APPENDIX J1 – XCEL ENERGY BASELOAD STUDY

I. INTRODUCTION

In our last Resource Plan, we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. In that plan, we described our vision of an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon. We explained that taking action now to transition our fleet mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. We specifically proposed to accelerate our transition away from coal by ceasing operation of our Sherburne County (Sherco) Units 1 and 2 in 2026 and 2023, respectively.

We provided robust technical analysis supporting our proposed retirement of those coal units, including Midcontinent Independent System Operator (MISO) preliminary retirement studies, a technical analysis that we performed in conjunction with Siemens Power Technologies, and an analysis of our Black Start Plan. We concluded that the most cost-effective way to mitigate technical issues resulting from the unit retirements and continue to meet our customers' load requirements would be to build an intermediate natural gas-fueled plant at the existing Sherco site. The Commission approved our proposed schedule to retire Sherco Units 1 and 2,[1] and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026.[2]

The Commission also required further study of an orderly and cost-effective retirement of our remaining baseload units in our next Resource Plan, as follows:[3]

> In its next resource plan filing, Xcel shall… describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.

The Baseload Study we performed in support of this Resource Plan builds on the outcomes of our previous plan and includes industry insights, and technical and

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[1] *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point No. 7, Docket No. E002/RP-15-21 (January 11, 2017).
[2] *Id.* at Ordering Point No. 8. While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a certificate of need. [Laws of Minnesota 2017, chapter 5—H.F. No. 113, section 1]
[3] *Id.* at Ordering Point No. 14(a).

economic analyses of retirement of our Allen S. King plant, Sherco Unit 3, Monticello Nuclear, and Prairie Island Nuclear Units 1 and 2.

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The Baseload Study we conducted is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.

- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision.

The plan we propose in this Resource Plan sets the NSP System on a trajectory to a clean energy future that will continue to power our customer's lives and possibilities with energy they can trust to be safe, reliable, affordable, and progressively clean. It also provides strategic flexibility to adjust as technologies continue to develop; as the industry collectively furthers its understanding of the impacts from the significant changes in the generation mix that are underway; and, while we and others ready the grid with increased transmission capabilities.

This Baseload Study is organized as follows:

I. Introduction
II. Grid Function, Design, and Attributes

III. The Grid is Evolving
IV. Xcel Energy Baseload Retirement Study
V. Summary and Conclusions

II. GRID FUNCTION, DESIGN, AND ATTRIBUTES

The electric "grid" is a large complex machine consisting of generation, transmission and distribution facilities that operate across a very large geographic area. The NSP System is part of MISO, which is part of the Eastern Interconnection that connects the generation and transmission assets of the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system impact other portions of the system.

At its core, to preserve system stability and customer reliability, the system must balance generation with changing load conditions and fluctuations caused by other disturbances. Large generating units like our current baseload units afford the capability for the system to "ride through" these disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be compromised. Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause cascading events.

A. Traditional Grid Function

Transmission, in its most basic sense is the connection between generation resources and the customer demand it is intended to serve. Because of that, the transmission system that we have today was traditionally meant to send power from large centralized power stations to the load centers utilizing high voltage transmission lines. These power stations were typically located by the areas of higher customer demand, which would minimize the amount of transmission needed to serve that demand. During the early electrification era, which made modern conveniences like electric lighting commonplace, each utility built, owned and operated their own generation resources and transmission systems meant to serve their customers.

During, and after this initial phase of electrification, growing customer demand for electricity was the primary driver for new, larger and more efficient generation resources and transmission sources meant to deliver that power. Demand growth was overall fairly steady, which allowed for effective long-term planning process to develop. Because of this predictability and the efficiencies found through economies of scale, most generation resources consisted of large coal, nuclear, or hydro facilities. Smaller, more nimble units were also utilized to supplement these large, centralized resources to meet the added stress of summer loads. Regional Coordination, and the "grid" as we know it today, was not a consideration for power companies at this time.

As these individual power companies began to identify efficiencies through coordination with other local power companies that could reduce costs, the full value the centralized power stations provided to the system was also realized. These large scale synchronous generation resources provided the backbone of the stable system we have today. The ability of these generators to provide the primary system support for adverse system conditions such as faults and loss of transmission elements, allowed for increased interconnection between local utilities and greater system reliability.

After the Northeast Blackout in 1965, the benefits of greater coordination, both locally and regionally, were recognized, and Power Pools were formed to share excess resources that each area had. To increase the ability of these resources to be shared amongst the Power Pool members, large bulk transmission facilities were developed to interconnect neighboring utilities and allow for large amounts of power to be transferred in emergencies. As a way to ensure these resources were not stretched too thin, Power Pools also set the amount of generation resources each company was required to keep in order to maintain adequate supply of power.

B. Grid Oversight and Evolution

As the initial phase of electrification was in full swing, the United States Congress established the Federal Power Commission (FPC) to coordinate the hydroelectric project under federal control. The Federal Power Act and Natural Gas Act, passed in 1935 and 1938 respectively, granted the FPC the power to regulate the sale and transportation of electricity and natural gas across state lines. Because of the chronic brownouts of the 1960's and the OPEC embargo in the 1970's, the FPC was reorganized and designated as the Federal Energy Regulatory Commission to oversee federal energy policy and the deregulation of the natural gas industry. The first FERC Order directed specifically at the restructuring of the electric industry was issued in 1996 as Order No. 888. Known as the Open Access Order, the intention of Order

888 was to ensure open and non-discriminatory access to the electric transmission system and encouraged the development of Price Exchanges to increase transparency in energy clearing prices.

Order 888 was followed shortly after by Order 889 to require the posting of transmission availability on a public bulletin board, referred to as the Open Access Same-Time Information System, or OASIS. The issuance of these Orders led to the development of Independent System Operators (ISOs) to facilitate the new requirements, in large part for existing Power Pools, set in place by Orders 888 and 889. In 1999, FERC issued Order 2000, which encouraged participation in Regional Transmission Organizations (RTOs) with the expectation that these RTOs would establish whole electricity markets to enable efficient use of the available resources and transmission system.

1. The Energy Policy Act of 2005 Created the Present FERC

The last major development, which led to the FERC we know today, was the passing of the Energy Policy Act of 2005, which greatly increased the authority FERC had over the jurisdictional entities across the country. This included the enforcement of transmission system reliability standards, the ability to levy fines for non-compliance, and other increased authorities. Today, FERC regulates interstate transmission of electricity, natural gas, and oil. Since the passing of the Energy Policy Act of 2005, FERC has issued several major orders to ensure the planning of the most efficient and cost effective transmission system possible through long-term planning requirements as well as ensuring the fair and non-discriminatory operation of wholesale electricity markets across the country.

2. NERC Oversees and Enforces Grid Reliability

NERC, created through FERC's increased authority under the Energy Policy Act of 2005, is a non-profit entity that oversees the eight regional reliability systems that stretch from Canada to Mexico. NERC is designated by the FERC as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk electric system (BES) throughout North America. NERC's primary responsibility is to develop power system standards, the monitoring and enforcement of those standards, and ensure power system operators are qualified through training.[4] Analysis of BES impacts from new generation and transmission facilities and changes to existing generation or transmission facilities are measured against NERC standards and

[44] NERC is also responsible for investigating power system outages that have a significant impact.

requirements. We provide an abbreviated outline of NERC Event Category definitions below:

Table 1: Abbreviated List of NERC Event Category Definitions[5]

P1	Single Contingency – Loss of one of the following:
	* Generator * Transmission Circuit * Shunt Device * Transformer * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Internal Breaker fault (non-Bus-tie-Breaker) * Bus Section fault * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Shunt Device * Transmission circuit * Single pole of a DC line * Transformer
P4	Multiple Contingency – (*Fault plus stuck breaker*) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Bus Section * Transmission Circuit * Loss of multiple elements caused by a stuck breaker (Bus-tie * Transformer Breaker) attempting to clear a Fault on the associated bus * Shunt Device
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Shunt Device * Transmission Circuit * Bus Section * Transformer
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Shunt Device * Transformer * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization (MRO). The MRO is a regional entity spanning from Manitoba and Saskatchewan Canada through the United States Midwest. The MRO is primarily tasked with ensuring compliance with reliability standards for the BES. The MRO conducts individual company assessments for any possible areas of improvement or violations.

[5] For a full description of NERC's event categories, *please see*: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

3. Midcontinent Independent System Operator

The first regional transmission organization to obtain approval by FERC was the Midwest (now Midcontinent) Independent System Operator (MISO); MISO is the ISO for the Upper Midwest. MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest, southern United States, and Manitoba, Canada.[6] The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

MISO's primary function is to ensure open and fair access to the transmission system. In addition, MISO administers the wholesale energy market for the same region.

C. Grid Basics

In this section, we provide an overview of the NSP System, factors effecting reliability, and the role played by baseload generating resources on our system.

1. NSP System Transmission Overview

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

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[6] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our BES is currently anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco and Monticello in the northwest, and King and Prairie Island in the east and southeast. Together these plants provide over 4,350 MW of capacity[7] and over 29,000 GWh of energy to our customers, which represents 47 percent of the NSP System accredited generating capacity and 65 percent of the system energy.[8] This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake.

The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

2. *A Reliable Grid Must Weather Unexpected Failures and Events*

NERC defines a reliable BES as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the

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[7] Nameplate capacity ratings.
[8] MISO accredited capacity values.

amount of available electricity, and divides reliability into two categories:[9]

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber-attacks. The BES must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power,

[9] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate firm dispatchable, load supporting generation to both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time. With our proposed plan to retire the remaining coal units on the NSP System, other load supporting generating resources will be needed to perform these important reliability functions.

3. Role of Baseload Generating Resources

As we have discussed, the ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. In fact, the Upper Midwest grid and the NSP System has been designed around the current baseload units, and relies on the unique aspects of these units to not only generate capacity and energy for our customers, but also to provide numerous essential system operational services.

When analyzing the impacts of ceasing operations at one of our existing coal or nuclear units, it is important to consider these operating and technical characteristics beyond just the unit's energy output. These include:

[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

- *Power Deliverability*. The existing transmission system has been developed to be able to receive the approximately 2,400 MW of power injected from Sherco,[11] 671 MW injected from Monticello, 598 MW injected from King, and 1,150 MW injected from Prairie Island and to deliver it to various area substations to meet the electrical power demands of customers.[12] This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.

- *Dynamic Stability*. The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Unit 3 and King have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current*. Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[13] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection

[11] Nameplate capacity ratings of entire site. SMMPA owns 41% of Unit 3 (approximately 380 MW).
[12] Nameplate capacity ratings.
[13] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.

- *Black Start Capability*. In the event of a major regional grid outage, firm dispatchable generating units with a secure fuel source are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only firm dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Once Sherco Units 1 and 2 retire, the Sherco Combined Cycle (CC) will be an important part of our black start plan. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. A large battery energy storage system can be configured to be technically capable of providing black start service, likely as part of a relatively small Initial Black Start Unit. However, they may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.

- *Voltage Support*. The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. Large synchronous power sources like our current baseload units, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation*. System regulation essentially means the ability of the system to respond to changes in usage, i.e. keeping the generators and loads matched at all times. Combined cycle generating units have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are changes to the generation/load balance, as when wind speeds drop or a large industrial load comes online, the frequency drops if there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system, typically in a longer timeframe.

The National Academies of Sciences, Engineering, and Medicine observed that large-scale interconnected generating units have two significant advantages:

(1) *Reliability*. By interconnecting hundreds or thousands of large generators in a network of high-voltage transmission lines, the failure of a single generator or transmission line is usually inconsequential, and

(2) *Economics*. By being part of an interconnected grid, electric utilities can take advantage of variations in the electric load levels and differing generation costs to buy and sell electricity across the interconnect. This provides incentive to operate the transmission grid so as to maximize the amount of electric power that can be transmitted.

However, large interconnections also have the undesirable side effect that problems in one part of the grid can rapidly propagate across a wide region, resulting in the potential for large-scale blackouts such as occurred in the Eastern Interconnection on August 14, 2003. Hence there is a need to optimally plan and operate what amounts to a giant electric circuit so as to maximize the benefits while minimizing the risks.[14]

D. Planning Overview

The MISO long-term planning process, defined in Attachment FF to the MISO Tariff, is an eighteen month, overlapping process through which annual transmission expansion plans are developed and approved. This process is made up of three distinct long term planning efforts: Reliability Planning, Economic Planning and Resource Adequacy. MISO has recognized that its present planning processes require update to recognize the increasing levels of renewable resources on the grid, as well as increasing levels of energy efficiency, demand response, and distributed energy resources (DER). We discuss this further in Part III below.

1. Reliability Planning

As a NERC registered Transmission Planner, the Company works jointly with MISO and neighboring utilities to develop long term transmission plan to ensure a reliable transmission system. This is accomplished through several local and regional planning efforts, as follows:

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[14] National Academies of Sciences, Engineering, and Medicine 2016. *Analytic Research Foundations for the Next-Generation Electric Grid*. Washington, DC: The National Academies Press, page 10. https://doi.org/10.17226/21919

Biennial Transmission Projects Report. In compliance with Minn. Stat. § 216B.2425, the Company participates in the Biennial Transmission Project Report efforts with other Transmission Owners. Starting in 2001, this effort completed its ninth iteration with the 2017 report. In 2003, the Minnesota Public Utilities Commission established six transmission planning zones across the state in 2003. Those six transmission planning zones are the Northwest Zone, the Northeast Zone, the West Central Zone, the Twin Cities Zone, the Southwest Zone, and the Southeast Zone. The Biennial Report identifies the present and reasonably foreseeable transmission "inadequacies" in the transmission system that exist in each of these six transmission planning zones. With information about each inadequacy identified provided. The Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard deadlines. We summarize our most recent Biennial Report in Appendix I: Supporting Infrastructure: Transmission & Distribution.

NERC Transmission Planner Registration. To satisfy the obligations associated with the Transmission Planner registration with NERC, the Company also participates in the annual Minnesota Transmission Assessment and Compliance Team (MNTACT) to perform annual long-term transmission planning studies in accordance with federal, state and local transmission reliability standards and criteria. The Company utilizes the results of these analyses to inform the regional planning efforts undertaken by MISO.

MISO Membership and FERC Order Obligations. In accordance with the obligations of MISO membership and FERC Orders 890 and 1000, the Company also participates in regional long-term planning efforts facilitated by MISO. While these efforts replicate work already undertaken by the Company in other planning efforts, participation in MISO reliability planning process provides an open and transparent planning process that allows input and discussion amongst a wide range of stakeholder and public advocacy groups. Based on the requirements of the MISO Transmission Owners agreement, MISO approval is also required for inclusion of new transmission facilities under MISO's functional control.

2. *Economic Planning*

In addition to the long-term transmission reliability analyses, participation in the MISO planning processes also includes an annual economic-based planning analysis to identify inefficiencies in the transmission system leading to less than ideal wholesale electricity market dispatch. Starting with a stakeholder-approved set of wide-ranging future scenarios, this analysis first identifies these areas of system inefficiencies – after which, stakeholder submitted solutions are analyzed to determine if there is a cost effective solution. The Huntley–Wilmarth 345 kV Project is an example of a cost effective solution analyzed to develop the most cost-effective market possible.[15]

3. *Resource Adequacy*

The Resource Adequacy process facilitated through the MISO process is designed to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during all time frames and at just, reasonable rates. Although the responsibility for resource adequacy, MISO's process provides support in their members individual resource adequacy efforts and provide forums to increase transparency into these more localized efforts. These support efforts include calculation of the Planning Reserve Margin, which defines the level of reserve generation capacity needed to ensure an adequacy supply of energy based on probabilistic analyses. Also facilitated in this process is the Deliverables to the Planning Resource Auction, including peak forecasted demand and Import/Export limitations for the following year.

Through the participation and outcomes of the different planning processes the Company participates in, several vital pieces of the long-term planning picture are analyzed and updated on an annual basis. This enables development of the most cost effective and efficient solutions and direction in the long-term use of the transmission system at a local, regional and interconnection-wide level.

4. *Black Start*

At a high level, a Black Start Plan specifies the process we use to restore our grid to full operation without relying on the external transmission network, following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Developing such a plan involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. The longer the system is down, the harder it is to restore, so we work to determine the most efficient paths possible.[16]

The restoration is initiated under the instruction of the Transmission Operator and

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[15] *See* Docket No. E002, ET6675/CN-17-184 or www.huntleywilmarth.com)

[16] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

proceeds under the general guidance of a site specific restoration plan. Not all power generation units have, or are required to have, this Black Start capability. Black Start-capable generating units have specific configurations, additional on-site emergency generators and must be held to the highest reliability standards to ensure responsiveness in the face of an emergency.

III. THE GRID IS EVOLVING

A. The Introduction of Energy Markets

The electrical transmission system has moved from being a locally-owned and operated power system that was weakly tied to one another through high-voltage transmission lines to a regional model focused on efficiency and reliability.

Through the incorporation and membership in the regional RTOs, locally-owned transmission facilities have been turned over to the function control of regional grid operators to participate in open and effective wholesale energy markets. Through the creation and operations of the wholesale electrical markets, MISO has effectively delivered a more efficient system. Where the old power pool had reserve requirements up to and exceeding 25 percent of the utility's demand, MISO – using modern modeling and markets operations – has been able to significantly reduce spinning reserve requirements (the most costly reserve requirement) for the region. In addition to the more efficient use of existing resources, this construct has allowed for more of the older, less efficient power plants to retire while maintaining system reliability.

MISO's open access Generator Interconnection Queue allows for new generation that has requested interconnection service to be studied for inclusion into the transmission system. This process ensures that there is a fair and transparent process for all generators to have unbiased access to the regions transmission system and allows competitive participation in the wholesale energy market. MISO's Wholesale Energy Market allows for the region to have the lowest cost generation mix available at the time while maintaining system reliability through a process referred to as a Security Constrained Economic Dispatch (SCED). One key aspect of market participation enables each generator owner to bid into the market at competitive prices ensuring the lowest wholesale energy cost for the customers across the MISO footprint. We discuss the current status and challenges with the MISO interconnection queue that are creating uncertainty for planning purposes in Appendix I: Supporting Infrastructure: Transmission & Distribution.

B. Shifting Resource Types and Mix

One major benefit realized through the implementation of an open and competitive wholesale energy market is the ability for zero-emission and renewable sources of generation being allowed to compete on a fair and equitable basis with more traditional forms of generation. Due to this, renewable development has grown in the MISO region largely through expansion of wind resources to-date – with significant growth in solar expected. The current significant wind resources are primarily in southwest Minnesota and northern Iowa, but over time have also expanded to almost every part of the MISO system.

1. Rapid Increase in Renewables

In the year 2000, there were approximately 2,500 MW of wind on the transmission system across the entire United States. Today, there is over 18,000 MW of wind just in the MISO footprint – with solar power now also being added to the mix. The initial drive for renewables was created through the development of public policy initiatives that allowed for tax credits to make the renewables more cost competitive against the more traditional coal and nuclear prices and set renewable energy goals for utilities subject to those local regulations. More recently, renewable forms of generation resources have been selected purely as the most economic resources. In addition to the more competitive renewable costs, public opinion has driven the push for a more carbon-neutral set of generating resources.

Since the first wind turbines were installed, the price for wind has dropped dramatically. As manufacturing processes have improved, and supply chain efficiencies incorporated, some economies of scale were realized, driving lower costs for new wind turbines. In addition to solely reducing installation costs, improvements in the power electronics have improved the performance of the new wind turbines to help with system reliability. Solar from both small and large utility-scale resources are increasingly part of the resource mix. Public policies for new solar coupled with dropping prices and tax incentives are helping to drive the increase. Solar has the added benefit of its peak output being closely correlated with peak demand.

Energy storage is just starting to be used in utility-scale settings, with processes only just now being developed to incorporate these technologies into long-term planning efforts. There are several energy storage methods that are being studied for commercial applications, one of which is battery storage. Battery storage is already being tested and incorporated in some electric markets around the world. Battery storage offers the ability to store excess power created that cannot reach customers at the time of generation, and release that stored energy when the system demands it.

Batteries have several benefits, including the ability to store power for the purposes of helping with grid stability through power electronics and small scale power injections and withdrawals as well as shifting energy production to hours with high demand. While batteries will play a roll in our carbon reduction goals, current technologies in the early stages of commercial use, and because of this, have not yet incorporated manufacturing and supply chain efficiencies that have made wind and solar generation resources more cost competitive.

2. The Changing Generation Mix is Putting Pressure on Area Reserve Requirements

In the wake of the electrical system transforming from local power pools to regional markets that include increasing levels of non-traditional and renewable resources, there has been an increase in the rate of retirements of aging baseload generating units. Most of the generation replacing these traditional, dispatchable units are from intermittent resources such as wind and solar. Because these intermittent resources are dependent on fuel availability (wind blowing or sun shining), their replacement of retired dispatchable units is putting extra pressure on the reserve requirements for the region, since wind and solar cannot be counted on at all times. While MISO recognizes this and is studying issues related to high renewable penetrations in its RIIA study, its planning construct has not yet adapted to recognize this reality. We discuss the RIIA study below, and in Appendix J2, along with our development of a Reliability Requirement as a bridge until the MISO planning construct changes.

In addition, most of the best locations to develop cost-effective wind and solar resources are located away, and in some cases, far away from populated areas and thus load centers. This requires a robust network of large bulk electric transmission lines to bring the renewable power to the load, which means that significant transmission development will be needed to support increasing levels of renewables. However, the more transmission infrastructure between the renewable resources and the load centers, the greater the risk that those resources will be unavailable to the load centers when needed. This is because long transmission line(s) are more likely than a short line to be impacted by severe weather or some other event that along the line – making it unavailable to deliver the energy from the resource(s). This reality lowers the accreditation of the renewable resource(s) – and increases the reserve requirements for the area.

3. Growing Penetrations of Distributed Energy Resources

In addition to baseload retirements and the rapid expansion of renewable generation resources, growing reliance on DER, including DR, introduce strains to the transmission system that have not been historically encountered. While both of these resources represent important and useful tools in planning for a reliable and cost-effective power system, they have indirect and sometimes counter-intuitive impacts on the transmission system. In levels that do not produce what would be considered reverse flows, resources originating on the distribution system and flowing onto the transmission system look similar to a localized reduction in demand on the transmission system. From a high level, this should only result in a reduction in the generation required to meet the demand. However, because of low market offer prices for renewable resources in the MISO market, when this localized reduction in demand occurs, it serves to increase long distance transfers on the transmission system, causing strain on those facilities.

4. Planning Impacts of the Shifting Resource Mix

A part of the MISO planning processes is an annual analysis of reserve levels. Planning reserves are the margin by which resources exceed expected customer demand. MISO's Resource Adequacy process establishes the margin by which each utility's resources are required to exceed demand in order to cover potential uncertainty in the availability of resources or level of demand.[17]

Reserve analysis is also incorporated into the NERC Long-Term Reliability Assessment (LTRA), which is an annual report highlighting national and regional trends and potential risks over a 10-year assessment period. While it is fairly common for a planning region to drop below the reference reserve margin levels in later years of the assessment period, the 2018 LTRA report specifically calls out MISO as one of three regions that are projected to drop below their reference reserve margin levels earlier than normally encountered – specifically by the year 2023.[18]

This report indicates that inclusion of generation with high likelihood of being incorporated into the MISO system (known as Tier 2 resources in the LTRA) would likely allow for the MISO footprint to preserve system reliability.[19] That being said, there has been an unprecedented rate of baseload generation retirements announced, but that are not yet taken into account in this analysis. There is also uncertainty regarding future capacity accreditation levels for renewable resources, particularly, as

[17] 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.
[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf
[19] NERC defines Tier 2 resources as being in the interconnection queue and having a signed/approved completion of a feasibility study, signed/approved completion of a system impact study, signed/approved completion of a facilities study, requested Interconnection Service Agreement, or is included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs).

well as the potential for increased reserve requirements. This all combines to cast doubt on whether those Tier 2 resources relied upon in the LTRA alone are sufficient to provide adequate reserves to mitigate the identified risk. Further, when considering the findings from NERC's *Generator Retirement Scenario Special Study*, we believe there is an increased level of risk that baseload generation retirement requests may result in system support resource (SSR) (or something similar) designations[20] – as was the case with our Sherco Units 1 and 2 MISO Attachment Y2 study, discussed in our last Resource Plan.

C. Early Studies Did Not Fully Contemplate the Level of Change Underway

When the wind generation was first injecting energy into the system, it was in small amounts that were able to utilize the existing bulk and non-bulk AC power system. The existing AC power system was developed to deliver energy to customers from large centralized power stations usually located next to areas of the highest customer demand. As more and more renewables were added to the system the AC grid has had to morph into more a hybrid system that shifts power back and forth depending on the generation pattern for the day.

Early studies done on the system did not anticipate the impact that rapid adoption of renewables would have on the existing system. These studies also tended to underestimate the early retirement of existing resources that provide important support to the system. We discuss these early studies below.

1. Upper Midwest Transmission Development Initiative

The Upper Midwest Transmission Development Initiative (UMTDI) was developed in 2008 as a coordination effort between the States of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin tasked with accomplishing two major tasks: (1) Establish a plan that will guide and encourage the construction of interstate transmission lines to serve the upper Midwest region's commitment to cost-effective renewable generation while maintaining reliability, and (2) Develop an equitable cost-sharing methodology for new transmission facilities.

A final report from the initiative provided five high-level areas that represented barriers to development of transmission to enable renewable generation:

- *The need for certainty in regional planning for transmission.* Developers and regulators

[20] In MISO, in some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.

need to know what the rules are for transmission planning. In the absence of such certainty, development stalls and the potential for inaccurate decision-making arises.

- *The right balance between remote and local renewable generation.* There is a need to cost effectively balance highly efficient renewable energy resources far from customers with local renewable energy resources closer to population centers.
- *Large transmission projects are expensive and will impact electric rates.* Billions of dollars of transmission investment may be necessary. Minimizing these costs through sound planning is critical to ensure that projects get built cost effectively.
- *Large transmission projects can cause large land-use impacts.* Transmission projects require the acquisition of sizeable tracts of land for right-of-way easements. Such acquisitions garner strong reactions from landowners and neighbors and the public at large. While recognizing that each state has the ultimate siting authority for transmission lines
- *Cost allocation for the needed transmission is contentious.* Arguably the largest hurdle to new construction is how the costs get distributed. In the absence of an equitable formula, projects will not get built, or parties not benefiting from the projects will end up paying for them.

Due to the significant overlap between the UMTDI effort and Regional Generation Outlet Study (RGOS) and Regional Expansion Criteria and Benefit Task Force being performed by MISO at the same time, the group transitioned its efforts to focus on advocacy in those regional efforts.

2. MISO Regional Generation Outlet Study

Beginning in 2008, MISO initiated the RGOS in response to the passing of Renewable Portfolio Standards by several of the MISO member states mandating the expansion of renewable energy resources in state utility portfolios. The purpose of this study was to determine a best fit solution in the form of a transmission overlay encompassing all MISO states – premised on a distributed set of wind zones – each with varying capacity factors and distances from load.

Despite this early and comprehensive study work, the unprecedented growth of renewable generation and the earlier than expected retirement of baseload generation have resulted in impacts to the current system that have far exceeded what was projected in the RGOS analyses.

3. Regional Expansion Criteria and Benefits

Concurrently with the development of the RGOS overlays, the MISO stakeholders developed the first significant round of cost allocation principles for transmission projects. This provided a formal process for assigning cost responsibility for transmission upgrades to in a way that is roughly commensurate with beneficiaries.

4. Minnesota Renewable Energy Integration and Transmission Study

In 2013, the Minnesota Renewable Energy Integration and Transmission Study (MRITS) was initiated to build upon prior work with respect to the integration of renewable energy, specifically looking at a potential increase of the Minnesota Renewable Energy Standard (RES) to 40 percent by 2030, and higher levels beyond that timeframe. The purpose of this study was to determine the reliability impacts of increase variable generation development as well as determining associated cost impacts.

The study consisted of three core analyses:

- *Power flow analysis* was utilized to develop a conceptual transmission plan, including transmission expansion required for both interconnection of additional variable resources as well as required expansion to allow the energy from those resources to reach the wider region.
- *Dynamics analysis* was utilized to determine issues with system stability and system strength.
- *Production Cost analysis* to determine more operationally focused challenges to the integration of significant levels of variable resources.

The results of this study stated that 40 percent of Minnesota's retail electricity sales can be reliably accommodate with upgrades to the existing system at the time of the analysis.

However, while there were several important pieces of information gleaned from the MRITS study, the unprecedented expansion of variable generation that has occurred combined with the retirement of several large baseload generators that was not fully anticipated at the time of this study, has made the assumptions that went into this analysis outdated – and as such, the full results cannot be directly applied to today's transmission system.

D. MISO Processes Must Further Evolve

To accommodate the rapid expansion of renewable generation resources in the region, MISO's generation interconnection process has undergone several process improvements, but does not yet fully reflect the state of the evolving grid. As additional variable generation replaces firm dispatchable resources, issues such as weak signal strength and system instability become more likely. Current interconnection processes study only two conditions (summer/peak and shoulder); current resource adequacy processes assign fixed annual capacity values to variable resources based on their *average* contribution to the grid. These practices do not properly assess other grid conditions for potential reliability impacts – nor do they recognize the portion of time that variable resources will provide less or no energy and capacity to serve customers.

When a large batch of inverter-based generation performs outside of what is expected, models typically show that the system can survive adverse conditions. But in 2016, the Australia power system experienced storm damage that forced several transmission lines to open. The wind farms that were being relied upon on at that time were not able to survive multiple ride-through capability cycles, and started to trip offline – resulting in a large-scale power outage in southern Australia. While there are standards and practices in place in the Eastern Interconnection, MISO and Minnesota transmission systems to help avoid this same scenario, the rapid escalation of renewable resources and the earlier than expected retirement of baseload generation places a greater strain on the transmission system to deliver more remote sources of generation, and increases the likelihood of events similar to the Australia power outage occurring on the local transmission system.

MISO's early generation queue was done in order of requests. While this process allowed for concrete identification of issues caused by individual generator interconnection requests, it was a slow and tedious process of study after study, followed by restudies when the inevitable request withdrawal happened.

As the rapid development of renewables continued, MISO shifted to group studies process to help deal with the volume of requests. This greatly increased the ability of the MISO process to analyze larger sets of interconnection requests, but failed to address the issues of restudies, queue parking and withdrawals. The most recent iteration of generator interconnection process changes incorporated elements to remove the ability to suspend requests, set higher hurdles for continuation through the process and incent early withdrawals of projects that are unable to complete the interconnection process at that time. While these studies are sufficient to determine network upgrades to allow interconnection of the requested facilities, they are performed with models of the existing system *at the time* of the study, which does not include future generation retirements, unless they are formally-confirmed.

Current generator interconnection studies are based on two conditions, summer and shoulder, and determine the system improvements needed for each study group. This is to represent two of the most strenuous scenarios for the transmission system – one during peak customer demand, in which all resources are employed to meet that demand – and the other, a scenario representing lower customer demand and high renewable generation output, leading to high levels of power transfers across the transmission system. Even though these two strenuous scenarios are analyzed, there are system conditions that exist that put a large strain on the system and are not studied as part of the generation interconnection process.

For example, MISO experienced a low wind day July 29, 2018, where wind produced below the accredited levels for more than 100 consecutive hours. Another example is during the most recent polar vortex when the vast majority of wind turbines shut down due to extreme cold temperatures, and output dropped sooner than the forecast had predicted. As a result, firm dispatchable resources were needed to fill the gap left by the forecast error and lack of wind. We discuss these case study days further in conjunction with the Reliability Requirement in Appendix J2.

As the grid further evolves to include increasing levels of renewable resources, there will be an increased need to identify impacts and propose solutions that ensure reliable delivery of energy every hour of every day, rather than relying on limited snapshots. These events that limit the availability of resources below what is expected are extreme and may represent only a small portion of potential operating conditions, but maintaining a reliable system through *all conditions* will be important in the changing future.

IV. XCEL ENERGY BASELOAD GENERATING RESOURCES STUDY

Order Point No. 14(a) of the Commission's January 11, 2017 Order in Docket No. E002/RP-15-21 required Company in its next Resource Plan to study the future of its baseload generating resources, and describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island. In this section, we outline the four-pronged approach we took to conduct this analysis.

A. Overview

Aging baseload generator retirements and increasing levels of renewable generation on the grid are trends underway in the industry that are not yet fully understood. The current transmission system is developed, operated and maintained in accordance with several sets of standards and processes to ensure the safe, reliable and efficient delivery of power. Some of these include standards and recommendations from the Institute of Electrical and Electronics Engineers (IEEE), the National Electric Safety Code (NESC), the Nation Electric Code (NEC) and countless industry standards referred to as "Good Utility Practice." One of the most impactful to the development, planning and operation of the transmission system is the standards set by NERC, which through the authority of FERC, has the ability to enforce the established NERC standards under penalty of fines. NERC standards touch on everything from system modeling requirements to system operations, including both physical and cyber security standards. Embedded in these standards are local system practices and protocols from which the standards are formulated.

While these standards and protocols have worked well in the past, the changes underway on the grid are introducing new challenges. This requires additional foresight in planning processes to ensure reliable delivery of power to customers utilizing a cost-effective transmission system. Although the trend toward high penetration levels of intermittent generation has been commonplace for several years, the industry is just starting to analyze the impacts of these changes from a holistic point of view. MISO and individual utility planning and study practices will need to adapt to ensure we continue to have a resilient system and strong customer reliability.

That said, the work that we have done with this Baseload Study provides helpful insights into this complex intersection of the future grid. Further studies and an orderly plan will be key to ensuring reliability and resilience through the clean energy transition we envision for our system.

B. Approach

The NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment). However, as noted above, planning and study practices have not fully adapted to trends underway. We believe however, that our technical and economic approach combined with relevant industry insights in this Study provides helpful insights to an orderly and cost-effective retirement of our current baseload generating units.

The components of our Study are as follows:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We have incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[21] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response.

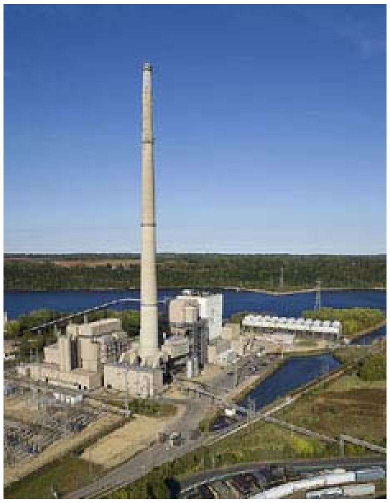
[21] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

All studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. These technical studies used the best information available at the time they were initiated. However, while the studies provide important insights, there are inherent limitations in any study effort. Technical studies simulating the removal/ absence of a generating unit(s) on the grid can only practicably analyze potential impacts with a point-in-time model in a limited set of grid conditions (i.e., peak, shoulder, etc.). Therefore, while they provide important insights for the limited number of scenarios studied, it is important to supplement the technical studies with industry insights and engineering judgement. We have attempted to offset these limitations by taking a multi-faceted approach to our Study, and note that further studies more proximate in time to the potential retirement dates will be necessary to determine actual impacts and actual mitigations.

C. Xcel Energy Baseload Resources Fleet

1. A. S. King



This plant was named in honor of Allen S. King, former president and chairman of Northern States Power Company, a predecessor to Xcel Energy. The King plant underwent a significant rehabilitation from 2004-2007 as part of Xcel Energy's Metro Emissions Reduction Project (MERP).

<u>Key Facts</u>

- *Power Production Capability:* 598 megawatts
- *Commercial Operation:* 1968
- *Generation Type:* Coal
- *Location:* Oak Park Heights, Minnesota, on the St. Croix River

In addition to generating electricity, A. S. King supplies hot water to neighboring Andersen Windows, a large window manufacturer. Located on the border of Minnesota and Wisconsin, King also provides stability to the Upper Midwest transmission grid.

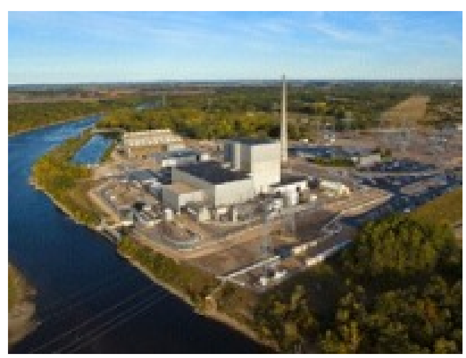
2. *Sherburne County (Sherco) Generating Station*

The Sherco plant is comprised of three generating Units with a total nameplate capacity of approximately 2,400 MW. Sherco is the largest plant in the Company's fleet in terms of square feet, steam production, and power generation capability. Units 1 and 2 are scheduled to retire in 2026 and 2023, respectively. This Resource Plan proposes to retire Unit 3 in 2030. Unit 3 is 41 percent owned by Southern Minnesota Municipal Power Agency, composed of municipal power companies operating on a cooperative basis.

<u>Key facts</u>

- Power Production Capability: 2,457 MW
    - Unit 1 – 765 MW
    - Unit 2 – 765 MW
    - Unit 3 – 927 MW
- *Commercial Operation:* Unit 1 - 1976; Unit 2- 1977; Unit 3 - 1987
- Generation Type: Steam Turbine
- *Location:* Becker, Minnesota, 45 miles northwest of the Twin Cities, on the Mississippi River

3. *Monticello Nuclear Generating Station*



The Monticello facility is among Xcel Energy's lowest-cost sources of electric generation on a per-megawatt basis and produces virtually no greenhouse gas emissions. As a base load 'always-on' plant, it runs essentially 24 hours a day, 7 days a week, except during refueling outages, which occur about every two years. Monti is a boiling water reactor plant is located on a 215-acre site 40 miles northwest of the Twin Cities. The plant generates approximately 10 percent of the electricity used by Xcel Energy's customers in the Upper Midwest.

<u>Key Facts</u>

- *Power Production Capability:* 671 Megawatts
- *Fuel Type:* Nuclear
- *Location:* Monticello, Minnesota

The plant received a 40-year operating license from the federal Nuclear Regulatory Commission in 1970, and it began commercial operation in 1971. In 2006, the NRC renewed the Monticello plant's license for 20 years, which allows operations until 2030. This Resource Plan proposes to extend the operation of the Monticello plant an additional 10 years, which will require a license extension from the NRC.

4. Prairie Island Nuclear Generating Station

The two pressurized water reactors at the Prairie Island facility generate about 20 percent of the electricity used by Xcel Energy's customers in the Upper Midwest. Prairie Island is among our lowest-cost sources of generation on a per megawatt-hour basis, and does not produce any greenhouse gas emissions. The plant runs essentially 24 hours a day, seven days per week, except during refueling outages, which occur approximately every 18 months and last about four to six weeks. The plant is about 40 miles southeast of Minneapolis-St. Paul and generates enough electricity to power about 1 million homes.

<u>Key Facts</u>

- *Power Production Capability:* 1,186 megawatts (593 MW per Unit)
- *Fuel Type:* Nuclear
- *Location:* Red Wing, Minnesota

The Unit 1 reactor began operating in December 1973 and the Unit 2 reactor in December 1974. The Nuclear Regulatory Commission first licensed the reactors for 40 years of operation and extended those licenses for an additional 20 years, until 2033 and 2034.

The Prairie Island and Monticello nuclear generating plants help Xcel Energy avoid producing hundreds of millions of tons of greenhouse gases or emissions. The plants avoid 13 million tons of carbon dioxide annually compared to fossil fuel plants, the equivalent of removing 2 million cars from the road each year.

D. Industry Studies and Outlook

We also considered industry trends and relevant studies on the effects of aging baseload units and the cumulative effects of higher renewables penetrations. Two of these studies were the MISO *Renewable Integration Impact Assessment* (RIIA) study, which is ongoing, and the December 2018 NERC *Generator Retirement Scenario Special Reliability Assessment.*

1. Industry Study – MISO Renewable Integration Impact Assessment

In 2017, MISO initiated a detailed exploration of assumptions regarding the way the electrical grid will work in the future in light the "profound" change in the types of generating resources across its operating area and the implications that such a shift means for long-standing power system design and operational practices. Under current practices, renewable resources are relied on mostly for their energy production attributes, but as they continue to replace existing assets, they will be expected to increase their contribution to grid reliability.

Given the current structure (physical infrastructure, operational practices, regulations, etc.) of the electric system in MISO and beyond, there are limitations on the maximum penetration of renewable energy. The complexity of overcoming these limitations are dependent on the types and distribution of renewable resources, the current layout of existing assets, and the actions of neighboring regions. Because the exact points of these limitations are not yet known, a framework is needed to examine renewable integration over a wide range of penetration levels, starting with the system we have today and examining penetration levels up to very high percentages of annual energy. This framework, when completed, will reflect and inform the conversations that MISO and other entities within the electricity sector have been having on the impacts of the evolving resource mix on the BES.

The study has three focus areas: (1) Resource Adequacy, or the ability to maintain the Planning Reserve Margin; (2) Energy Adequacy, or the ability to operate within generator limits such as ramp rates, min/max capacity, etc., transmission limits/ratings, and system limits such as energy balance and operating reserves; and (3) Operating Reliability, or the ability to operate the system within acceptable voltage and thermal limits and the ability to maintain stable frequency and voltage, and meet system performance requirements. The study is being conducted in phases, with each phase examining increased levels renewable penetration. Phase II was completed in Q1 2019, and examined region-wide renewable penetrations in the 40-50 percent range.

This is being accomplished by identifying "milestones" or inflection points of integration complexity, initially identified through four modules:

- *Operational Adequacy*. Simulation of the Day-Ahead (DA) and Real-Time (RT) to examine the Ancillary Services Market (ASM), including aspects such as ramping, emergency/dump energy, reserve requirements, congestion, etc..
- *Transmission Adequacy*. Analysis of the power system utilizing more traditional power system analyses. This analysis examines peak demand, shoulder demand and low demand scenarios to assess the ability of the transmission system at each milestone.
- *System Stability*. Analysis of the very short term capabilities of the transmission system to maintain system stability. This analysis utilizes scenarios similar to the Transmission Adequacy module, but focuses on the sub-second to multiple second response timeframe to determine the ability to maintain voltage and transient stability and ensure adequate system response capability is available.
- *Resource Adequacy Limitations*. Determination of the impacts to resource reserve margins and load carrying capability of intermittent resources and interdependencies between resource types.

These modules are being applied through three Phases that study these impacts at increasing levels of renewable resources.

a. Key Takeaways To-Date

One of MISO's key conclusions to-date is that integration complexity increases dramatically between 30 percent and 40 percent. At a 40 percent MISO-wide renewables penetration level, curtailments are encountered during almost all non-summer days, reaching nearly 7,000 GWh of curtailments in the worst month of the base case at this level. Other interim conclusions relevant to our study of an orderly cost-effective transition of our baseload units thus far include:

- Renewable integration complexity increases sharply from 30 percent to 40 percent penetration. Currently synchronous baseload units provide necessary services to the grid that mitigate the impacts of the inherent variability of renewable generation.
- As wind and solar penetration increases, its contribution to peak load conditions reduces because the risk of losing load compresses into a smaller number of hours and shifts to later in the day (from 3:00 p.m. to 6:00 p.m). As a result, the available energy from wind and solar during high risk hours

decreases, and the marginal contribution of renewables reaches a plateau. We discuss this further in Part IV.D below, and in conjunction with the Reliability Requirement we developed for this Resource Plan, discussed in Appendix J2. This issue is both a current and future risk to system resilience and reliability that is not currently addressed in the MISO planning construct.

- As renewable penetration grows, renewable curtailment becomes increasingly significant; enhanced transmission reduces curtailment. With increased levels of renewables inevitable to achieve significant carbon reductions, substantial transmission development will be necessary.
- As renewable penetration increases, the number of thermal units online increases during off-peak hours despite a decrease in average output – and fewer thermal units are operating at their minimum stable level.
- Thermal overloads and voltage violations increase as penetration levels increase, with solution complexity (cost of the transmission fixes) also increasing with penetration level. North Dakota and parts of Minnesota start to show severe thermal and short circuit issues due to vast amount of wind resources sited in those locations and relatively limited transmission capacity.
- Diversity of technologies and geography improves the ability of renewables to meet load.
- Overall, the 40 percent scenario increased the instances of dynamic stability issues, operational stressors, and resource adequacy requirement increases.

In observing that the level of renewable resources in the MISO footprint is growing at a rate of about 1.5 GW per year since being nearly non-existent in 2005, MISO acknowledged challenges along the way – and is taking action to evaluate the impacts of renewable resources growing to even higher levels over the long-term. As described by MISO, its RIIA assessment will give MISO and its stakeholders specific areas around which to focus effort and help inform the sequencing of actions required to manage certain renewable penetration levels. The assessment will illustrate specific areas of system weakness, show when those weaknesses could become problematic and identify potential means to address them – and will seek to facilitate a broader conversation about renewable integration impacts on the reliability of the electric system.[22] The study is now continuing on to Phase III.

[22] *See* https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd=

2. *Industry Study – NERC Special Reliability Assessment – Generation Retirement Scenario*

Below we summarize a recent special report from NERC that implies there may be potential for delay or cancellation of announced retirements due to insufficient system support services provided by synchronous generation being available in some regions.

NERC published a Generation Retirement Scenario Special Reliability Assessment December 18, 2018 as part of its ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American BES. In initiating this special assessment NERC observed that the BES is undergoing a significant transformation, marked by growth in new natural gas, wind, and solar resources replacing retiring fossil-fired and nuclear generating resources. The drivers underlying this shift that NERC cited include federal and state policies, continued low natural gas prices, wholesale market forces, customer preference, and low and improving technology costs.

NERC also observed that managing generator retirements and the transition to replacement resources is a complex process. The report characterizes the changes currently underway with the generation resource mix as "revolutionary," and observes that the changes alter the operating characteristics and constraints of the BES. The report stresses that these changing characteristics must be well understood and incorporated into planning to assure continued reliability.[23]

NERC's key conclusion is that the generator retirements that are occurring disproportionately affect large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur. Resource planners at all levels should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service. Ensuring reliability throughout a significant retirement transition will likely include construction of new transmission and fuel infrastructure

This NERC study underscores the importance of taking a measured approach to baseload unit retirement that includes thorough examination of potential reliability implications. This also supports our belief that appropriate analysis may require supplemental study beyond the studies prescribed in present protocols.

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[23] Executive Summary, NERC Special Reliability Assessment: Generation Retirement Scenario (December 18, 2018).

As part of its oversight and governance activities, NERC also conducts an annual reserve margin analysis across all system operators in North America in a report called the LTRA, discussed earlier in this Study. The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[24] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

E. MISO Retirement Studies

The current process for retirement of generation resources in the MISO footprint is generally governed by Attachment Y to the MISO Tariff. Preliminary retirement studies fall under Attachment Y2, which is a confidential MISO analysis to determine if any adverse system impacts would occur as a result of potential generating resource retirement – without/prior to committing to retire or suspend the resource. If adverse impacts are identified, they provide an indication of the mitigations that would need to occur prior to actual unit retirement. As we discuss below, we submitted requests for several Attachment Y2 studies as part of this Baseload Study.

Final determination of adverse impacts however, occurs with an Attachment Y notice – or new provisions under Attachment X of the MISO Tariff, if the notice of retirement includes replacement generation. In May 2019, FERC approved changes to the Attachment X Tariff that allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[25] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. The resulting studies under this provision of Attachment X, the generation replacement is considered as part of MISO's analysis of potential adverse impacts. We discuss Attachment X and its importance in achieving the fleet transformation we

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[24] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[25] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) Is located at the same point of interconnection as the retiring resource, (2) Is less than or equal to the generating capacity of the retiring resource, (3) Does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

envision in Appendix I: Supporting Infrastructure: Transmission & Distribution provide with this Resource Plan.

1. Preliminary Retirement Studies of NSP System Baseload Units

Attachment Y2 studies assess current, point-in-time system impacts in the absence of the identified generating resource(s). The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, The studies assess transmission system performance to identify any violations of planning criteria due to the unavailability of the generation resource. The relevant MISO Transmission Owner and/or regional reliability criteria are used for monitoring such violations. The Attachment Y2 studies are not intended to determine long-term system reliability impacts, which is why we supplemented them with other reliability studies to provide further insights into impacts from potential retirement scenarios. It is important to note that the assumptions used in the MISO Y2 studies are based on expected conditions at the time they were initiated in 2018, plus the addition of certain pending and proposed generating units, including the Sherco CC and our approved and in-progress wind projects.[26]

For purposes of this Baseload Study, we submitted seven Attachment Y2 study requests with MISO – all of which use a retirement date of May 31, 2027, on models developed to depict 2030 system conditions as follows:

Y2 Baseload Unit(s) Retirement Scenarios
Sherco Unit 3
Allen S. King (King)
Prairie Island (PI)
Monticello (Monti)
All Nuclear (Monti and PI)
All Coal (Sherco 3 and King)
All Coal and All Nuclear

2. Y2 Study Results

Generally, the studies found that reconductoring (or line rebuilds) and transformer replacement would be needed to achieve adequate performance for all the scenarios analyzed. In addition, the observed voltage violations would require installation of

[26] MTEP17 (built for the 2017 MISO planning cycle) model series 2027 scenarios that were scaled to represent 2030 load levels. The model also included the following pending and proposed generating units: Crowned Ridge 1 Wind, Crowned Ridge 2 Wind, Crowned Ridge 3 Wind, Blazing Star 1 Wind, Blazing Star 2 Wind, Sherco CC.

extensive reactive devices throughout the region due to the loss of dynamic reactive support from the large amount of retiring resources.

The studies also found that if Xcel Energy were to retire all of its remaining baseload units about the same time, which would be the majority of the large power producing units in the Upper Midwest, it would put a substantial strain on the BES to import power from the rest of MISO. It would also substantially impact MISO's ability to balance out the system to allow for the needed high renewable transfers to other parts of MISO. The Y2 study that examined the combined retirement of the Monticello Unit 1, Prairie Island Units 1 & 2, King Unit 1 and Sherco Unit 3 at the same time stated the following:

> The combined retirement…causes extensive thermal overloads and numerous voltage issues that would require substantial reinforcements to fully address the issues and permit retirement. It is unlikely that the large number of upgrades needed to alleviate thermal overloading and voltage issues would be completed before the planned retirement date resulting in the need for one or more generators to be retained as System Support Resources.

MISO currently is able to use the large Xcel Energy baseload generating units to help balance out the system and provide significant amounts of system response – allowing for high renewable transfers to other parts of MISO. On low wind days, the large generating units are also needed to replace the lost energy from the renewable sources to reliably serve customers' needs. An orderly retirement schedule with sufficient lead times is necessary to ensure reliability mitigations and adequate support of renewables integration and transfers, including generator replacements and transmission development.

Incremental retirements identified more manageable impacts. In the case of a King-only or Sherco 3-only retirement, neither resulted in thermal or voltage degradation such that the Unit would be designated as a SSR.[27] However, the All Coal/King and Sherco 3 combined study found the need for an estimated $38.2 million to address several thermal overloads. The Monticello Y2 study showed some thermal overloads that could be addressed with system readjustment. Some voltage issues would additionally need to be addressed before it could retire. The retirement of Prairie Island would require some voltage mitigation, but there were no thermal overload

[27] In some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available. Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

issues. Retirement of all nuclear units would result in some thermal and voltage issues that would need mitigation before they could be retired.

As noted above, the All-Coal and All-Nuclear Retirement scenario resulted in major thermal and voltage violations. This scenario would require significant system upgrades to eliminate all of the thermal and voltage issues; the MISO planning level estimates for all transmission facilities improvements to address the steady state thermal and voltage issues was estimated to be $299.3 million. As transmission development, permitting and construction processes generally involve rather long timeframes of 5-7 years on the low end and as much as 15-20 years in some cases, we expect that addressing all of the system violations would involve an extensive effort over a relatively long timeframe to be complete.

That said, the MISO system is dynamic and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured. These results are indicative of issues requiring mitigation at the time of these studies. A more comprehensive analysis will be necessary in conjunction with a notice under Attachment Y or Attachment X in closer proximity to the planned retirements to determine final adverse impacts and to develop mitigation options.

The Y2 Studies identified planning level costs, which are estimates provided only as an indication of the upgrades needed to mitigate issues caused by the retirement(s) and are based on assumptions that include new proposed generation resources without any of the associated network upgrades.[28] The Y2 reports clarify that further analysis is required in a subsequent retirement study to fully consider only those interconnected resources with executed interconnection agreements in order to more accurately determine costs of the mitigation upgrades.

For purposes of this Baseload Study, we incorporated the MISO planning level estimated costs from the Y2 studies into our economic modeling of the baseload retirement scenarios. We outline our Strategist analysis in Part G below, and discuss it in more detail in Chapter 4: Preferred Plan, Chapter 5: Economic Modeling Framework, and Appendix F2: Strategist Modeling Assumptions & Inputs.

[28] Costs specified in the Attachment Y2 studies are based on the "MISO Transmission and Substation Cost Estimation Guide for MTEP" except where costs were established for previously identified upgrades and are subject to change.

F. Xcel Energy Transmission Reliability Studies

As discussed above, the MISO Y2 study process focuses on maintaining transmission system elements within their thermal and voltage limits.[29] While this provides a thorough analysis of the impacts of the retiring generation resource in those two areas, it does not adequately capture the impacts that resource(s) has on the stability of the power system, which requires a more focused area of study around the retiring resource.

Historically, limiting the study to voltage and thermal assessments was sufficient. This was because individual generating unit changes had limited impact on overall system reliability because there were excess capabilities from the remaining generation fleet to replace/adequately perform the necessary stability services. However, as the system moves further away from large synchronous generating facilities, system stability and response becomes a significantly greater risk for generation retirement than voltage violations or thermal constraints. Therefore, a more robust study that includes consideration of other grid impacts is necessary to ensure system reliability and resilience. The complementary studies we undertook studied other grid impacts of various generation retirement scenarios using a more traditional NERC reliability assessment approach.

Combined with the Y2 results, these studies provide a more robust analysis of the potential retirement of our remaining baseload units. The results from our analysis indicate the following:

- There will be several thermal and voltage violations that will need to be addressed to remain NERC compliant.
- The location of resources plays a large part in the ability of the system to respond to faults. In the absence of large synchronous resources replacing retiring units in place, significant transmission infrastructure development will be necessary. See Figures 2 and 3 (Stability Plots) below.
- While a zero baseload future may be able meet certain aspects of a reliable power system, current technologies cannot maintain system stability, adequately recover from contingencies, nor can they ensure reliable service to customers every hour of every day without the assistance of a sufficient level of synchronous generation.

Final system impacts will depend on the scenario, the specific Unit retirement(s), and

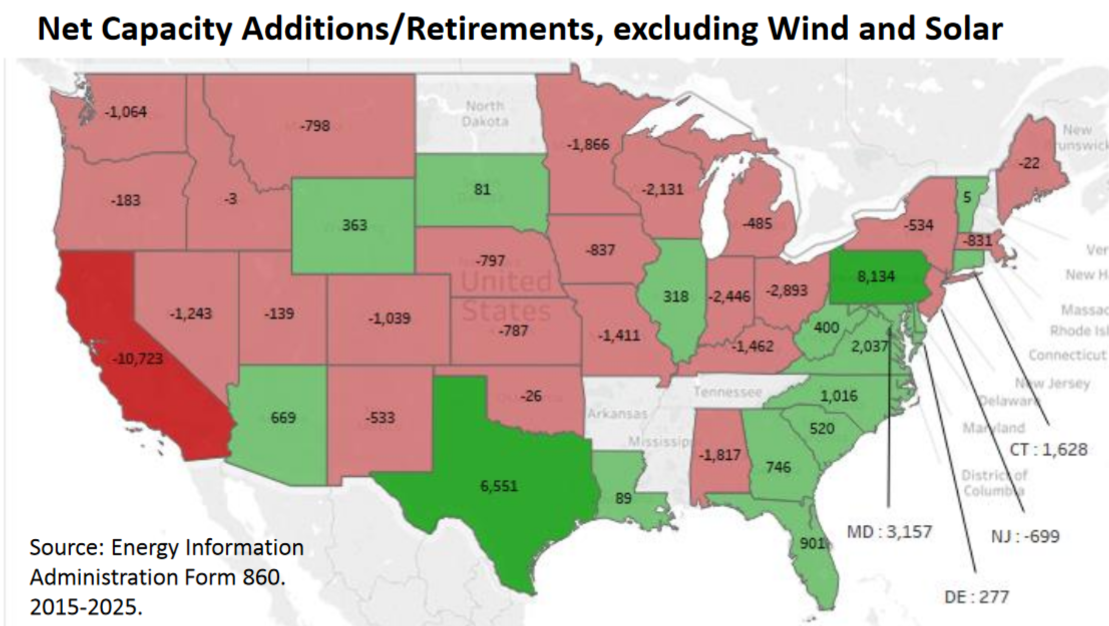
[29] MISO will perform limited stability analysis upon request.

what, if anything, will replace the Unit(s).

1. Approach

We undertook these studies at a point in time in the industry when there are more large generating units retiring than being added to the grid. As shown below, the capacity availability in the MISO states is projected to fall by nearly 8,700 MW by 2025 from 2015 totals.

Figure 1: Net Capacity Additions, Excluding Wind and Solar



With the trend of declining levels of large synchronous generating units being largely replaced with renewable and intermittent resources in mind, we undertook two study efforts to determine the impact of baseload retirements on the Upper Midwest grid:

- **Metro Stability Study** – analyzed the capability of the Twin Cities metro area to remain stable utilizing a scenario in which large scale baseload retirements took place both on the NSP System, as well as neighboring systems.
- **NSP Resource Contribution to System Stability** – analyzed the stability of the Upper Midwest grid when only the NSP System reduced its baseload generating resources.

These technical studies simulate a number of varied conditions that consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might fail to maintain a stable power signal, assuming specific circumstances. Study 1 focused on regional (neighboring utilities') changes to determine local (Twin Cities Metro) impacts. Study 2 was to determine the regional impact of NSP System changes.

2. *Study 1: Metro Stability Study*

The goal of this study was to determine the minimum amount of system services required to maintain a stable major demand center, which in this case was the Twin Cities Metro area, with major changes to the surrounding system. The results indicate that while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies on the system today cannot maintain system stability without the assistance of a sufficient level of synchronous generation.

a. Study Assumptions and Approach

For the purposes of this Study, we utilized three natural gas generators located at strong points on the system to determine the *minimum amount* of system services necessary to maintain a stable major demand center with major changes to the surrounding system.[30] We performed the stability assessment using the 2018 MTEP dynamic model, representing light load with 90 percent wind output conditions in the year 2023. We assumed no load growth between 2023 and 2030 to limit the number of variables potentially affecting the results.

Consistent with the industry trends and our clean energy vision, we expect substantial additions of renewable energy to be added to the system as we transition the our generating fleet. For purposes of this Study, we assumed the addition of 5,800 MW of nameplate renewable generation dispatched at 4,440 MW to depict a higher reliance on renewable energy resources – and which would replace the assumed retirements. We show the renewable additions in Table 2 below.

[30] This does not take into account maintenance, forced outages, or economic factors into the ability of those services to be provided in all hours by the three units utilized in the analysis, which can increase the total number of units required to provide sufficient levels of service in all hours.

Table 2: Stability Study – Renewable Generation Additions Modeled

				Number of Megawatts	
Location	**State**	**Fuel**	**kV**	**Nameplate**	**Dispatched (Pgen)**
Alexandria	MN	Solar	345	100	60
Quarry	MN	Solar	345	100	60
Chub Lake	MN	Solar	345	100	60
Prairie Island	MN	Solar	345	200	120
North Rochester	MN	Solar	345	150	90
Byron	MN	Solar	345	150	90
Pleasant Valley	MN	Solar	345	150	90
Sheas lake	MN	Solar	345	100	60
Wilmarth	MN	Solar	345	100	60
Adams	MN	Solar	345	100	60
Cedar Mountain	MN	Solar	345	150	90
Big Stone	MN	Solar	345	150	90
Hazel Creek	MN	Solar	345	150	90
Lyon County	MN	Solar	345	150	90
Nobles	MN	Solar	345	150	90
Split Rock	MN	Solar	345	150	90
Owatonna	MN	Solar	161	100	60
Fort Ridgley	MN	Solar	115	100	60
Chanarambie	MN	Solar	115	100	60
Brookings	SD	Solar	345	150	90
Lyon County	MN	Wind	345	350	315
Hazel Creek	MN	Wind	345	250	225
Nobles	MN	Wind	345	250	225
Split Rock	MN	Wind	345	250	225
Lakefield	MN	Wind	345	200	180
Cedar Mountain	MN	Wind	345	250	225
Pleasant Valley	MN	Wind	345	250	225
Mchenry	ND	Wind	230	200	180
Ellendale	ND	Wind	345	200	180
Bison	ND	Wind	345	300	270
Big Stone	SD	Wind	345	400	360
Brookings	SD	Wind	345	300	270
Total				5,800	4,440

Table 3 below shows the resource retirements we applied in this analysis, which are intended to reflect a regional trend of baseload unit retirements in the Upper Midwest. These are not intended to represent actual Unit retirement plans; these are only assumptions utilized to develop a model representing the intended scenario.

Table 3: Generation Turned Off In Analysis

Bus Name	Pgen (MW) in MTEP Model	New Pgen (MW)
[PR IS31G 20.000]	553	0
[PR IS32G 20.000]	552	0
[MNTCE31G 22.000]	592.9	0
[FEP CT G 18.000]	63.4	0
[FEP ST G 13.800]	50	0
[ARNOLD1G 22.000]	651	0
[OTTUMW1G 24.000]	457.3	0
[COL G1 22.000]	585	0
[COL G2 22.000]	585	0
[WES G4 19.000]	600	0

b. Study Methodology and Results

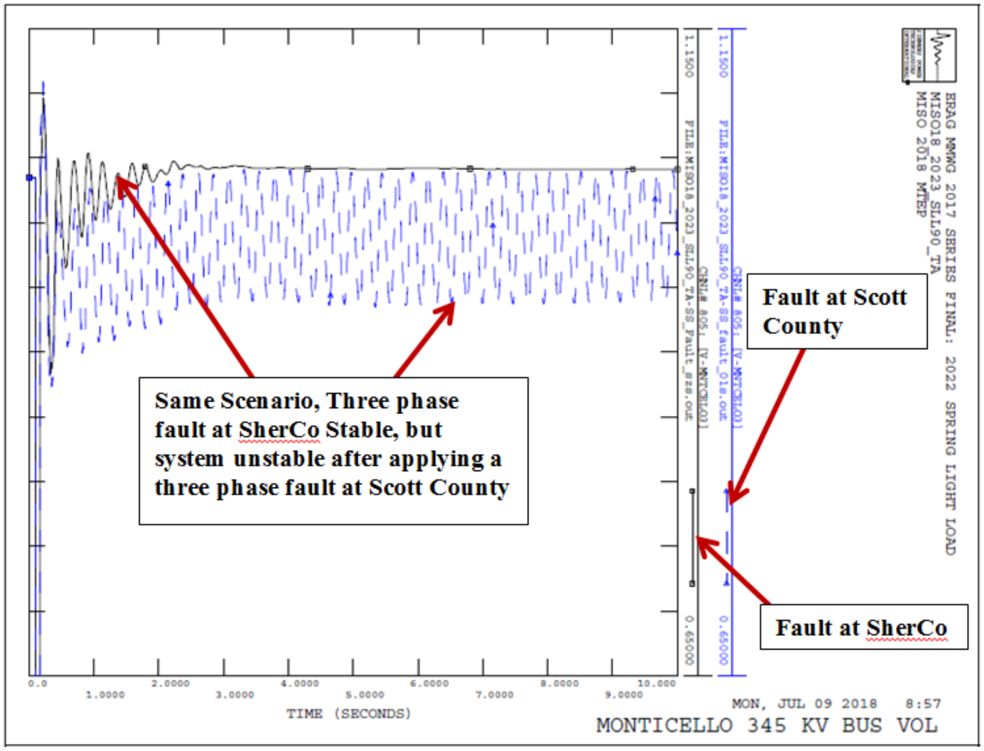
We then introduced faults on the system to assess the ability of the grid to recover and return to a normal state. We outline the fault events that we analyzed in Table 4.

Table 4: Major Faults Analyzed

Fault Name	Fault Description	Result
Fault_01s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Scott County	Unstable
Fault_02s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Helena	Unstable
Fault_03s	Loss both Cedar Mountain – Helena circuit with normal clearing	Unstable
Fault_szs	Normal close in 3 phase fault on SherCo - Coon Creek 345 kV line near SherCo	Stable

Figure 2 illustrates the importance of location and siting on system stability. This scenario is demonstrating the effect of a single fault on the system. The black line represents a fault near our Sherco facility, which in this scenario has our future Sherco CC online; the system recovers rather quickly. The blue line represents a similar fault at Scott County, where there is no nearby generating resource – and the system becomes unstable.

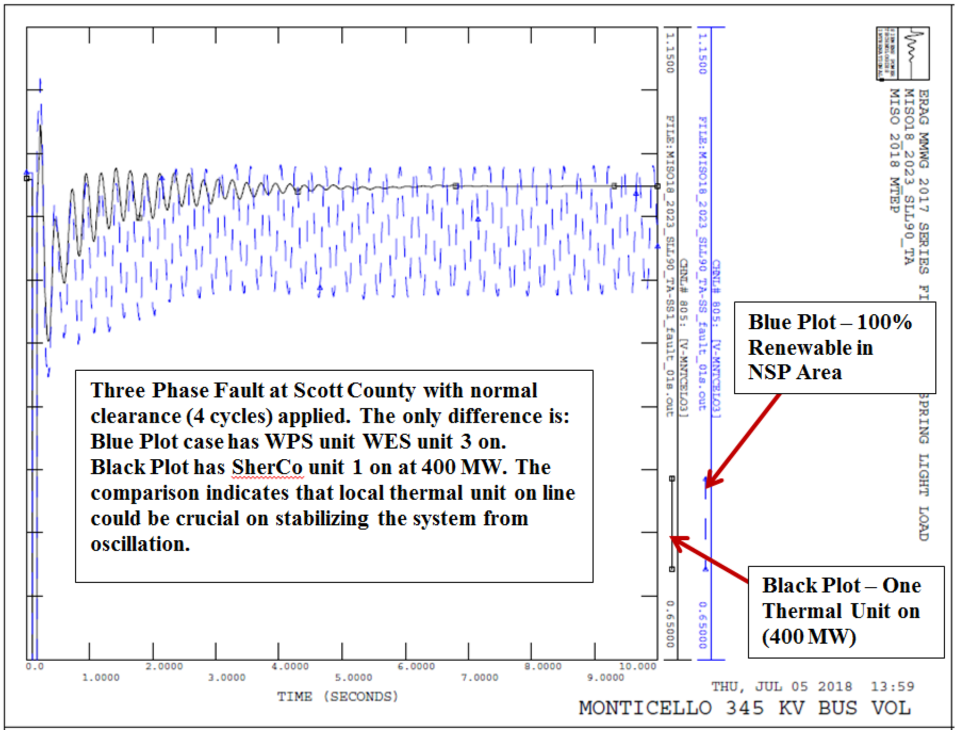
Figure 2: Stability Plot – Importance of Resource Siting on Stability



The results of this scenario demonstrate that the system remains stable when a fault occurs on a part of the transmission system where sufficient system stability services – in this case, a large synchronous generator – are available nearby. Whereas, experiencing a fault at a location with distant synchronous resources connected through long transmission lines to demand centers greatly increases the risk of system instability.

Similar to how system stability differs based on the location of the fault in relation to a system stability resource, the location of synchronous resources plays a large part in the ability of the system to respond to faults. As shown in the stability plot in Figure 3 below, the system response to a fault at Scott County is unstable when relying on energy imports from non-NSP System resources. When we moved a same-sized resource to a location nearer to the Twin Cities Metro area, the system regains stability with little issue after experiencing the same fault.

Figure 3: Stability Plot – Importance of Resource Siting on System Response



As the transition to increased reliance on renewable resources continues, replacement of synchronous resources at current resource locations or substantial transmission infrastructure development will be fundamentally essential to the reliable delivery of energy.

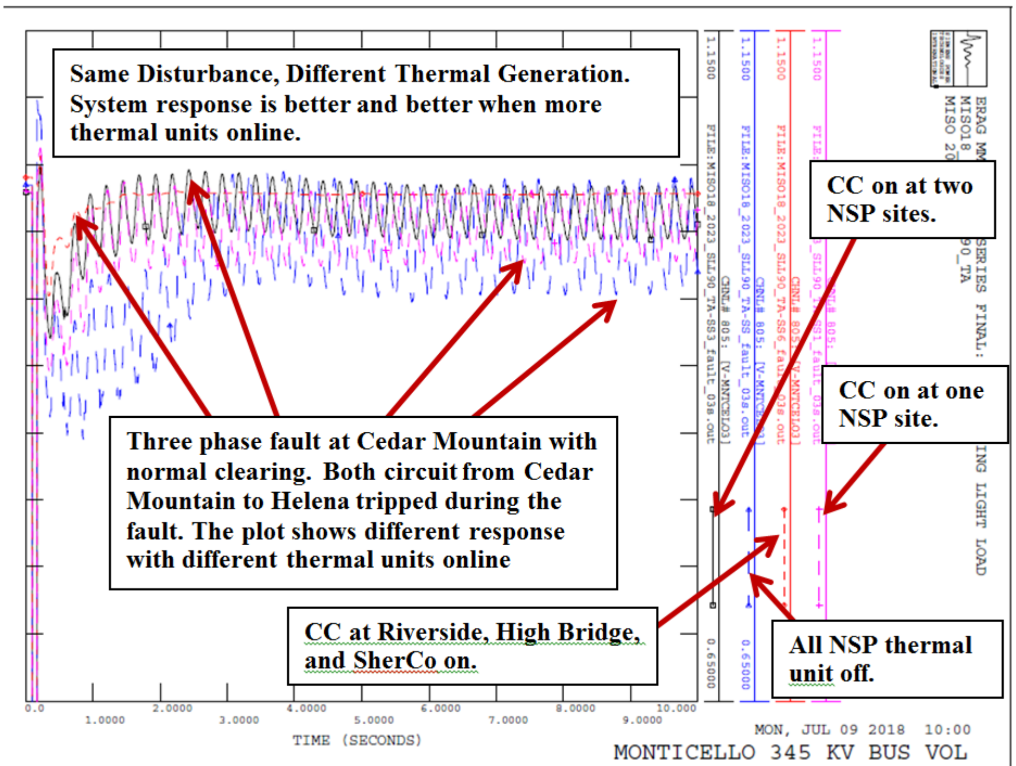
c. Step-by-Step Re-Aaddition of Gas Units in Metro to Regain System Stability

Moving away from the specific locational aspects of faults and resources, we analyzed a wider range of events of differing severities to determine what is needed to maintain system stability with high reliance on renewable resources.

To determine the level of stability services needed, we stepped through turning generating units retired in earlier scenarios back on to analyze the impacts under severe conditions. In this scenario, we turned-off all of the Upper Midwest synchronous generating units, and a major transmission path for renewable generation to get to the Metro area.

As shown in the results of this analysis below, while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies on the grid today cannot maintain system stability without the assistance of a sufficient level of synchronous generation. An equivalent level of system services as provided in the model by Riverside, High Bridge, and the Sherco CC are all required to be operating at all times to ensure the system remains stable and can sufficiently recover from contingencies on the transmission system.

Figure 4: Incremental Steps to Result in 3-Unit Metro Equivalent Services



Every generation resource on the system can have significant impacts on the stability of the system, which may differ based on the order in which they are retired or replaced. This study demonstrates that it is vital to perform a system stability analysis, and resolve any issues, for each potential unit retirement proximate to the planned retirement, so the analysis as closely as possible mirrors expected actual conditions at the time of unit retirement.

3. Study 2: NSP Resource Contribution to System Stability

The second study also analyzed the stability of the grid in the Upper Midwest – however when only the NSP System reduced its baseload generating resources. In this analysis, we analyzed the effects of local/NSP System baseload reductions on a regional basis. Our objective with this Study was to determine the importance of retaining sufficient system services in high demand areas (such as the Twin Cities Metro area) in order to understand the role that current NSP System baseload generating resources have on the stability of the Upper Midwest BES and the ability of non-metro locations to remain stable in low Metro-area baseload scenarios.

The results of this analysis found that the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios and system instability in light load scenarios.

a. Study Assumptions and Scenarios

We analyzed light load, summer shoulder, and summer peak scenarios for the year 2023 in this study. Renewables in the NSP System are modeled at an 80 percent level in all three models, while the existing natural gas CCs are turned-on to represent 20 percent firm dispatchable generation in each model. We outline the dispatch assumptions we made in the three different load scenarios in Table 5 below.

Table 5: Dispatch Assumptions

Year	Season	Load Level	20% Thermal
2023	Light Load	5,150 MW	1,030 MW
2023	Summer Shoulder	7,195 MW	1,440 MW
2023	Summer Peak	10,250 MW	2,050 MW

As with Study 1, we applied baseload unit retirements in this analysis that are not intended to represent actual retirement plans. Rather, the assumptions in Table 6 below were only used to develop a model representing the intended scenario.

Table 6: Generation Turned-Off in Analysis

	Year 2023		
Baseload Generator	Summer Light Load	Summer Shoulder	Summer Peak
Sherco #1	Offline	478.3 MW	730 MW
Sherco #2	Offline	427.2 MW	730 MW
Sherco #3	Offline	608 MW	925 MW
King	Offline	560 MW	560 MW
Monticello	593 MW	637 MW	637 MW
Prairie Island 1	553 MW	553 MW	553 MW
Prairie Island 2	552 MW	552 MW	552 MW

Table 7 below outlines the resources we used to replace energy supply in the absence of the assumed retirements above.

Table 7: Additional Generation Assumptions

			2023		
Bus Number	Bus Name	Unit	Summer Light Load	Summer Shoulder	Summer Peak
600007	RIVRS77G 16.000	7	160 MW	160 MW	Online
600070	RIVRSIDEG9 718.000	9	158 MW	158 MW	Online
600071	RIVRSIDG10 718.000	10	158 MW	158 MW	Online
600065	HBR C71G 18.000	7	162 MW	162 MW	Online
600066	HBR C72G 18.000	8	162 MW	162 MW	Online
600067	HBR S73G 13.800	9	226 MW	226 MW	Online
600012	BLK D72G 13.800	2	N/A	115 MW	Online
600164	J399 BLK D7618.000	6	N/A	214 MW	Online
600047	G261 MEC-CT115.000	1	N/A	N/A	Online
600172	G261 MEC CT215.000	1	N/A	N/A	Online
600046	G261 MEC-ST 19.500	1	N/A	N/A	Online

In this Study, we compare the transmission line outages to a Base scenario that has no outages, as follows:

- Base: No Outages
- Outage #1 (PO1): Sheas Lake – Helena 345 kV line
- Outage #2 (PO2): Scott County – Helena 345 kV line
- Outage #3 (PO3): Chub Lake – Helena 345 kV line

Finally, Table 8 below outlines the various faults that we analyzed for each of the above Outage Scenarios.

Table 8: Faults Analyzed

Name	Description
Fault_PI	5 Cycle 3 PH fault at PI
Chisago-345	5 Cycle Three phase fault at Chisago
Fault_eks	5 Cycle Three phase fault at King
Fault_odell	5 Cycle Three phase fault at CRANDAL
Fault_01s	5 Cycle Three phase fault at SherCo
Fault_05s	5 Cycle Three phase fault at Helena on Helena - Sheas Lake line
Fault_04s	4 Cycle Three phase fault at Chisago 500 kV
Monti-slf2	SLGF at Monticello
Monti-3ph2	5 Cycle Three phase fault at Monticello
Fault_pys	SLGF at PI
fault_02s	5 Cycle Three phase fault at Helena on Helena - Scott County line
Fault_03s	5 Cycle Three phase fault at Helena with common structure out
Fault_mcs	SLGBF fault at Sherco on Coon Creek #3 line with 8M40 Stuck
Fault_mts	SLGBF fault at Monticello with 8N6 stuck
Fault_pcs	SLG fault at King-Eau Claire line with a breaker failure at king
Fault_n03s	12 Cycle SLG fault at Red Rock 345 kv bus with failure of 8P24
Fault_mw3s	3 phase fault at Wilmarth on Wilmarth - Sheas Lake 345 kV line
Fault_mqs	SLGBF fault at Sherco on Unit #3
Fault_mjs	SLGBF fault at CHISAGO
Fault_m6s	5 Cycle 3 PH fault at Parkers Lake 345 kV
Fault_m5s	10 Cycle 3 PH fault at Coon Creek 345 kV bus with failure of 8M40
Fault_m4s	10 Cycle 3 PH fault at Terminal
3P_Terminal_TR9_B3s	3 phase fault at Terminal 345 kV bus, normal clearing
3P_Adams_Mitch	Three phase fault at Adams
3P_Briggs_NorthMad	Three phase fault at Briggs Road
3P_Brookings_Hawks	Three phase fault at Brookings County
3P_ChubFault_OpentoHelena	Three phase fault at Chub lake on Chub Lake - Helena line
3P_HelenaFault_OpentoChub	Three phase fault at Helena on Chub Lake - Helena line
3P_Lakefield_Huntly	Three phase fault on Lakefield JCt - Huntley line
3P_Lakefield_LakeJct	Three phase fault on Lakefield JCt - Lakefield line
3P_Lakefield_Obrien	Three phase fault on Lakefield JCt - Obrien line
3P_Sioux_SplitRock	Three phase fault on Sioux - Split Rock line
3P_Split_Nobles	Three phase fault on Split Rock - Nobles County line
SLG_Alexandria_BKR3325	SLG fault at Alexandria with breaker 3325 stuck
SLG_Hawksnest_8N82_Stuck	SLG fault at Hawksnest with breaker 8N82 stuck
SLG_Lakefield	SLG fault at Lakefield with breaker stuck
SLG_Wilmarth_8S23_Stuck	SLG fault at Wilmarth with breaker 8S23 stuck

b. Study 2 Results

In general, the lack of system margin from the significant absence of synchronous generation results in the inability of the system to recover from system events.

This lack of margin is also evident when analyzing the loss of a major transmission source to the Twin Cities Metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System baseload generation resources available as they are today. In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor/highest concentration locations, such as southwestern Minnesota, results in a less resilient system. In these scenarios, utilizing the current transmission system creates a single point of failure that can result in an inability to operate the system. This further demonstrates that it is likely that significant transmission development will be necessary as current baseload generating resources retire and renewable resources take an increasingly large role on the Upper Midwest grid.

Table 9 below shows the results for the scenarios (Base, PO1, PO2, PO3) for each of the outage events – with the yellow highlights being thermal overloads. We note that in Summer Peak conditions for PO1 and PO2, the model could not converge toa solution, meaning significant upgrades would be required if only to create a stable enough system and enable the analysis of other system impacts.

Table 9: Thermal Overload Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena – Scott County 345 kV	1078 MW	678 MW	N/A	1602 MW 118%*	1545.2 MW 118%*	1158.5 MW	N/A	2232.5 MW 173%	1737.3 MW 138%	No Solution	No Solution	2323 MW 188%
Helena – Chub Lake 345 kV	720 MW	394 MW	1391 MW	N/A	1001 MW	695.2 MW	1931 MW 117%	N/A	868.5 MW			N/A
Sheas Lake – Helena 345 kV	1040 MW	N/A	809 MW	905.4 MW	1125.3 MW	N/A	780.4 MW	930 MW	1721.8 MW 137%			1544.5 MW 125%

*The line rating is calculated based on the bus voltage

Similar to the thermal overloads above, Table 10 outlines the voltage violations in the same grid conditions, scenarios, and outage conditions. In this case, the violations occur only in summer peak conditions. However, again, there are two cases where the model was unable to solve the violation.

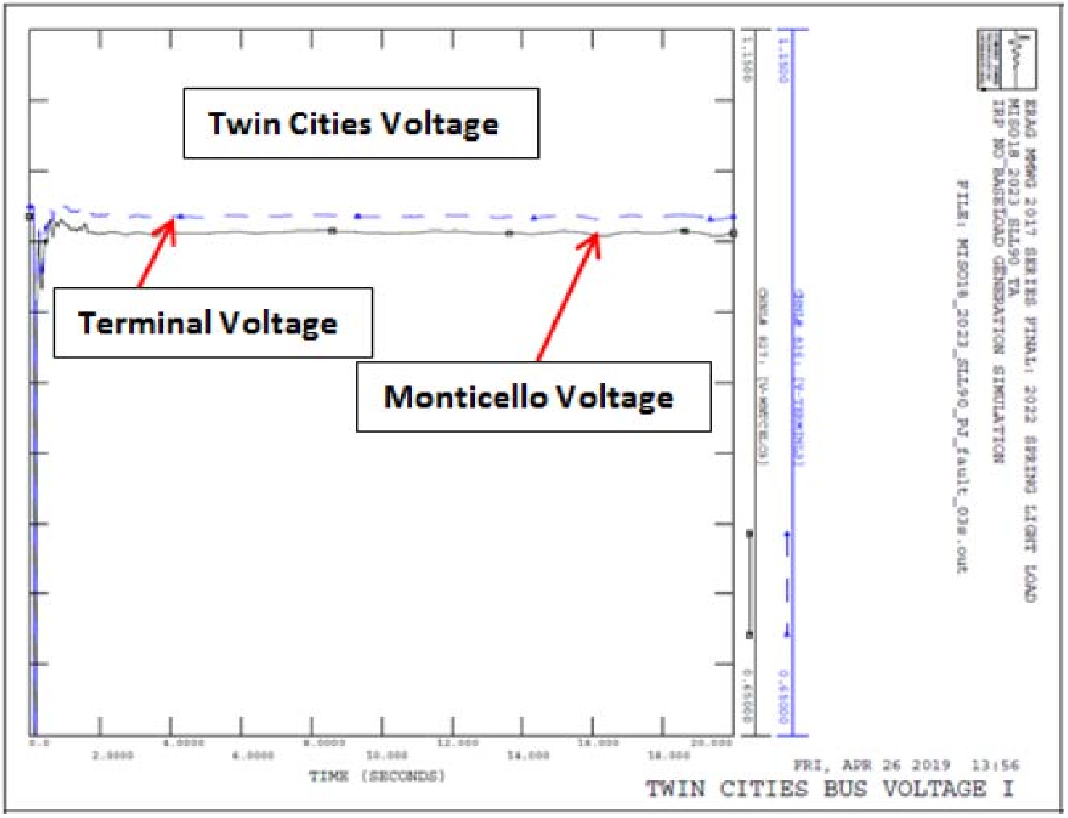
Table 10: Voltage Violation Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena 345 kV	1.006	1.011	0.987	0.990	0.954	0.954	0.920	0.938	0.921	No Solution	No Solution	0.896
Sheas Lake 345 kV	1.001	1.006	0.986	0.988	0.951	0.978	0.924	0.938	0.917			0.898
Scott County 345 kV	1.015	1.017	1.016	0.999	0.968	0.972	0.975	0.948	0.940			0.910

As a result of increased reliance on renewable resources sited in locations to take advantage of higher capacity factors, the transmission system between those high capacity factor/concentration areas and areas of high energy usage become overly stressed, resulting in violations of facility ratings. As is the case in the summer peak scenarios, insufficient margin is available to come to a solution during higher demand scenarios.

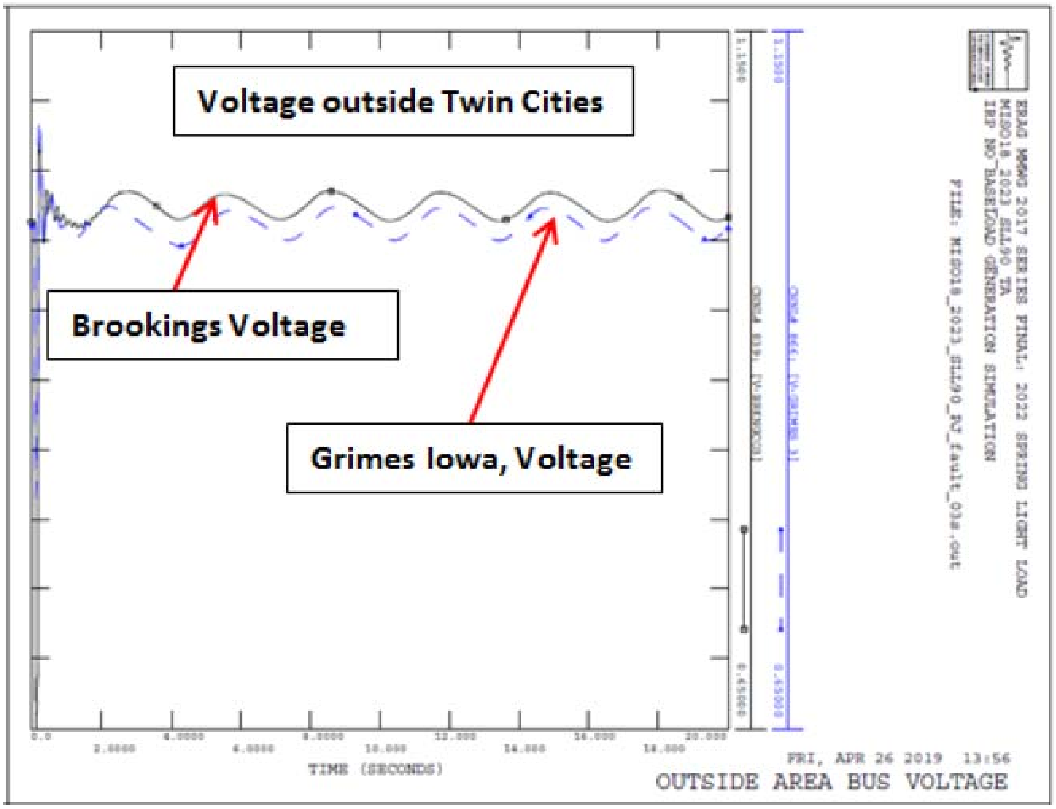
The stability plots in Figures 5 and 6 below show this effect. While the Twin Cities Metro area is able to mostly recover from an event, in all system disturbances tested, the ability of the system in southwest Minnesota and Iowa where there are large concentrations of renewables experience difficulty recovering voltage stability in light load cases.

**Figure 5: Stability Plot – Insufficient System Damping
Twin Cities Metro Area Voltage**



Damping is the flattening of the line as time progresses. Figure 5 above and Figure 6 below show that, while the Twin Cities Metro area can maintain stability, other areas outside of the Twin Cities Metro are unable to do so.

**Figure 6: Stability Plot – Insufficient System Damping
Outside Twin Cities Metro Area Voltage**



While the scenarios developed for the light load cases were able to fully solve, despite some inability to remain stable, the summer scenarios with high levels of energy demand that are shown as "no solution" in yellow highlight in Tables 9 and 10 above resulted in system collapse due to insufficient resource margin available on the system to rebalance and regain stability after an event is experienced..

Figures 7 and 8 below demonstrate the system collapse, which is would result in widespread power outages and require black start procedures for MISO Load Resource Zone 1 to rejoin the grid once the system regained stability.

Figure 7: System Collapse – Summer 2023 P01 Case

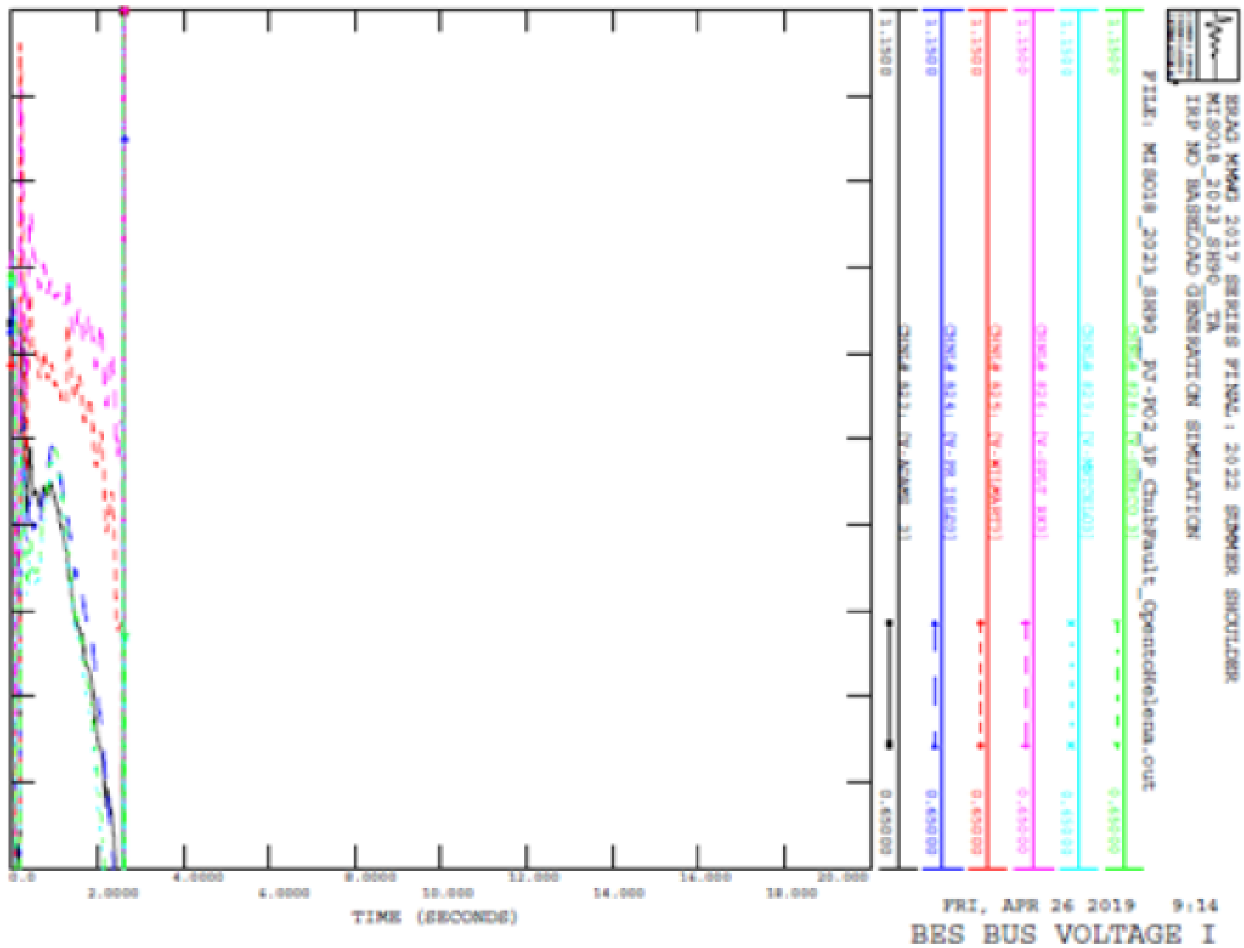
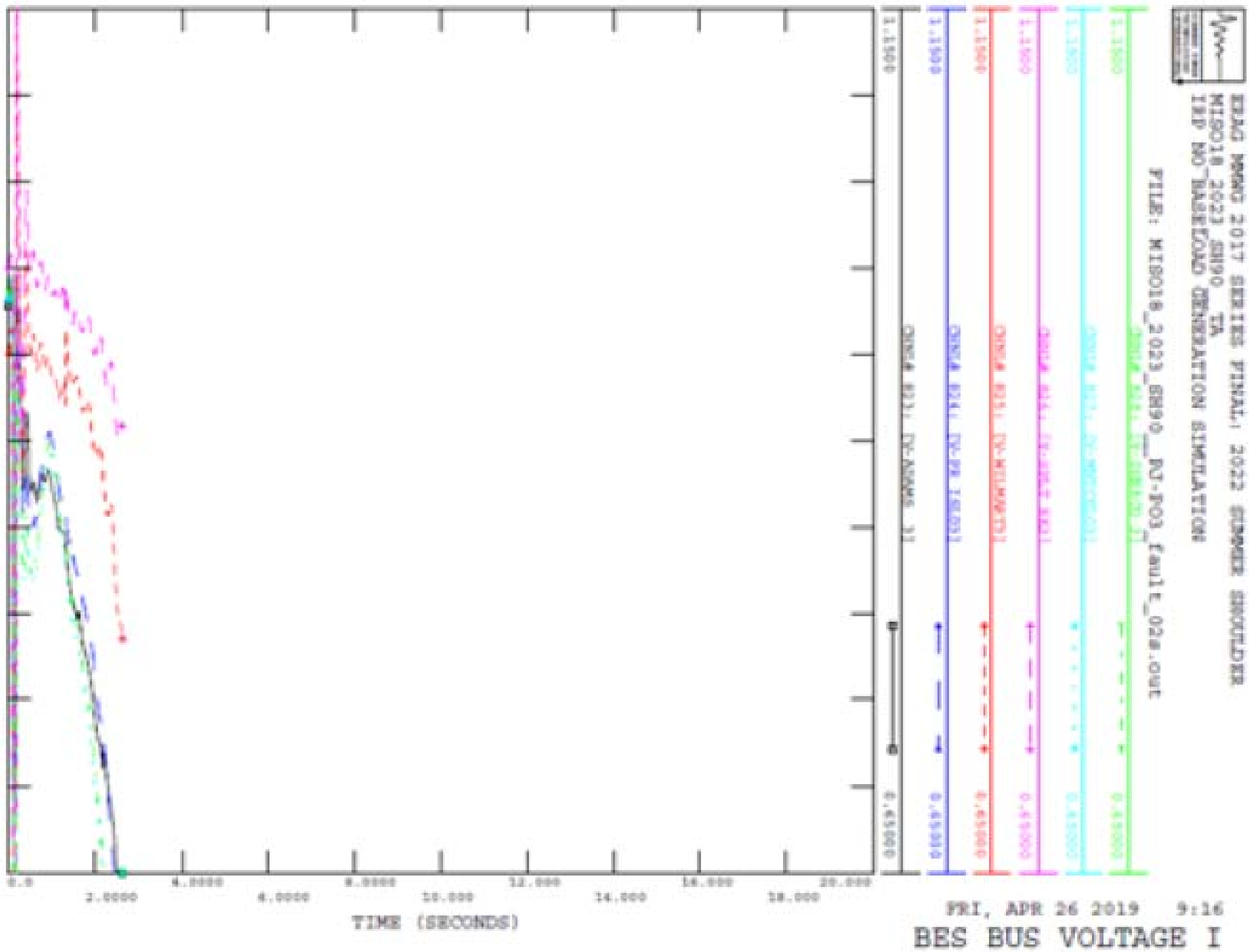


Figure 8: System Collapse – Summer 2023 P02 Case



4. Summary of Results

As shown by the results of this analysis, the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios, and system instability in light load scenarios.

The lack of system margin results in the inability of the system to recovery from any of the system events analyzed in either the base summer peak scenario or the prior outage summer peak scenario. This lack of margin is also evident when analyzing the loss of a major source to the Twin Cities metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System base load generation resources available as they are today.

In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor locations results in a less resilient system. In these scenarios, utilizing the current transmission system results in a single point of failure that can result in an inability to operate the system. Additional transmission development will likely be necessary to improve system resilience and facilitate increased levels of renewable resources in the Upper Midwest.

These two efforts help to better understand the impacts of increased baseload retirement on system stability and reliability trend toward the same conclusion. Without sufficient dispatchable and synchronous generation resources available to maintain sufficient margin, the system cannot remain stable resulting in even minor disturbances leading to the potential for cascading failures and system collapse. In addition, increased reliance on renewable resources without utilizing current interconnection rights and transmission system capabilities will result in significant transmission expansion required to maintain system reliability and ensure the safe, resilient and cost effective delivery of power.

G. Strategist Baseload Economic Analysis

To help inform our Preferred Plan with an economic view of an orderly, cost—effective baseload retirement schedule, we developed fifteen Strategist scenarios with varying combinations and timing of baseload unit retirements. These scenarios also identified the size, type, and timing of new resources needed to continue meeting customers' needs and achieve our 2030 carbon reduction goals.

We compared these scenarios to a Reference Scenario, which is essentially an extension of our most recent Resource Plan with respect to all of the baseload units retiring at their currently scheduled retirement dates.[31] These scenarios are generally grouped into "families," which we outline below. First, however, we summarize the retirement dates for the respective baseload units in the Table 11.

[31] The Scenarios and Sensitivities are discussed in Chapter 5: Economic Modeling Framework and Appendix F2: Strategist Modeling Assumptions & Inputs.

Table 11: Economic Analysis – Baseload Unit Retirement Date Assumptions

Baseload Unit	Current Schedule/ Reference Case	Early Retirement	Life/License Extension
A.S. King	2037	2028	NA
Sherco Unit 3	2040	2030	NA
Monticello	2030	2026	2040
Prairie Island Unit 1	2033	2024	2043
Prairie Island Unit 2	2034	2025	2044

Early Coal Family. These scenarios are designed to evaluate the economics of retiring King and/or Sherco 3 early.

- Scenario 2 *(Early King)* – King is retired early; Sherco 3 and the nuclear units are unchanged.
- Scenario 3 *(Early Sherco 3)* – Sherco 3 is retired early; King and the nuclear units are unchanged.
- Scenario 4 *(Early All Coal)* - King and Sherco 3 are retired early; the nuclear units are unchanged.

Early Nuclear Family. This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together – and with the combination of early coal retirements.

- Scenario 5 *(Early Monticello)* – Monticello is retired at the end of 2026; coal and Prairie Island are unchanged.
- Scenario 6 *(Early Prairie Island)* – Prairie Island is retired by the end of 2025; coal units and Monticello are unchanged.
- Scenario 7 *(Early All Nuclear)* – Prairie Island and Monticello are both retired early; coal units are unchanged.
- Scenario 8 *(Early All Baseload)* – All baseload units (coal and nuclear) are retired early.

Extend Nuclear Family. This family of scenario is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending the operational life by ten years beyond the current end of license dates.

- Scenario 9 *(Early Coal, Extend Monticello)* – All coal is retired at the early dates; Monticello is extended for 10 years; Prairie Island is unchanged.

- Scenario 10 *(Early King, Extend Monticello)* – King is retired early; Monticello is extended for 10 years; Sherco 3 and Prairie Island are unchanged.
- Scenario 11 *(Early Coal, Extend Prairie Island)* – All coal is retired early; Prairie Island is extended for 10 years; Monticello is unchanged.
- Scenario 12 *(Early Coal, Extend All Nuclear)* – All coal is retired early; Monticello and Prairie Island are extended.
- Scenario 13 *(Extend Monticello)* –Monticello is extended; King, Sherco 3, and Prairie Island are unchanged.
- Scenario 14 *(Extend Prairie Island)* – Prairie Island is extended; King, Sherco 3, and Monticello are unchanged.
- Scenario 15 *(Extend All Nuclear)* – Both Monticello and Prairie Island are extended; King and Sherco 3 are unchanged.

After identifying the scenarios for analysis, we utilized the Strategist modeling tool to identify sets of resources needed to continue to meet customer needs for each scenario, along with their resultant costs and emissions impacts. We also included the planning level mitigation cost estimates from the MISO Y2 studies – and we applied the Reliability Requirement, discussed in detail in Appendix J2.

From a modeling perspective, the Present Value Revenue Requirement (PVRR) and Present Value Societal Cost (PVSC) results are primary indicators of the economics of various scenarios, or paths forward. The modeling indicated that the nuclear extension scenarios paired with early coal retirements yielded the most attractive present value compared to the Reference Case. This economic view of various options provided helpful insights that informed the Preferred Plan we propose in this Resource Plan, which correlates to Scenario 9.

In summary, the baseload retirement aspects of our Preferred Plan include:

(1) Retirement of our remaining two coal units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early).

(2) Operating our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).

We discuss results of our Strategist modeling in more detail in Chapter 4: Preferred Plan and Appendix F2: Strategist Modeling Assumptions & Inputs of this Resource Plan.

V. CONCLUSION

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision. The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Through this work we believe the retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units. It will be important to maintain sufficient firm dispatchable, load supporting resources to support integration of renewable resources, and ensure customer reliability and system resilience. Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day. Finally, we also believe significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.