76
2037	$2,160.61	$36.86
2038	$2,177.83	$36.94
2039	$2,194.88	$37.02
2040	$2,211.74	$37.08
2041	$2,228.39	$37.14
2042	$2,244.83	$37.17
2043	$2,261.03	$37.20
2044	$2,276.99	$37.21
2045	$2,292.69	$37.21
2046	$2,308.10	$37.19
2047	$2,323.21	$37.16
2048	$2,338.01	$37.11
2049	$2,352.47	$37.05
2050	$2,366.57	$36.97
2051	$2,413.90	$37.71
2052	$2,462.18	$38.46
2053	$2,511.43	$39.23
2054	$2,561.65	$40.01
2055	$2,612.89	$40.81

T. Market Purchase Carbon Rate

In order to account for emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the Table F-40 below. These estimates were developed based on MISO's MTEP21 Future 2 modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

Table F-40: Market Purchase Carbon Rate

Market Purchase CO2 Rate																
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
lbs/MWh	1119	1029	938	848	758	668	578	560	542	524	506	489	481	463	446	428
	2040	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**
lbs/MWh	452	424	414	403	393	383	373	362	352	342	331	321	311	301	290	280

ATTACHMENT 4 (ND APPENDIX G) – SCENARIO SENSITIVITY ANALYSIS – PVRR SUMMARY

NPV ($m) 2024-2040		B	C	D	E	G	H	I	J	K	Q
	PVRR	**High Fuel/Mkt Price**	**Low Fuel Mkt Price**	**High Load PVRR**	**Low Load PVRR**	**High Tech Cost**	**Low Tech Cost**	**Edison Energy Prices with ATB Trend**	**Edison Energy Pre 2030**	**High Integration Cost**	**Market Off**
Scenario 1	$34,818	$34,624	$34,677	$38,643	$33,552	$35,510	$33,684	$36,640	$34,970	$35,493	$38,188
Scenario 2	$34,570	$34,241	$34,560	$38,489	$33,350	$35,181	$33,587	$36,114	$34,792	$35,011	$37,908
Scenario 3	$34,313	$34,003	$34,286	$38,171	$33,078	$34,903	$33,364	$35,959	$34,483	$34,656	$37,640

NPV ($m) 2024-2047		B	C	D	E	G	H	I	J	K	Q
	PVRR	**High Fuel/Mkt Price**	**Low Fuel Mkt Price**	**High Load PVRR**	**Low Load PVRR**	**High Tech Cost**	**Low Tech Cost**	**Edison Energy Prices with ATB Trend**	**Edison Energy Pre 2030**	**High Integration Cost**	**Market Off**
Scenario 1	$45,163	$45,265	$44,710	$51,163	$43,281	$46,469	$43,087	$48,974	$45,246	$46,741	$49,502
Scenario 2	$45,279	$45,159	$45,045	$51,464	$43,600	$46,397	$43,518	$48,567	$45,474	$46,469	$49,544
Scenario 3	$45,053	$44,855	$44,902	$51,254	$43,433	$46,129	$43,381	$48,311	$45,258	$46,119	$49,288

NPV ($m) 2024-2050		B	C	D	E	H	I	J	K	L	Q
	PVRR	**High Fuel/Mkt Price**	**Low Fuel Mkt Price**	**High Load PVRR**	**Low Load PVRR**	**High Tech Cost**	**Low Tech Cost**	**Edison Energy Prices with ATB Trend**	**Edison Energy Pre 2030**	**High Integration Cost**	**Market Off**
Scenario 1	$49,352	$49,618	$48,726	$56,489	$47,254	$50,874	$46,945	$54,277	$49,425	$51,471	$54,088
Scenario 2	$49,628	$49,633	$49,261	$56,943	$47,693	$50,922	$47,588	$53,895	$49,744	$51,276	$54,278
Scenario 3	$49,421	$49,312	$49,173	$56,787	$47,577	$50,673	$47,480	$53,601	$49,627	$50,992	$54,031

NPV ($m) 2024-2040		B	C	D	E	H	I	J	K	L	Q
DELTAS	**PVRR**	**High Fuel/Mkt Price**	**Low Fuel Mkt Price**	**High Load PVRR**	**Low Load PVRR**	**High Tech Cost**	**Low Tech Cost**	**Edison Energy Prices with ATB Trend**	**Edison Energy Pre 2030**	**High Integration Cost**	**Market Off**
Scenario 1	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	($248)	($383)	($117)	($153)	($201)	($330)	($97)	($527)	($179)	($482)	($280)
Scenario 3	($505)	($621)	($391)	($472)	($474)	($607)	($321)	($681)	($487)	($837)	($548)

ATTACHMENT 4 (ND APPENDIX G) – SCENARIO SENSITIVITY ANALYSIS – PVRR SUMMARY

NPV ($m) 2024-2047

DELTAS	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load PVRR	Low Load PVRR	High Tech Cost	Low Tech Cost	Edison Energy Prices with ATB Trend	Edison Energy Pre 2030	High Integration Cost	Market Off
Scenario 1	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	$116	($106)	$335	$301	$319	($71)	$431	($408)	$228	($272)	$42
Scenario 3	($110)	($410)	$192	$90	$153	($339)	$294	($664)	$12	($622)	($215)

NPV ($m) 2024-2050

DELTAS	PVRR	High Fuel/Mkt Price	Low Fuel Mkt Price	High Load	Low Load	Low Tech Cost	Edison Market Cost	High Reg High SC-GHG	Low Reg Low SC-GHG	0 Reg high SC-GHG	Market Off
Scenario 1	$	$	$	$	$	$	$	$	$	$	$
Scenario 2	$276	$15	$535	$453	$440	$48	$643	($382)	$319	($194)	$190
Scenario 3	$69	($306)	$447	$298	$323	($201)	$536	($677)	$202	($479)	($57)

ATTACHMENT 5 (ND APPENDIX T) – MISO GRID CONGESTION

I. INTRODUCTION

The North Dakota Century Code (NDCC) 69-09-12-04(3)(g) requires a discussion of the "opportunities for existing and planned transmission facilities to reduce congestion, transmission line losses, energy costs, and to increase export or import capability." Congestion is a complex issue that requires careful planning, management and coordinated efforts from multiple stakeholders. Here we provide an overview of the problem of congestion as it relates to resource planning and outline the steps we are taking to address it.

Though we cannot address congestion alone, we are looking for solutions to address congestion for our customers' benefit and furthering policy objectives. We have engaged in multiple efforts to find and mitigate transmission constraints, consideration of the "expansion of, improvements to, and more efficient use of existing . . . transmission facilities" as required by NDCC 69-09-12-04 (3)(a). Further, we analyzed our North Dakota Preferred Plan using a PROMOD analysis looking at congestion impacts to analyze the "qualitative benefits and quantitative value of baseload and load following generation resources and the value of proximity of such resources to load" in accordance with NDCC 69-09-12-04 (3)(f). While many of our investments target physical improvements to constraints impacting our system, we are also reviewing regional policies to ensure adequate measures are in place to avoid future congestion impacts. Our efforts underpin our commitment to provide our customers with affordable, safe, reliable, and resilient energy.

II. DEFINING GRID CONGESTION

The Xcel Energy operating companies NSP-Minnesota and NSP-Wisconsin, operate an integrated transmission system (the NSP System) that comprises more than 8,400 miles of transmission and sub transmission facilities operating at voltages between 23.7 kilovolts (kV) and 500 kV, and approximately 550 transmission and distribution substations. The NSP System is within the Midcontinent Independent System Operator (MISO) footprint and serves retail customer loads in Minnesota, North Dakota, South Dakota, Wisconsin and Michigan.

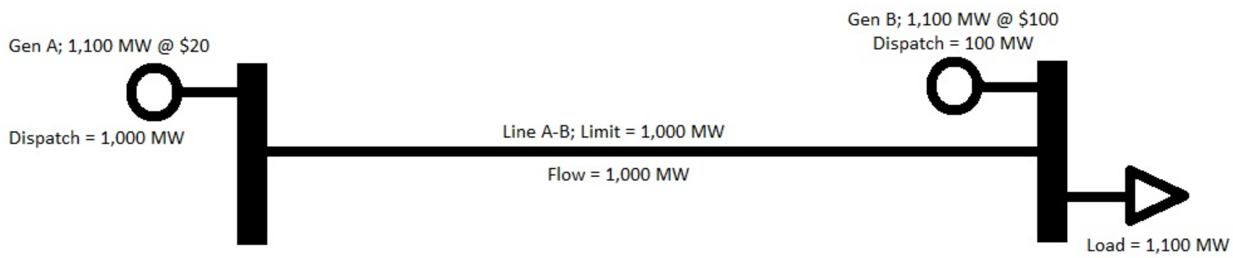
Limits on transmission facilities can prevent MISO from dispatching the most efficient generation resources during all hours of the year, thereby increasing wholesale energy costs. Transmission constraints are the physical limits on the amount of electricity flow the system is allowed to carry in order to ensure safe and reliable operation. Transmission constraints occur at different points on the transmission system, such as transmission lines, substations, or in specific regions. Regardless of the source, these constraints result in bottlenecks in the transmission system, and higher costs for electricity delivery.

These transmission constraints create inefficiencies in the wholesale energy market and increase costs through shadow prices. Locational marginal prices (LMPs) are economic indicators used to reflect the value of electricity at specific locations within the grid. MISO calculates LMPs for over 2,000 nodes. LMPs include marginal energy costs (i.e., cost of generating the last megawatt-hour MWh of energy in order to balance supply and demand in the market) as well as congestion costs and transmission losses. Collections of nodes are often represented by zones or hubs that provide a summary of regional prices and a benchmark for forward trading of power. When there is congestion in the transmission system, shadow prices signal the congestion cost savings for increasing a given transmission path by 1 Megawatt (MW). Shadow prices are used throughout the industry to determine which transmission paths or flowgates are the most congested and are used by the market model to set LMPs at different nodes throughout the system. The price of electricity is not uniform across the grid due to constraints and losses. Ignoring the effect of transmission losses, when no transmission constraints are restricting economic dispatch, all marginal prices at all points would be identical. If there is a constraint, the marginal prices on two sides of the constraint will differ. The difference in price is an economic measure of congestion.

Transmission congestion are the economic impacts on the users of electricity that result from operation of the system within these limits. Congestion occurs when demand for electricity in a particular region exceeds supply, and there is insufficient transmission capacity to move the least costs generation to customers. Once the system is overloaded, cheaper generation cannot be dispatched, and more expensive generation is used to serve load. Higher cost generators from areas without transmission constraints must be used to meet customer demand, thereby raising the price of electricity.

Figure T-1 below is an illustration of how congestion affects the energy used and pricing in a single moment of time. The illustration assumes an energy need of 1,100 MW that could be supplied by two potential generators, one at a charge of $20 per MW and one at $100 per MW.

Figure T-1: Congestion Illustration



In this theoretical intact system, Generator A could serve the entire 1,100 MW needed, but cannot do so because of the 1,000 MW limit on Line A-B. Instead, Generator A's dispatch is limited to 1,000 MW and Generator B will be called on to deliver the 100 MW balance. If Generator A were able to deliver the entire 1,100 MW it can generate, the energy cost would be $22,000 assuming no energy is lost during transmission. Due to system constraints, the total cost to deliver the 1,100 MW rises to $30,000 because 100 MW cannot be delivered, and replacement energy is required (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B). In short, the congestion causes the overall cost of energy to increase $8,000 or 36 percent based on this simplified example. When there is no congestion, the lowest cost generator, regardless of fuel source, is the one that serves load.

Managing congestion is critical to minimizing costs associated with electricity production and transmission and enabling further investments in renewable energy. LMPs play a crucial role in managing grid congestion and optimizing the operation of the electricity market by using economic indicators to manage the flow of electricity. However, congestion also represents increased prices for our customers. By addressing the causes of congestion directly we can work to mitigate its impact on electricity prices.

III. CAUSES AND IMPACTS OF GRID CONGESTION

Generally, we see congestion on the transmission system because of the increasing demands for electricity, both in terms of load, and the changing generation mix of its supply. Integrating new renewable generation can lead to congestion on the MISO system, causing transmission constraints as the system may lack the flexibility to accommodate further resources without physical improvements. The existing transmission infrastructure may be outdated, in need of significant upgrades, or unable to accommodate additional generation leading to congestion as energy must find alternative pathways to get to customers. Further, policy may also contribute to congestion through unintended impacts. While there are many causes of congestion, its impact on higher prices for our customers must be accounted for in our system planning.

Across our footprint we are experiencing significant growth in energy demand, prompting us to seek innovative solutions to meet the increasing electricity needs of our customers. One prominent approach has been an escalating reliance on wind and solar generation. With its abundant wind resources and the growing solar potential, the upper Midwest is emerging as a leader in renewable energy deployment. Wind farms are becoming a common sight across the region and solar installations, ranging from rooftop arrays to large-scale solar farms, are proliferating, harnessing the region's sunlight. By harnessing wind, solar and other forms of renewable energy, we are striving to meet the surging energy demand while achieving a greener and more sustainable energy future.

The growth in renewable generation may both increase and decrease the need for new transmission. As legacy units retire, they are often being replaced by wind and solar generation, but the fuel sources for these resources are often locationally dependent. Regions with favorable conditions, and abundant resources are not often located near load centers. Historically, transmission lines delivered power from large scale base load generators to population centers. The infrastructure needed to support the dispersed replacement generation for retiring baseload units is continuously growing.

While there are abundant levels of wind, solar, and even biomass in the Upper Midwest, often they are located in more remote locations. Siting renewables in these remote locations requires new or upgraded transmission to efficiently deliver energy to load centers. More remote areas lack the necessary transmission infrastructure for large scale renewable projects due to their lower population density, and lower historical electricity demand as they were not historically prioritized with for extensive transmission infrastructure development in the past. As a result, the existing transmission system does not always have the capacity to accommodate the additional power generated by large renewable energy projects.

Further, in addition to the physical constraints mentioned, fuel costs can increase congestion impacts. Congestion costs can be exacerbated by high natural gas prices due to natural gas fueled generation generally being dispatched to offset congested renewables due to the natural gas generation's flexibility and distance to the load.

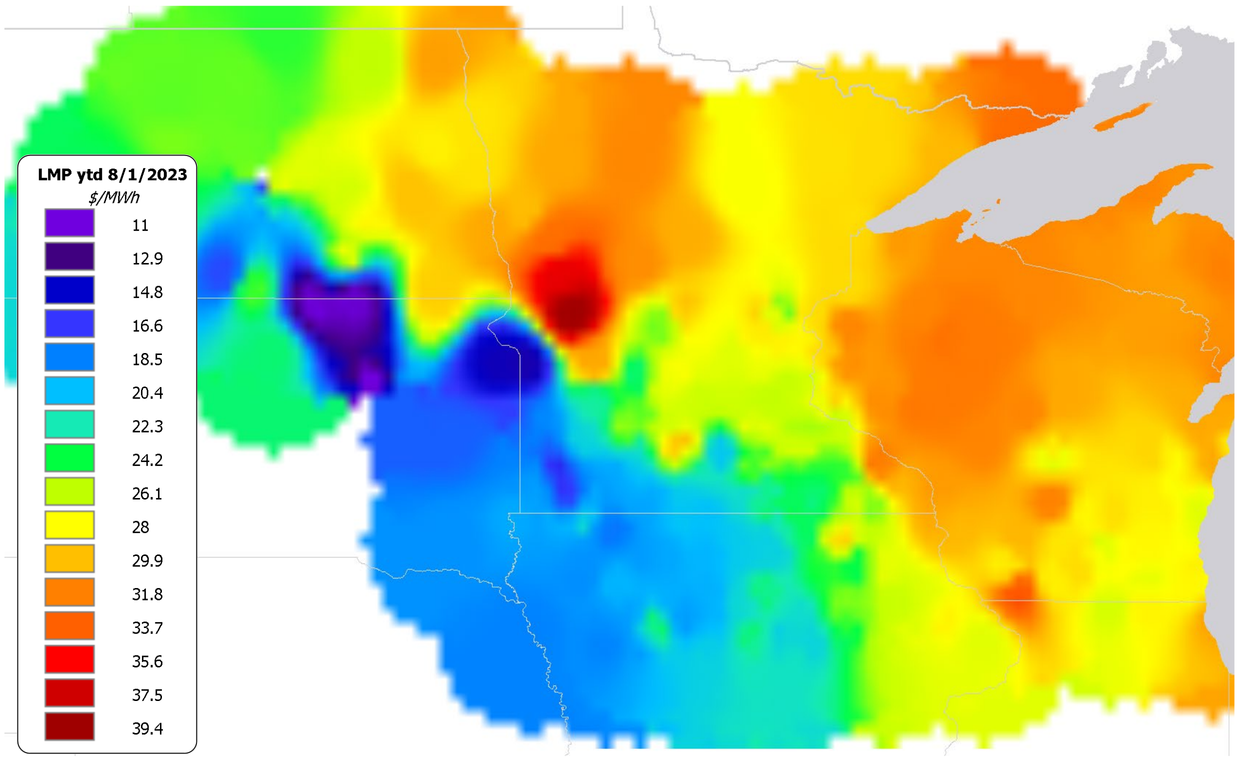
Finally, as mentioned, policy may also contribute to congestion through unintended impacts. We identified congestion impacts that resulted in increased costs to customers as part of the MISO Generator Interconnection Process. One of the ways in which MISO exercises its role of managing the flow of electricity is by analyzing transmission service requests by parties looking to use the transmission system. The MISO Generator Interconnection Process is used to analyze interconnection requests for new generators connecting to MISO facilities to ensure the reliability of the transmission system and ensure the deliverability of new and existing network resources.

In our work with MISO and stakeholders, we found that the MISO Generator Interconnection Process had resulted in increased costs to customers though the thresholds in which generators were made responsible for upgrade costs, and how the dispatch of resources in the Interconnection Process study were being implemented. The MISO thresholds at the time the issue was identified were that a 5 percent or greater contribution would require a generator seeking Network Resource Interconnection Service (NRIS) to pay for an identified upgrade. For a generator seeking Energy Resource Interconnection Service (ERIS), a contribution level of 20 percent or greater was required to be assigned the costs of an upgrade. This resulted in needed upgrades being identified during the System Impact Study efforts, but due to contribution levels being below the thresholds, these constraints were not being mitigated.

Over time we have seen increasing congestion on the MISO system. As a visual representation, we can examine historical congestion through examining the average LMPs on MISO system. Figure T-2 below shows LMPs on the MISO system in our area year to date as of August 1, 2023.[1]

[1] Hitachi Energy Velocity Suite simple average, LMPs on the MISO system in our area year to date as of August 1, 2023.

Figure T-2: MISO Historical LMP Averages



Areas which are dark blue to purple show low average LMPs and represent the market signal an abundance of generation and a lack of load while orange to dark red signal an abundance of load, and lack of generation. Regions with a drastic price difference in a relatively short distance are highly congested areas signaling constraints on the system.

Currently, wind generation from the western part of MISO flows toward the load centers in the east, such as the Twin Cities Metro area and load centers beyond the transmission interconnection between Minnesota and Wisconsin. The existing west-to-east transmission capacity is at times operating at its limit. The transmission interface across the Minnesota-Wisconsin border is currently stability-limited and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. This forces us into curtailing wind energy at its source in the west as it is operationally and economically inefficient to utilize the otherwise inexpensive energy to which we have access.

We can quantify the cost impacts of congestion. Table T-1 below shows congestion and curtailment information for 2022 and 2023. These are the official curtailment values and reflect the curtailment billed to the Company. The months where the curtailment data was not available, we used the MWh derived in our monthly curtailment estimate calculation. The costs for these months were the MWh from our estimate, multiplied by the average monthly cost of curtailment.

Table T-1: Congestion and Curtailment Costs for 2022 and 2023

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

The monthly costs (listed as negative values) of recent congestion impacts are provided in Table T-1 above in the column titled Total Impact. Monthly Total Impact is the sum of the Congestion and Curtailment costs, offset by Financial Transmission Right (FTR) revenue. Curtailment and Congestion are considered negative and Financial Transmission Right (FTR)s are considered revenue positive in the calculation.

Beginning in June 2020 the NSP system began to see a significant increase in congestion costs in MISO settlements, exhibiting another step increase in April 2021. In the beginning of 2023 through June of 2023, congestion costs have fallen off to some degree as compared to 2022; however, there remains significant volatility as observed in April 2023, which may increase moving forward. Therefore, to better align the 2024 forecast with costs expected for congestion, we have updated our MISO cost and revenue forecast to include data inclusive of results observed for April 2021 through June 2023 which are annualized to provide the forecast for 2024. Figure T-3 below shows NSP congestion costs from January 2019 to June 2023.

Figure T-3: NSP Congestion Costs

[PROTECTED DATA BEGINS

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Because of the rising transmission costs, we have received interest in congestion levels from various parties in recent resource plans. Suggestions have ranged from incorporating congestion levels directly in modeling to not incorporating congestion impacts at all.

As part of this resource plan, we utilized PROMOD to analyze to incorporate congestion impacts into our plan, rather than forcing a congestion cost adder directly into EnCompass itself. Figure T-4 below shows the results of the congestion impacts to the NSP system using the PROMOD analysis.

Figure T-4: IRP Congestion Costs

[PROTECTED DATA BEGINS

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Our PROMOD results include additional detail about congestion, including non-model-based congestion mitigation efforts and the locational detail shows the different ways that this issue can be mitigated or contemplated in specific resource acquisitions, through operational measures, and also through integrated planning efforts with transmission planning.

As shown in Figure T-4 above, NSP is forecasting an increase in congestion costs as we approach the 2040 horizon. This analysis includes the Long-Range Transmission Plan (LRTP) Tranche 1 projects. The Tranche 1 transmission buildout relieves congestion in the near term, but with the progression of carbon-free resources, more transmission will be needed.

IV. EFFORTS TO ADDRESS CONGESTION

With Xcel Energy's strong carbon emission goals, the NSP system has seen a significant increase in congestion due to the renewable energy transition. Managing congestion is crucial for minimizing production and transmission costs. A strong transmission system ensures continued reliable and affordable service, and the ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy.

NDCC 69-09-12-04(3)(g) requires a discussion of the "opportunities for existing and planned transmission facilities to reduce congestion, transmission line losses, energy costs, and to increase export or import capability," whereas NDCC 69-09-12-04 (3)(a) require discussion of "expansion of, improvements to, and more efficient use of existing . . . transmission facilities." Congestion costs are directly affected by transmission investment. If transmission investment removes a constraint to relieve congestion, then the investment will reduce congestion costs to customers. The congestion costs avoided are a direct measure of the economic benefit from, or value of, this investment. However, projects must be measured to ensure the value of the investment exceeds the costs.

A. MISO Developed Projects

The MISO Transmission Expansion Plan (MTEP) is a comprehensive process undertaken by MISO to assess, plan and propose transmission system improvements within its operational footprint. MTEP aims to ensure reliability, efficiency, and the cost effectiveness of the electrical transmission infrastructure within the MISO region through identifying needs, developing scenarios, studying alternatives, performing cost benefit analysis, and conducting stakeholder engagement. The MTEP process aims to address congestion and level the playing field for all generators to deliver their energy based on supply and demand. This in turn ensures that the energy market operates in the most efficient and cost-effective manner.

MISO adheres to the planning principles outlined in FERC Order No. 890 and 1000 in developing the MTEP. These FERC Orders require an open and transparent regional transmission planning process and include the requirement to plan for public policy and for coordinated inter-regional planning and cost allocation. Consistent with these FERC directives, the MTEP process seeks to ensure the reliable operation of the transmission system, support the achievement of state and federal energy policy requirements, and enable a competitive energy market to benefit all customers. Xcel Energy plays an active part in the entirety of the MTEP process including the futures development and model development, and validation.

The development of the MTEP typically starts in June every other year and is an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. As part of the process MISO usually performs a Market Congestion Planning Study (MCPS). The 2016 MCPS was an example of how transmission can produce lower APC as this study resulted in the development of our Huntley-Wilmarth 345 kV line Market Efficiency Project (MEP). The Huntley to Wilmarth 345 kV project alleviated the observed congestion at the Minnesota/Iowa border. Though we acquired new right-of-way to construct the 345 kV circuit on the approved route, approximately 40 percent of the line was constructed as a double circuit with the existing Wilmarth-Lakefield Jct. 345 kV line.

The last MCPS was performed in 2019, with the 2020, 2021, 2022, and 2023 MCPS Studies being eliminated to open resources for Long-Range Transmission Planning (LRTP)—which is MISO's largest ever undertaking to update and modernize the transmission system. The LRTPs are a comprehensive planning effort outlining the transmission infrastructure needs and tests expansion plans for the MISO region to accommodate widespread changes in the electric landscape due to changing technology and customer needs. The scale and pace of these changes have required prompt attention to develop the most efficient, cost-effective investments to ensure grid reliability in the future. The LRTP initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system.

The LRTP projects are sorted into various tranches depending on their priority. Tranche 1 resulted in a $10.3 billion transmission portfolio that was approved by the MISO Board of Directors in July 2022. The projects in the Upper Midwest represent about $3 billion in total investment; with Xcel Energy's assigned projects representing about $1.2 billion of the total Upper Midwest investment. The MISO LRTP Tranche 1 projects in Minnesota utilize the existing 345 kV second circuit capabilities where possible, which will increase the overall ability to transfer power across the system while limiting environmental and landowner impacts.

The LRTP Tranche 1 transmission portfolio supplies our renewable locations with enough outlet to reach our twin cities load pocket and the rest of MISO, as congestion costs in 2030 are show in Figure T-4 above around $50M. However, as our clean energy transition continues, the Tranche 1 transmission buildout isn't enough and NSP is seeing a huge increase in congestion costs as we get out to 2035 and 2040. NSP's MN Preferred Plan includes more renewable energy resources compared to the ND Preferred Plan, which has a direct correlation to higher congestion costs.

As Tranche 1 alone is not enough to mitigate congestion alone, we have also submitted additional projects as part of MISO LRTP Tranche 2 portfolio currently in development. As Tranche 2 projects are announced, we will continue to engage in transmission development, and look forward to developing approved projects to enhance the capacity of the grid.

B. Utility Developed Projects

While Xcel Energy regularly participates in MISO to address congestion and expand capacity, we additionally study congestion with our project partners, or on our own. For instance, Xcel Energy, as part of Grid North Partners[2] conducted a study to identify the root causes of congestion from July 2020 to July 2022. The study identified 94 facilities in and around Minnesota causing congestion in Minnesota. The second circuit on the Brookings County - Lyon County and Helena-Hampton transmission lines, along with five other projects to upgrade facilities were submitted in MISO's MTEP to mitigate some of this congestion. A total of 17 facilities were able to be upgraded at low cost (under $1 million) and another five upgrades we found (under $10 million) to mitigate congestion. Much of the congestion observed is due to high-wind weather patterns with much longer duration than the typical 4-hour batteries available as a non-transmission alternative.

Also, as a result of the study, Xcel Energy initiated an out-of-cycle request to MISO for completing the second 345 kV circuit from Brookings County - Lyon County and Helena-Hampton for the existing CAPX Brookings-TC facility. In addition, though not a Market Efficiency Project per se, Xcel Energy recently initiated two projects, the MN Energy Connection and the King Connection, which are designed to utilize

[2] Grid North Partners include DPC, OTP, MP, MRES, CMMPA, RPU, SMMPA, WPPI, Xcel Energy and GRE.

existing transmission access rights and will enable further renewable investment. The MISO interconnection queue has many new interconnection requests seeking to connect to a system that is already congested. Reusing existing transmission rights through the MN Energy Connection and King Connection Projects allows Xcel Energy to interconnect additional MWs through its existing transmission rights, avoiding lengthy delays often related to MISO queue interconnection studies.

In addition to these larger transmission projects, Xcel Energy has been developing multiple market participant-funded transmission projects to address congestion. These projects aim to enhance the reliability, efficiency, and capacity of the electric transmission grid by addressing constraints. For instance, we converted the bifurcated 115 kV line from High Bridge to Rogers Lake to a double circuit 115 kV line to alleviate congestion on the High Bridge Generating Plant. Additionally, we constructed new breaker positions at High Bridge and Rogers Lake to accommodate the second 115 kV circuit to remove the bifurcation ties at both ends of the High Bridge – Rogers Lake 115 kV line while adding breaker positions at both substations.

Xcel Energy performed its own internal analysis to determine small projects designed to address constraints and remove system limiters on congested lines. The projects listed in Table T-2 below focus on substation equipment and sag limits in Southwest Minnesota.

Table T-2: Xcel Energy Congestion Projects

Substation	Chisago County (CHI)
Scope	Replace primary and secondary 115 kV bus 1 differential relays for TR05 and TR06
Property Units	(4) Control System
ISD	8/1/2022
Substation	Inver Hills (IVH)
Scope	Replace busbar
Property Units	(1) Conductor
ISD	3/1/2023
Substation	Kohlman Lake (KOL)
Scope	Replace meter on breaker 5P106
Property Units	(1) Control System
ISD	8/1/2022

Substation	Prairie (PRA)
Scope	Replace meter on breaker 5G8
Property Units	(1) Control System
ISD	8/1/2022
Substation	Scott County (SCO)
Scope	Replace busbar
Property Units	(1) Conductor
ISD	3/1/2023
Substation	Wilmarth (WLM)
Scope	Replace bushing current transformers on breaker 5S11, and switches 8S26B1, 8S25B, 8S25A, 8S26B1
Property Units	(1) Circuit Breaker (BCT) (4) Switches
ISD	3/1/2023
Substation	Riverside (RIV)
Scope	Replace switches 5M330B, 5M331B, 5M329A, 5M330A, 5M329B, 5M331A, aux current transformers on 5M304 and 5M305, and two sections of busbar
Property Units	(6) Switches (2) Device, Potential (2) Conductor
ISD	3/1/2023
Substation	Red Rock (RRK)
Scope	Replace bushing current transformers on breaker K2, switches K2B1, 946B, K2B2, 946A, and meters on 946 and K2
Property Units	(1) Circuit Breaker (BCT) (4) Switches (2) Control Systems
ISD	3/1/2023

We are working with the Grid North Partners' Tech Team to further identify simple system upgrades (≤ $1M cost) to improve transmission line ratings.

Xcel Energy has been monitoring congestion and curtailment on a weekly basis to find new issues as they arise and determine whether a permanent solution is warranted or if the congestion is related to temporary system conditions. For example, Xcel Energy Transmission Operations takes both system reliability and curtailment and congestion cost impact into consideration when scheduling transmission outages. Also, we started an internal study process to determine any transmission system reconfigurations on the underlying transmission system able to positively impact the bulk transmission system and congestion. We confirmed our first system reconfiguration project in Southwest Minnesota to help alleviate congestion in the area.[3] Finally, we implemented a process to study reconfiguration requests from outside entities. These requests are looked at to determine effectiveness, duration, and impact on the transmission system. Reliability is the primary determinant to whether a reconfiguration request is approved. MISO is working on setting up their process which Xcel Energy will participate in.

C. Policy Issues

Lastly, policy can contribute to congestion. As mentioned, we found that the MISO Generator Interconnection Process had resulted in increased costs to customers through the thresholds in which generators were made responsible for upgrade costs, and how the dispatch of resources in the Interconnection Process study were being implemented. After working with MISO and stakeholders, a 10 percent rather than 20 percent contribution threshold for generators requesting ERIS was implemented for facilities 230 kV and lower. This represents a step in the right direction and will alleviate some future congestion related impacts going forward, however we will continue monitoring the contribution of ERIS requests on 345 kV facilities to determine the impact. Due to this policy change, new wind coming online in the future will likely contribute less to congestion than previous projects due to triggering more transmission upgrades before the project goes online.

V. NON-TRANSMISSION SOLUTIONS

Upgrading or replacing aging infrastructure helps ensure the safe and efficient transmission of electricity, however constructing transmission lines can be technically complex, expensive, and time consuming. Developing or upgrading transmission infrastructure requires significant planning and coordination, obtaining all necessary permits and regulatory approvals. As a project's scale increases, so do the permitting

[3] This request was reversed after several months due to a policy issue with MISO and SPP. In October MISO and SPP began coordinating their Day Ahead studies to recognize some of each other's flow gates which will help reduce SPP flows on the system. SPP previously did not recognize MISO flow gates and set a dispatch that could negatively impact MISO's dispatch. Xcel Energy Transmission Operations takes both system reliability and curtailment and congestion cost impact into consideration when scheduling transmission outages.

and environmental considerations. Anticipated benefits, by themselves, may or may not be sufficiently large and recurrent to warrant the investment and reducing congestion costs is not the only economic benefit that might justify a transmission investment. For these, and similar reasons we explore non-transmission solutions to addressing congestion.

NDCC 69-09-12-04 (3)(f) requires an analysis of the "qualitative benefits and quantitative value of baseload and load following generation resources and the value of proximity of such resources to load". As stated, the growth in renewable generation may both increase and decrease the need for new transmission. While in cases it can cause new congestion issues, in others places new generation near load centers may help alleviate congestion impacts. For this reason, we did not believe it was accurate to model congestion directly in EnCompass capacity expansion plans as part of our resource plan, but rather through PROMOD so that we may address congestion in more targeted evaluations during resource acquisitions in specific locations.

Using regional LMPs as part of generation planning offers a nuanced approach to mitigating congestion impacts. By closely examining the MISO Historical LMP Averages, such as depicted in Figure T-2, planners can identify areas where the cost of electricity delivery is significantly higher due to congestion. These high-cost areas often indicate a mismatch between local generation and demand. Incorporating this LMP data into generation planning allows for strategic placement of new generation assets, particularly near load centers marked by high LMPs. This targeted approach not only optimizes the use of existing transmission infrastructure but also minimizes the need for costly upgrades. Moreover, it provides a financial incentive for developers to invest in regions where their generation capacity can be most effectively utilized. By aligning generation planning with regional LMPs, utilities can make data-driven decisions that contribute to a more efficient, reliable, and cost-effective grid, thereby alleviating both current and future congestion-related impacts.

Finally utilizing DER or increasing energy storage technology on the load-side of a constraint, will also have a similar effect in reducing congestion costs. Investment in energy storage technology such as batteries can help alleviate grid congestion by allowing excess generation to be stored for later use. This can reduce the amount of electricity that needs to be transmitted over congested lines.

VI. CONCLUSION

Transmission congestion is a significant challenge. Addressing congestion is important for ensuring the reliable and affordable delivery of electricity to consumers. By expanding transmission capacity, improving coordination between transmission system operators, periodically reexamining policies, investing in generation and storage technology, we can do our part to help alleviate grid congestion and ensure reliable delivery of electricity to Xcel Energy customers.