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October 13, 2023

VIA ELECTRONIC MAIL AND
FEDERAL EXPRESS

Mr. Steven M. Kahl
Executive Director
North Dakota Public Service Commission
State Capitol Building, Department 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: NORTHERN STATES POWER COMPANY ADVANCE DETERMINATION OF PRUDENCE – BIG STONE SOUTH – ALEXANDRIA – BIG OAKS 345kV TRANSMISSON LINE PROJECT
CASE NO. PU-23-_____

Dear Mr. Kahl:

Northern States Power Company, doing business as Xcel Energy (the Company), respectfully submits this Application for an Advance Determination of Prudence (ADP) to the North Dakota Public Service Commission (Commission) for the portions of the Big Stone South – Alexandria – Big Oaks 345 kV Transmission Line Project (the Project) in which it will have an ownership interest.

Consistent with N.D.A.C § 69-02-02-04, an original and seven copies of the Application are also being provided, along with Affidavits of Mr. Grant Stevenson and Mr. Jason Standing supporting the Company's Application. The Company is providing affidavits in lieu of prefiled direct testimony to support the Application. The Company believes that affidavits will expedite review and approval of the Application. The Company can provide prefiled direct testimony if requested by the Commission.

The Company provided the $175,000 filing fee required by N.D.C.C. § 49-05-16(1)(b) under separate cover.

Please contact me at (612) 492-6129 or simpser.zev@dorsey.com if you have any questions regarding this filing.

Respectfully submitted,

DORSEY & WHITNEY LLP

ZEV SIMPSER

ZS:mrl

Enclosures

cc: Via Email
- John M. Schuh (jschuh@nd.gov)
- Victor Schock (vschock@nd.gov)
- Robert Frank (rfrank@nd.gov)
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE DETERMINATION OF PRUDENCE FOR THE BIG STONE SOUTH –ALEXANDRIA – BIG OAKS 345 KILOVOLT TRANSMISSION LINE PROJECT	CASE NO. PU-23-_____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (NSP, Xcel Energy or the Company) respectfully submits to the North Dakota Public Service Commission (Commission) this Application for an Advance Determination of Prudence (ADP) for the portions of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (the Project or LRTP2) in which it will have an ownership interest.

The Project was studied, reviewed, and approved as part of the Long-Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO)[1] Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.[2]

The LRTP Tranche 1 Portfolio will provide significant benefits to MISO's Midwest Subregion by facilitating more reliable, safe, and cost-effective energy delivery. The Project, designated as LRTP2 by MISO, is an important component of the overall LRTP Tranche 1 Portfolio and like all the projects within the portfolio is designed to address specific needs. The existing 230 kV transmission system in eastern North Dakota, eastern South Dakota, and central and western Minnesota is at its capacity leading to a number of reliability concerns that could affect customers' service quality. Together, the Project and the line from Jamestown to Ellendale designated as LRTP1 by MISO ("LRTP1") are intended to address that constraint. The Project is needed to mitigate current capacity issues with the 230 kV system, provide additional capacity, and

[1] MISO is a member-based non-profit regional transmission organization (RTO) that is responsible for the planning and operation of transmission grid and wholesale energy market across 15 states and the Canadian province of Manitoba. MISO's members include 48 transmission owners with more than 65,800 miles of transmission lines and $34.5 billion in transmission assets that are under MISO's functional control.

[2] A copy of the MTEP21 Report Addendum that discusses the need for the LRTP Tranche 1 Portfolio, including the Project is provided as Schedule 2 to the Affidavit of Jason Standing.

improve electric system reliability throughout the region. Moreover, analyses of the Tranche 1 Portfolio as a whole and of the Project in particular indicate economic benefits should exceed costs.

The Project consists of new 345 kV transmission facilities between Big Stone City, South Dakota, and Sherburne County, Minnesota which will be comprised of two segments:

- the western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- the eastern segment will continue from the existing Alexandria Substation to the Riverview Substation to a new Big Oaks Substation[3] in Sherburne County, Minnesota (Eastern Segment).

The Company will own the new Big Oaks Substation and co-own the Eastern Segment of the Project.

Given the advantages of the Project, including its contribution to addressing transmission capacity constraints and the economic benefits it is expected to produce, the Company requests that the Commission grant an ADP for those portions of the Project in which it will have an ownership interest.

The remainder of this Application addresses the following:

- Compliance Matters;
- Project Description and Purpose;
- Economic Analysis;
- Alternatives; and
- Prudence of the Project.

II. COMPLIANCE MATTERS

A. Description of Applicant

NSP is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a foreign corporation. NSP conducts business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission

[3] The Big Oaks Substation was previously referred to as the Cassie's Crossing Substation. Some documents related to the Project and/or the MISO LRTP Tranche 1 Portfolio use that prior name for the planned new substation.

pursuant to Title 49 of the North Dakota Century Code (N.D.C.C.). The name and address of NSP is:

Northern States Power Company, a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

The Company also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009, and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same case on January 10, 2023, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. The Company presently serves approximately 94,500 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota, and owns approximately 1,450 conductor miles of transmission and 3,810 conductor miles of electric distribution lines in North Dakota.

B. Communication and Service

The Company respectfully requests that the following persons be placed on the Commission's official service list for all official communications in this case:

Alex J. Nisbet
Regulatory Policy Specialist
Xcel Energy
2302 Great Northern Drive
Fargo, North Dakota 58102
Alex.J.Nisbet@xcelenergy.com

Christine Schwartz
Records Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, Minnesota 55401
regulatory.records@xcelenergy.com

C. Standard of Review

North Dakota Century Code section 49-05-16(1)(d) authorizes the Commission to issue an ADP if the Commission "determines that the resource addition is prudent." This standard is similar to the "honestly and prudently invested" standard that the

Commission uses for ratemaking.[4] The general prudence standard calls for determining whether the utility action was reasonable at the time the utility took the action under all relevant circumstances.[5] Under Section 49-05-16(1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;

b. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars;

c. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and

d. The commission determines that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

D. Authority for Relief Requested

North Dakota Century Code section 49-05-16 allows a public utility, at the utility's discretion, to seek an ADP from the Commission for any intended resource addition. The statute defines a "resource addition" as "construction, modification, purchase, or lease of an energy conversion facility, renewable energy facility, demand response system, transmission facility, or a contract to acquire energy, capacity or demand response for the purpose of providing electric service." The Project fits within that definition as it is a transmission facility.

In the Settlement Agreement in the Company's 2007 rate case, Case No. PU-07-776, the Company agreed to file an application for an ADP for the acquisition of transmission facilities that are at least 50 miles long.[6] The Project fits within that commitment as both the entire Project and the Eastern Segment, which the Company will co-own, are longer than 50 miles. This commitment was further refined in Case No. PU-12-59, in which NSP committed to filing ADP applications for "the types of

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[4] *See* N.D.C.C. § 49-06-02.

[5] *See* Charles F. Philips, Jr., *The Regulation of Public Utilities – Theory and Practice* at 292 (Public Utility Reports 1988); *see also* David J. Muchow & William A. Mogel, *Energy Law and Transactions* at § 4.02[3][b] (2009).

[6] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT, Settlement Agreement at 6 (Dec. 31, 2008).

resource additions contemplated in the 2007 rate case settlement" within 14 days of seeking similar approvals from the Minnesota Public Utilities Commission (MPUC).[7]

The Company filed an Application for a Certificate of Need (CON) for the Project with the MPUC on September 29, 2023. Accordingly, the Company is submitting this Application within 14 days, as required by the commitment made in Case No. PU-12-59, along with supporting affidavits. The Company also notes that cost recovery of the projects in MISO LRTP Tranche 1 Portfolio, including the Project, will be addressed pursuant to the relevant provisions of MISO's tariff, as discussed further below.

III. PROJECT DESCRIPTION AND PURPOSE

A. Electrical System Overview

To provide context for the Project, this section provides a high-level overview of the electrical system and describes where transmission projects, like LRTP2, fit into that system.

The electric grid is generally broken down into two systems: the transmission system and the distribution system.

The transmission system is made up of high-voltage transmission lines and bulk transformers at 69 kV and above. Transmission lines, in turn, are made up of conductors, which complete a three-phase circuit and are usually accompanied by a shield wire that protects the line from lightning strikes. The transmission system is designed to withstand the outage of a single transmission line without major disruption to the overall power supply.

Substations are also a part of the transmission system and contain high-voltage electric equipment to monitor, regulate, and transmit electricity. Transmission substations allow transmission lines to connect with one another.

Substation configuration depends on the project and anticipated future needs based on the physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines. The configuration of a substation may change over time to accommodate future load growth or electric system needs, as is the case with the substations that are being upgraded for this Project.

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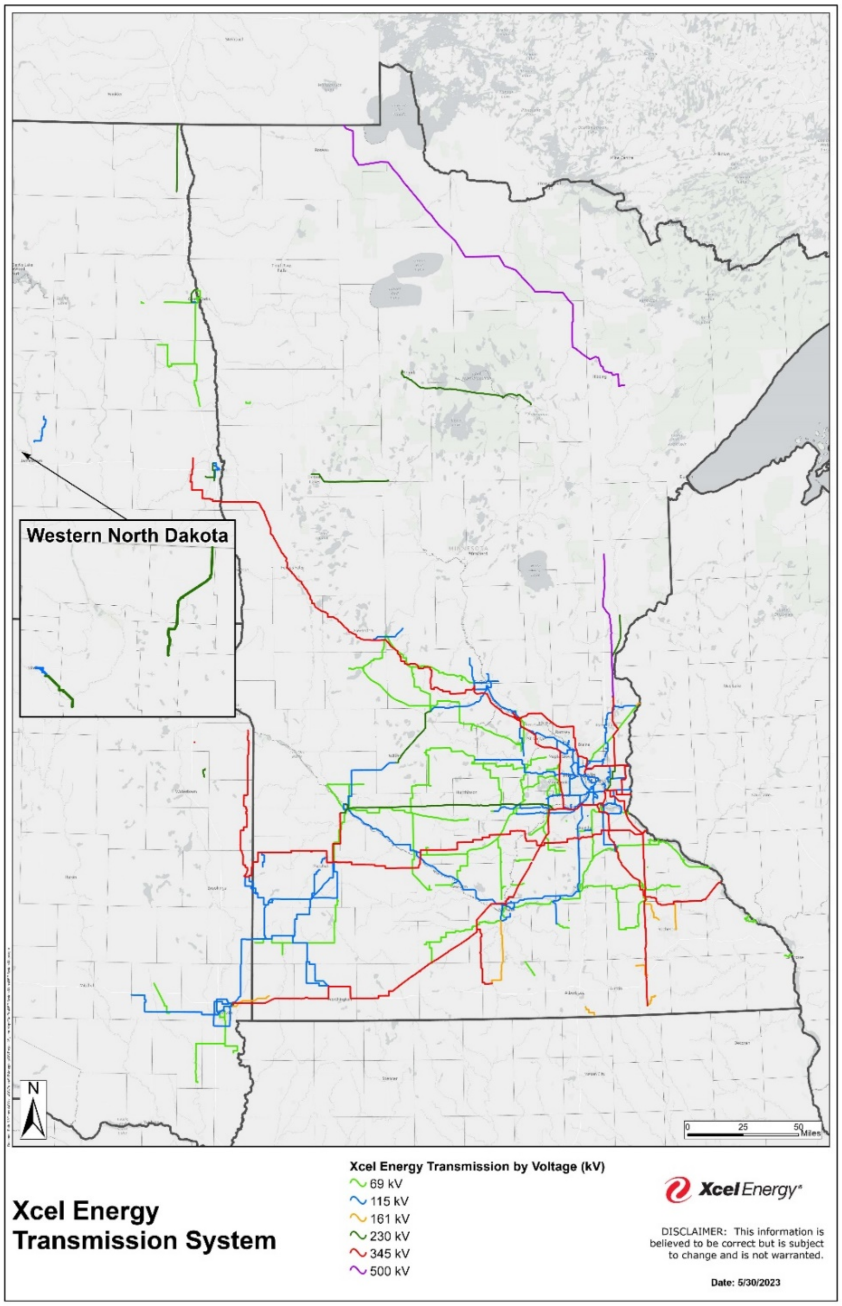
[7] *N. States Power Co. Advance Prudence – Geronimo Wind Application*, Case No. PU-12-59, LETTER OF COMMITMENT (Nov. 5, 2012).

Xcel Energy's transmission system in Minnesota, North Dakota, and South Dakota is depicted below in **Figure 1**.

Figure 1: Xcel Energy's Transmission System in Minnesota, North Dakota, and South Dakota[8]



[8] Portions of the lines depicted above are transmission facilities that Xcel Energy owns with other utilities.

The transmission system is used to transport power relatively long distances from generation sources to the distribution system. Electric energy is generated at a specific voltage and frequency. Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant.

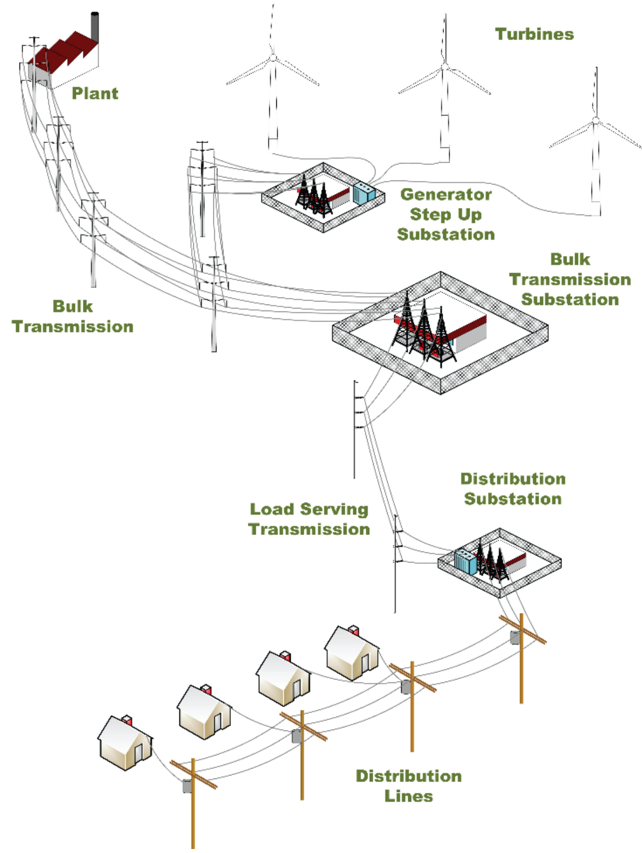
Stepping-up the voltage between the generator and transmission system reduces electrical losses on the system, allowing more of the energy generated to reach consumers. Electricity is typically transported over transmission lines at voltages of 69 kV and above. As voltage increases, electric current decreases assuming the same amount of power flowing through a transmission line. Due to the relationship between power losses, electrical resistance, and electrical current, reducing current along a transmission line has a much greater impact on reducing power losses than reducing resistance of a power line.

Once electricity reaches the distribution system, the transmission voltage (69 kV and higher) is reduced (stepped down) by transformers at a distribution substation facility to voltages appropriate for distribution to end use customers, typically below 69 kV.

The electricity is then further transformed (stepped down) and distributed at distribution "primary" voltages (e.g., 13.8 kV) within communities by the distribution system, which delivers power for individual customer use to the end location where it is stepped down further to, most commonly, 240 V or 120 V.

A diagram showing the transfer of electricity from generator to consumer is shown below in **Figure 2.**

Figure 2: Electrical System



Note that **Figure 2** is an artistic portrayal of key features of an electrical system and is not a detailed representation showing all components.

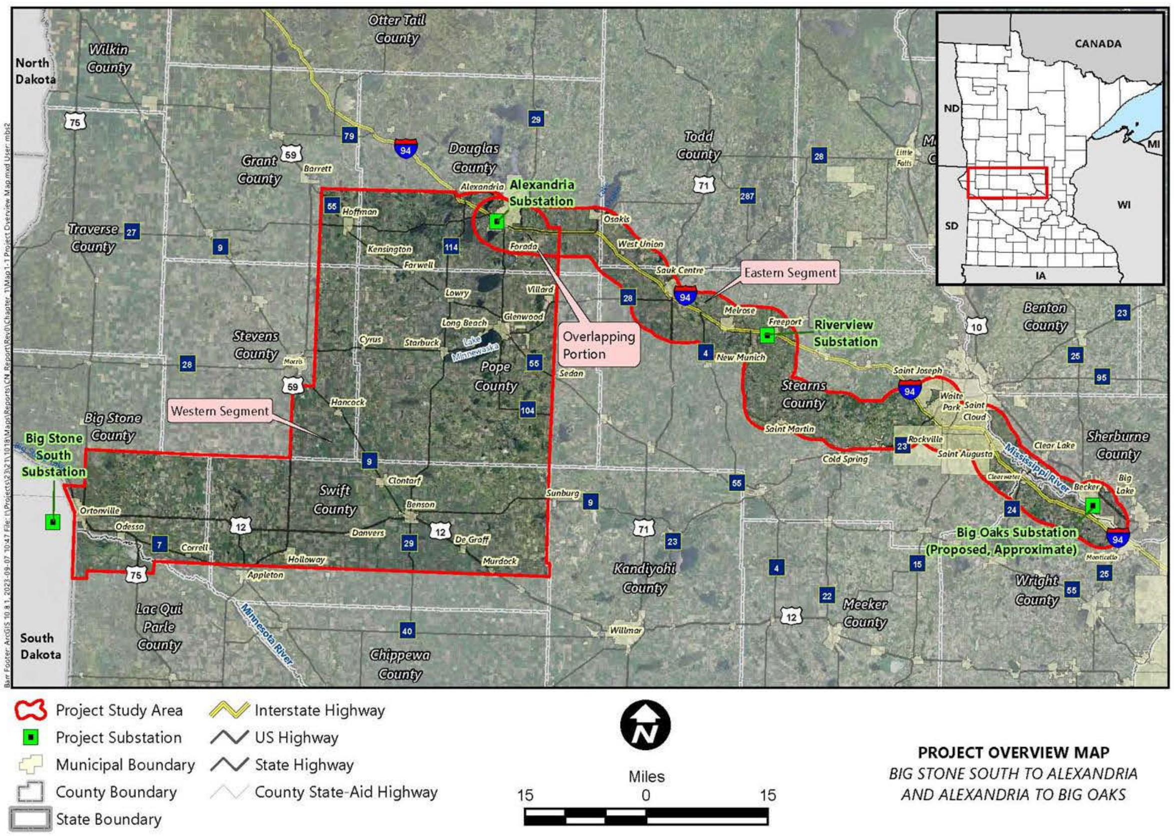
B. Facility Description

The overall Project consists of new 345 kV transmission facilities from Grant County, South Dakota, to Sherburne County, Minnesota which will be comprised of the Western Segment, the Eastern Segment, upgrades to existing substations, and the new Big Oaks Substation.[9] NSP will share in ownership of the Eastern Segment and will have sole ownership of the Big Oaks Substation and the existing Quarry Substation;[10] however, the Company will describe the entire Project so that the Commission may evaluate this Application in the appropriate context.

Figure 3 below depicts the entire Project and **Figure 4** depicts the Eastern Segment.

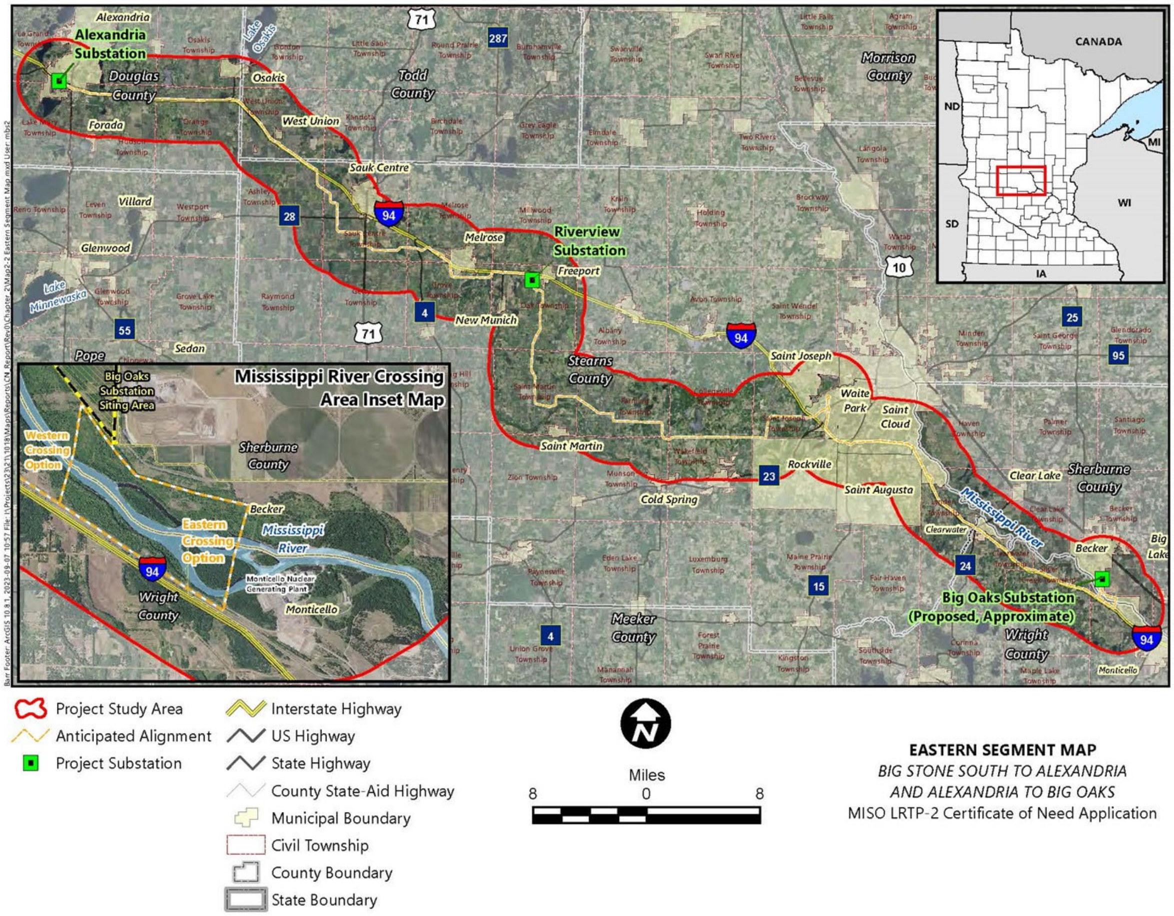
[9] Affidavit of Mr. Grant D. Stevenson, Ex. 1 (GDS-1) (Stevenson Aff.) ¶ 8.
[10] Stevenson Aff. ¶¶ 8-9.

Figure 3: Project Location[11]



[11] Stevenson Aff. Figure GDS-1.

Figure 4: Eastern Segment[12]



1. *Eastern Segment*

This segment of the Project will run from the existing Alexandria Substation in Douglas County, Minnesota to the new Big Oaks Substation in Sherburne County, Minnesota.[13] The majority of the Eastern Segment will consist of adding a second 345 kV circuit to existing double-circuit transmission structures within the existing 150-foot right-of-way.[14]

At four locations, the proposed route for the Eastern Segment deviates from the existing transmission line right-of-way.[15] Three of those segments are: (1) a new right-of-way to allow the new 345 kV transmission line to tap into the Alexandria Substation; (2) a reconfiguration of the existing 345 kV circuit from the Alexandria Substation to

[12] Stevenson Aff. Figure GDS-2.
[13] Stevenson Aff. ¶ 11.
[14] Stevenson Aff. ¶ 13.
[15] Stevenson Aff. ¶ 14.

the Quarry Substation to bypass the Riverview Substation near the city of Freeport; and (3) the new 345 kV circuit from the Riverview Substation to the Big Oaks Substation to bypass the Quarry Substation near the city of Waite Park.[16] The cumulative length of those three segments is less than one mile.[17] More significantly, the fourth deviation from the existing right-of-way is the Mississippi River crossing. New right-of-way will be required for a new crossing to connect the new 345 kV transmission line near Monticello to the new Big Oaks Substation located northwest of the Monticello Nuclear Generating Plant in Becker.[18] Two options are currently being considered by the Project's co-owners for this river crossing: (1) a western option with a crossing directly south of the new Big Oaks Substation and (2) an eastern option with a crossing just west of the Monticello Nuclear Generating Plant.[19] The new 345 kV line constructed as part of the Project is anticipated to be located in a 150 foot wide right-of-way.[20]

When the existing structures along the portion of the Eastern Segment between the Alexandria Substation and the Riverview Substation were originally installed, space was left for a future second circuit to allow electrical capacity to be increased at a limited expense.[21] The Project will now use those existing structures.[22] However, there are also a limited number of locations along that existing route where new structures will be required.[23] These new structures are needed in select areas to accommodate angles (i.e., where the alignment turns), highway crossings, and the four segments where the anticipated alignment deviates from the existing right-of-way.[24] Approximately 67 to 78 new structures are contemplated; the exact number will depend on which location for the Mississippi River crossing is ultimately selected.[25] The angle structures were originally designed as two-pole structures, typical for double circuit 345 kV lines; one full circuit and a shield wire attached to each pole.[26] When the first circuit was installed, there was no need for the second monopole; also, without wires attached, the second monopole would have been susceptible to damage from vibration.[27] As part of this Project, the second monopole will now be installed at those angles.[28] Where a second monopole structure is required next to an existing structure, it will be placed within the existing right-of-way, 40 to 60 feet from the existing structure.[29] H-frame structures

[16] Stevenson Aff. ¶ 14.
[17] Id.
[18] Id.
[19] Id.
[20] Stevenson Aff. ¶ 15.
[21] Stevenson Aff. ¶ 13.
[22] Id.
[23] Id.
[24] Stevenson Aff. ¶ 16.
[25] Stevenson Aff. ¶ 17.
[26] Stevenson Aff. ¶ 18.
[27] Id.
[28] Id.
[29] Id.

may also be used at the Mississippi River crossing or if needed to accommodate longer spans.[30]

The existing and proposed new structures typically range in height from approximately 90 feet to 160 feet tall.[31] The typical span between structures will be about 1,000 feet.[32] All structures are anticipated to be installed on concrete foundations.[33]

The Project's owners are currently evaluating several different conductor types for the new 345 kV transmission line.[34] The proposed transmission line will be designed and built in accordance with relevant standards and local and state codes, including National Electrical Code standards and Xcel Energy standards.[35]

2. *Western Segment*

Although it will not have an ownership interest in the Western Segment, the Company will briefly describe it so that the Commission can understand the Project as a whole. The Western Segment will consist of new single-circuit 345 kV line that will be placed on structures that are double-circuit capable so as to facilitate a potential future expansion.[36] This segment of the Project will run from the existing Big Stone South Substation, near Big Stone City in South Dakota, to the existing Alexandria Substation in Minnesota.[37] This portion of the Project will be installed along new rights of way, the precise route of which will be determined based on proceedings in Minnesota and South Dakota.[38]

3. *Substations*

The Project includes a new Big Oaks Substation, which will be owned by Xcel Energy.[39] This new substation is the eastern endpoint of the Project and will be constructed southwest of the City of Becker, in Sherburne County, Minnesota.[40] It will be a 345 kV switching station that will include eighteen 345 kV circuit breakers configured to accommodate connection of up to twelve 345 kV transmission lines.[41]

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[30] Stevenson Aff. ¶ 18.
[31] Stevenson Aff. ¶ 19.
[32] Id.
[33] Id.
[34] Stevenson Aff. ¶ 20.
[35] Stevenson Aff. ¶ 21.
[36] Stevenson Aff. ¶ 23.
[37] Stevenson Aff. ¶¶ 8, 22.
[38] Stevenson Aff. ¶ 24.
[39] Stevenson Aff. ¶ 26.
[40] Id.
[41] Id.

The substation will be located on a graded and fenced area of approximately 10 acres.[42] The following transmission lines will connect to the Big Oaks Substation:

- The Eastern Segment of the Project;
- Four existing 345 kV transmission lines originating at the Sherburne County Substation; and
- Two planned 345 kV transmission lines designated as LRTP3 in the MISO LRTP Tranche 1 portfolio (Benton County – Big Oaks Line #1 and Benton County – Big Oaks Line #2).[43]

In addition, the Project includes improvements to the Big Stone South Substation, the western endpoint of the Project, the Alexandria Substation, the midpoint between the Western Segment and Eastern Segment of the Project, the Riverview Substation, and Xcel Energy's existing Quarry Substation.[44] At the Quarry Substation, which Xcel Energy owns, these improvements will consist of the addition of equipment so as to allow the substation to provide reactive power support.[45] The fenced area at the Quarry Substation will also be expanded to accommodate the added equipment.[46]

C. Project Ownership

The Eastern Segment will be co-owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail Power Company ("Otter Tail"), and Western Minnesota Municipal Power Agency ("Western Minnesota").[47] Otter Tail and Western Minnesota will co-own the Western Segment.[48] As noted above, Xcel Energy will own the new Big Oaks Substation and is the owner of the existing Quarry Substation.[49] The Big Stone South Substation is owned by Otter Tail, Western Minnesota owns the Alexandria Substation, and Great River Energy is the owner of the Riverview Substation.[50] The owners of the Eastern Segment have not yet agreed upon their respective ownership shares; Xcel Energy will plan on updating the Commission in a future filing in this matter after that decision has been made.

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42 Stevenson Aff. ¶ 27.
43 Stevenson Aff. ¶ 28.
44 Stevenson Aff. ¶¶ 29-33.
45 Stevenson Aff. ¶ 33.
46 Id.
47 Stevenson Aff. ¶ 9.
48 Id.
49 Id.
50 Id.

D. Project Background and Need

As noted above, the Project, also known as LRTP2, is one of the eighteen projects within MISO's LRTP Tranche 1 portfolio.[51]

MISO has a responsibility, established by the Federal Energy Regulatory Commission (FERC), to study the transmission system within its footprint to identify necessary transmission projects to address reliability issues. Pursuant to that responsibility, MISO develops its MISO Transmission Expansion Plan (MTEP) each year in collaboration with utilities and other stakeholders. Each MTEP is developed in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report.[52]

MISO carries out its MTEP development pursuant to the planning principles outlined in FERC Order Nos. 890[53] and 1000[54] in developing the MTEP. These FERC Orders require an open and transparent regional transmission planning process and include the requirement to plan for public policy objectives and for coordinated inter-regional planning and cost allocation. Accordingly, each MTEP cycle MISO provides numerous opportunities for advice and input from stakeholders, including utilities, state regulators, and non-profit organizations.[55]

The MISO footprint is experiencing a fundamental change in the energy industry landscape – including shifts in generation resources and decentralization of generation. Earlier, generation across MISO was largely provided by coal generation and some natural gas, and customer demand was the largest source of day-to-day operating variation. By 2020, coal generation had already shrunk to approximately one-third of MISO's annual energy production and annual energy from wind and solar generation had risen to 13 percent.[56] Driven by a combination of federal and state policy, customer preferences, economics, and utility goals, the retirement of legacy fossil fuel generators and the replacement of those units with geographically dispersed wind and solar generation is expected to continue and accelerate across the MISO footprint over the foreseeable future.[57]

Responding to these changes, in 2019 MISO launched the LRTP.[58] The LRTP is a multi-year multi-phase study to identify a regional "backbone" to cost-effectively

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[51] Affidavit of Jason Standing (Ex. 2) (JS-1) (Standing Aff.) ¶ 12.
[52] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 6-8
[53] FERC Order No. 890, 18 C.F.R. parts 35, 36 (2007), *available at* https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.
[54] FERC Order No. 1000, 18 C.F.R. part 35 (2011), *available at* https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.
[55] See Standing Aff. Sch. 2 (MTEP21 Report Addendum), Executive Summary at 7.
[56] Standing Aff. Sch. 3 (MISO Futures Report), Executive Summary at 2.
[57] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 10-13.
[58] Standing Aff. ¶ 13, Sch. 2 (MTEP21 Report Addendum) at 11-13.

maintain reliability and serve future needs. The objective of the MISO LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply;

- **Cost Efficient** – enable access to lower-cost energy production;

- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint; and

- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice.[59]

MISO evaluated the LRTP and potential LRTP projects in accordance with MISO's federally approved tariff.[60] For any transmission project to be deemed needed under MISO's tariff, it must meet defined criteria. In MISO's LRTP, MISO and stakeholders worked to identify a transmission plan that simultaneously addresses multiple regional needs[61] – which under Attachment FF to MISO's Electric Tariff (the MISO Tariff)[62] is defined as a Multi-Value Project (MVP). For a project to be deemed needed by MISO as a MVP it must meet one of the following criteria:

- Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade;

- Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the

[59] Standing Aff. Sch. 2 (MTEP21 Report Addendum) Executive Summary at 6.
[60] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 7-8.
[61] Standing Aff. Sch. 2 (MTEP Report Addendum) at 13.
[62] The MISO Tariff is on file at FERC and can be found on MISO's website at: Tariff (misoenergy.org).

associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value; or,

- Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

MISO Tariff, Attachment FF at Section II.C.

MISO used three different future scenarios in evaluating and analyzing potential LRTP projects. These are known as MTEP21 Future 1, Future 2, and Future 3. Future 1, the least transformation scenario, assumes changes announced through September 2020 in utility resource plans, 85% achievement of announced decarbonization goals, and load growth consistent with current loads.[63] Futures 2 and 3 assume greater load growth, driven by electrification, and more aggressive reductions in carbon emissions.[64] The three futures are summarized in **Figure 5** below.

Figure 5
MTEP21 Futures Assumptions[65]

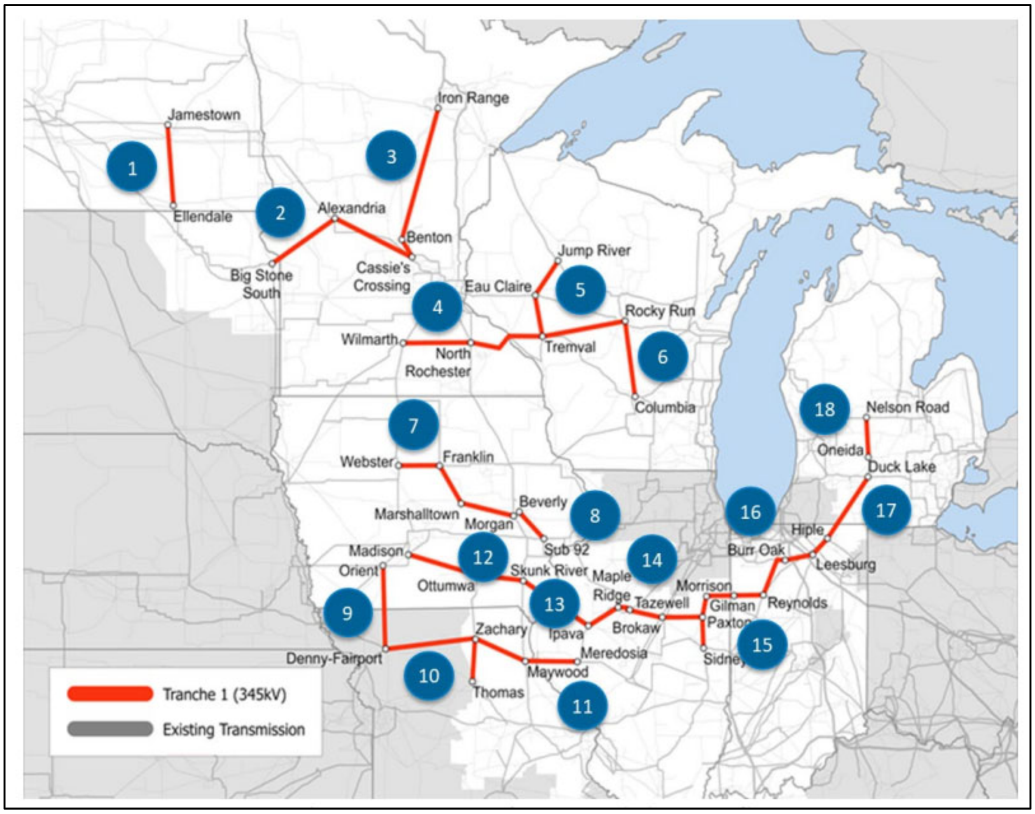
Future I	Future 2	Future 3
• The footprint develops in line with 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences • Emissions decline as an outcome of utility plans • Load growth consistent with current loads	• Companies/states meet their goals, mandates and announcements • Changing federal and state policies support footprint-wide carbon emissions reduction of 60% by 2040 • Energy increases 30% footprint-wide by 2040 driven by electrification	• Changing federal and state policies support footprint-wide carbon emissions reduction of 80% by 2040 • Increased electrification drives a footprint-wide 50% increase in energy by 2040

In July 2022, MISO approved the first phase or "tranche" of the LRTP.[66] The MISO LRTP Tranche 1 Portfolio consists of 18 transmission projects, including the Project, which is identified in **Figure 6** as project number two.[67] The MISO LRTP Tranche 1

[63] Standing Aff. Sch. 3 (MISO Futures Report) at 3.
[64] Id.
[65] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 12.
[66] Standing Aff. ¶ 14.
[67] Standing Aff. ¶¶ 12, 16; Sch. 2 (MTEP 21 Report Addendum) Executive Summary at 2.

Portfolio includes more than 2,000 miles of new and upgraded high voltage transmission.[68]

Figure 6
MISO LRTP Tranche 1 Portfolio



The LRTP Tranche 1 Portfolio is needed to:

- Address reliability violations as defined by the North American Electric Reliability Corporation (NERC) at over 300 different sites across the Midwest.[69] In addition, increase transfer capability across the MISO Midwest Subregion to allow reliability to be maintained for all hours under varying dispatch patterns driven by differences in weather conditions;[70] and

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[68] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 15.
[69] See Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 25, 28, 31, 38, 40, 44.
[70] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 64.

- Support the reliable interconnection of approximately 43,431 MW in new primarily renewable generation capacity across the MISO Midwest Subregion.[71]

In the identification of the LRTP Tranche 1 Portfolio MISO considered multiple alternatives both to each of the eighteen individual projects and to the aggregate portfolio, which are discussed further below in Section V.[72]

MISO identified that the MISO LRTP Tranche 1 Portfolio is needed to prevent numerous thermal and voltage reliability issues – summarized in **Table 1** below. The MISO LRTP Tranche 1 Portfolio is designed to help ensure the MISO transmission grid can continue to reliably deliver energy from future generation resources to future load under a range of projected system conditions in the 10-year and 20-year time horizon.

Table 1
LRTP Tranche 1 Portfolio Reliability Need Summary

LRTP Project ID(s)[73]	Summary of Reliability Need[74]
LRTP 1 & 2 ***Proposed Project: LRTP2***	Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
LRTP 3	Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies
LRTP 4, 5, and 6	Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies
LRTP 7 and 8	Relieves 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies
LRTP 9, 10, and 11	Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
LRTP 12 through 18	Addresses 600 thermal reliability violations at 77 different sites.

Focusing specifically on the Project, MISO summarized the need for the LRTP2, along with the LRTP1 project (Jamestown – Ellendale 345 kV transmission line) as follows:

> The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the

[71] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 52.
[72] Standing Aff. Sch. 2 (MTEP Report Addendum) at 22, 25, 29, 34-36, 39, 43, and 46.
[73] See Figure 6 above for the relevant LRTP Tranche 1 Project IDs.
[74] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 25, 28, 31, 38, 40, 44.

> Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.[75]

MISO also found that the LRTP Tranche 1 Portfolio is needed to increase the transfer capability across the MISO footprint.[76] As the generation fleet transitions to more wind and solar generation resources whose output is dependent on weather conditions, the ability to transfer energy across the MISO system is critical to serving demand when wind or solar is not available in a particular area.[77] As weather patterns regularly change, the LRTP Tranche 1 Portfolio provides flexibility to transfer more energy where it is needed and when.[78] In addition, the increased transfer capability provided by the LRTP Tranche 1 Portfolio enables more geographic diversity which allows grid operators to better manage generation dispatch volatility and uncertainty.[79]

E. Project Costs and Schedule

Xcel Energy and the other owners of the proposed Project have prepared high and low estimates for the overall cost.[80] The difference between the high and low estimates largely reflect uncertainty with regard to the route of the Western Segment, with the higher figure representing a longer route and the lower figure a shorter route, and some uncertainty with regard to the equipment that will need to be installed at substations.[81] These estimates include transmission line material and construction costs, substation modification material and construction costs, right-of-way costs, land acquisition costs, permitting, design, and may include risk reserve and Allowance for Funds Used During Construction (AFUDC) or Construction Work in Progress (CWIP).[82]

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[75] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 23.
[76] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at Executive Summary at 3, Addendum at 16, 21-22, 62-64.
[77] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 58.
[78] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 58, 72.
[79] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 19-20.
[80] Stevenson Aff. ¶ 36.
[81] Stevenson Aff. ¶ 37.
[82] Individual project owners took different approaches in budgeting for specific portions of the Project. Stevenson Aff. ¶ 36.

Of course, estimates, particularly those made relatively early in the development process, are subject to change, particularly in an inflationary environment.[83] However, the current range of cost estimates give the Commission reasonable information to evaluate the prudency of the Project.

Table 2
Construction Cost Estimates[84]

Project Components	Low Capital Expenditures (2022$) ($Millions)	High Capital Expenditures (2022$) ($Millions)
Big Stone South – Alexandria 345 kV Transmission Line (Western Segment)	$385.0	$441.2
Big Oaks – Alexandria 345 kV Transmission Line (Eastern Segment)	$123.1	$130.9
Big Stone South Substation Modifications	$12.0	$20.0
Alexandria Substation Modifications	$20.0	$28.0
Riverview Substation Modifications	$3.0	$3.0
Quarry Substation Modifications	$3.0	$4.0
New Big Oaks Substation	$60.4	$72.3
Total Project Costs*	**$606.5**	**$699.4**
**There may be differences between the sum of the individual component amounts and Total Project Costs due to rounding*		

As a reminder, the portions of the Project in which Xcel Energy will have an ownership interest are: the Eastern Segment, the existing Quarry Substation, and the new Big Oaks Substation.

[83] Stevenson Aff. ¶ 38.
[84] Stevenson Aff. Table GDS-2.

MISO earlier developed cost estimates for each of the 18 transmission projects in the LRTP Tranche 1 Portfolio.[85] MISO's cost estimate for this Project was $574 million in 2022 dollars.[86] The cost estimate prepared by the Project owners is higher than MISO's cost estimate for several reasons. The MISO cost estimate did not include the costs associated with the 67 to 78 new foundations and structures discussed above in Section III.B.1 that will be required along the Eastern Segment.[87] The MISO cost estimate also did not include the costs associated with adding reactive equipment, expanding the existing Riverview and Quarry substations, and adding remote end relays at the Big Oaks Substation, which were discussed above in Section III.B.3.[88] In addition, material and labor costs have also increased since the MISO cost estimate was developed.[89]

The schedule for the Eastern Segment is set forth in **Table 3** below.

Table 3
Eastern Segment – Anticipated Project Schedule[90]

Activity	Estimated Dates
Minnesota Certificate of Need and Route Permit for Eastern Segment Issued	Second/Third Quarter 2024
Land Acquisition Begins	Third Quarter 2024
Survey and Transmission Line Design Begins	Second Quarter 2024
Other Federal, State, and Local Permits Issued	First Quarter 2025
Start Right-of-Way Clearing	Second Quarter 2025
Start Project Construction	Second Quarter 2025
Project In-Service	Fourth Quarter 2027

It is anticipated that the Western Segment will come into service by the end of 2030.[91] However, as the Western Segment will be built on new right-of-way on a route that is not yet determined there is somewhat greater uncertainty and there is a possibility that the in-service date could be delayed until 2031.[92]

IV. PRUDENCE ANALYSIS

A. Project Benefits

MISO and the Company both conducted analyses to determine the system reliability and economic benefits of the Project. While the Project is primarily designed to

[85] Stevenson Aff. ¶ 39.
[86] Id.
[87] Id.
[88] Id.
[89] Id.
[90] Stevenson Aff. Table GDS-1.
[91] Stevenson Aff. ¶ 35.
[92] Id.

improve the reliability of the transmission system, it is also expected to provide economic benefits that significantly exceed estimated project costs under the most realistic future scenario.

1. Reliability

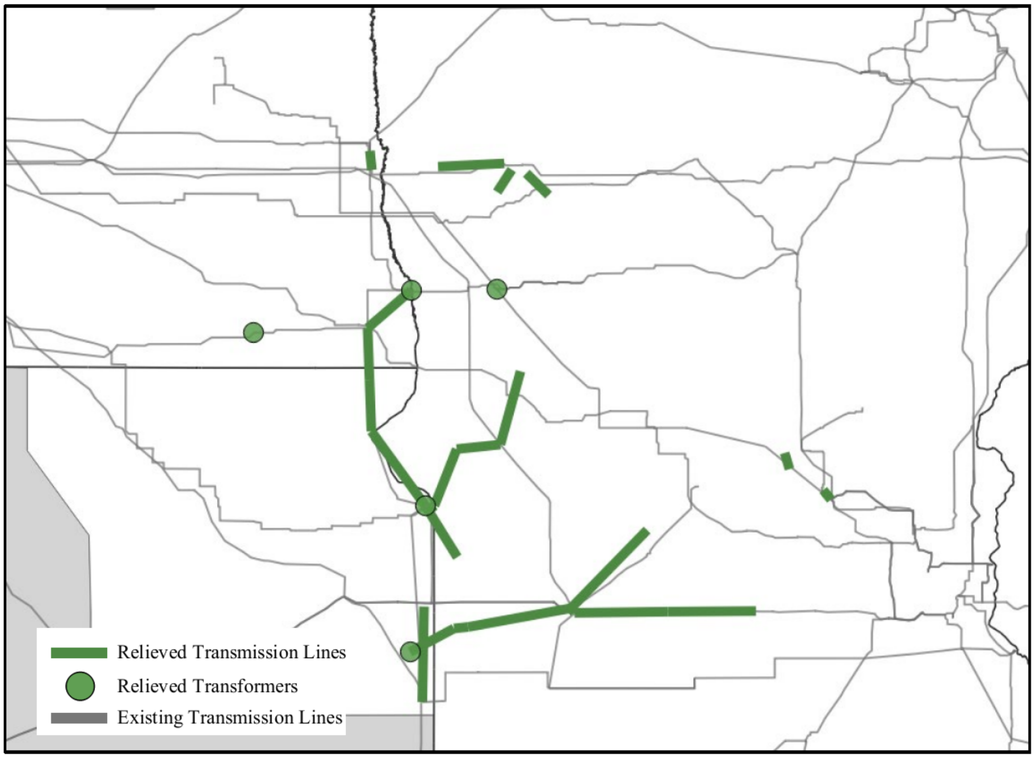
a. MISO

MISO analyzed the impact of the Project and LRTP1 on the reliability of the transmission system. MISO concluded that the two projects, taken together, address many of the thermal and voltage issues in eastern North Dakota, eastern South Dakota, and western and central Minnesota by providing additional capacity to relieve the currently constrained 230 kV system.[93]

MISO's analysis identified that the Project and the LRTP1 project address many of the thermal and voltage issues identified in eastern North Dakota, eastern South Dakota, and western Minnesota as shown in **Figure 7** below.[94] The solid green lines in **Figure 7** depict the transmission lines that no longer have overloads and the circles depict transformers that no longer have overloads following construction of the Project and the LRTP1 project.[95] Most notably, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved of all N-1 and N-1-1 contingencies.[96] An N-1 contingency is an event that involves the loss of a single generator or transmission component. An N-1-1 contingency is an event that involves the initial loss of a single generator or transmission component, followed by system adjustments, and then another loss of a single generator or transmission component.

[93] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 23-24.
[94] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 24.
[95] Id.
[96] Id.

Figure 7[97]
Reliability Issues Addressed by the Project and LRTP1



As shown in **Table 4** and **Table 5** below, MISO determined that the Project and the LRTP1 project relieved 40 thermal overloads and 97 voltage violations under N-1 contingency in the Future 1 scenario.[98]

[97] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 24.
[98] Standing Aff. Sch. 2 (MTEP 21 Report Addendum) at 25. MISO considered a constraint relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst pre-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Id. at 24.

Table 4[99]
Elements with Thermal Issues Relieved by LRTP2 and LRTP1 in Future 1

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 5[100]
Elements with Voltage Issues Relieved by LRTP2 and LRTP1 in Future 1

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

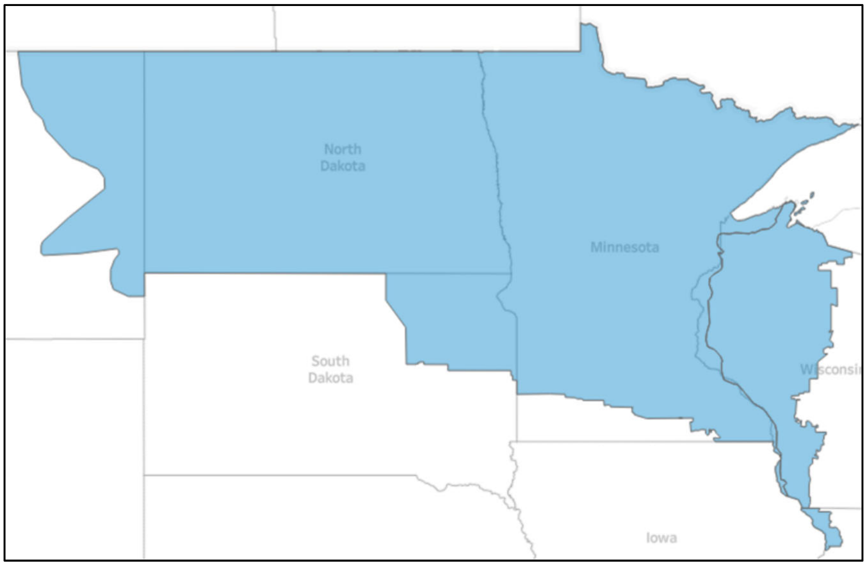
b. Xcel Energy

The Company also conducted its own study of the impact of the Project on transmission system reliability.[101] The Company's analysis involved looking at the impact of the Project in two different scenarios.[102] One scenario used MISO's MTEP22 model of the transmission system and assumed no additional generation resources have been added to the system.[103] The other scenario, based on year 20 of Future 1 from MISO's 2021 MTEP, was used to analyze the impact of the Project at a time when additional generation will have been added to the system.[104]

In analyzing the impact of the Project in the near-term future, with no added generation, and a longer-term future, with added generation, the Company focused on the summer shoulder season, with high winds, which represents a time of year and weather condition in which the transmission system in the area is particularly stressed.[105] The Company's analysis studied reliability in the MISO Local Resource Zone 1 (LRZ1) area, which is shown in **Figure 8** below.[106]

[99] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 25.
[100] Id.
[101] Standing Aff. ¶ 46.
[102] Standing Aff. ¶ 47.
[103] Standing Aff. ¶ 48.
[104] Standing Aff. ¶ 49.
[105] Standing Aff. ¶ 50.
[106] Standing Aff. ¶ 51.

Figure 8[107]
MISO Local Resource Zone 1



The Company's reliability analyses studied all NERC contingency categories (P1-P7) and looked at facility overloads under a variety of transmission system modeling assumptions, including the following:

- Base Model – assuming no additional transmission projects are constructed (*i.e.*, the current base transmission system remains in place);
- Only LRTP2 – assuming the Project is constructed, but no other LRTP Tranche 1 projects are constructed;
- All LRTP Tranche 1 projects except LRTP2 – assuming construction of all LRTP Tranche 1 projects except the Project; and
- LRTP Tranche 1 – assuming construction of all LRTP Tranche 1 projects.[108]

While LRTP Tranche 1 is a portfolio of 18 individual projects designed to work together to provide benefits, Xcel Energy's reliability analyses provide an alternative way to look at the reliability improvements resulting from the Project. The results of the reliability studies are provided in the following sections, which illustrate which overloads are remedied with implementation of the Project.

[107] Standing Aff. Figure JS-1.
[108] Standing Aff. ¶ 52.

(1) Without Added Generation – Reliability Results

The Company conducted an analysis for the LRZ1 area based on the MISO MTEP22 transmission system model assuming no additional generation is added to the system.[109] This analysis looked at the year 2027, which is nearest to MISO's approved in-service date for the Project, to show improvements to system reliability related to the construction of the Project.[110]

The results of this analysis are provided in **Table 6** below. The table lists the "Overloaded Facilities" and provides the number of different contingencies that cause thermal issues on the facility listed for each transmission model studied.[111] The table also includes the "Fixed By LRTP2" column showing the number of thermal issues that are resolved with implementation of the Project.[112]

The number of thermal issues resolved by the Project reflects issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model.[113] A thermal overload was considered to be resolved by the Project if it showed up in the "Base Model" but not the "LRTP2" model or full "Tranche 1" model.[114] Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.[115]

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[109] Standing Aff. ¶ 54.
[110] Id.
[111] Standing Aff. ¶ 55.
[112] Id.
[113] Standing Aff. ¶ 56.
[114] Id.
[115] Id.

Table 6[116]
Reliability Results
MTEP22 2027 Summer Shoulder – High Wind

Totals			MTEP22 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	8956	4503	7	0	4480
Helena - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	5042	4508	13	0	559
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4453	2	0	0	4451
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4394	0	0	0	4394
Big Stone - Highway 12 115 kV Ckt 1	SD	N-1, N-1-1	582	0	2	0	582
Highway 12 - Ortonville 115 kV Ckt 1	SD, MN	N-1, N-1-1	301	0	1	0	301
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	270	2	0	0	268
Ortonville - Ortonville Quarry 115 kV Ckt 1	MN West	N-1, N-1-1	259	0	0	0	259
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	182	0	58	0	182
Hoot Lake - Fergus Falls 115 kV Ckt 1	MN West	N-1, N-1-1	171	0	1	0	171
Sheyenne - Lake Park 230 kV Ckt 1	ND	N-1, N-1-1	167	0	167	0	167
Audubon - Lake Park 230 kV Ckt 1	MN West	N-1, N-1-1	167	0	167	0	167
Inman - Wing River 230 kV Ckt 1	MN West	N-1, N-1-1	139	0	0	0	139
Big Stone - Big Stone South 230 kV Ckt 2	SD	N-1, N-1-1	85	0	83	0	85
Wahpeton - Fergus Falls 230 kV Ckt 1	MN West	N-1, N-1-1	83	0	0	0	83
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	55	0	0	0	55
Big Stone - Big Stone South 230 kV Ckt 1	SD	N-1, N-1-1	27	0	27	0	27
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	5	0	0	0	5

As shown in the last column of **Table 6**, the major reliability benefits of the Project can be seen on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in eastern North Dakota and South Dakota and western Minnesota.[117] For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Scott County – Blue Lake and from Helena – Chub Lake has a large number of thermal issues that are mitigated with the addition of the Project.[118] There are several areas on the underlying 230 kV and 115 kV systems that also see reliability benefits, such as the areas around the Big Stone, Wahpeton, Morris, Sheyenne, and Audubon substations.[119]

(2) Future 1 (Added Generation) – Reliability Results

The Company also analyzed the LRZ1 area based on the MISO MTEP21 Future 1 (at year 20) to show impacts to system reliability resulting from the Project in the future when additional generation is expected to be online.[120] This analysis shows the impact that the Project has under a high wind model with the added generation that the LRTP Tranche 1 Portfolio will enable.[121]

The results of this analysis are provided in **Table 7** below. The table lists the overloaded facilities and provides the number of different contingencies that cause thermal issues

[116] Standing Aff. Table JS-1.
[117] Standing Aff. ¶ 57.
[118] Id.
[119] Standing Aff. ¶ 58.
[120] Standing Aff. ¶ 59.
[121] Standing Aff. ¶¶ 49-50, 59.

on the overloaded facility for each transmission model studied.[122] The table also includes the "Fixed By LRTP2" column showing the number of thermal issues that are resolved by the Project.[123]

The number of thermal issues resolved by the Project reflects thermal issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model.[124] A thermal overload was considered to be resolved by the Project if the overload showed up in the "Base Model" but not the "LRTP 2" model or full "Tranche 1" model.[125] Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.[126]

Table 7[127]
Reliability Results
MTEP21 Future 1 Year 20, Summer Shoulder – High Wind

Totals			F1Y20 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Tamarac - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36957	46967	54054	43711	17092
Cormorant Junction - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36867	46349	54151	2006	22945
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6740	7	0	0	6736
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6685	7	0	0	6681
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	3758	0	2	0	3760
North Rochester - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	1498	1552	43845	7622	36133
Tamarac - Pelican Rapids 115 kV Ckt 1	MN West	N-1, N-1-1	309	139	275	99	184
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	233	116	175	126	121
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	123	0	0	0	123
Big Stone - Browns Valley 230 kV Ckt 1	SD	N-1, N-1-1	98	0	0	0	98
Browns Valley - New Effington 230 kV Ckt 1	SD	N-1, N-1-1	74	0	0	0	74
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1-1	16	0	2	0	18
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	6	0	0	0	6

The major reliability benefits of the Project can be seen on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in western Minnesota and eastern South Dakota.[128] For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Chub Lake and Blue Lake – Scott County – North Rochester has a large number of thermal issues mitigated with the addition of the Project.[129] There are also several areas on the underlying 230 kV and 115 kV systems that see reliability benefits, such as the areas around the Big Stone, Browns Valley, Tamarac, Cormorant, and Morris substations.[130]

[122] Standing Aff. ¶ 60.
[123] Id.
[124] Standing Aff. ¶ 61.
[125] Id.
[126] Id.
[127] Standing Aff. Table JS-2.
[128] Standing Aff. ¶ 62.
[129] Id.
[130] Id.

2. *Economic Benefits*

a. MISO

While the LRTP Tranche 1 Portfolio was designed by MISO to primarily address reliability issues, MISO also estimated the economic benefits of the portfolio of projects and compared those benefits to the estimated forecasted costs. MISO projects that the MISO LRTP Tranche 1 Portfolio will provide $23.2 billion to $52.2 billion in net economic savings over the first 20 to 40 years (respectively) of the portfolio's service – a benefit to cost ratio range of 2.6 to 3.8.[131]

b. Xcel Energy

The Company used the PROduction MODeling (PROMOD) computer modeling program to carry out its own evaluation of the economic impact of the Project (as opposed to the broader LRTP Tranche 1 Portfolio which MISO analyzed).[132] PROMOD is the industry standard market simulation software for economic transmission planning.[133] PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load.[134] This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load.[135] The model can thus calculate future estimated costs of producing electricity, transmission costs, and energy losses based on these assumptions.[136]

The Company typically analyzes the economic impacts of a transmission project by considering the project's impact on adjusted production cost (APC), which is the total production costs of a generation fleet including fuel, variable operations and maintenance, startup cost, and emissions, adjusted for energy market sales and purchases.[137] If a project is forecasted to produce APC savings, those are the estimated

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[131] Standing Aff. Sch. 2 (MTEP21 Report Addendum) Executive Summary at 3-4. The Company notes that MISO included economic benefits from reductions in carbon emissions in its estimate of benefits. However, carbon emission reduction benefits are only $3.5 billion (present value) for a 20-year period and only $17.4 billion (present value) for a 40-year period, both of which are substantially less than the net benefit amounts of $23.2 billion (20 year present value) and $52.2 billion (40 hear present value). See id. at 3. Consequently, the overall portfolio is projected to provide substantial net benefits even if decarbonization benefits are excluded.

[132] Standing Aff. ¶ 65.

[133] Id.

[134] Id.

[135] Id.

[136] Id.

[137] Standing Aff. ¶ 66.

benefits of the project.[138] The Company then compares those estimated APC savings to project costs and other impacts.[139]

This section first briefly describes how expanding transmission capacity can save customers money. The balance of the section provides the estimated APC savings from the Project.

(1) Congestion

Insufficient transmission capacity has become an increasingly serious problem in the MISO territory in recent years.[140] MISO operates day-ahead and real-time energy markets as part of carrying out its responsibility to operate an energy market in an efficient manner.[141] Limited transmission capacity can impair the efficient operation of these markets.[142] Limits on the capacity of transmission facilities can prevent MISO from dispatching the generation mix with the lowest marginal cost during all hours of the year, increasing wholesale energy costs.[143]

There is currently energy with low marginal costs available in the region that is sometimes unable to serve load centers, due to transmission constraints in North Dakota, South Dakota, and Minnesota.[144] Some energy cannot be provided to load centers because the loading limits on certain transmission system components preclude this additional energy from being delivered along those facilities.[145] As a result, energy with a higher marginal cost from other areas without transmission constraints must be dispatched.[146] This curtailment creates inefficiencies in the wholesale energy market and increases costs.[147]

Figure 9 below illustrates how transmission constraints affect the energy used and pricing in a single moment of time. The illustration assumes an energy need of 1,100 megawatts (MW) that could be supplied by two potential generators, one at a marginal cost of $20 per MW and one at a marginal cost of $100/MW.[148]

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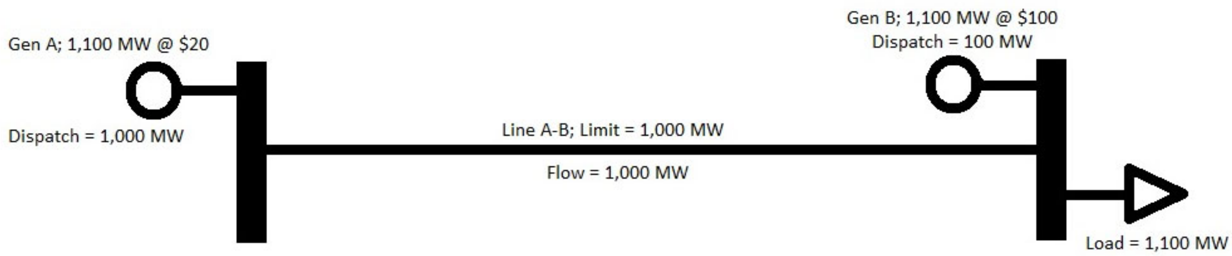
138 Standing Aff. ¶ 67.
139 Id.
140 Standing Aff. ¶¶ 69-70.
141 Standing Aff. ¶¶ 70-71.
142 Standing Aff. ¶ 72.
143 Standing Aff. ¶¶ 72-73.
144 See Standing Aff. ¶¶ 73-74.
145 Standing Aff. ¶ 73.
146 Standing Aff. ¶¶ 72-74.
147 Standing Aff. ¶¶ 72-74.
148 Standing Aff. ¶ 76.

Figure 9[149]
Transmission Constraint Illustration



In this theoretical intact system, Generator A has the generation capacity to serve the entire 1,100 MW needed at a marginal cost of $20/MW but cannot do so because of the 1,000 MW transmission capacity limit on Line A-B.[150] Instead, Generator A's dispatch is limited to 1,000 MW and Generator B will be called on to deliver the remaining 100 MW at a marginal cost of $100/MW.[151] If Generator A were able to deliver the entire 1,100 MW it can generate, the energy cost would be $22,000 assuming no energy is lost during transmission.[152] Due to system constraints, the total cost to deliver the 1,100 MW rises to $30,000 because 100 MW cannot be delivered, and more expensive replacement energy is required from Generator B (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B).[153] The upshot is the transmission limits lead to inefficiencies whereby the overall cost of energy increases to $8,000 or 36% in this simplified example.[154] When there is sufficient transmission capacity, the lowest-cost generator, regardless of fuel source, is the one that serves load.

Transmission constraints have become an increasingly significant factor in MISO, including in MISO Zone 1, which includes the Project area.[155] The analysis of the Project's benefits in the following section demonstrates the increases in transmission capacity provided by the Project is forecasted to produce significant savings as a result of more efficient market operation.

(2) APC Benefits of the Project

The Company used PROMOD to analyze the APC savings from the Project. The Company performed this analysis using MISO's MTEP21 Future 1, MISO's MTEP21 Future 2, which assumes a higher level of decarbonization and renewable generation

[149] Standing Aff. Figure JS-2.
[150] Standing Aff. ¶ 77.
[151] Standing Aff. ¶¶ 78-79.
[152] Standing Aff. ¶ 80.
[153] Standing Aff. ¶ 81.
[154] Standing Aff. ¶ 82.
[155] Standing Aff. ¶¶ 69-74.

than Future 1 along with higher load growth resulting from electrification, and an adjusted version of Future 1 that takes account of the Company's current resource plans and recent procurements.[156] Schedule 4 of the Affidavit of Jason Standing provides the assumptions the Company used in adjusting Future 1. **Tables 8, 9 and 10** show the present value of forecasted APC benefits over a 20-year period and a 40-year period.[157] Benefits are shown for both MISO as a whole and MISO Local Resource Zone 1 (LRZ1).[158]

Table 8[159]
APC Savings Benefits of the Project under MTEP21 Future 1 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$509.05	$684.8
40 Year Present Value	APC Benefits ($Millions)	$806.8	$1,083.5

Table 9[160]
APC Benefits of the Project under MTEP21 Future 2 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$796.3	$654.2
40 Year Present Value	APC Benefits ($Millions)	$1,218.3	$912.9

156 Standing Aff. ¶ 86.
157 Standing Aff. ¶ 90.
158 Id.
159 Standing Aff. Table JS-3.
160 Standing Aff. Table JS-4.

Table 10[161]
APC Savings Benefits of the Project under MTEP21 Future 1 Model With Xcel Energy's Upper Midwest IRP Generation Added

Timeline	APC Benefit	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$2,061.8	$2,316.7
40 Year Present Value	APC Benefits ($Millions)	$3,758.6	$4,185.1

Notably, the benefits are highest under the adjusted version of Future 1, which is the scenario that is likely most accurate for the relevant portion of MISO as it reflects Xcel Energy's plans with regard to resource additions.[162] Also, given the expected lives of transmission assets, 40 years of benefits is more realistic than 20 years.[163]

B. Cost Sharing

MISO has determined that the Project, along with the other projects in MISO LRTP Tranche 1 portfolio, meets the criteria for a MVP under the terms of Attachment FF to the MISO Tariff.[164] Consequently, the Project (and the rest of the LRTP Tranche 1 portfolio), qualifies for regional cost allocation. MISO stated in its MTEP21 Addendum that "[a]s Multi-Value Projects, the cost of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion."[165] The allocation of the Project's costs to transmission customers is governed by Schedule 26-A, Multi-Value Project Usage Rate, in MISO's tariff.[166] The annual revenue requirement for the Project is determined by the formula rate in Attachment MM-MVP Charge in the MISO Tariff. Withdrawing Transmission Owners in the MISO Midwest Subregion pay the annual revenue requirement through Schedule 26-A charges assessed based on actual monthly energy consumption by customers.[167]

Customers of the NSP system will be allocated a share of the annual revenue requirement for the LRTP Tranche 1 projects based on the annual load share of the

[161] Standing Aff. Table JS-5.
[162] Standing Aff. ¶ 91.
[163] Standing Aff. ¶ 89.
[164] Standing Aff. ¶ 92, Sch. 2 (MTEP21 Report Addendum) at 68.
[165] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 68-69. The MISO Midwest Subregion includes MISO transmission customers in North Dakota, South Dakota, Minnesota, Montana, Iowa, Wisconsin, Missouri, Illinois, Indiana, Michigan, and Kentucky. Id., Executive Summary at 4.
[166] Standing Aff. ¶ 92; MISO Tariff at Attachment MM.
[167] Standing Aff. ¶ 92; MISO Tariff at Attachment MM.

NSP companies. MISO provided an indicative estimate of these MVP usage charges by pricing zone in Appendix A-4 of MTEP21, which indicated that load share is approximately 11.3%.[168] Costs will then be allocated to North Dakota customers based on the allocators then in effect. Currently, we would expect North Dakota customers to pay approximately 0.6% of the overall revenue requirement for the LRTP Tranche 1 Portfolio.[169] As this cost-sharing was approved pursuant to MISO's FERC-approved tariff, it does not depend on the outcome of this proceeding for either the Project or the other LRTP projects.

Schedule 5 to the Affidavit of Jason Standing provides revenue requirement calculations for the NSP system (both Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW)), which are then adjusted to a North Dakota jurisdictional basis for NSPM. These revenue requirement calculations do not account for any future operation and maintenance costs for the Project or fuel impacts. These revenue requirement calculations assume that the Project is jointly-owned as anticipated.

V. ALTERNATIVES

As part of its MTEP21 process, MISO considered multiple alternatives to each of the 18 projects in the LRTP Tranche 1 portfolio.[170] In that evaluation, MISO analyzed this Project together with the LRTP1 project as the two projects are together meant to address issues resulting from constraints on the 230 kV system in eastern North Dakota, eastern South Dakota, and western and central Minnesota.[171] MISO considered five alternatives to LRTP1 and LRTP2. Those alternatives are:

- **Alternative 1:** Big Stone South – Alexandria 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;
- **Alternative 2:** Big Stone South – Hankinson – Fergus Falls 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;
- **Alternative 3:** Big Stone South – Hazel Creek – Blue Lake 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;

[168] Standing Aff. ¶ 93; MISO LRTP Tranche 1 MTEP21 Appendix A-4 Schedule 26A *available at* https://cdn.misoenergy.org/LRTP Tranche 1 Appendix A-4 Schedule 26A Indcative625788.xlsx.
[169] Standing Aff. ¶ 93.
[170] Standing Aff. ¶ 17.
[171] Id.

- **Alternative 4:** Big Stone South – Alexandria 345 kV transmission line, Big Stone South –Hazel Creek – Blue Lake 345 kV transmission line, and Jamestown – Ellendale 345 kV transmission line; and

- **Alternative 5:** Big Stone South – Breckenridge – Barnesville 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line.[172]

MISO concluded that none of the options it analyzed is a more reasonable or prudent alternative. MISO concluded that the alternatives are not more reasonable or prudent for the following reasons:

- **Alternative 1:** Without double-circuit Eastern Segment to Big Oaks, there are new N-1 issues around Alexandria;

- **Alternative 2:** While this alternative resolves overloads of concern on the 230 kV system around Wahpeton, North Dakota, it creates new issues on the 230 kV and 115kV systems around Fergus Falls, Minnesota;

- **Alternative 3:** This alternative reduces nearly all overloads of concern, but not to the same extent as the Project and LRTP1;

- **Alternative 4:** This alternative, a combination of alternatives 1 and 3, fully relieves the reliability issues of concern, but (a) creates new overloads on the 115 kV system around Alexandria, Minnesota, and (b) the southern circuit to Blue Lake does not add sufficient additional value; and

- **Alternative 5:** This alternative solves many of issues of concern without creating new issues but leaves a few key overloads on the 230 kV system around Wahpeton, North Dakota unresolved.[173]

Xcel Energy also considered multiple alternatives to the Project in addition to those studied by MISO. These alternatives include: (i) size alternatives (different voltages); (ii) type alternatives (direct current (DC) lines, underground lines, and alternative conductors); and, (iii) the no build alternative.[174] After its review, Xcel Energy

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[172] Standing Aff. Sch. 2 (MTEP21 Report Addendum) at 25.
[173] Id.
[174] Standing Aff. ¶¶ 19-44.

determined that none of those other options are more reasonable and prudent of alternatives than the Project.[175]

VI. PRUDENCE OF THE PROJECT

The Project arises out of MISO's LRTP planning process and is needed because the existing 230 kV system in eastern North Dakota, eastern South Dakota, and western and central Minnesota is at capacity. The analyses carried out by both MISO and the Company show that adding the Project will improve transmission system reliability in North Dakota, South Dakota, and Minnesota. The Project, including the portions in which Xcel Energy will have an ownership interest, will serve the public need, and it has been approved by MISO. This Project will be subject to cost-sharing along with the rest of the LRTP Tranche 1 Portfolio.

LRTP2 is also prudent because its estimated costs, which will be shared among utilities in the Midwest Subregion of MISO, are significantly outweighed by the estimated benefits under the most realistic future scenario, MISO's MTEP21 Future 21 adjusted based on the Company's IRP. Benefits also exceed costs under all scenarios when accounting for 40 years of benefits, which is less than the expected life of a new transmission line. The Project has an estimated cost of between $606.5 million and $699.4 million (2022$). Using the Future 1 scenario adjusted based on the IRP, the Project has projected MISO-wide benefits of between $2,061.8 million and $3,758.6 million (the present value of 20-years and 40 years of APC benefits, respectively). The cost-benefit ratios for the Project based on those forecasted benefits and the high and low-cost estimates are between 2.95 and 6.2. For these reasons, the Project is a prudent and financially viable investment for enhancing regional transmission system reliability.

[175] Standing Aff. ¶¶ 19-44.

VII. CONCLUSION

For all the reasons set forth above, the Company respectfully requests the Commission grant an ADP for those portions of the Project in which the Company will have an ownership interest. The Project is needed to resolve issues with the existing 230 kV system in eastern North Dakota, eastern South Dakota, and western and central Minnesota, and it is projected to result in economic benefits that materially outweigh its costs.

Dated: October 13, 2023

Northern States Power Company

Respectfully submitted,

/s/
MONSHERRA S. BLANK
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

AFFIDAVIT OF MR. JASON STANDING

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the Big Stone South – Alexandria – Big Oaks 345 Kilovolt Transmission Line Project

Case No. PU-23-____

Exhibit 2 (JS-1)

STATE OF MINNESOTA)
IN THE)
COUNTY OF HENNEPIN)

I, Jason Standing, under oath, state:

I. Introduction

1. My name is Jason Standing. I am the Manager of Transmission Planning for Xcel Energy Services Inc. (XES), the service company subsidiary of Xcel Energy, Inc. (XEI), which provides services to the Applicant, Northern States Power Company, a Minnesota Corporation (Xcel Energy or the Company).

2. My business address is 414 Nicollet Mall – MP8, Minneapolis, Minnesota, 55401.

3. The Company is a utility operating Company subsidiary of XEI and provides vertically integrated utility service in Minnesota, North Dakota, and South Dakota.

4. I have worked for XES since March 2004 in the area of transmission planning.

5. I have been in my current position as Manager of Transmission Planning since 2019.

6. I oversee a team of engineers and policy experts involved in the development of transmission planning policy and regional transmission plans in the Midcontinent Independent System Operator, Inc. (MISO), and Southwest Power Pool

Regional Transmission Organizations, and the West Connect Order 1000 Transmission Planning organization.

7. Prior to my current position, I was a Transmission Analytics Engineer for XES.

8. I was an engineer for different companies before joining XES in roles involving distribution planning, system protection, substation design, field engineering, and project management.

9. My statement of qualifications is provided as Schedule 1.

10. I am providing this affidavit in support of the Application for an Advanced Determination of Prudence (ADP) filed by Xcel Energy for portions of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (the Project or LRTP2) in which the Company will have an ownership interest. Mr. Grant D. Stevenson provides a more fulsome description of the Project in his affidavit.

11. My affidavit addresses the development of the Project, the impacts the Project will have on the reliability of the transmission system, and the economic prudence of the Project.

II. Development of the Project

12. The Project is one of 18 projects in Midcontinent Independent System Operator, Inc.'s (MISO) Long Range Transmission Planning (LRTP) Tranche 1 portfolio.

13. MISO launched LRTP in 2019. It is a multi-year, multiphase process aimed at providing an orderly and timely plan for expansion of the transmission system. LRTP takes place within MISO's Transmission Expansion Plan (MTEP), which is itself provided for in Attachment FF of MISO's Electric Tariff (the MISO Tariff), which is on file at the Federal Energy Regulatory Commission (FERC).[1] The LRTP Tranche 1 projects were each evaluated based on the criteria for Multi-Value Projects (MVPs) set forth in Attachment FF of the MISO Tariff.

14. The LRTP Tranche 1 portfolio, including the Project, was approved by the MISO Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.

15. In the second quarter of 2022, MISO issued an Addendum to its MTEP21 Report that discusses the 18 LRTP projects, including LRTP2, the needs each project will address, and the economic and reliability analyses conducted by MISO. A true and correct copy of this Addendum (MTEP21 Report Addendum) is included as Schedule 2 to this affidavit.

16. In addition to the Project, the LRTP Tranche 1 Portfolio includes 17 other projects located in MISO's Midwest Subregion. One of those other projects is the proposed 345 kV transmission line from Jamestown, North Dakota to Ellendale, North Dakota, which MISO designated as LRTP1 (LRTP1). LRTP1 is also known as JETx

[1] The MISO Tariff, including its various attachments and schedules, can be found at: Tariff (misoenergy.org).

and will be co-owned by Otter Tail Power Company and Montana-Dakota Utilities, which have publicly indicated they plan to apply for a route permit from the Commission in 2024.[2]

III. Alternatives

17. As part of the MTEP21 process, MISO considered numerous alternatives to each of the projects in the LRTP Tranche 1 Portfolio. During that evaluation, MISO assessed this project together with the LRTP1 project because the two projects are meant to jointly address issues stemming from constraints on the 230 kV system in eastern North Dakota.

18. To that end, MISO considered five alternatives to LRTP1 and LRTP2 and concluded that none of those other options would have been a reasonable and prudent alternative to LRTP1 and LRTP2. MISO's analysis is set forth in the MTEP21 Report Addendum (Schedule 2).

19. The Project's owners themselves also reviewed various alternatives to the proposed project. Those alternatives include: (i) size alternatives (different voltages); (ii) type alternatives (direct current (DC) lines, underground lines, and alternative conductors); and, (iii) the no build alternative.

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[2] The LRTP1 project's website is: Jamestown to Ellendale Transmission Project.

A. Size Alternatives

20. The Project's owners evaluated the feasibility of different line voltages (both higher and lower) to relieve current capacity issues and to improve electric system reliability throughout the region.

21. In examining transmission alternatives to relieve congestion, the capacity of a single transmission line is an important consideration, as the amount of congestion present on the transmission system, in part, is a function of the amount of available transmission capacity on a single transmission line. Generally speaking, the higher the voltage of a transmission line, the higher capacity the line has to carry power, assuming the same current.

22. In the region, 345 kV is the standard high voltage that is utilized to transfer large amounts of power long distances. The 345 kV voltage is the standard because it provides sufficient capacity to accommodate large power transfers, can be easily incorporated into the existing transmission system, and minimizes line losses. Voltages higher than 345 kV are currently less utilized in this region and are reserved for long distance point-to-point power transfers (i.e., moving power from Manitoba's hydroelectric generation facilities).

23. Higher voltage 765 kV and 500 kV transmission lines were considered as alternatives to the proposed 345 kV transmission lines. However, 765 kV or 500 kV transmission lines are more expensive and would require the addition of new substation transformers. Specifically, integrating higher voltage lines with the existing electric

system, mainly comprised of 345 kV, 230 kV, 115 kV, 69 kV, and 41.6 kV lines in the Project area, would require installation of additional transformers at the existing Big Stone South Substation, the existing Alexandria Substation, the existing Riverview Substation, and at the new Big Oaks Substation.

24. A 500 kV or 765 kV transmission line would also require a wider right-of-way than the proposed 345 kV transmission line. A 500 kV or a 765 kV transmission line would require at least 200 feet of right-of-way while a 345 kV transmission line only requires 150 feet of right-of-way.

25. Given the increased costs, the Project's owners concluded that higher transmission lines above 345 kV are not a more reasonable or prudent alternative to the proposed Project.

26. The Applicants also analyzed lower voltage alternatives to the Project. As there are existing 230 kV, 115 kV, 69 kV, and 41.6 kV transmission lines in the Project area, these voltages were considered as alternatives to the proposed 345 kV transmission line.

27. The Project is designed to address issues on the heavily constrained 230 kV system in eastern North Dakota and South Dakota and western and central Minnesota. Given the lower capacity of 115 kV, 69 kV, and 41.6 kV transmission lines, the Project's owners eliminated those lower voltage alternatives from further study as these voltages would not have sufficient capacity to meet the need the Project is designed to address.

28. The existing 230 kV system in the Project area is currently heavily congested, so it is beneficial to install transmission facilities with voltages greater than 230 kV to unload the existing 230 kV system. In addition, the cost of a 345 kV line is similar to 230 kV, but allows for significantly greater capacity to support future generation in the Project area.

29. Another consideration is that integrating a new line at the 345 kV voltage fits into the existing system and will not require as many additional substation facilities as would be the case with a lower voltage line. The existing Big Stone South and Alexandria substations already have 345 kV infrastructure such that additional transformation is not required. If a lower voltage alternative such as 230 kV or 115 kV is selected, additional transformers might be needed at these substations resulting in increased costs.

30. Lower voltage lines also tend to have higher losses than higher voltage lines, which was an additional consideration.

31. Based on the analysis discussed above, the Project's owners determined that lower voltages are not a more reasonable or prudent alternative to the Project.

B. Type Alternative

1. Alternative Routes

32. One form of type alternative is to construct one or more alternative projects with different beginning and end points. MISO analyzed multiple such

alternative routes, which are discussed in the MTEP21 Report Addendum (Schedule 2), and concluded that none was a more prudent alternative.

2. Direct Current Line

33. A High Voltage Direct Current (HVDC) line was considered as a possible alternative. An HVDC transmission system consists primarily of a converter station, in which the AC voltage of the conventional power grid is converted to HVDC voltage, a transmission line, and another converter station at the other end, where the voltage is converted back into AC.

34. HVDC transmission lines are generally employed to deliver generation over a considerable distance, more than 300 miles, to a load center. HVDC systems typically do not allow for cost-effective interconnections along the line.

35. While line losses and conductor costs associated with HVDC lines are generally less than those associated with high voltage AC lines, HVDC lines also require expensive converter stations at each end point of the line to convert power from AC to DC and DC to AC. HVDC converter stations do not eliminate the need for AC substation facilities that would be required after the power is converted back to AC. There are also extended lead times (6 years or more) for HVDC systems.

36. Converter stations for 500 to 600 kV HVDC lines can range from approximately $400 million to $500 million. Given the substantial additional cost imposed by the required HVDC converter stations and the extended lead times, the

Project's owners concluded that HVDC is not a more prudent or reasonable alternative to the proposed Project.

3. Underground Line

37. Underground transmission, both AC and DC, were also considered as possible alternatives.

38. High voltage AC underground cable systems at 345 kV are generally limited in length to approximately 50 miles or less because of its impact on reactive power. While longer installations can be constructed with the addition of shunt reactors along the line, this is an atypical design and practical applications of underground high voltage AC lines for more than 50 miles are cost prohibitive due. High voltage DC cable systems are used for underground lines of approximately 100 miles or more. High voltage DC systems do not have the same reactive power limitations and line losses as high voltage AC underground cable systems. However, high voltage DC cable systems require costly converter stations on each end of the line and do not readily accommodate interconnections at midpoints along the lines.

39. Indicative estimates for underground high voltage DC over 100 miles are $25 million or more per mile, depending on the ultimate design. As with any high voltage DC option, the costs of two converter stations would be approximately $800 million to $1 billion. Construction costs for AC underground transmission are anticipated to be similar to underground high voltage DC but would not require converter stations. The Project's owners developed a cost estimate to underground two

miles of a 345 kV line using an open trench construction method of at least $20 million per mile (2023$). In addition, specific features of a given underground line can further increase costs.

40. An underground line would also not be able to take advantage of the existing double-circuit capable structures that will be used for much of the Project's Eastern Segment, which is one aspect of the Project that keeps costs lower than they would otherwise be.

41. Based on the costs, the Project's owners determined that the underground design is not a reasonable alternative.

4. Generation and Storage Alternatives

42. The Project's owners also considered the addition of new generation resources as alternatives. Transmission congestion occurs when there is not enough transmission capacity to support all generation output at a particular time. Thus, regardless of the type of the generation facility evaluated, construction of additional generation facilities would: (1) further exacerbate the congestion already present on the system; (2) result in underutilization of existing generation resources; and (3) likely be more costly than the proposed Project. In addition, the LRTP Tranche 1 Portfolio was designed to address the needs of the MISO Midwest subregion and it is not likely or cost effective that a generation alternative would be able to provide the regional benefits needed in the MISO Midwest subregion. Energy storage was determined to not be a reasonable alternative to the proposed Project because in order to provide the same

amount of congestion relief as the proposed Project, an energy storage solution would need to be a large and costly facility.

5. Alternative Conductors

43. The conductor used for the Project has not yet been determined and will be based on the results of a conductor optimization study. This conductor optimization study will identify the optimal conductor configuration or configurations for the Project based on a technical and economic analysis of different conductor sizes and configurations.

6. No Build Alternative

44. The no-build alternative was considered, but would not relieve the existing issues with the 230kV system in eastern North Dakota, eastern South Dakota, and western and central Minnesota. It would also not add additional transmission capacity or provide the economic benefits the Project is forecasted to create.

IV. Project Benefits

A. Reliability Benefits

45. As discussed in the MTEP21 Report Addendum, the Project and the LRTP Project designated as LRTP1 were designed to address reliability issues with the 230kV system in eastern North Dakota, eastern South Dakota, and western and central Minnesota. MISO's analysis of the impact of the proposed Project and LRTP1 is discussed in the MTEP21 Report Addendum (Schedule 2).

46. In addition to MISO's analysis, the Company also conducted its own reliability analyses.

47. The Company analyzed the impact of the Project on the reliability of the transmission system in two different scenarios.

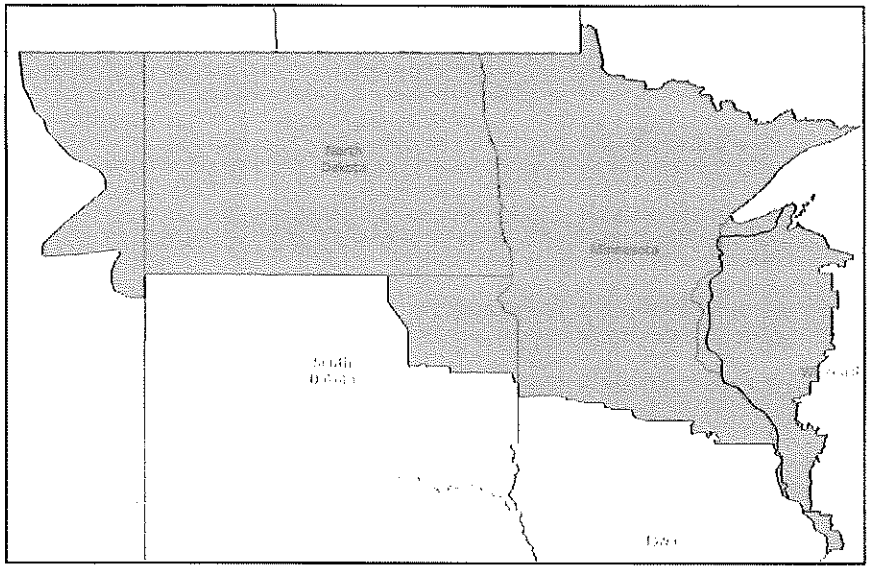
48. The first scenario used MISO's MTEP22 model of the transmission system and assumed no additional generation resources have been added to the system.

49. The second scenario, based on year 20 of Future 1 from MISO's 2021 MTEP, which is detailed in the MISO 2021 Futures Report attached as Schedule 3, was used to analyze the impact of the Project at a time when additional generation will have been added to the system.

50. In analyzing the project's impact in the near-term future *without* added generation, and in the longer term *with* added generation, the Company focused on the summer shoulder season, with high winds, which represents a time of year and weather condition in which the transmission system in the area is particularly stressed.

51. The Company's analysis studied reliability in the MISO Local Resource Zone 1 (LRZ1) area, which is shown in **Figure JS-1** below.

Figure JS-1
MISO Local Resource Zone 1



52. The Company's reliability analyses studied all NERC contingency categories (P1-P7) and looked at facility overloads under a variety of transmission modelling assumptions, including: (1) Base Model – assuming no additional transmission projects are constructed (*i.e.*, the current base transmission system remains in place); (2) Only LRTP2 – assuming the Project is constructed, but no other LRTP Tranche 1 projects are constructed; (3) All LRTP Tranche 1 projects except LRTP2 – assuming construction of all LRTP Tranche 1 projects except the Project; and (4) LRTP Tranche 1 – assuming construction of all LRTP Tranche 1 projects.

53. The MISO LRTP Tranche 1 is a portfolio of 18 individual projects designed to work together to provide benefits, but the Company's reliability analysis provides an alternative way to look at the reliability improvements resulting from the

Project. The results follow and illustrate the overloads that this Project's implementation will alleviate.

1. Without Added Generation – Reliability Results

54. The Company conducted an analysis for the LRZ1 area based on the MISO MTEP22 transmission system model assuming no additional generation is added to the system. This analysis looked at the year 2027, which is nearest to MISO's approved in-service date for the Project, to show improvements to system reliability related to the construction of the Project.

55. **Table JS-1** below delineates the results of this analysis. The table contains the "Overloaded Facilities" and provides the number of different contingencies that cause thermal issues on the facility listed for each transmission model studied. The table also includes the "Fixed By LRTP2" column showing the number of thermal issues that are resolved with implementation of the Project.

56. The number of thermal issues resolved by the Project reflects issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model. A thermal overload was considered to be resolved by the Project if it showed up in the "Base Model" but not the "LRTP2" model or full "Tranche 1" model. Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.

Table JS-1

Totals			MTEP22 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	8956	4503	7	0	4480
Helena - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	5042	4508	13	0	559
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4453	2	0	0	4451
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4394	0	0	0	4394
Big Stone - Highway 12 115 kV Ckt 1	SD	N-1, N-1-1	582	0	2	0	582
Highway 12 - Ortonville 115 kV Ckt 1	SD, MN	N-1, N-1-1	301	0	1	0	301
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	270	2	0	0	268
Ortonville - Ortonville Quarry 115 kV Ckt 1	MN West	N-1, N-1-1	259	0	0	0	259
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	182	0	58	0	182
Hoot Lake - Fergus Falls 115 kV Ckt 1	MN West	N-1, N-1-1	171	0	1	0	171
Sheyenne - Lake Park 230 kV Ckt 1	ND	N-1, N-1-1	167	0	167	0	167
Audubon - Lake Park 230 kV Ckt 1	MN West	N-1, N-1-1	167	0	167	0	167
Inman - Wing River 230 kV Ckt 1	MN West	N-1, N-1-1	139	0	0	0	139
Big Stone - Big Stone South 230 kV Ckt 2	SD	N-1, N-1-1	85	0	83	0	85
Wahpeton - Fergus Falls 230 kV Ckt 1	MN West	N-1, N-1-1	83	0	0	0	83
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	55	0	0	0	55
Big Stone - Big Stone South 230 kV Ckt 1	SD	N-1, N-1-1	27	0	27	0	27
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	5	0	0	0	5

57. As shown in the last column of **Table JS-1**, the major reliability benefits of the Project are evident on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in eastern North Dakota and South Dakota and western Minnesota. For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Scott County – Blue Lake and from Helena – Chub Lake has a large number of thermal issues that the Project's addition mitigates.

58. Numerous areas on the underlying 230 kV and 115 kV systems that also derive reliability benefits, such as the areas around the Big Stone, Wahpeton, Morris, Sheyenne, and Audubon substations.

59. The Company also analyzed the LRZ1 area based on the MISO MTEP21 Future 1 (at year 20) to show the Project's system-reliability impacts in the future when additional generation is expected to be online. The results—shown below—illustrate the Project's impact under a high wind model with the added generation that the LRTP Tranche 1 Portfolio will enable.

60. **Table JS-2** below contains the results of this analysis. It lists the overloaded facilities and provides the number of different contingencies that cause thermal issues on the overloaded facility for each transmission model studied. The table also includes the "Fixed by LRTP2" column showing the number of thermal issues that are resolved by the Project.

61. The number of thermal issues resolved by the Project reflects thermal issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model. A thermal overload was considered to be resolved by the Project if the overload showed up in the "Base Model" but not the "LRTP 2" model or full "Tranche 1" model. Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.

Table JS-2

Totals			F1Y20 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Tamarac - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36957	46967	54054	43711	17092
Cormorant Junction - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36867	46349	54151	2006	22945
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6740	7	0	0	6736
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6685	7	0	0	6681
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	3758	0	2	0	3760
North Rochester - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	1498	1552	43845	7622	36133
Tamarac - Pelican Rapids 115 kV Ckt 1	MN West	N-1, N-1-1	309	139	275	99	184
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	233	116	175	126	121
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	123	0	0	0	123
Big Stone - Browns Valley 230 kV Ckt 1	SD	N-1, N-1-1	98	0	0	0	98
Browns Valley - New Effington 230 kV Ckt 1	SD	N-1, N-1-1	74	0	0	0	74
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1-1	16	0	2	0	18
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	6	0	0	0	6

62. The Project's major reliability benefits are evident on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in western Minnesota and eastern South Dakota. For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Chub Lake and Blue Lake – Scott County – North Rochester

has a large number of thermal issues mitigated with the addition of the Project. There are also several areas on the underlying 230 kV and 115 kV systems that see reliability benefits, such as the areas around the Big Stone, Browns Valley, Tamarac, Cormorant, and Morris substations.

B. Economic Benefits

1. MISO's Economic Analysis of LRTP Tranche 1 Portfolio

63. MISO designed the LRTP Tranche 1 Portfolio primarily to address reliability issues, but MISO also estimated the economic benefits of the portfolio of projects and compared those benefits to the estimated forecasted costs.

64. MISO projects that the MISO LRTP Tranche 1 Portfolio will provide $23.2 billion to $52.2 billion in net economic savings over the first 20 to 40 years (respectively) of the portfolio's service – a benefit to cost ratio range of 2.6 to 3.8. A discussion of that analysis and the results is contained in the MTEP21 Report Addendum, Schedule 2.

2. The Company's Economic Analysis

a. Economic Analysis Generally

65. The Company used the PROduction MODeling (PROMOD) computer modeling program to evaluate the economic impact of the Project—an industry standard for market simulation software that provides geographically and electrically detailed representations of the topology of the electric power system, including generation resources, transmission resources, and load. The model can consequently

capture the effect of transmission constraints on the ability to flow power from generators to load and can calculate future estimated costs of producing electricity, transmission costs, and energy losses based on these assumptions.

66. The Company typically analyzes the economic impacts of a transmission project by considering the project's impact on adjusted production cost (APC); comprised of the total production costs of a generation fleet including fuel, variable operations and maintenance, startup cost, and emissions, adjusted for energy market sales and purchases.

67. If a project produces APC savings, those are the estimated benefits of the project. The Company then compares those estimated APC savings to project costs and other impacts.

68. APC does not account for the capital costs of transmission projects, though APC savings can be compared to the capital cost of projects and revenue requirements to evaluate whether the investment is projected to lead to net savings.

b. Congestion Overview

69. The MISO electric transmission system currently has insufficient transmission capacity.

70. Insufficient transmission capacity is a problem of increasing importance within MISO.

71. MISO operates day-ahead and real-time wholesale energy markets.

72. Limited transmission capacity impairs the efficient operation of these markets by impairing MISO's ability to dispatch power with the lowest marginal cost, thereby increasing wholesale energy costs.

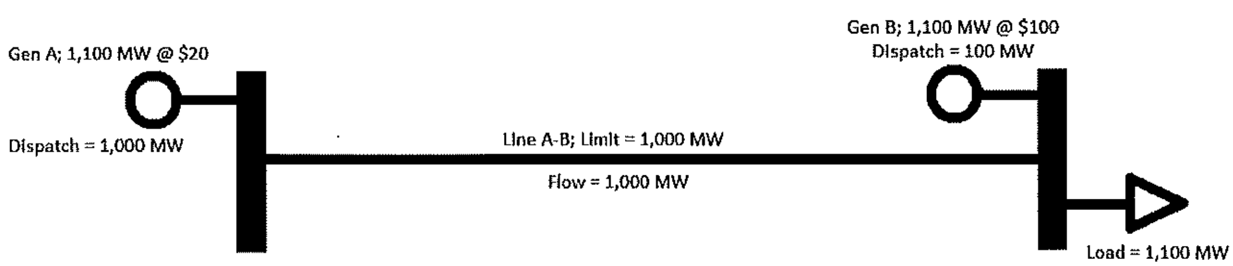
73. In fact low-marginal-cost energy is currently available in MISO but constraints stemming from congestion prevent that low-cost power from serving load centers.

74. Consequently, the system must dispatch energy with higher marginal costs, thereby increasing costs and generating inefficiency in the wholesale energy market.

75. Figure JS-2 illustrates how congestion—and the ensuing transmission constraints—affect the energy used and pricing in a single moment of time.

76. The illustration assumes an energy need of 1,100 megawatt (MW) that could be supplied by two potential generators, one at a marginal cost of $20 per and one at a marginal cost $100/MW.

Figure JS-2:
Congestion Illustration



77. Generator A has the generation capacity to serve the entire 1,100 MW needed at a marginal cost of $20/MW but cannot do so because of the 1,000 MW transmission capacity limit on Line A-B.

78. Instead, Generator A's dispatch is limited to 1,000 MW.

79. Consequently, Generator B must instead deliver the remaining 100 MW at a marginal cost of $100/MW.

80. If Generator A were able to deliver the entire 1,100 MW it can generate, the marginal energy cost to serve the entire load would be $22,000, assuming no energy is lost during transmission.

81. The marginal cost to deliver the entire 1,100 MW rises to $30,000 because 100 MW cannot be delivered due to system constraints and therefore Generator B must supply more expensive replacement energy (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B).

82. Accordingly, the congestion causes the marginal cost of energy to serve the 1,100 MW to increase $8,000 or 36 percent in this simplified example.

By comparison, the lowest-cost generator would serve the demand if there were sufficient transmission capacity.

c. Assumptions and Time Periods Used for the PROMOD Company's Analysis

83. To analyze Project benefits, PROMOD requires various assumptions regarding future conditions.

84. MISO, in coordination with stakeholders, develops a variety of future scenarios or "Futures" under which to study potential transmission projects.

85. Each Future contains different assumptions as to future demand and energy levels; fuel prices; generation retirements and additions; and potential environmental regulations.

86. The Company analyzed the Project using assumptions from MISO's MTEP21 Future 1, MISO's MTEP21 Future 2, which assumes a higher level of decarbonization and renewable generation than Future 1 along with higher load growth resulting from electrification, and an adjusted version of Future 1 that takes account of the Company's current resource plans and recent procurements. The MISO Futures are detailed in the MISO 2021 Futures Report attached as Schedule 3. Schedule 4 to this Affidavit provides the assumptions the Company input to PROMOD for its adjusted version of Future 1.

87. PROMOD provides results for a 20-year period.

88. 20 years is the period MISO typically uses to calculate APC savings for projects subject to regional cost-sharing. The 20-year period ensures the benefits used to justify the project are realized well before the end of the project's useful life.

89. Using the trend-line from the 20-year APC data, the Company also estimated the projected APC savings for a 40-year period. The book life of the Project is approximately 63 years, and the Project should provide benefits to customers over

that full life, so the 40-year period is closer the length of time over which the Project is expected to provide benefits.

d. Results of the Company's PROMOD Analysis

90. **Tables JS-3, JS-4** and **JS-5** show the present value of forecasted APC benefits over a 20-year period and a 40-year period. Benefits are shown for both MISO as a whole and MISO Local Resource Zone 1 (LRZ1).

Table JS-3
APC Savings Benefits of the Project under MTEP21 Future 1 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$509.05	$684.8
40 Year Present Value	APC Benefits ($Millions)	$806.8	$1,083.5

Table JS-4
APC Benefits of the Project under MTEP21 Future 2 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$796.3	$654.2
40 Year Present Value	APC Benefits ($Millions)	$1,218.3	$912.9

Table JS-5
APC Savings Benefits of the Project under MTEP21 Future 1 Model with Xcel Energy's Upper Midwest IRP Generation Added

Timeline	APC Benefit	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$2,061.8	$2,316.7
40 Year Present Value	APC Benefits ($Millions)	$3,758.6	$4,185.1

91. The benefits are largest under the analyses that are based on Future 1, as adjusted to reflect the Company's Upper Midwest IRP.

V. Revenue Requirements

92. MISO has determined that the Project, along with the other projects in MISO LRTP Tranche 1 portfolio, meets the criteria for a MVP under the terms of Attachment FF to the MISO Tariff. As a result, the LRTP Tranche 1 portfolio, including the Project, qualifies for regional cost allocation. The cost of the Project will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. The annual revenue requirement for the Project is determined by the formula rate in Attachment MM-MVP Charge in the MISO Tariff. Withdrawing Transmission Owners in the MISO Midwest Subregion pay the annual revenue requirement through Schedule 26-A charges assessed based on actual monthly energy consumption by customers.

93. Customers of the NSP System will be allocated a share of the annual revenue requirement determined based on the percent of energy used by the NSP

companies. MISO provided an estimate of these MVP usage charges by pricing zone.[3] After allocation between NSP-Wisconsin and NSP-Minnesota pursuant to the FERC-approved Interchange Agreement and jurisdictional allocation within NSP-Minnesota, the Company's North Dakota customers can expect to pay approximately 0.6 % of the costs of the LRTP Tranche 1 Portfolio.

94. Schedule 5 to this Affidavit provides revenue requirement calculations for the NSP system (both Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW)), which are then adjusted to a North Dakota jurisdictional basis for NSPM. These revenue requirement calculations do not account for any future operation and maintenance costs for the Project or fuel impacts. These revenue requirement calculations assume that the Project is jointly owned as anticipated.

95. The revenue requirements projections in Schedule 5 do not account for future operation and maintenance expenses for the Project or fuel impacts.

VI. Conclusion

96. The Project is a prudent addition to the transmission system because it will provide substantial reliability benefits as discussed above and in the MTEP21 Report Addendum (Schedule 2). It is also forecasted to create substantial economic benefits.

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[3] MISO LRTP Tranche 1 MTEP21 Appendix A-4 Schedule 26A *available at* https://cdn.misoenergy.org/LRTP Tranche 1 Appendix A-4 Schedule 26A Indcative625788.xlsx.

[SIGNATURE PAGE FOLLOWS]

Further, Affiant sayeth not.

Jason Standing

Subscribed and sworn to before me
This 12th day of October, 2023

Notary Public

JODI LYNN YANZ
NOTARY PUBLIC
MINNESOTA
My Commission Expires 01/31/2027

SCHEDULE 1:
STATEMENT OF QUALIFICATIONS
MR. JASON STANDING

Jason T. Standing

SUMMARY

Degreed Electrical Engineer experienced in management in government, commercial, and utility markets. Capable of satisfying customer needs and expectations through creative engineering problem solving techniques and accurate communications.

PROFESSIONAL EXPERIENCE

Xcel Energy, Minneapolis, MN 2019-current
Manager Transmission Planning, NSP/NSPW

- Lead a team of transmission experts to develop long-term plans to ensure reliable transmission operations
- Coordination of diverse groups of contributors to develop regional and local plans
- Serve as expert witness in state permitting and regulatory process
- Develop future planning tools and processes to help with the grid of the future

Xcel Energy, Minneapolis, MN 2015-19
Principal Transmission Planning Engineer

- Lead Transmission Planning engineer for the Twin Cities area
- Responsible for training new Transmission Planning engineers
- Involved in local and regional policy with states and RTOs
- Develop computer programming skills and incorporate into Transmission Planning

Xcel Energy, Minneapolis, MN 2014-15
PROMOD Planning Engineer

- Provide Production Cost Modeling for the NSP area
- Evaluate transmission project impacts to generation
- Congestion analysis

Xcel Energy, Minneapolis, MN 2004-14
Senior Specialty Transmission Planning Engineer

- Responsible for leading and improving the Constructability I process for which all new transmission projects must be approved through
- Lead Technical expert for the Hiawatha Certificate of Need
- Lead the MISO MTEP process for NSP and NSPW areas
- Involved with neighboring and regional entities to create cost effective solutions to the regional and bulk transmission issues
- Work closely with MISO to ensure Xcel Energy's interests are being heard through multiple working groups

Wunderlich-Malec Systems, Minnetonka, MN 2002-2003
Project Manager

- Managed the design, electrical system analysis, and procurement for substation projects

- Responsible for delivering cost analysis to the customer, preparing equipment bids, while monitoring expenses
- Provided field support for the construction team to ensure that the substation was delivered on time and to the customer's satisfaction

Design Engineer

- Lead design engineer for the American Transmission Company's new 69 kV substation
- Lead engineer responsible for accurate settings of the system protection relays
- Responsible for ensuring the NEC codes were followed
- Created new drawing sets while updating old drawing sets to ensure accuracy for the customer

Sebesta Blomberg and Associates, Roseville, MN 2000-2002
Project Engineer

- Commissioning specialist whose duties included creating test sheets for various types of electrical equipment, field visits, overseeing testing specialists at the Pentagon and other commercial sites
- Design engineer who used creative problem-solving techniques to redesign customer's 230 kV and 115 kV breaker control panels.
- Developed load flow and system protection studies

Alliant Energy, Madison, WI 1999-2000
Distribution Systems Planner

- Responsible for running load flow analysis for the southern Wisconsin electrical distribution and transmission systems
- Involved in maintaining and updating existing computer models to reflect changes to the physical system
- Prepared cost analysis reports for management

EDUCATION

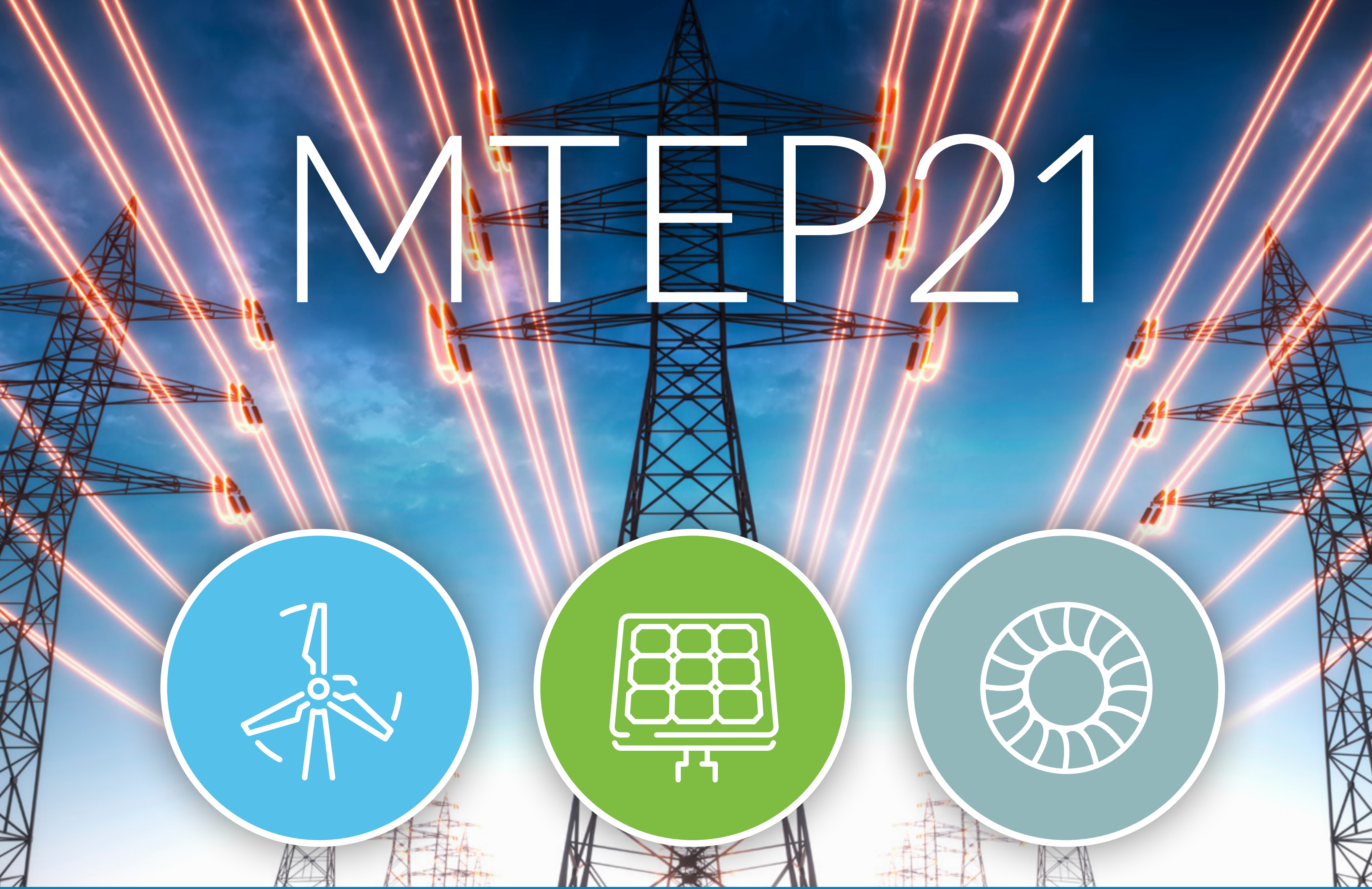
B.S. in Electrical Engineering, North Dakota State University, Fargo, ND 1999
MBA, University of Minnesota, Minneapolis, MN 2011
Profession Engineer Minnesota, PE 2012

COMPUTER EXPERIENCE

PSSE, PROMOD, Synergi, SKM Power Tools, Microsoft Office

SCHEDULE 2:
MTEP2021 REPORT ADDENDUM

MTEP21



MTEP21 REPORT ADDENDUM:
LONG RANGE TRANSMISSION PLANNING TRANCHE 1
EXECUTIVE SUMMARY

Highlights

- This addendum proposes a portfolio of 18 transmission projects located in the MISO Midwest Subregions with a total investment of $10.3 billion, and benefit-to-cost ratios average of 2.6, where benefits well exceed costs

- This Tranche 1 portfolio of least-regrets transmission projects will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change over the next 20 years

- The Tranche 1 portfolio, with more than 2,000 miles of transmission line, represents the most complex transmission study efforts in MISO's history

MISO

misoenergy.org

MISO's Long Range Transmission Planning to address the Reliability Imperative: Tranche 1 Portfolio

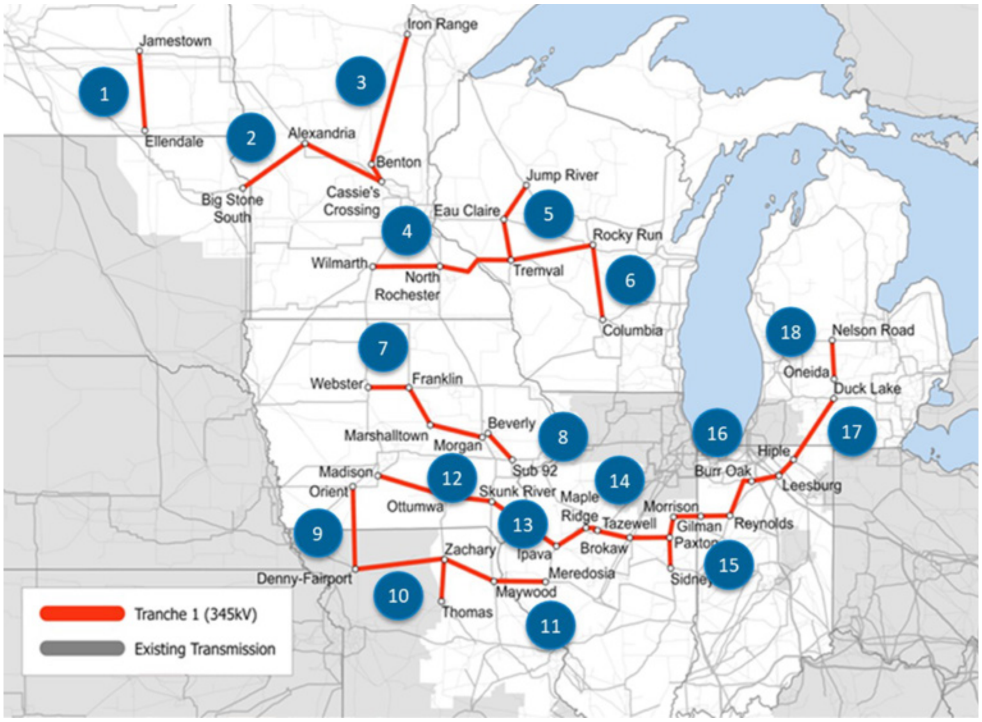
The *Long Range Transmission Planning (LRTP) Tranche 1 Portfolio* report presents the study findings and benefits analysis associated with the development of regional transmission solutions needed to provide reliable and economic delivery of energy. The report proposes a set of least-regrets transmission projects that will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change and represents the largest and most complex transmission study effort in MISO's history. Since the last major set of regional overlay projects was approved in 2011, the pace towards more variable renewable generation has increased. Carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery and hybrid projects. Indeed, the anticipated landscape changes are much more significant and require transformational changes at a faster rate than the previous 2011 portfolio of projects were built to accommodate.

The resulting urgency has required a much more intensive and focused effort. While it took four years to develop the 2011 portfolio of projects, this LRTP Tranche 1 portfolio, which is significantly larger in terms of the cost and line miles, came to fruition in less than half that time, without sacrifice of analytical quality or identification of robust solutions. The resulting portfolio includes 18 transmission projects located in the MISO Midwest subregion, with a total initial investment of $10.3 billion.

The LRTP Tranche 1 portfolio was developed to ensure that the regional transmission system can meet demand in all hours while supporting the resource plans and renewable energy penetration targets reflective of MISO member utilities' goals and state policies. LRTP approached transmission portfolios in tranches in part because the urgent needs identified by the Reliability Imperative are appearing in the near-term for the Midwest subregion, including retirements and resource portfolio changes. This more urgent need put the focus for Tranches 1 and 2 in the Midwest Subregion. Tranche 3 will shift to focus on the South Subregion, with Tranche 4 then looking to strengthen the connection between the Midwest and South subregions.

Further, reflecting the portfolio's urgency, the LRTP Tranche 1 portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way, which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high-value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environmental and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

In addition to the primary benefits of system reliability, the LRTP Tranche 1 portfolio meets the criteria for Multi-Value Projects defined in the Tariff through addressing policy, reliability or economic needs, meeting the minimum cost threshold, and exceeding a benefit-to-cost ratio of 1.0. The types of economic benefits that could be used to meet these criteria represent a broad range of benefits provided by this portfolio of projects.



ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

Figure 1: LRTP Tranche 1 portfolio includes 18 projects in MISO's Midwest Subregion, with an investment cost of $10.3 billion

QUANTIFIED BENEFITS INCLUDE:

- **Congestion and Fuel Savings** – LRTP projects will allow more low-cost resources to be integrated, replacing higher-cost resources and lowering the overall cost to serve load.
- **Avoided Capital Cost of Local Resources** – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local buildout.
- **Avoided Transmission Investment** – LRTP projects will reduce loading and avoid future reliability upgrades, avoiding the cost for replacing facilities due to age and condition.
- **Resource Adequacy Savings** – LRTP projects will increase transfer capability, which will allow access to resources in otherwise constrained areas and defer the need for investment in local resources.
- **Avoided Risk of Load Shedding** – The LRTP portfolio will enhance the resilience of the grid and reduce risk of load loss caused by severe weather events.
- **Decarbonization** – The higher penetration of renewable resources enabled by the LRTP portfolio will result in less carbon dioxide emissions.

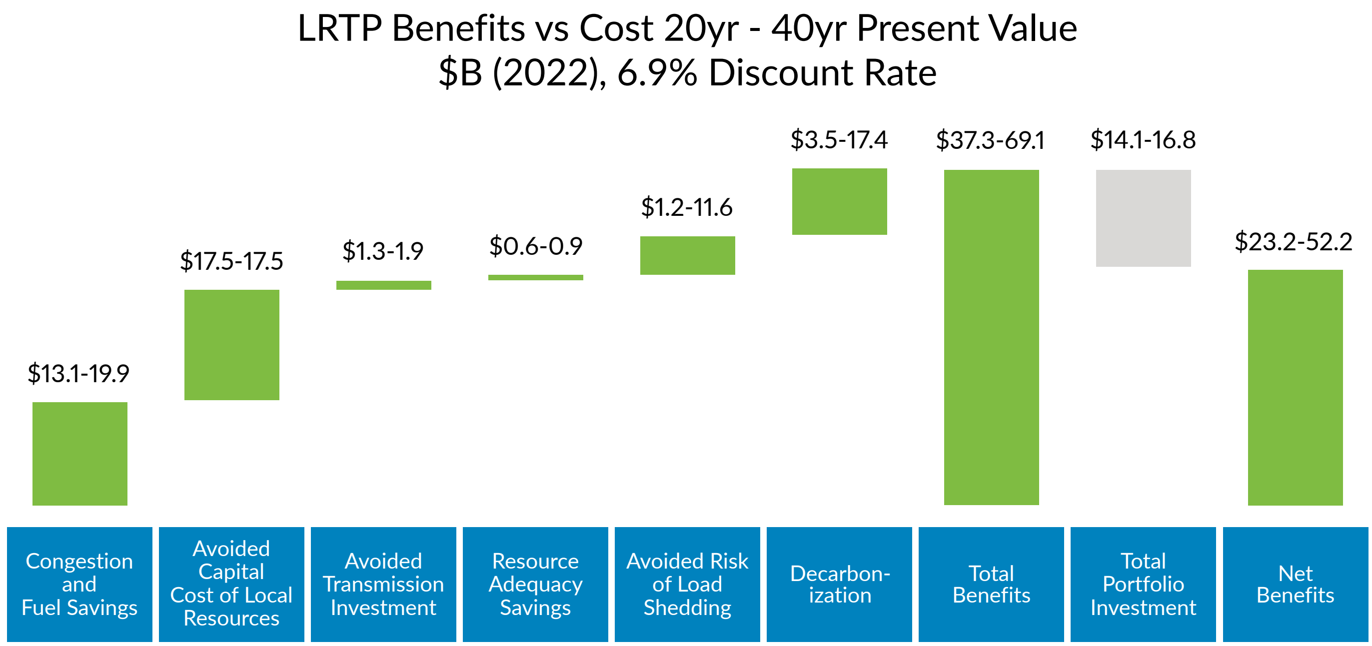


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

The Tranche 1 portfolio has a benefit-to-cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit-to-cost ratio of at least 2.2 for every zone, with benefits well in excess of the LRTP costs. The proposed projects and costs are spread across the entire MISO Midwest subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

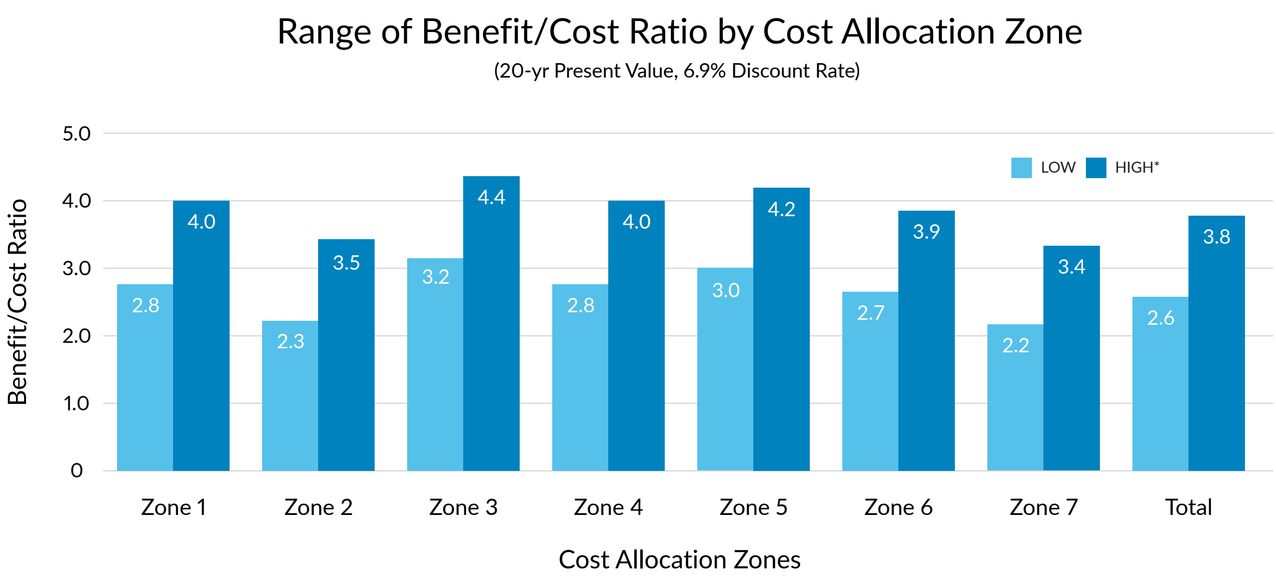


Figure 3: Benefits from the LRTP Tranche 1 portfolio exceed costs in every Midwest Subregion cost allocation zone

* The low and high range of benefit/cost ratios by Cost Allocation Zone are driven by changing two assumptions in the 20-year present value analysis: 1) increasing the Value of Lost Load (VOLL) from $3,500/MWh (low) to $23,000/MWh (high); and 2) increasing the price of carbon from $12.55/ton (low) to $47.80/ton (high).

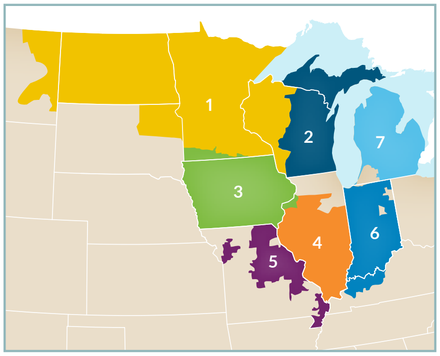


Figure 3a: Map of Midwest Cost Allocation Zone Boundaries (MISO Tariff, Attachment WW)

Transmission for the Future: LRTP Tranche 1 Projects are a "Least Regrets" Imperative

This least-regrets portfolio meets the needs of the first of MISO's three future planning scenarios, Future 1, which incorporates known and projected generation and load presented by member plans. This portfolio is "least regrets" because MISO is planning for an uncertain future and has chosen to plan towards the needs that represent a current view of member plans. Those portfolio plans continue to accelerate and expand, making Future 1 the conservative, expected case and presenting reliability implications that the Tranche 1 portfolio addresses. That's why Tranche 1 is a "yes-and" set of transmission that the Tranche 2 study will build off of to continue to meet the increasing renewable penetration levels and electrification growth that the MISO system is expected to see in the future.

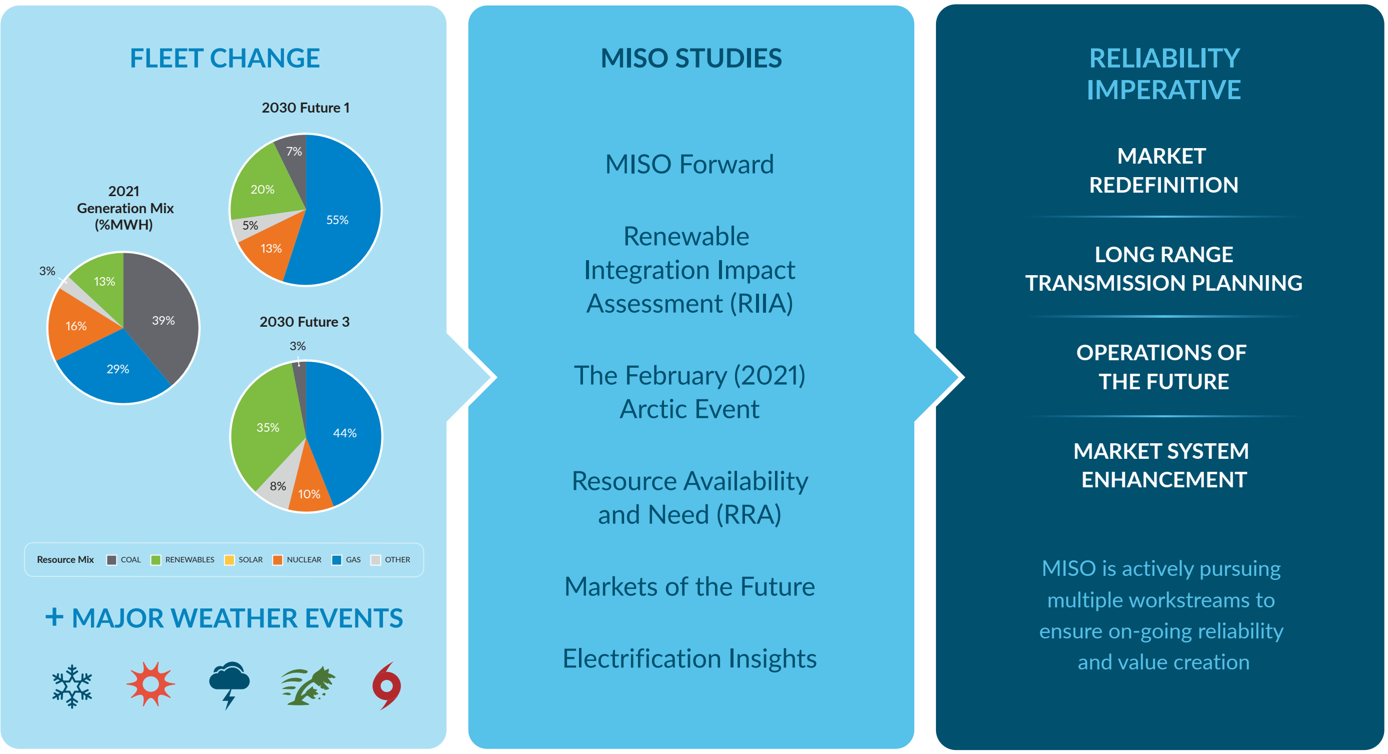


Figure 4: Challenges resulting from the changing resource portfolio and increasing extreme weather risk have created an imperative for broad changes

Subsequent tranches will improve interconnectivity, which helps to move power from where it's generated to where it's needed and, in doing so, not only integrates weather-based resources but improves resiliency during emergency events. Collectively, the multiple tranches of the LRTP comprise one of the four key elements of MISO's Reliability Imperative, which outlines a shared responsibility to evolve MISO's planning, markets, operations, and systems in an orderly fashion that preserves system reliability in the face of rapid changes in the MISO region. Unlike generation resource additions and retirements, which take as little as six months to complete, transmission projects can take up to 10 years from conception to in-service date. Given the long lead time, we must act now to ensure the transmission infrastructure is in place by 2030 to move both renewable and conventional generation across the grid in an efficient and reliable manner.

RELIABLE SYSTEM	Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
COST EFFICIENT	Enable access to lower-cost energy production
ACCESSIBLE RESOURCE	Provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
FLEXIBLE RESOURCES	Allow more flexibility in the fuel mix for customer choice

Figure 5: The LRTP Tranche 1 results were identified consistent with the objectives of the LRTP effort

How the Portfolio Evolved: MISO, Stakeholders Execute Accelerated, Robust Study

In response to resource shift trends, MISO began working with its stakeholders through the Planning Advisory Committee (PAC) and LRTP workshops to identify the transmission infrastructure needed to support these changes and ensure reliability. MISO introduced the LRTP conceptual roadmap to stakeholders in March 2021 and began discussions on the study scope and approach. A few months later, MISO began a series of monthly technical workshops to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings. In September 2021, MISO introduced a business case development process to identify the components and define the metrics for quantifying the benefits provided by the initial LRTP Tranche 1 portfolio of LRTP transmission investments.

In parallel, MISO engaged its stakeholders to develop an appropriate cost allocation methodology for such a transmission portfolio through the Regional Expansion Cost and Benefits Working Group (RECBWG).

The conceptual roadmap provided a long-range conceptual regional transmission plan to map out further study and potential solution ideas needed to address future transmission needs. Reliability analysis was then conducted on a series of study models representing various system conditions and dispatch patterns, as reviewed by MISO and stakeholders. Next, MISO evaluated potential alternative solutions developed by stakeholders and MISO to identify the most effective transmission solutions, including both reliability and economic analysis.

Once Tranche 1 projects were identified, MISO calculated the economic benefits of the portfolio. While the primary objective of the LRTP projects was to address reliability issues considering a range of system conditions, their value can extend well beyond reliability. This is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant broad economic benefits as well.

COSTS COMMENSURATE WITH BENEFITS

The transmission limitations between MISO Midwest and MISO South subregions effectively reduced the flow of benefits between the two subregions. To ensure costs align with beneficiaries, MISO submitted a cost allocation option for new Multi-Value Project portfolios, the cost of which would be regionally allocated on a subregional basis.

In February 2022, after months of work with stakeholders and state regulators, MISO filed with FERC for a cost allocation methodology for Multi-Value Projects to meet the unique needs of the region in developing the LRTP projects. The filing, supported by a majority of MISO transmission owners, was submitted and subsequently approved on May 18, 2022.

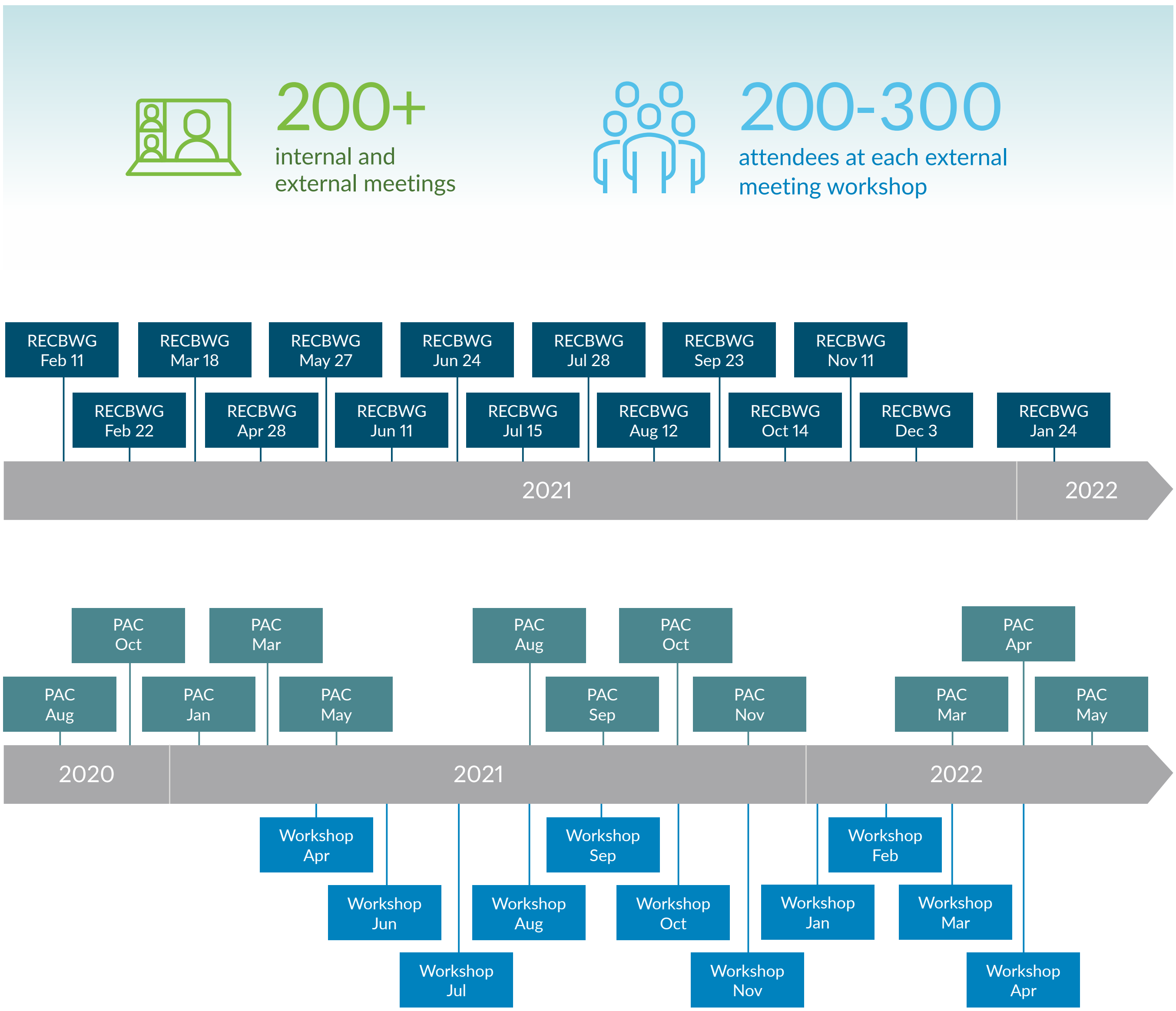


Figure 6: MISO's Long Range Transmission Plan Tranche 1 followed an extensive stakeholder process

Tranche 1 projects solve specific transmission issues across the MISO footprint

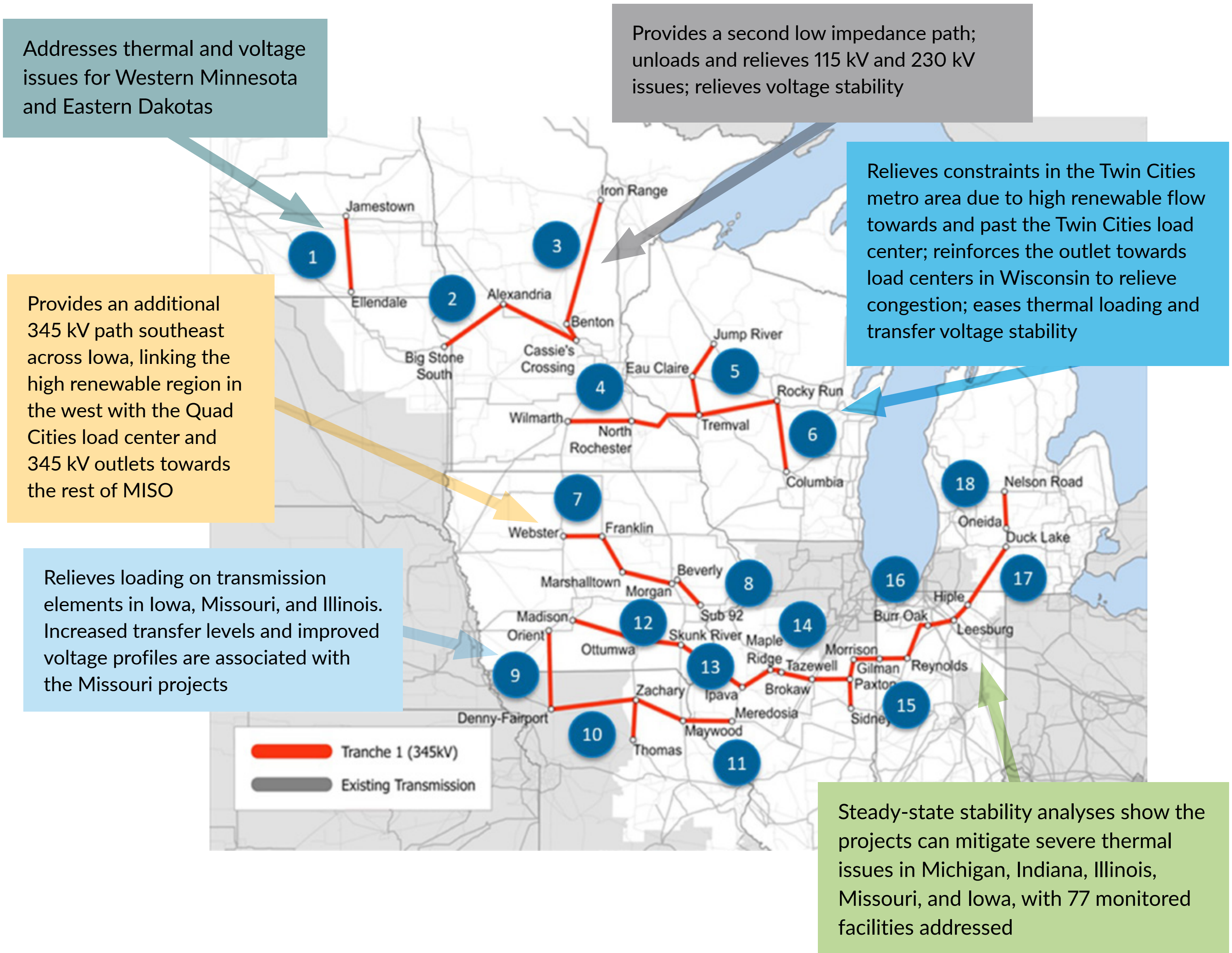


Figure 7: The Tranche 1 portfolio of 18 transmission projects can be divided into six sections with unique regional benefits

ID	DESCRIPTION
1	Jamestown – Ellendale
2	Big Stone South – Alexandria – Cassie's Crossing
3	Iron Range – Benton County – Cassie's Crossing
4	Wilmarth – North Rochester – Tremval
5	Tremval – Eau Claire – Jump River
6	Tremval – Rocky Run – Columbia
7	Webster – Franklin – Marshalltown – Morgan Valley
8	Beverly – Sub 92
9	Orient – Denny – Fairport
10	Denny – Zachary – Thomas Hill – Maywood
11	Maywood – Meredosia
12	Madison – Ottumwa – Skunk River
13	Skunk River – Ipava
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East
15	Sidney – Paxton East – Gilman South – Morrison Ditch
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple
17	Hiple – Duck Lake
18	Oneida – Nelson Rd

Next Steps: A Foundation for Future Needs

A more interconnected system is stronger. Additional study work and stakeholder engagement will help identify the nature and benefits of future LRTP tranches needed to address further deployment of variable, weather-dependent resources, continued volatility created by severe weather events and the benefits of improved interregional connectivity.

While Tranche 1 provides a meaningful start, much work is left to ensure that the shifting resource fleet transition occurs in an orderly, efficient and reliable manner. Though Tranche 1 provides a more robust system in the Midwest, future tranches are needed to address other parts of the MISO footprint and future levels of fleet transition beyond what is captured in Future 1. MISO looks forward to continuing the conversation with stakeholders and regulators to ensure adequate planning to meet future needs.

MISO

misoenergy.org

MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report

Table of Contents

1 Introduction

MISO's multi-year Long Range Transmission Planning (LRTP) initiative assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. Projections show a drastically different resource fleet, along with other influences such as electrification, that is driving a need for the bulk electric system to be better prepared for these massive shifts. MISO proposes a Tranche 1 Portfolio of 18 transmission projects, equaling approximately $10 billion of investment, to enhance connectivity and maintain adequate reliability for the Midwest Subregion by 2030 and beyond (Figure 1-1, Table 1-1).

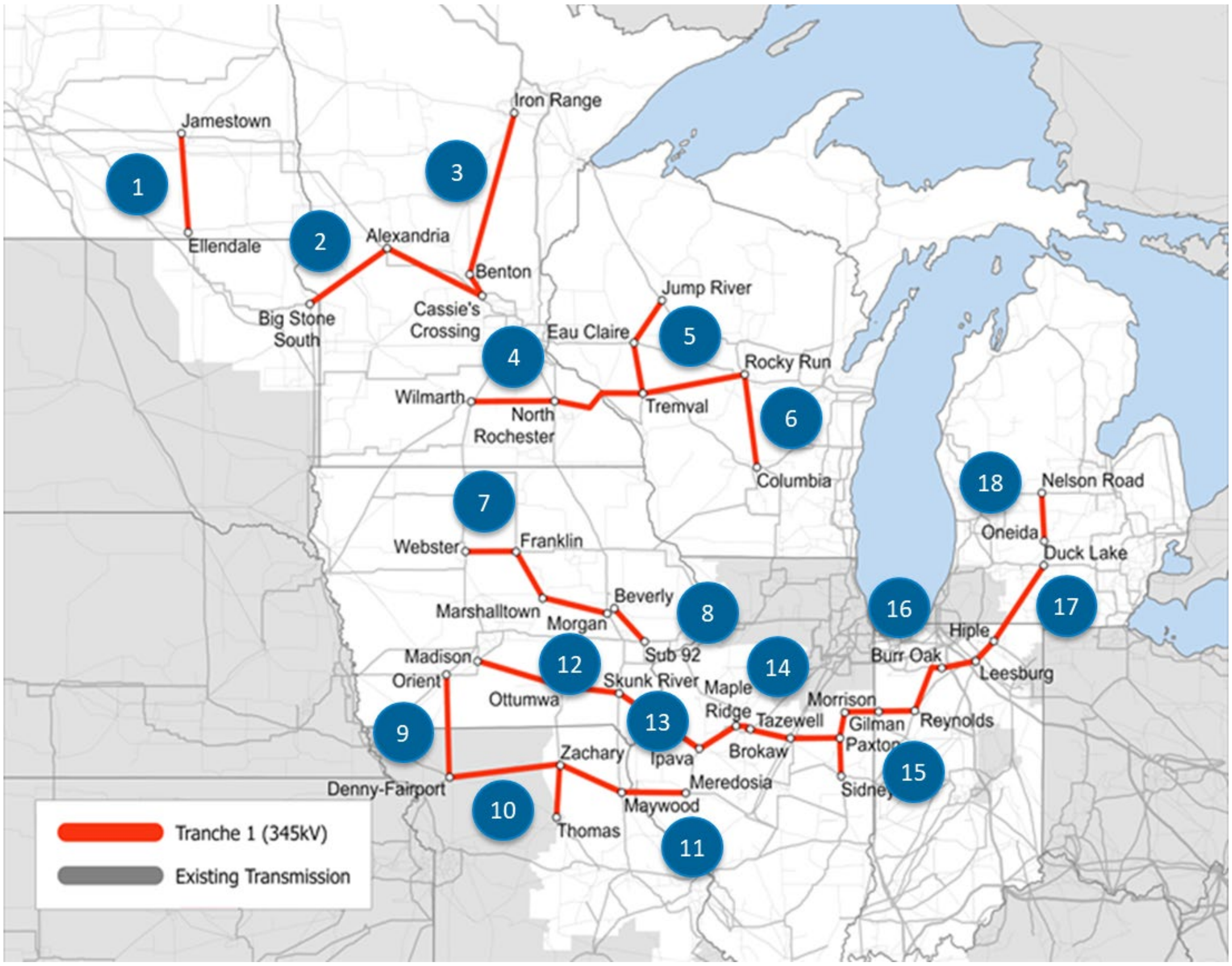


Figure 1-1: LRTP Tranche 1 Transmission Portfolio

LRTP Tranche 1 Portfolio of Projects

ID	Description	Expected ISD	Estimated Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574M
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970M
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689M
5	Tremval – Eau Claire – Jump River	6/1/2028	$505M
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755M
8	Beverly – Sub 92	12/31/2028	$231M
9	Orient – Denny - Fairport	6/1/2030	$390M
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769M
11	Maywood – Meredosia	6/1/2028	$301M
12	Madison – Ottumwa – Skunk River	6/1/2029	$673M
13	Skunk River – Ipava	12/31/2029	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	6/1/2029	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261M
17	Hiple – Duck Lake	6/1/2030	$696M
18	Oneida – Nelson Rd.	12/29/2029	$403M
	Total Project Portfolio Cost:		$10,324M

Table 1-1: Proposed Tranche 1 Portfolio of Projects
(Costs as of June 1, 2022 and are subject to change. Costs represent "overnight" costs)

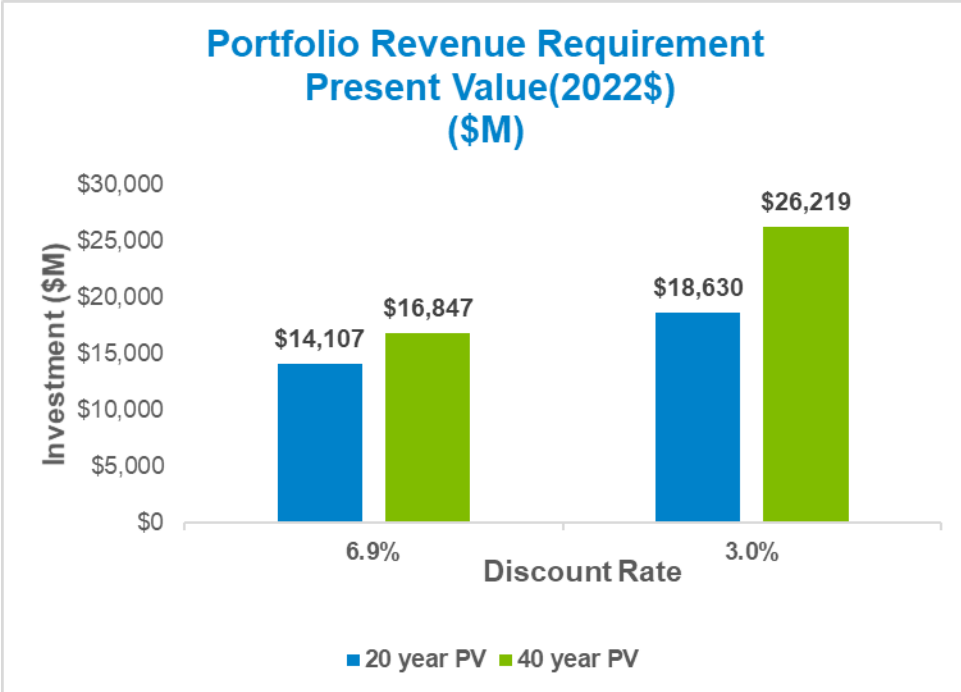


Figure 1-2: Present Value of LRTP Tranche 1 Portfolio (values as of 6/1/2022)

The Tranche 1 Portfolio has a benefit to cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit to cost ratio of at least 2.2 for every Cost Allocation Zone, well in excess of the LRTP Tranche 1 Portfolio costs (Figure 1-2 and 1-3). The proposed projects and costs are spread across the entire MISO Midwest Subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

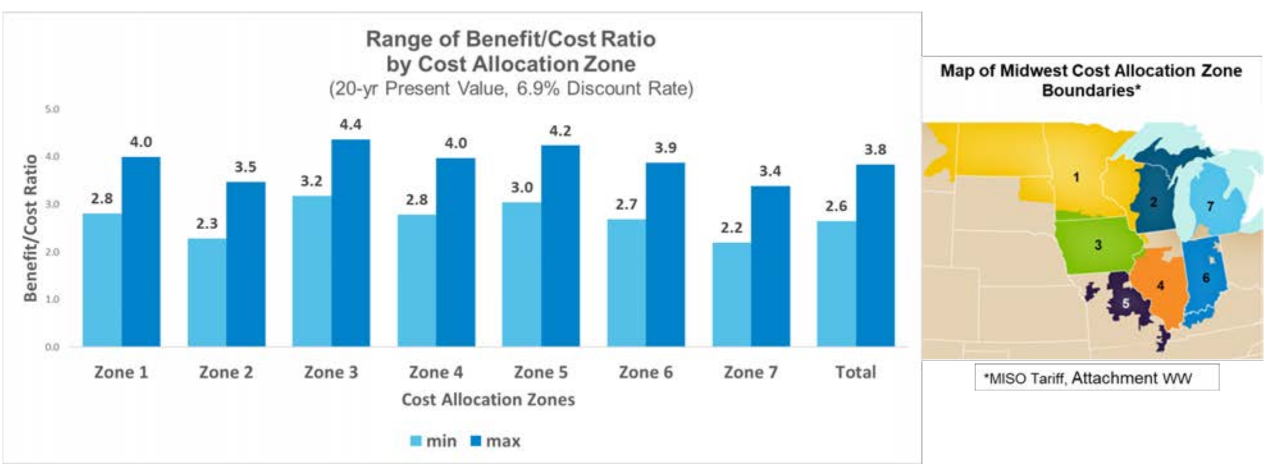


Figure 1-3: Distribution of benefits to Cost Allocation Zones in Midwest (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP study was initiated in 2020, and the LRTP Tranche 1 Portfolio Report is the first iteration of MISO's findings and recommendations. This report identifies reliability challenges in the Midwest Subregion associated with MISO's Future 1.

Efforts on Tranche 2 will be underway in the second half of 2022 and will continue to focus on the Midwest Subregion and addressing the needs identified in MISO's Futures. Tranche 3 of the LRTP study will focus on identifying system needs in the MISO South Subregion, and Tranche 4 will look at the part of the system connecting the Midwest and South Subregions.

While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.

2 History of MISO's Innovative Long Range Transmission Planning Process

The transmission grid, while not top of mind for many people, is a critical component of ensuring the lights come on when a switch is flipped, our favorite devices can be charged, and life-saving machines can operate. But even with that level of importance, transmission investments, especially on a large scale, are very difficult to undertake and are not very common in the United States currently. However, the clear direction of the industry, towards a cleaner energy future, requires investments of this nature. Fortunately, MISO has a proven process, experience, and an engaged stakeholder community to draw upon as we embark on this very difficult journey. This is not the first time we have been here, or successfully facilitated significant grid investment.

As a Regional Transmission Organization/Independent System Operator, MISO coordinates with its members to facilitate transmission system investments needed to ensure continued reliable and efficient delivery of least-cost electricity across the MISO region. This requires a continuous execution of MISO's recurring transmission planning process. The culmination of the extensive work executed during each 18-month planning cycle, including proposed new projects, are codified annually in a MISO Transmission Expansion Plan (MTEP). These plans have put in motion approximately $42 billion in transmission investments going back to 2003.

Section 1.2 of MTEP21 provides an overview of MISO's overall transmission planning process, so only the primary aspects are described here to provide high-level context. The process involves both top-down and bottom-up identification of issues and potential solutions associated with transmission system maintenance and enhancement. There are also several aspects, or objectives of different components of MISO's transmission planning process, including resolving grid reliability issues, transmission expansion needed to connect new generation resources to the grid, and reducing congestion on the system. Assessing these types of needs can occur as often as annually and involves looking out 5-15 years to identify near- and mid-term needs.

The overall process also includes a component that has been exercised less frequently, the long-range transmission planning (LRTP) process, which considers challenges projected in the 20 year and beyond timeframe. Given the extensive lead time associated with large-scale transmission investment, this process is designed to be responsive to situational grid needs and utilized when incremental transmission system fixes, upgrades, and/or additions will not be sufficient to effectively or efficiently address those needs. These situations require that MISO consider the range of potential future states, the implications of those outcomes for the industry, and the transmission system needs this will create. Those potential future scenarios serve to provide bookends for the uncertainty that exists when planning this far out.

The inaugural iteration of MISO's long range planning process culminated in the first-of-its-kind portfolio of projects being approved by the MISO Board of Directors in 2011. Beginning in 2007, in response to an increase of individual Renewable Portfolio Standards within MISO states, MISO began the initial execution of the LRTP process to mitigate the significant impact on the future generation mix and the reliability of the system. During this multi-year effort, a new project type — Multi-Value Project (MVP) — was developed. As codified in the MISO Tariff, a project must meet one or more of the following criteria to be included in an MVP portfolio:

> *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.*
>
> *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
>
> *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

As the criteria demonstrate, economic benefits are a significant part of the requirements for these types of projects. Given the regional scope of these projects, the level of investment, and the uncertainty associated with the time horizon, a strong business case is paramount. The types of economic benefits that could be used to meet these criteria were defined through collaboration with stakeholders. Those benefits are:

- *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be* *realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements.*

- *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.*

The ground-breaking work executed during this process culminated in a nearly $6 billion portfolio, with a projected 1.8-3.1 benefit-to-cost ratio, being approved by the MISO Board of Directors in 2011. MISO was required to periodically reassess the projected benefits to determine if modifications to the MVP criteria were necessary. Each of those analyses found that the projected benefits remained consistent with, and were sometimes greater than, initially estimated, as shown in Figure 2-1. This, along with the fact that all but one of the 17 MVP projects are currently (as of June 2022) in service and fully utilized, demonstrates the effectiveness of MISO's value-based planning process and the use of future scenarios to bookend uncertainty and identify robust solutions, and to project benefits.

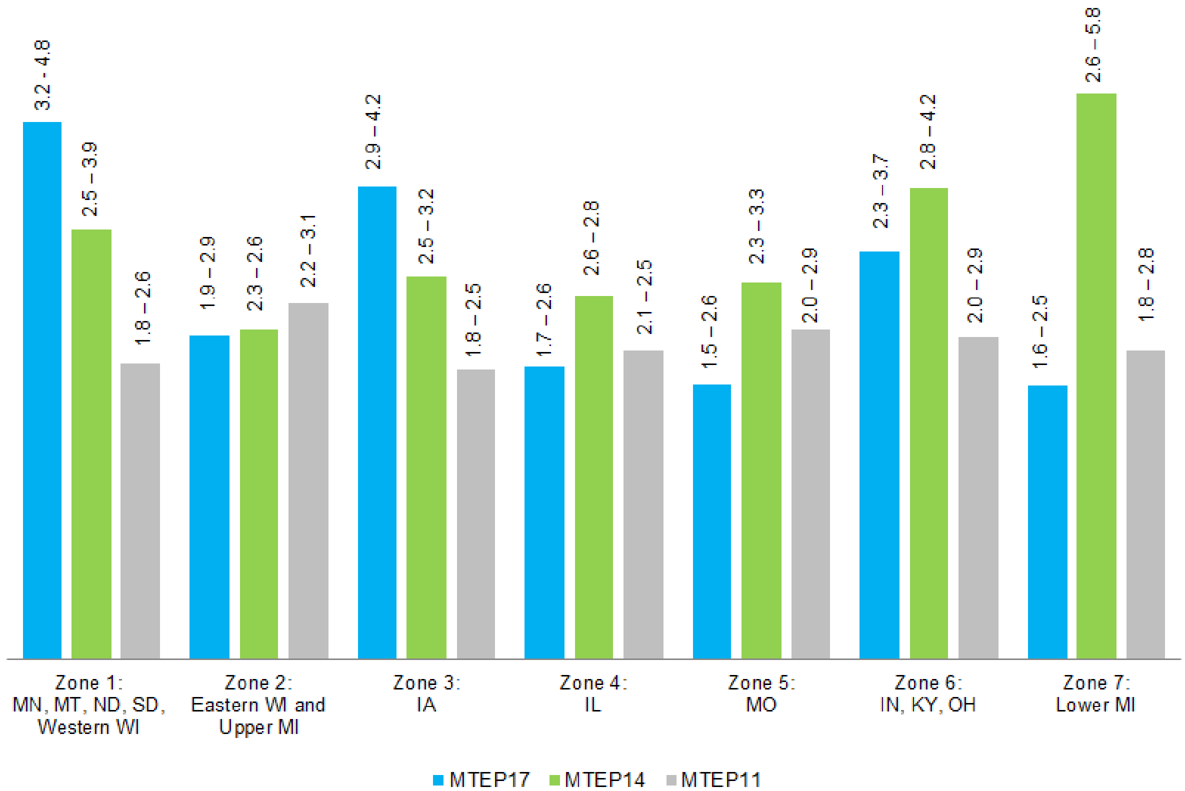


Figure 2-1: Zonal benefit to cost ratios for the original MTEP11 MVP Analysis and subsequent MTEP14 and MTEP17 Triennial Reviews

In the years immediately following the approval of the MVP portfolio, the level of annual investment put forward in MTEP reports returned to historical levels of approximately $1.5 billion annually. Upgrades or replacements of aging assets, and the added investment associated with the integration of the South Subregion have contributed to the annual average investment rising to $3.4 billion over the last five years, but still well below the level approved in 2011 with the MVPs. While this increased rate of investment is strengthening the grid in the MISO Region, it is not reflective of the magnitude of change that has been occurring across the landscape during this time.

3 The Long Range Transmission Planning Component of MISO's Broad-Based Response to Current Industry Change

The generation mix evolution in the MISO Region that drove the need for the MVP portfolio didn't end with that portfolio's approval. In fact, the pace towards more renewables has increased since that time. Progressively increased carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery storage and hybrid projects. MISO made a number of incremental changes to its markets, tools, and processes along the way to mitigate the early impacts of this change. However, beginning in 2016, the challenge was becoming obvious and more difficult to mitigate.

Change Drivers and Implications Contributing to Aligning Interests

Over the last several years, MISO began to experience operational situations that required the use of emergency procedures, even outside of the summer period when demand peaks occur, and supply becomes strained. In the real time horizon, when resource margins are projected to be significantly low, MISO will begin to implement the steps in its emergency procedures in an attempt to gain access to additional resources. While not having to make a single emergency declaration in the two years preceding 2016, 41 such emergency declarations have been required since 2016. These events are largely the result of reduced generation capacity due to the retirement of conventional generation as the fleet has transitioned toward more renewable resources and greater reliance on Load Modifying Resources for meeting capacity requirements.

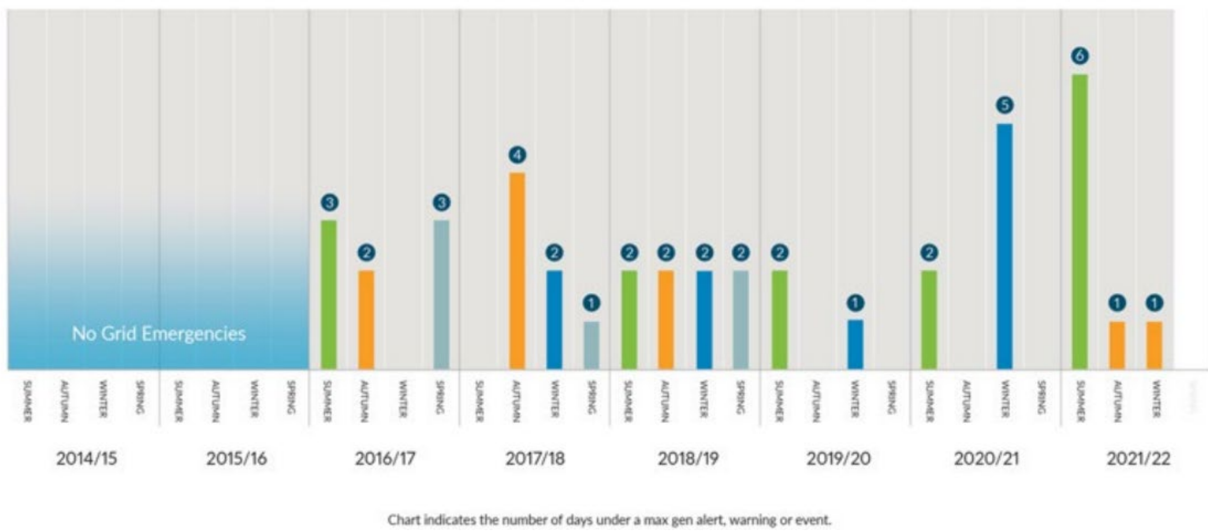


Figure 3-1: Historical MISO MaxGen Alerts, Warnings, and Events

In response to this growing challenge, MISO launched the Resource Availability and Need (RAN) initiative to understand the drivers and identify a variety of changes to markets and resource adequacy process solutions to generation availability issues.

At the same time, and driven by the ongoing fleet shift, MISO executed a multiple-year study called the Renewable Integration Impact Assessment (RIIA) to deepen its understanding of the implications of more renewable generation on the system. This assessment identified inflection points, or renewable energy penetration levels where challenges would get increasingly more complex. It also identified key risks that would result, including insufficient transmission infrastructure.

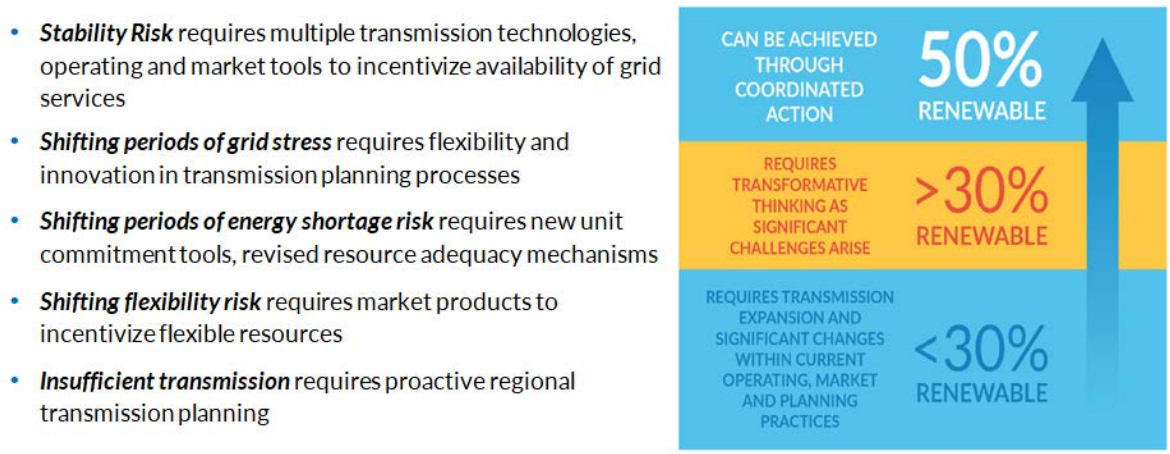


Figure 3-2: RIIA Study Identified Key Risks with increasing levels of Renewable Energy

The timing of when the region would reach these inflection points was then uncertain. However, an additional driver emerged that accelerated the pace towards more renewables: a growing customer preference for clean energy. MISO began to see a growing number of member utilities and state policies incorporating decarbonization goals into their resource fleet strategies. Around this same time another trend was emerging on the demand side as well. The movement towards electrification will have a significant impact on electricity demand, which has in recent years been relatively stable.

This level of uncertainty makes it very difficult to plan for the future with confidence. However, as demonstrated with the development of the 2011 MVP portfolio, MISO has an existing process to effectively manage these types of risks. MISO, in collaboration with stakeholders, establishes future planning scenarios to understand the economic, policy and technological impacts on future resource needs. Starting in 2019, MISO examined three future scenarios to define and bookend regional resource expectations over the next 20 years (MISO Futures Report[1]). These Futures recognize the widespread clean energy goals of states and utilities within the region, as well as the associated rapid pace of regional resource transformation.

[1] MISO Futures Report

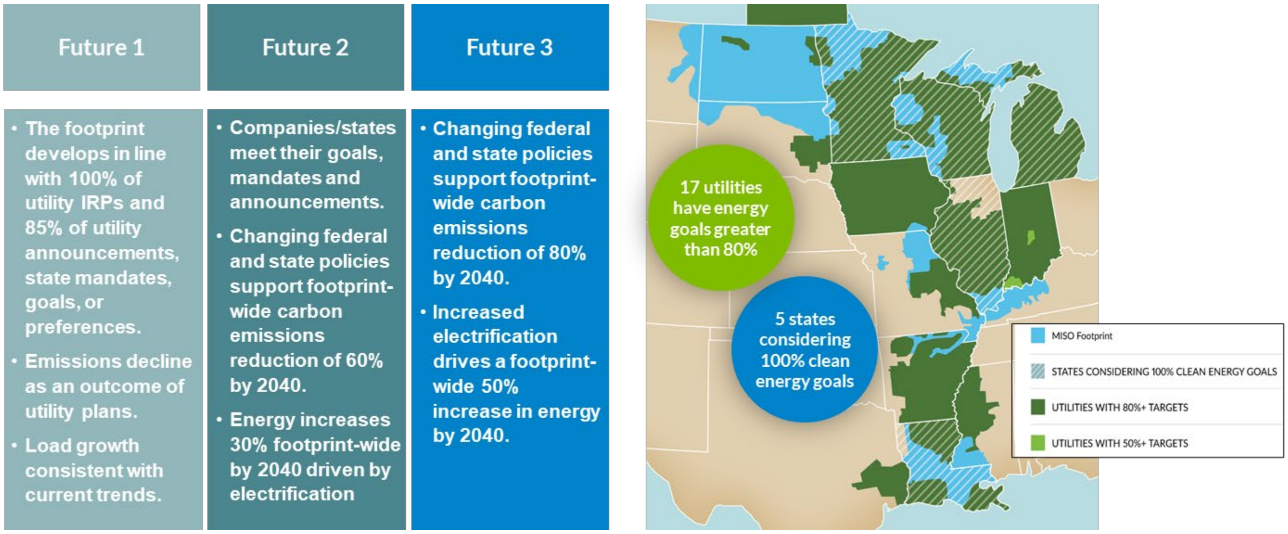


Figure 3-3: MISO Futures Key Drivers

MISO's Reliability Imperative Response: The Long Range Transmission Planning Initiative

These future scenarios reflect the significance of the changes the region must prepare for, and similar to the situation facing the region back in 2007, incremental changes will no longer be adequate. The magnitude of landscape changes has created an imperative for transformational changes across MISO's markets, planning, operations, and technology. The Reliability Imperative Report[2] documents the collection of related initiatives that address the growing risks and that are required to enable member resource plans and strategies. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges.

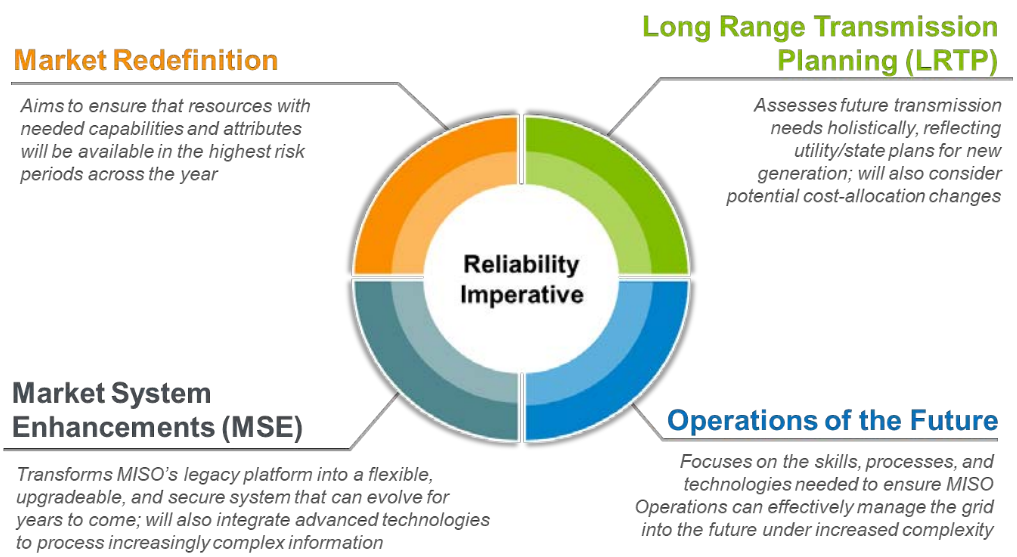


Figure 3-4: MISO's Reliability Imperative Key Initiatives

[2] MISO'S Response to the Reliability Imperative

As work has been underway, an additional risk emerged that has increased the urgency associated with progressing these initiatives. An increase in the frequency of extreme weather events is exacerbating the risks and challenges that originally drove the need for the Reliability Imperative. These types of scenarios can force a large number of generators out of service in a local area, putting reliability at risk. This has contributed to the emergency procedure declarations over the last several years (Figure 3.1).

Robust Business Case for Long-Range Transmission Plan

As the region faces both a changing resource fleet and increased prevalence of extreme weather events, the ability to move electricity from where it is generated to where it is needed most becomes paramount. One needs only to consider the need for increased power flow within and between regions during Winter Storm Uri in February 2021 to understand the importance of transfer capability. MISO can leverage its large geographic footprint and diversity of resources to ease some of these challenges. However, adequate transmission infrastructure is key.

With the landscape once again shifting and expected to do so even more dramatically in the future, the transmission planning aspect of the Reliability Imperative includes the second execution of MISO's long-range transmission planning process. The MISO LRTP initiative, introduced to stakeholders in August 2020 to invite their collaboration, provides a regional approach to transmission planning that addresses future challenges of the resource fleet evolution and electrification. The transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

The objective of LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
- **Cost Efficient** – enable access to lower-cost energy production
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice

LRTP is designed to assess the region's future transmission needs in concert with utility and state plans for future generation resources.

LRTP is a multi-year effort to address the myriad and complex issues associated with the significant resource transformation underway. Because there is urgency to keep pace with this rapid evolution, MISO is seeking to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses. While it is important to move quickly, MISO must ensure reliable power delivery for customers with investment decisions that appropriately balance generation and transmission solutions on a regional scale to ensure the best cost outcomes for customers.

LRTP continues the MISO Value-Based Planning approach to extend value beyond the traditional planning processes to achieve a more efficient comprehensive long-term system plan.

Tariff Requirements

The needs driving the LRTP portfolio, the scope of the projects and types of benefits they enable aligns relatively well with those of the MVP portfolio and the associated MVP tariff requirements are being applied for the LRTP. The criteria to meet the project definition are listed in their entirety in Section 2, and in summary are: 1) enable the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws, 2) provide multiple types of economic value, with a benefit-to-cost of 1.0 or greater, or 3) address at least one reliability issue and provide at least one type of transmission-based economic value.

LRTP Cost Allocation Aligned with Beneficiaries

A condition that must be met prior to any transmission investment being approved is to determine how the costs will be allocated. The original MVP ruleset established a cost allocation methodology of spreading costs footprint-wide on a load-ratio share basis. With the initial Tranche of LRTP projects identified to address reliability issues in MISO's Midwest Subregion only, this approach was not going to meet FERC's requirement of costs spread roughly commensurate with benefits.

To address this risk, MISO proposed a modified MVP methodology where costs could be spread to a subregion only, if the projects within the portfolio primarily provide benefits to a single subregion. This proposal was approved by FERC on May 18, 2022 with a May 19, 2022 effective date. With FERC's approval the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion.

4 Rigorous, Collaborative Approach Ensures Robust LRTP Solutions

With this being the second execution of MISO's long-range transmission planning process, it was not groundbreaking, but it is no less significant than the first execution that developed the 2011 MVP portfolio. In fact, the landscape changes being planned for are much more significant now and require prompt action to address the fast pace of transformational changes occurring in the industry. The initial tranche of LRTP projects was developed in a focused effort to deliver a set of least regrets solutions that would be ready to address needs in the next 10 years.

While the process was executed in significantly less time, the quality of the analysis and commitment to identifying robust solutions was not sacrificed. This portfolio of projects represents over 2,000 miles of transmission, a significant level of investment unprecedented in the industry and will have its benefits and costs shared broadly. Given this backdrop, it is incumbent on MISO to perform a rigorous analysis to ensure we identify a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs.

The process MISO follows to identify projects and create a portfolio is designed to result in a business case that justifies the investments. As described in Section 3 of this report, the first step in this process is to create potential future scenarios, or Futures, to essentially establish a target for our planning efforts. In some situations, the Futures could bookend very different directions for the region's generation fleet due to uncertainty around energy policy and other factors. However, given the current clear trends that include Members and States increasingly establishing clean energy goals, the continued retirement of fossil fueled resources from the system, and a growing trend toward electrification, the current set of futures reflect different progressions or the velocity of change in that singular direction.

MISO developed a long range conceptual regional transmission plan to explore and further study possible solutions needed to address future transmission needs. The conceptual plan serves as a set of solution ideas that guide the development of candidate transmission projects that meet the objective of long range planning to achieve reliable and economic delivery of energy in a range of future scenarios. Reliability analysis is conducted on a series of study models that represent various system conditions and dispatch patterns to identify issues. MISO then evaluates the candidate projects and potential alternative solutions developed by MISO and stakeholders to identify the most effective transmission investments to address the issues and performs an economic analysis that factors into selecting the best of the options. Section 5 of this report is a detailed walk-through of the reliability analysis that was undertaken, with the results provided in Section 6.

Once the portfolio of projects is identified, MISO then calculates the economic benefits created by the portfolio. The primary objective of the LRTP projects was to address reliability issues identified in the planning studies that considered a range of system conditions. However, while transmission investments are usually built for a specific purpose, the value that any particular investment brings can extend well beyond addressing the singular issue driving it. That is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant economic benefits as well.

While the objective of LRTP is primarily focused on the need for reliable energy delivery, the analysis of economic benefits is essential to the demonstration of value of the portfolio as required by the Tariff for eligibility as regionally cost shared projects. The economic benefit types that can be assessed were identified in Section 2 of this report in the discussion on Multi-Value Projects, which the LRTP will be categorized as. The specific metrics that were used to determine the economic benefits of the LRTP portfolio are:

- Congestion and fuel savings – LRTP projects will allow more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
- Avoided local resource capital costs – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local resource build out.
- Avoided future transmission investment – LRTP projects will reduce loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
- Reduced resource adequacy requirement – LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
- Avoided risk of load shed – the LRTP portfolio will increase the resilience of the grid and lower the probability that a major service interruption occurs.
- Decarbonization – the higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO_2 emissions.

The methodology used to calculate each of these economic benefits and the results are the focus of Section 7.

As described in Section 8 of this report, the allocation of LRTP portfolio costs is spread broadly to the entire Midwest Subregion. The Federal Energy Regulatory Commission requires that transmission costs associated with investments of this nature be allocated roughly commensurate with how the benefits are realized. Given the large-scale of the LRTP projects and the fact that they span the Midwest Subregion, benefits flow to the entire subregion. To illustrate this and demonstrate support of FERC's guidance, Section 8 shows the benefits by MISO Cost Allocation Zone.

Given the expected continued key role of natural gas generation, volatility in the price of natural gas can have a significant impact on the cost of producing electricity. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than natural gas. Chapter 8 includes a sensitivity analysis performed using a range of natural gas prices to demonstrate the robustness of the LRTP Tranche 1 Portfolio across a range of scenarios.

5 LRTP Tranche 1 Portfolio Development and Scope

Most good plans result not from a single work effort, but rather develop from refinements to an effective starting point. The latter characterizes the path to the LRTP Tranche 1 Portfolio. In anticipation of reliability needs in a future with growing renewable penetration and load consumption, MISO developed an indicative transmission roadmap of potential transmission expansions throughout the region for both Future 1 and a combined Future 1, 2, and 3. The roadmap provides an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures and candidate transmission solutions to be used as a starting point in determining potential projects. This roadmap was developed by MISO planning staff as extensions of the existing grid that would provide for logical connections that could increase connectivity, close gaps between subregions, and support a more robust and resilient grid by enabling the delivery of energy from future resources to future loads and increasing the reliance on geographic diversity to manage the increased dispatch volatility and uncertainty associated with the future resource fleet. The indicative roadmap is not a final plan but instead a starting point for considering solutions to transmission issues expected.

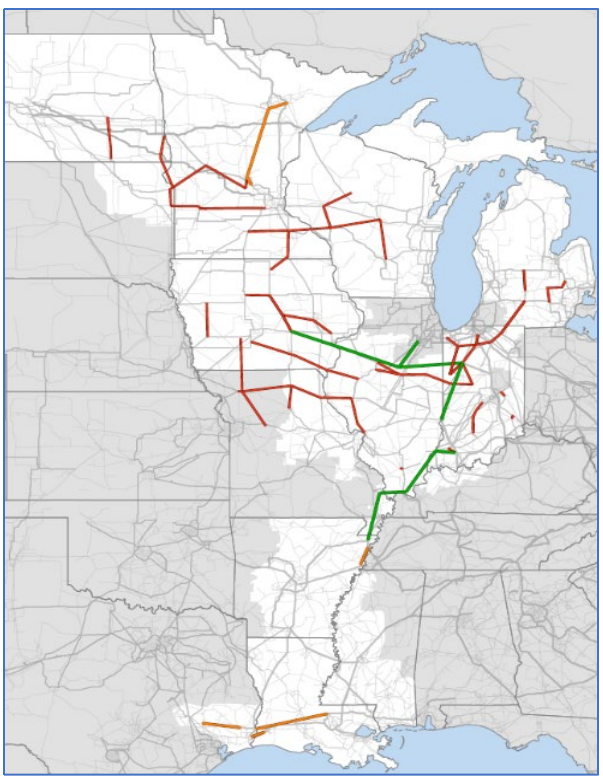


Figure 5-1: Future 1 Indicative Roadmap

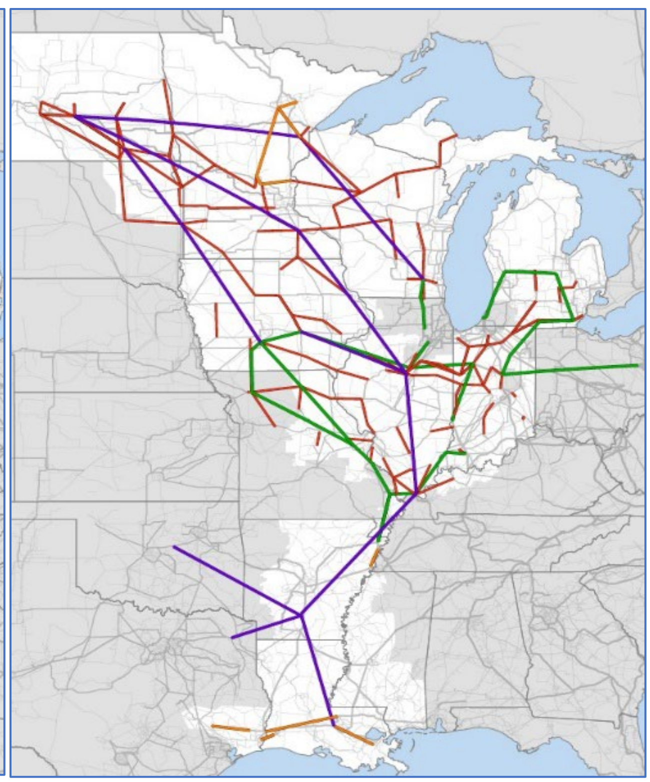


Figure 5-2: Futures 1, 2, & 3 Indicative Roadmap

The initial tranche of the LRTP is focused primarily on enabling the resource expansion and load forecasts associated with the 10- and 20-year timeframe under Future 1 in the Midwest

Subregion. In Future 1, the most significant aspects are resource retirements and increased renewable penetration.

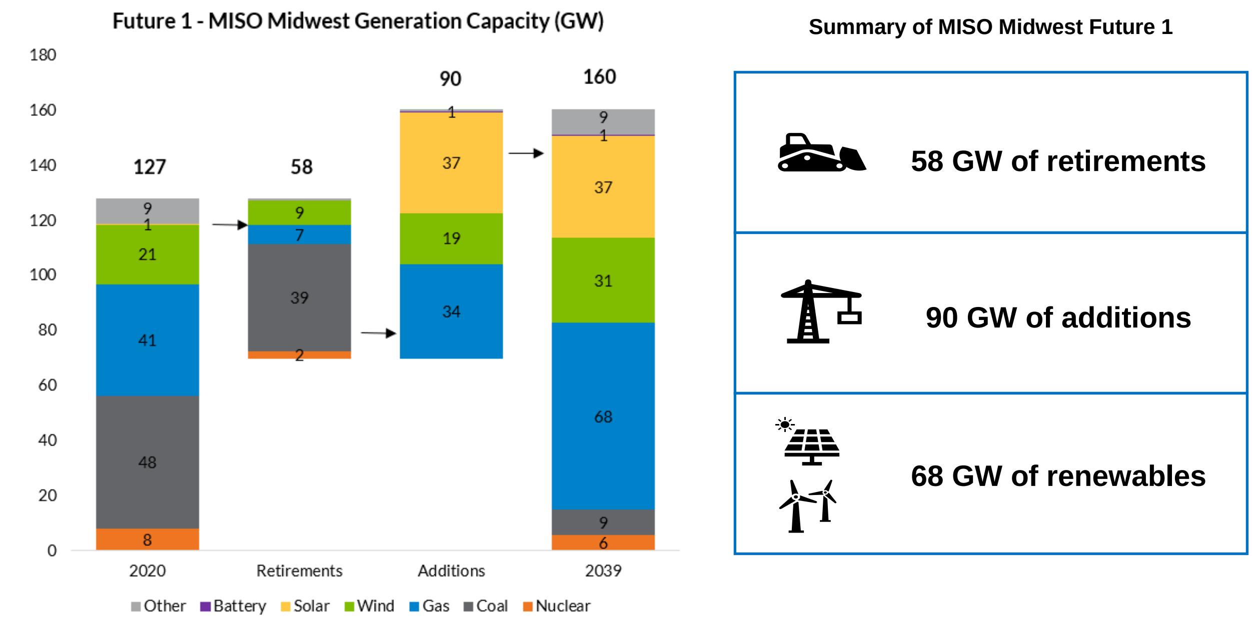


Figure 5-3: Future 1 changes in Generation Capacity for Midwest Subregion

In Futures 2 and 3, higher levels of resource retirements and renewable resource penetration coupled with higher levels of electrification will be significant. Later tranches of LRTP will focus more on Future 2 and Future 3 scenarios.

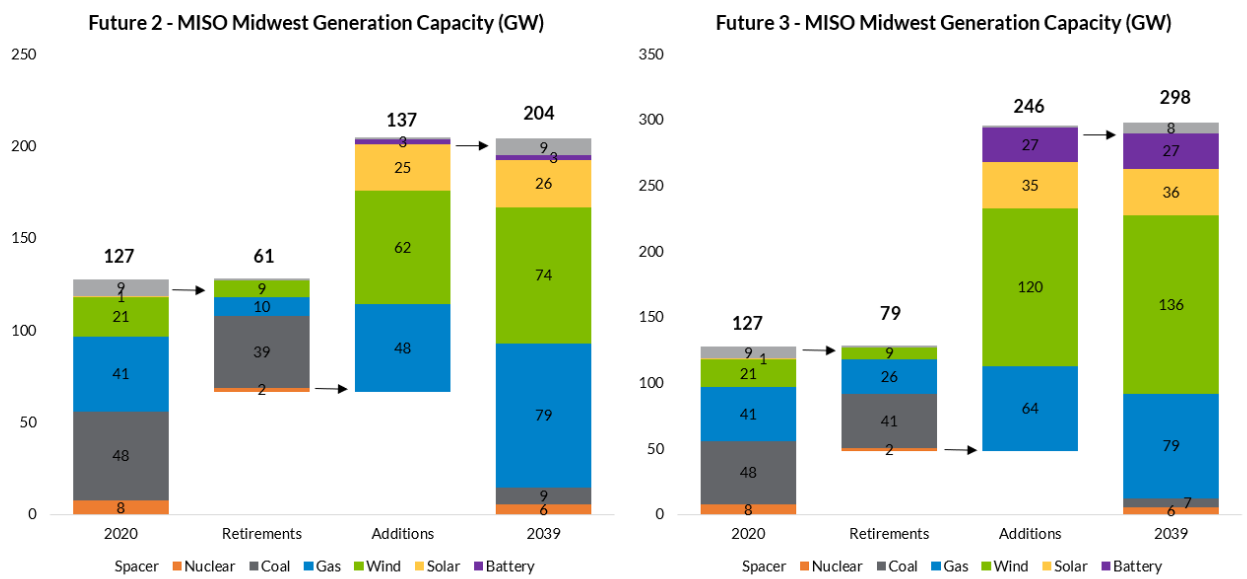


Figure 5-4: Future 2 & 3 changes in Generation Capacity for Midwest Subregion

Reliability Study Scope

MISO developed snapshots of system stress under a Future 1 resource expansion in the 10-year and 20-year timeframe. These scenarios, or base cases, vary based on season of the year, time of the day, load level, and coincident availability of renewable resources. MISO then used the scenarios to test the impact of the LRTP Tranche 1 Portfolio.

Model	Season	Hours	Range of dates and hours used to characterize the model	LRTP modeling definition of load level
1	Summer Peak	Day	Summer :6/21 to 9/20 Hours ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served. (system load >=90 percentile during day)
2	Summer Peak	Night	Summer: 6/21 to 9/20 Hours NOT ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served (system load >=90 percentile during night)
3	Fall/Spring Light load	Day	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Day)
4	Fall/Spring Light load	Night	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours NOT ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Night)
5	Fall/Spring shoulder load	Day	Fall: 9/21 to 12/20 Spring à 3/21 to 6/20	70% to 80% of the Summer Peak Load (Day)
6	Winter Peak	Day	Winter: 12/21 - 3/20 Hours ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during day)
7	Winter Peak	Night	Winter: 12/21 - 3/20 Hours NOT ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during night)

Table 5-1: Temporal and load parameters for defining base models

The purpose of the reliability study is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 1 scenario in the 10-year and 20-year time horizon. The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty and voltage stability analysis to ensure voltage stability in the Midwest subregion.

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the seven base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP20 NERC Category P0, P1, P2, P4, P5, and P7 contingency events and selected NERC Category P3, P6 events. Facilities in the Midwest Subregion were monitored for steady state thermal loading in excess of 80% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria.

Transfer analysis is performed to test for robust performance under varying dispatch patterns. The LRTP transfer study includes eight transfer scenarios to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

Scenario	Description	Objective	Resource	Sink
1	Central to Iowa	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	All Gen. Local Resource Zones (LRZ) 4-6	Wind in LRZs 1&3
2	MISO to Michigan	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	Renewables in LRZs 1-6	Renewable in LRZ 7
3	Michigan to MISO	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZ 7	Renewables in LRZs 1-6
4	Iowa/MN to MH	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Manitoba Hydro load
5	MISO West to Wisconsin	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Renewables in LRZ 2
6	Central Renewables to rest of MISO Midwest	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZs 4-6	Gen. in LRZs 1,2,3,7
7	MISO Midwest to Central Region	Ensure reciprocal export capability to MISO Subregions in high resource deficiencies	Gen. in LRZs 1,2,3,7	Gen. in LRZs 4-6
8	MISO West to East across the Mississippi	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	MISO West of the Mississippi River Renewables in LRZs 1,2,3,5	MISO East of the Mississippi river Gen. in LRZs 4,6,7

Table 5-2: Transfer Scenarios

Economic analysis supports reliability analysis evaluation of project candidates as needed for selecting the preferred solutions. Production cost simulations analyze the impact of the proposed project on production costs to assess how the economic performance of a project compares to other alternatives that have been proposed. These results are used to supplement the reliability analysis results and provide an additional measure of economic performance to aid in selecting the preferred solution.

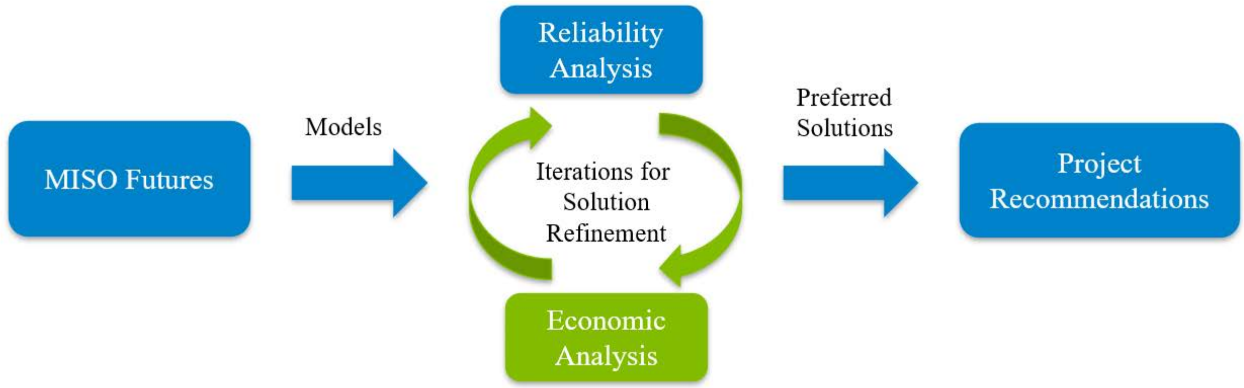


Figure 5-5: Iterative Solution Refinement

The results of the reliability analysis contained in Section 6 of this report discusses the detailed results from this iterative selection process and explains the reasons for selecting the preferred solution, including a summary of any significant economic analysis findings, for projects to be included in the LRTP Tranche 1 Portfolio.

6 LRTP Tranche 1 Projects and Reliability Issues Addressed

The reliability studies were performed on the Future 1 power flow models to assess the system performance and identify any necessary upgrades to ensure reliable energy delivery under different load and dispatch patterns. Analysis of the Future 1 10-year and 20-year base case models without the LRTP Tranche 1 Portfolio indicated numerous thermal and voltage violations throughout the Midwest Subregion. Additionally, transfer analysis was performed to assess transfer capability and identify limiting constraints to be addressed to assess effectiveness of projects under broader future assumptions. Variations of candidate projects identified in the LRTP indicative roadmap were studied to determine areas of focus for project development.

It is important to understand that LRTP is not a NERC compliance study whereby every issue identified must be resolved according to NERC standards and requirements. A NERC compliance study, which is more local in nature in terms of modeling assumptions, is different than the approach taken in a long-range transmission planning study. From that perspective, the LRTP reliability solution testing sought to find solutions that provided a balance between issues resolved and cost to mitigate. This included discounting some issues, for example, as more local in nature or others that will be dealt with in the generator interconnection process. It is also related to the fact that more study work will be done in the next tranches using other Futures and additional needs will be dealt with at that time.

In doing so, MISO used the roadmap as a starting point for testing system solutions but also looked to alternative solutions either from MISO or submitted by stakeholders. Several alternatives have been considered for the Tranche 1 effort. The final portfolio represents those solutions that provided the best fit solution. It is also important to note that the ability to efficiently use existing corridors in developing transmission is a key element. As final solutions were developed, the ability of those solutions to use existing system right of way was a key consideration. Ultimately though final routing will be determined by the applicable state and/or local authorities.

Project selection involved detailed analysis in five geographic focus areas:

- Dakotas and Western Minnesota
- Minnesota – Wisconsin
- Central Iowa
- Northern Missouri Corridor
- Central-East Corridor

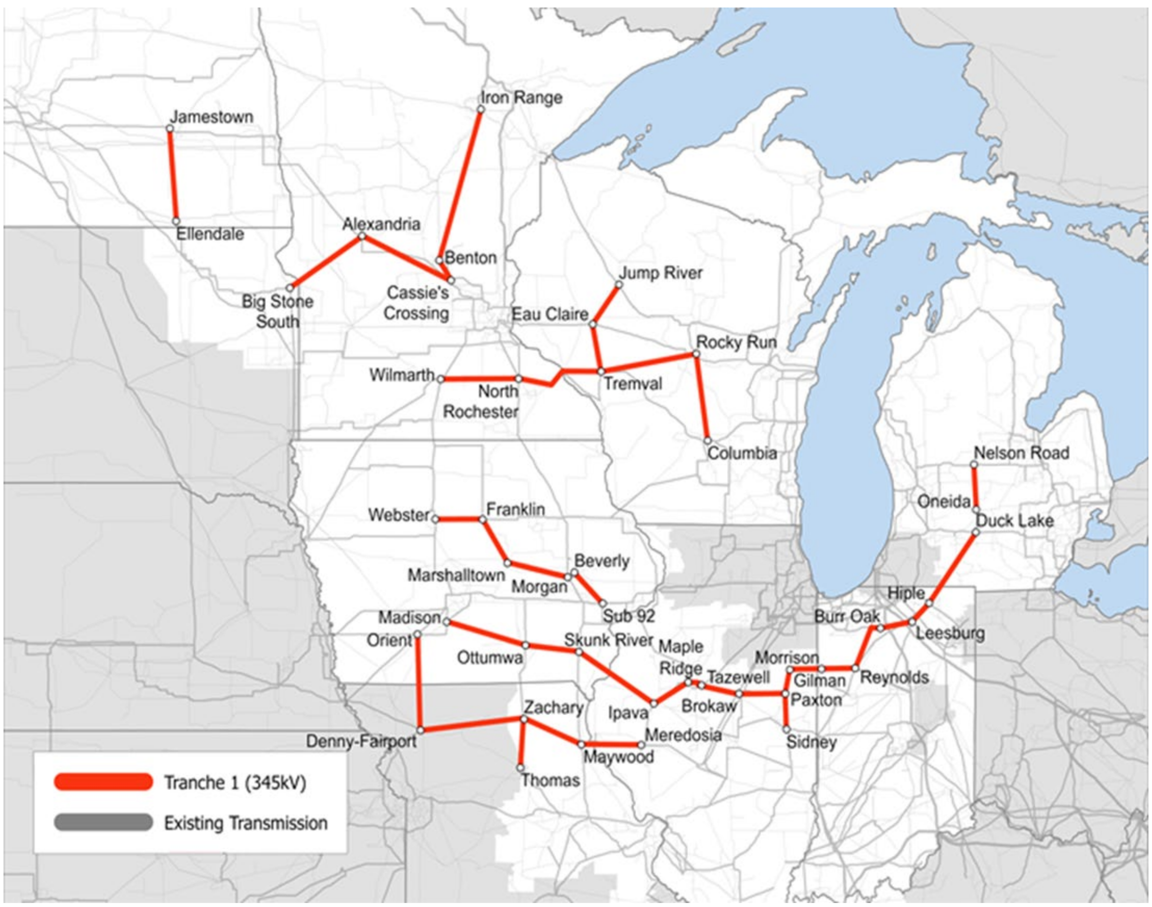


Figure 6-1: LRTP Tranche 1 Transmission Portfolio

Dakotas and Western Minnesota

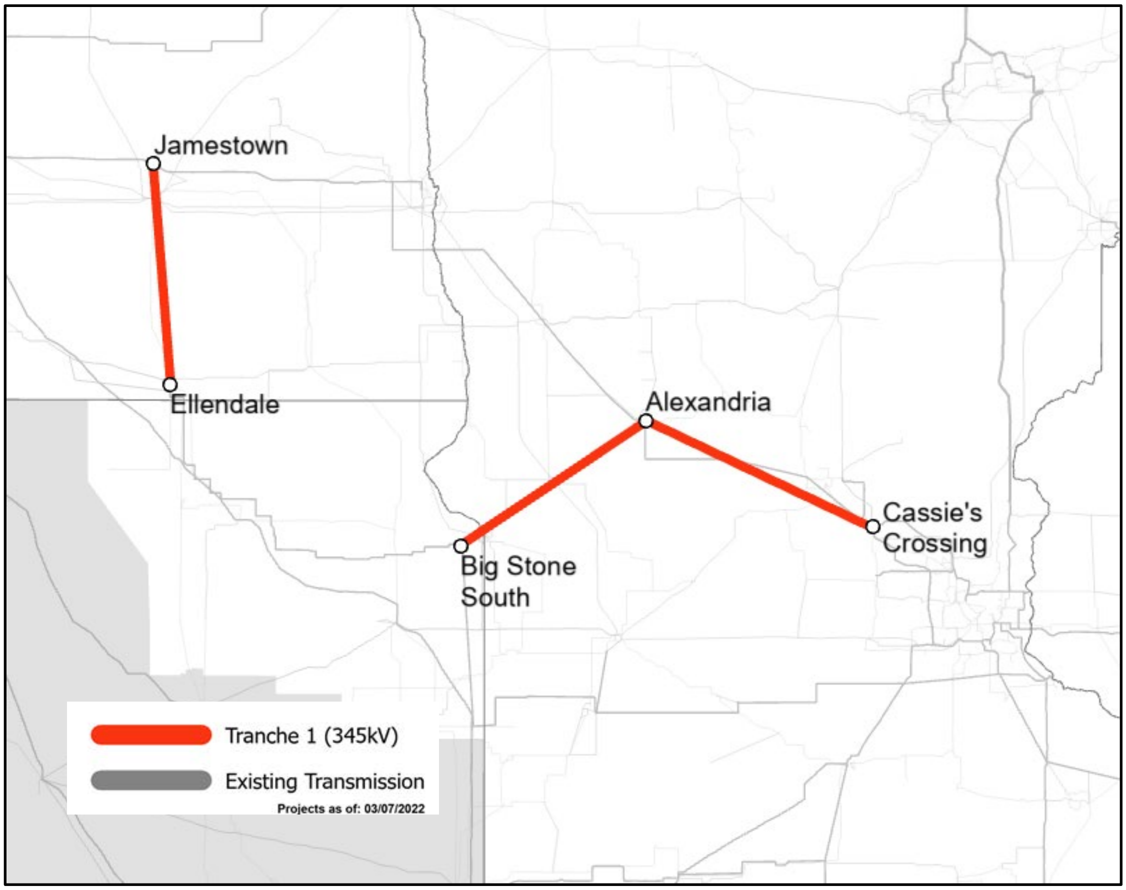


Figure 6-2: Dakotas and Western Minnesota Final Solution

Projects:
Jamestown - Ellendale 345 kV
Bigstone – Alexandria – Cassie's Crossing 345 kV

Rationale:
The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.

Issues Addressed:

The Dakotas and Western Minnesota project addresses many thermal and voltage issues for Western Minnesota and Eastern Dakotas. Most notable, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved for all N-1 and N-1-1 outages, as you can see in Figure 6-3 geographically. The solid green lines in Figure 6-3 depict Transmission Lines which no longer have overloads because of the project with circles depicting transformers that are relieved. Voltage depression was seen for a wide geographical area along the South Dakota, North Dakota, and Minnesota border typically described as the Red River Valley Area. Table 6-1 describes overloads seen in Future 1 for the Dakotas and Western Minnesota area which are relieved by the Big Stone South – Alexandria – Cassie's Crossing & Jamestown – Ellendale project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

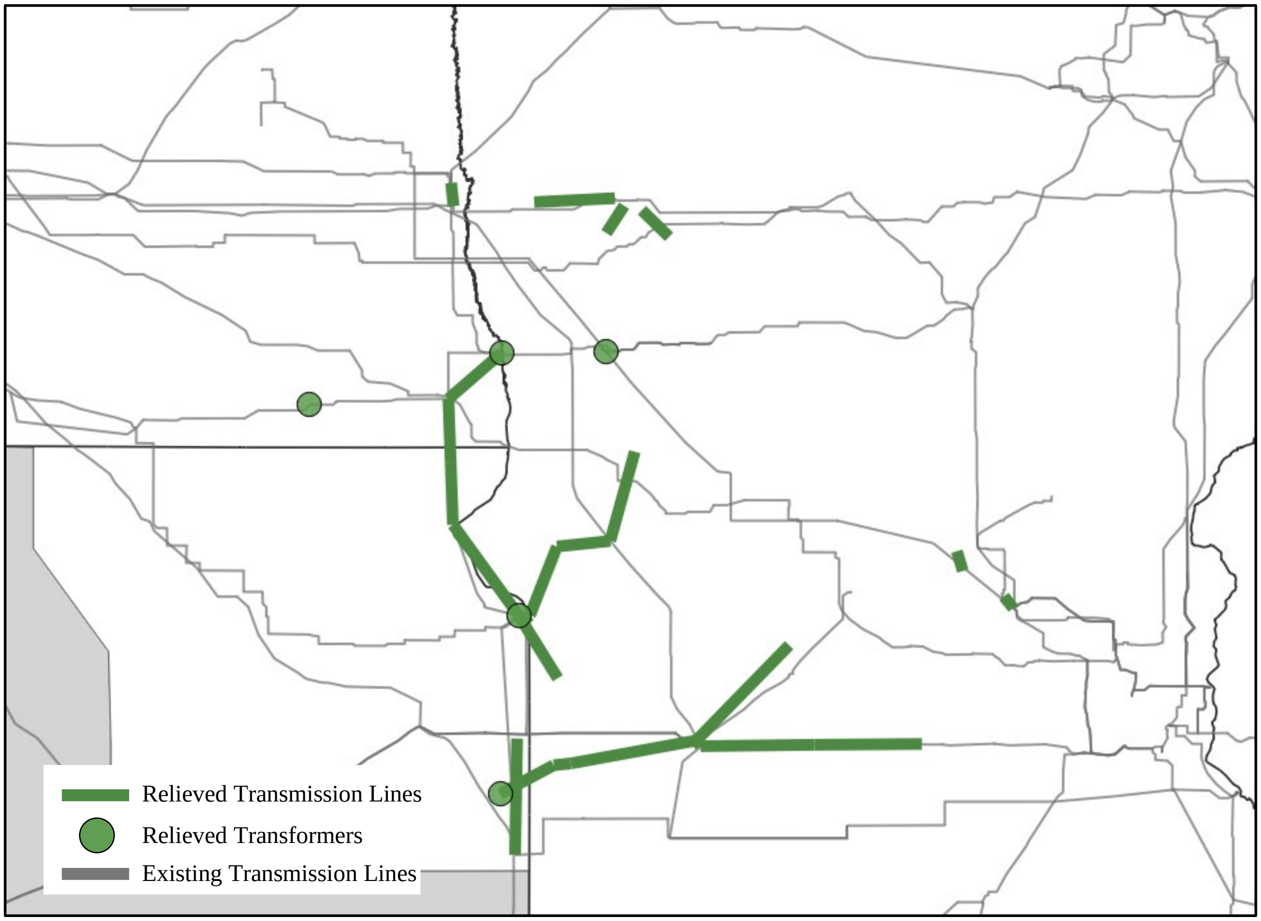


Figure 6-3: Dakotas and Western Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 6-1: Elements with thermal issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

Table 6-2: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the OTP area (620)

Alternatives Considered:

Big Stone South – Alexandria 345 kV & Jamestown – Ellendale 345 kV
Without double circuit to Cassie's Crossing there are new N-1 issues around Alexandria.

Big Stone South – Hankinson – Fergus Falls 345 kV & Jamestown – Ellendale 345 kV
Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls.

Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV
Reduces nearly all overloads of concern but not to the extent of the preferred project.

Big South – Alexandria 345 kV & Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV.
Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake (Alternative 3) does not add enough additional value over the preferred project.

Big Stone South – Breckenridge – Barnesville 345 kV & Jamestown – Ellendale 345 kV
Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative.

Western Minnesota - Dakota

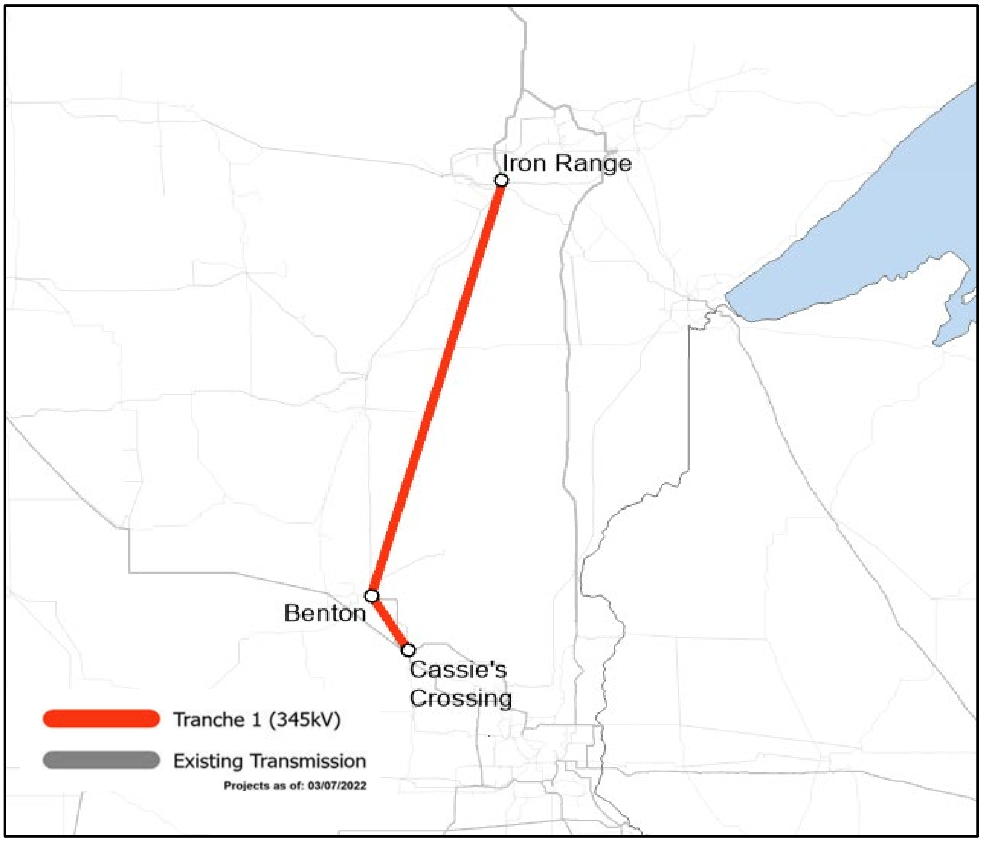


Figure 6-4: Western Minnesota - Dakota Final Solution

Project:
Iron Range – Benton - Cassie's Crossing 345 kV

Rationale:
Minnesota has and is projected to continue to undergo fleet change. This generation shift has resulted in central and northern Minnesota to have a drastic decrease in generation resources creating a large geographical area to be served by only 115 kV and 230 kV transmission. Central to northern Minnesota has moderate load, with heavy load being further north relating to iron mining operations. During the winter, Minnesota load increases significantly. This causes strain on the widespread 115 kV and 230 kV system as power is needing to get from the twin cities to the north to serve load. This large geographical disparity in generation and weak transmission causes voltage stability concerns for a majority of the Minnesota system north of the Twin Cities. The Iron Range – Benton – Cassie's Crossing 345 kV line provides a second low impedance path for power flow from southern Minnesota to the north. This unloads and relieves the 115 kV and 230 kV issues seen and relieves voltage stability concerns.

Issues Addressed:

Iron Range – Benton – Cassie's Crossing 345 kV prevents many thermal and voltage issues on the lower voltage system in central and northern Minnesota, especially for situations where the single 500 kV line heading north from the Twin Cities is lost. Under heavy winter loading situations central and northern Minnesota suffer from voltage collapse issues during transfer scenarios.

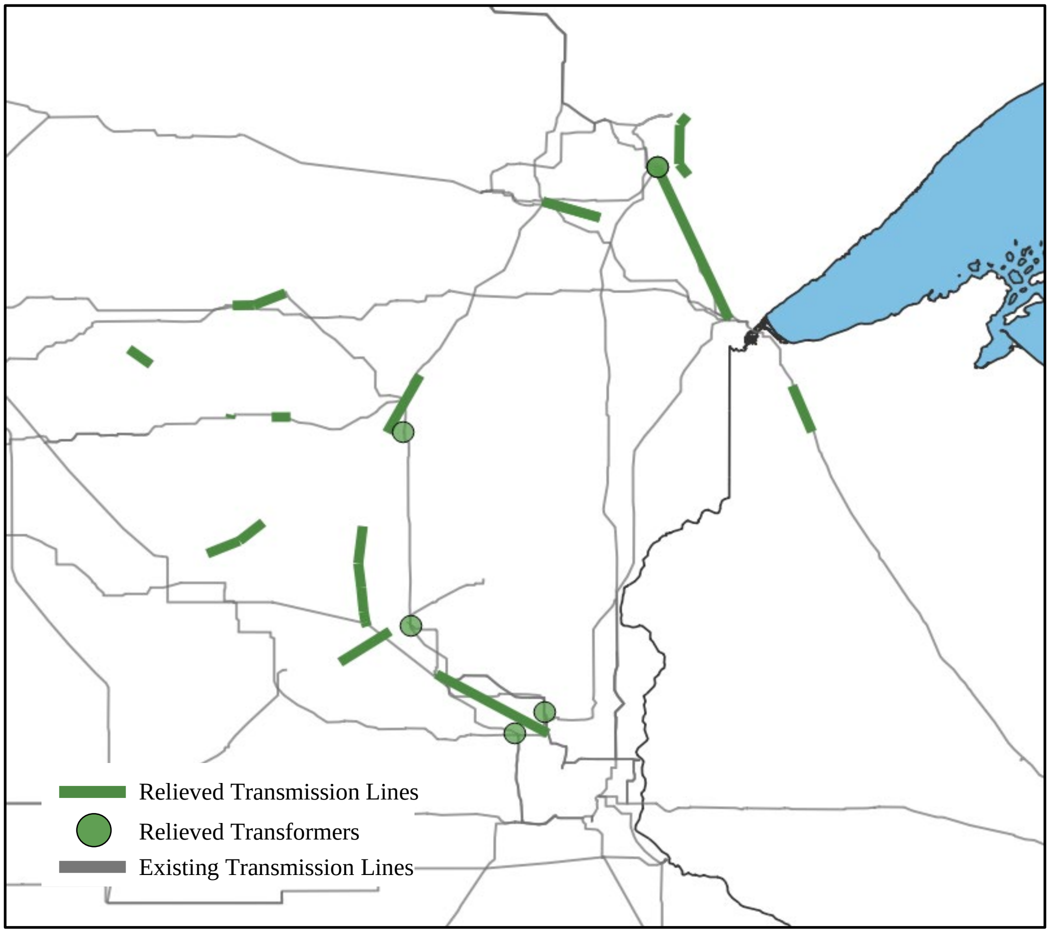


Figure 6-5: Central and Northern Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

The chart below is a graph of the Red River Valley area (northwestern Minnesota) voltage after loss of the 500 kV line from Chisago to Forbes for varying levels of transfer to the north through Minnesota. Without Iron Range – Benton – Cassie's Crossing voltage collapses for transfers less than 500 MW. Post project, transfers through Minnesota can be greater than 2000 MW without voltage collapse.

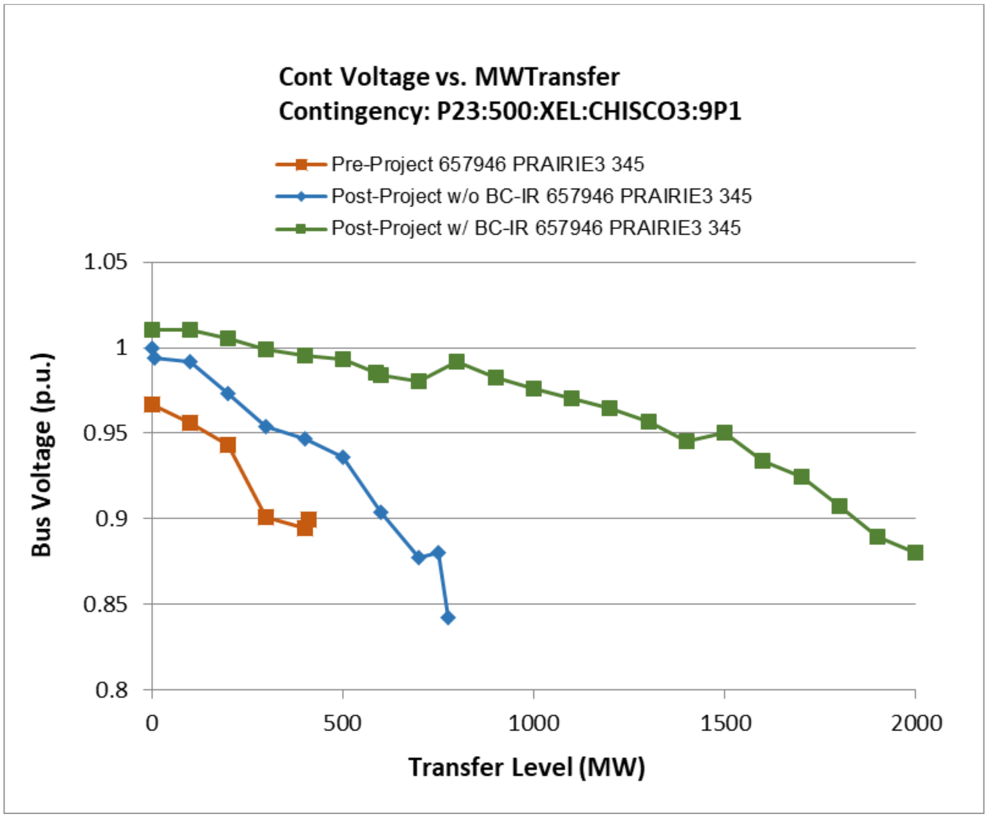


Figure 6-6: Voltage Stability Analysis P-V curve for Minnesota transfers after losing the 500 kV lines from Chisago to Forbes

The tables below describe thermal and voltage issues relieved by the Iron Range to Benton to Cassie's Crossing 345 kV line. Figure 6-5 shows geographically lines and transformers relieved by the project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	15	110	25	165

Table 6-3: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	23	<0.80	105	0.80
230 kV Buses	3	0.93	18	0.85

Table 6-4: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the MP area (608).

Alternatives Considered:

1. Iron Range – Alexandria 500 kV
2. Iron Range – Arrowhead 500 kV
3. Iron Range – Bison 500 kV
4. Iron Range – Benton 500 kV

A study interface was created to analyze alternatives to the Iron Range – Benton – Cassie's Crossing line. This interface is defined as the northern Minnesota interface (NOMN) which includes the Forbes – Chisago 500 kV line and six underlying 230 kV lines which connect central and northern Minnesota to the Twin cities and North Dakota. This interface was determined to study the system's ability to meet two primary goals.

1. Understand an operating limit for central and northern Minnesota to ensure the ability to serve peak load with a 10% or greater stability margin.
2. Maintain the ability to serve the existing 1400 MW Manitoba Import Limit while also achieving goal 1.

The proposed project, Iron Range – Benton County – Cassie's Crossing double circuit 345 kV meets both goals. Alternatives 1 (Iron Range – Alexandria 500 kV), 2 (Iron Range – Arrowhead 500 kV), and 3 (Iron Range – Bison 500 kV) do not achieve the above goals. Alternative 4 (Iron Range – Benton 500 kV) achieves both goals, however the double circuit 345kV was chosen for many reasons over the 500 kV as described below:

a. Double circuit 345 kV has a higher capacity
    i. 500 kV: 1732 MVA
    ii. 345 kV: 1195 MVA per circuit (2390 MVA Total)
b. Double circuit 345 kV is cheaper per mile compared to 500 kV
    i. 500 kV: $3,036,384 per mile
    ii. 345 kV: $2,829,742 per mile
c. A double circuit creates two lines for N-1 protection
d. Series compensation near Riverton would allow for easier 345/230 kV conversion for future expansion and support for central Minnesota as 345 kV to lower kV is more standard in the Minnesota area than 500 kV to lower kV transformation

Minnesota – Wisconsin

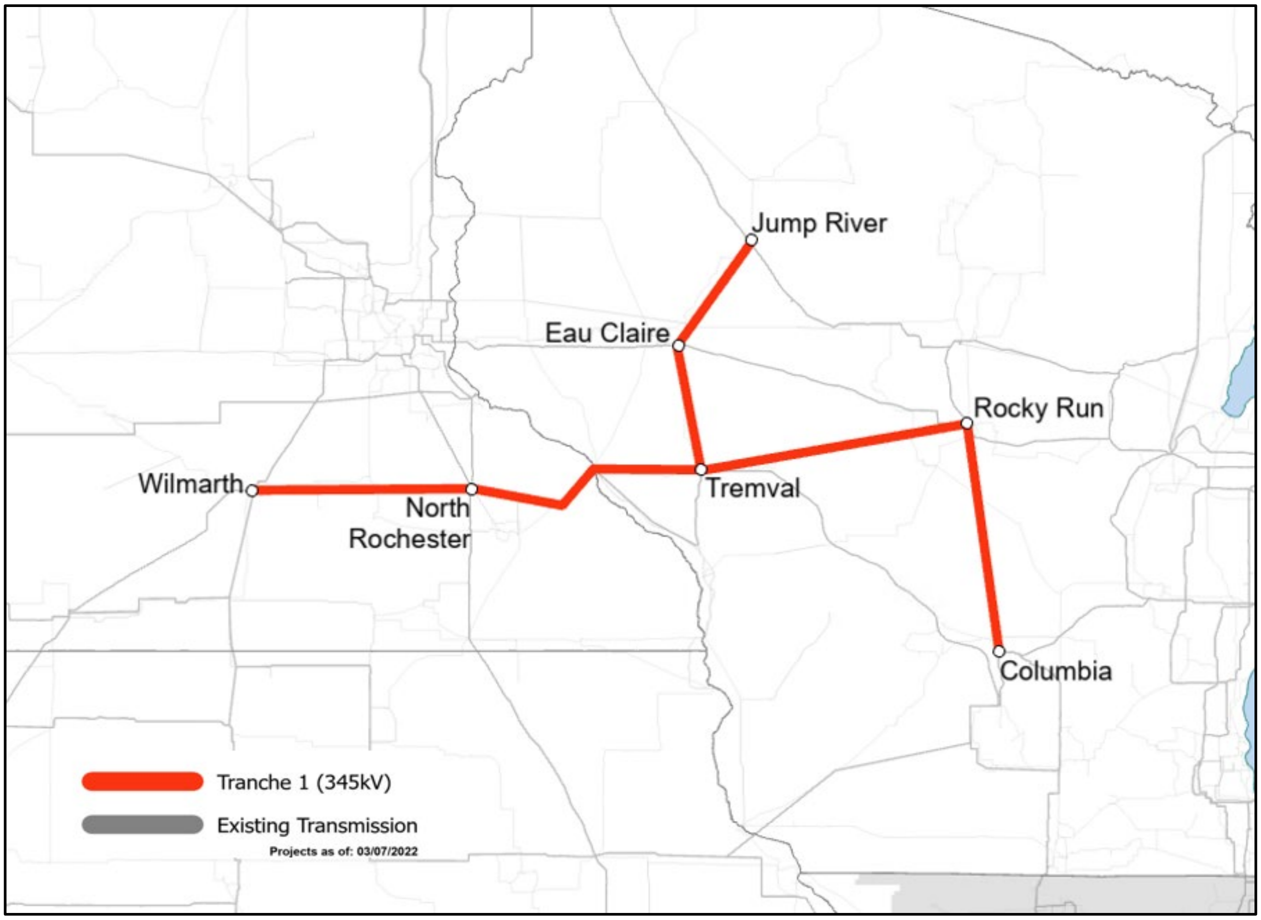


Figure 6-7: Minnesota-Wisconsin Final Solution

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

Rationale:
The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

Issues Addressed:

The Minnesota – Wisconsin series of projects work together to relieve a number of related issues. Table 6-5 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 Portfolio attributed to the Minnesota – Wisconsin set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-8.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	39	95-132%	96	95-151%
345 kV Lines	6	98-119%	9	97-120%
345/xx kV Transformers	9	97-132%	12	95-132%

Table 6-5: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases

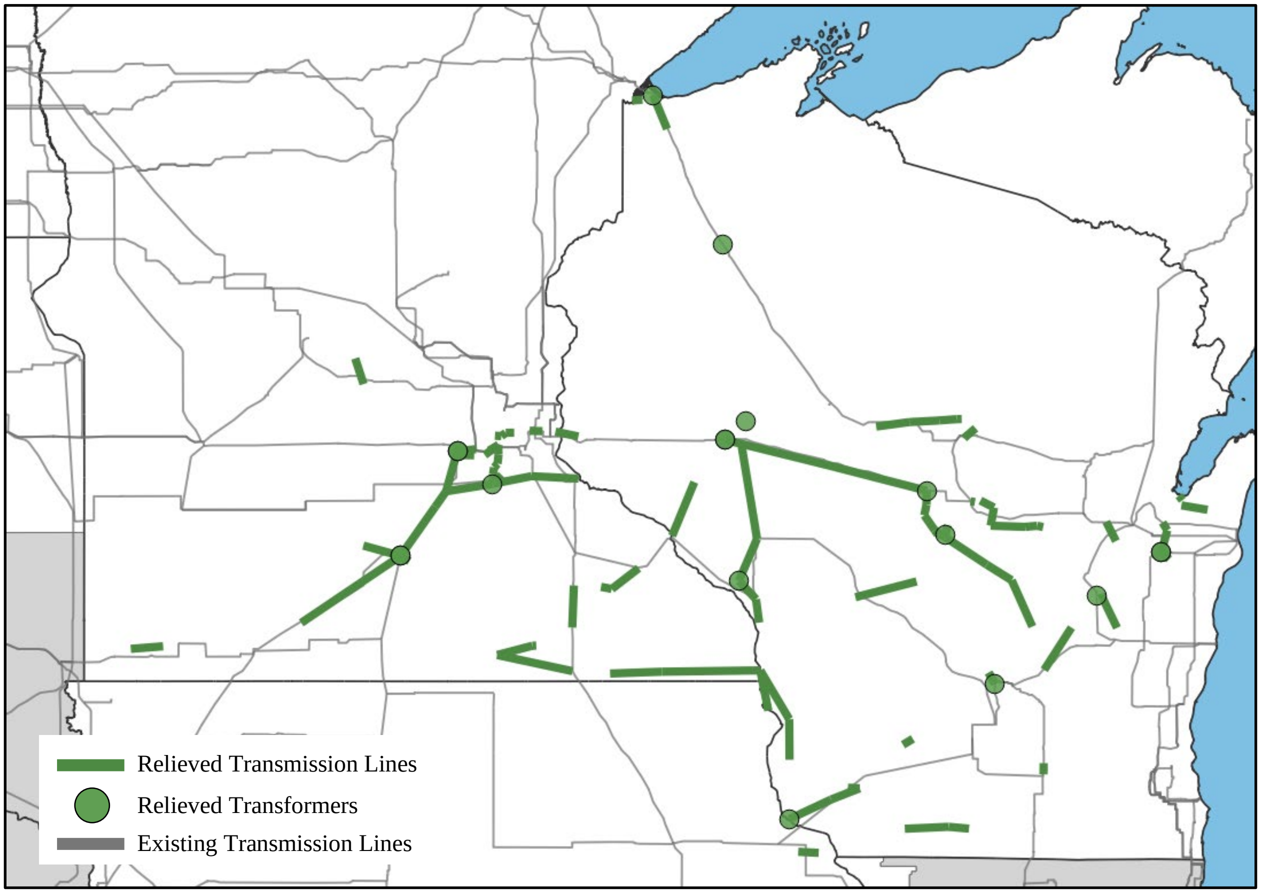


Figure 6-8: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Wilmarth to North Rochester parallels a number of 345 kV lines across the Southern Twin Cities that are heavily loaded under high renewable output from southwestern Minnesota and northwestern Iowa. In doing so, it relieves several 345 kV lines and 345/115 kV transformers in the region including Wilmarth – Shea's Lake – Helena – Chub Lake 345 kV and 345/115 kV transformers at Wilmarth and Scott County. These increased flows cause new congestion and overloads on the existing Crandall – Wilmarth 345 kV line. This project includes the rebuild of that line. If uprated, the congestion savings associated with the Wilmarth – North Rochester circuit specifically, and the rest of the Minnesota – Wisconsin project generally, increase significantly.

The connection out of North Rochester towards Tremval and east creates a lower impedance path that pulls power across Wilmarth – North Rochester and diverts power from other heavily loaded Twin Cities facilities, increasing the efficacy of that line. The sections from Tremval to Eau Claire and Jump River relieve loading on a handful of 161 kV and 115 kV facilities in Northwest Wisconsin. Those facilities increase the redundancy of the two Northern 345 kV circuits across Wisconsin and relieve overloads seen on one of the Eau Claire 345/161 kV transformers.

The new path from Tremval to Rocky Run to Columbia completes an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers. These circuits also bolster voltage stability limited transfer capability across and into Wisconsin. It also relieves overloads on a variety of 345 kV and 138 kV facilities throughout central Wisconsin.

The traditional analysis of voltage stability for the voltage stability interface across Western Wisconsin uses a load to load transfer. MISO performed this analysis for a transfer using Local Resource Zone 2 (LRZ2, roughly comprised of ATC member companies in eastern and central Wisconsin) as the destination subsystem, to capture the impact of directly serving LRZ2 load. MISO measured the impact to voltage stability both with and without Tremval – Rocky Run and Rocky Run – Columbia segments are included in this project. The addition of these facilities adds 250 MW to the transfer capability. Figure 5-9 shows the post-contingent bus voltage for the most limiting bus and outage for either the pre-project or post-project case. Those buses and outages are:

Eau Claire 345 kV for loss of King – Eau Claire 345 kV
Eau Claire 345 kV for loss of Stone Lk. – Gardner Pk 345 kV
Briggs Rd. 345 kV for loss of Stone Lk. – Gardner Pk 345 kV

Both the steady state voltages and the final nose of the stability curve can be seen to improve, with the increase measured from either point being approximately 250 MW. MISO also reviewed this analysis for scenarios using a wide area load subsystem consisting of both Wisconsin load and loads further East in MISO's system. Those cases also showed an approximate increase of 250 MW in the low voltage and voltage stability limits of the system.

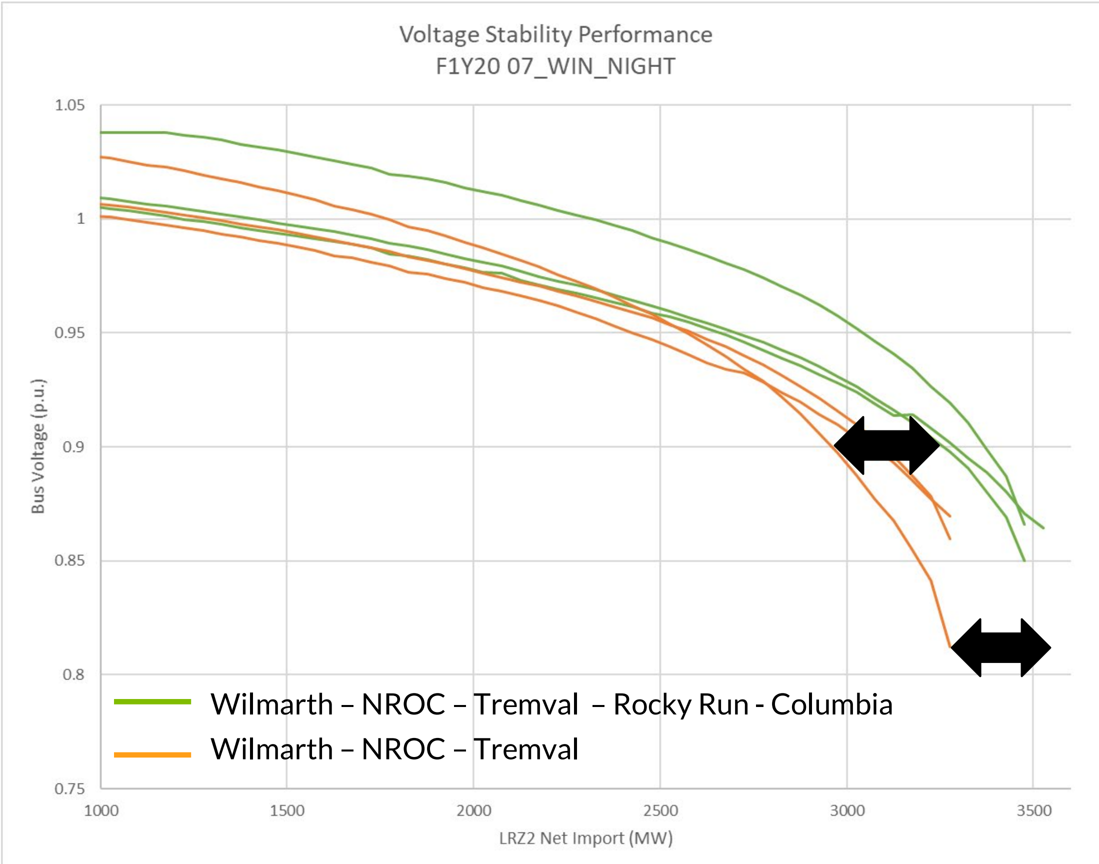


Figure 6-9: Voltage performance for key buses and outages for transfers into LRZ2. Orange lines indicate buses and outages with just Wilmarth – North Rochester – Tremval 345 kV, while green lines indicate performance with Tremval – Rocky Run – Columbia 345 kV included as well

System Design Benefits of Tremval – Eau Claire – Jump River

To date there are three 345 kV lines that connect Minnesota to Wisconsin. The lines and their lengths are listed below:

Arrowhead – Stone Lake - Gardner Park:	220 Miles
King – Eau Claire – Arpin - Rocky Run:	183 Miles
North Rochester – Briggs Road – North Madison:	250 Miles

Assuming an average Surge Impedance Loading (SIL) value of approximately 400 MW for legacy 345 kV lines such as the ones above, the Safe Loading Limits on these three 345 kV long lines based on the St. Clair curve would be as follows:

Arrowhead – Stone Lake - Gardner Park:	460 MW
King – Eau Claire – Arpin - Rocky Run:	560 MW
North Rochester – Briggs Road – North Madison:	440 MW

Safe Loading Limits[3] were proposed to avoid or mitigate excessive operating risks by limiting the voltage drop along a transmission circuit to 5% or less while maintaining a Steady State Stability Margin of 30% or greater along the transmission circuit. The excessive 345 kV line lengths between Minnesota and Wisconsin result in safe loading limits for these 345 kV lines well below the thermal limits of the lines. Even more alarming is the fact that under an N-1 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall from 1,460 MW to 900 MW, and for an N-2 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall to 440 MW.

The addition of the fourth 345 kV circuit from Minnesota – Wisconsin will significantly improve the situation above by adding additional transmission capacity across MWEX. In the case of a North Rochester – Rocky Run line, the length and Safe Loading Limit of this additional 345 kV line would be as follows:

North Rochester – Rocky Run 345 kV Mileage:	162 – 187 Miles
North Rochester – Rocky Run Safe Loading Limit:	540 MW – 600 MW

While the fourth 345 kV circuit adds considerable benefit, for an N-2 contingency with the fourth 345 kV circuit added, the combined safe loading limit of the 345 kV circuits falls to about 900 MW.

An effective method to strengthen the four parallel 345 kV circuit is to add an intermediate connection between the four 345 kV circuits as close to the midpoint as possible. A major benefit of the Tremval 345 kV Substation and the Tremval – Eau Claire – Jump River 345 kV line is that under contingency conditions, the overall reduction in the combined Safe Loading Limit of the parallel 345 kV circuits is minimized. For example, for a loss of the Eau Claire – Arpin 345 kV circuit, a 345 kV connection remains between the King - Eau Claire 345 kV circuit, and the other three 345 kV lines across the MWEX interface. This not only mitigates loading issues on the transformers at Eau Claire, but also reduces the effective 345 kV impedance across the MWEX interface, which in turn increases the capacity and combined safe loading limit of the MWEX interface. In addition, because the King – Eau Claire 345 kV circuit is still connected at the midpoint of the MWEX interface, the distributed line capacitance associated with the King – Eau Claire 345 kV circuit is available to support voltages in western Wisconsin. Lower overall impedance coupled with higher distributed capacitance means a higher effective SIL for the MWEX interface under contingency conditions.

In summary, there are desirable benefits of tying together long lines at an intermediate point, and there are examples of this technique throughout North America. These types of system design benefits will be crucial to the success of the future transmission system to operate with reliability,

[3] Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

robustness, and resilience under a future with higher renewable generation penetration and electrification.

Alternatives Considered:

MISO reviewed a wide variety of project alternatives in the project focus area between Minnesota and Wisconsin – many of them submitted by stakeholders.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included Wilmarth – North Rochester – Tremval – Eau Claire – Jump River as well as a double circuit rebuild between Adams and North Rochester, and a new 345 kV line from Colby to Adams. MISO found that the Wilmarth – North Rochester segment was important for resolving Twin Cities area loading, and that the river crossing from North Rochester to Tremval and then Tremval to elsewhere in Northern Wisconsin was effective at both relieving loading across Western Wisconsin and boosting the effectiveness of Wilmarth – North Rochester by providing an outlet and a shorter electrical path towards load centers. The double circuit from North Rochester to Adams directly relieved loading on parallel facilities. Colby – Adams relieved some loading associated with a large amount of future generation sited at Adams, but the effects were very localized.

Several stakeholders submitted alternative projects along the "Southern Corridor". These included a line from Huntley to Pleasant Valley (between Adams and North Rochester), and from Adams to Genoa and Hill Valley. One stakeholder also submitted Colby – Adams as an alternative. MISO reviewed the performance of Huntley – Pleasant Valley and Colby – Adams as alternatives to the Wilmarth – North Rochester line. Colby – Adams by itself is not effective at reducing the West to East loading across Southern Twin Cities 345 kV facilities and shows little reliability value on its own. Huntley – Pleasant Valley, when combined with a double circuit rebuild between Pleasant Valley and North Rochester, resolved many but not all of the same 345 kV and 345 stepdown transformer overloads as Wilmarth – North Rochester. It also showed higher adjusted production cost savings when included in PROMOD simulations. However, the difference in production cost savings was less than the difference in increased cost of Huntley-Pleasant Valley to North Rochester. MISO sees Huntley – Pleasant Valley as a valuable project that may be helpful in reinforcing this region in future cycles of the LRTP study.

Another proposed stakeholder alternative was a line from Adams to Genoa and Hill Valley. MISO initially viewed this project as an alternative to North Rochester – Tremval – Jump River – Eau Claire. However, analysis showed these paths address different sets of reliability concerns, with the Adams – Genoa – Hill Valley project better addressing constraints across northeast Iowa and southern Wisconsin. When tied into Hill Valley, once the Hickory Creek – Hill Valley line is in service, this would effectively form an additional path parallel to Adams – Hazleton 345 kV, and relieve flows being pushed south across eastern Iowa. MISO is prioritizing a northern path (North Rochester – Tremval) in order to address the voltage stability interface and tie into load centers. For that reason, MISO does not propose pursuing Adams – Genoa Hill Valley at this time, but

MISO understands the project's value, especially when paired with Huntley-Pleasant Valley, to potentially reinforcing the region in future cycles of the LRTP study.

MISO initially viewed Tremval – Eau Claire – Jump River and Tremval – Rocky Run – Columbia as alternatives to each other, specifically due to their relationship to the existing voltage stability interface. After some review, though, MISO found them to be addressing separate but complementary sets of issues. Tremval – Eau Claire -Jump River has only a minor impact to the voltage stability performance but relieves a variety of constraints across northern Wisconsin, including several sub-345 kV facilities and some high loading on one of the 345/161 kV transformers at Eau Claire. Tremval – Rocky Run – Columbia has a more significant impact on the voltage stability performance and resolves a number of thermal constraints East of Tremval and Eau Claire. That complimentary performance is what prompted MISO's recommendation of both project segments. MISO also reviewed several variations on the Tremval – Eau Claire – Jump River segment, which proposed different endpoints along either North Rochester – Briggs Rd – North Madison 345 kV or Stone Lake – Gardner Park. MISO found that a line from Alma to Eau Claire would have very similar cost and perform just as well electrically, when compared to Tremval – Eau Claire. MISO sees Tremval as a better tie-in point, due to its more easterly location with better accessibility, which would position it as a better long term hub. A line from Eau Claire to Stone Lake, in comparison to Eau Claire – Jump River, would be significantly more expensive and MISO's screening showed that it was less effective at relieving thermal loading on lines that Eau Claire – Jump River successfully unloaded.

Central Iowa

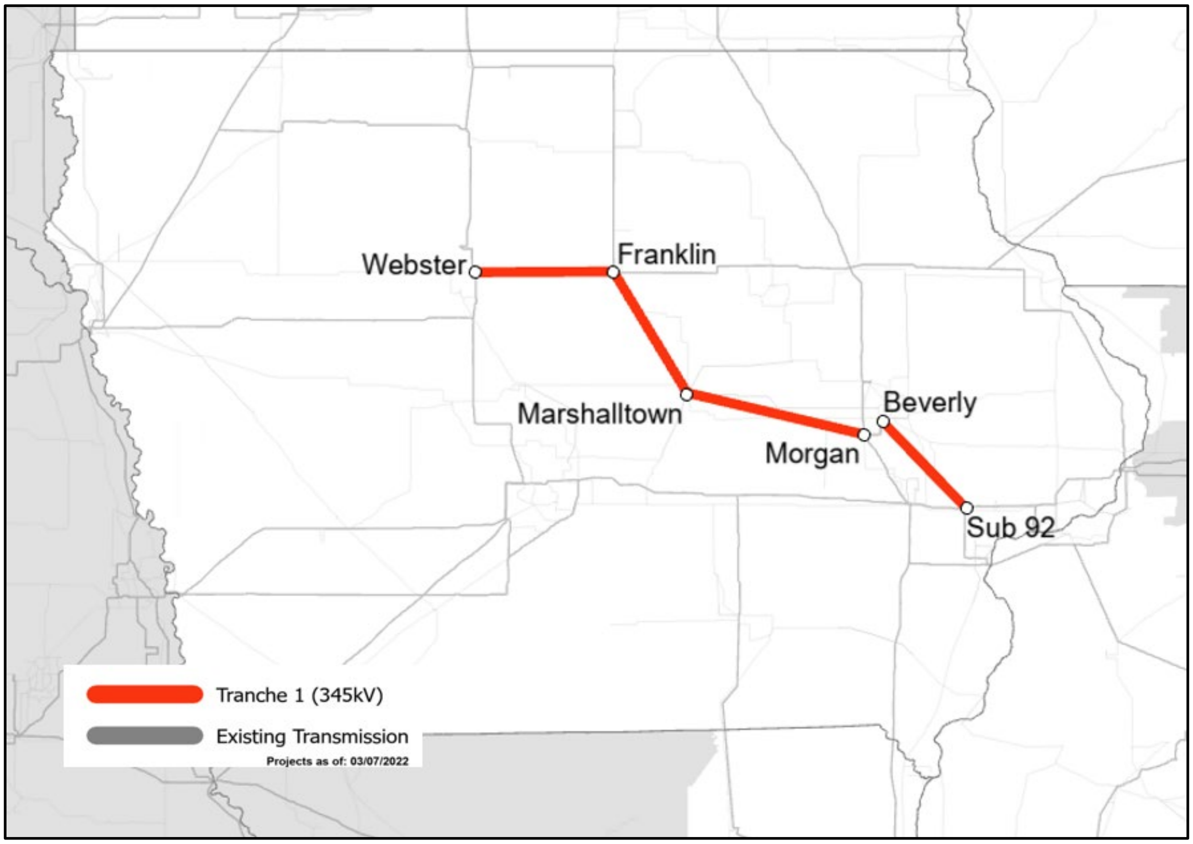


Figure 6-10: Central Iowa Final Solution

Projects:
Webster – Franklin – Morgan Valley 345 kV
Beverly – Sub 92 345 kV

Rationale:
Within MISO's system, the state of Iowa acts as both a major source of renewable energy and a gateway between MISO's members in the upper Midwest and MISO's Central planning region – Missouri, Illinois, and Indiana. Wind resources sited in Iowa are located primarily in the north and west parts of the state, and a large amount of wind resources are also located in western Minnesota and the Dakotas. During hours with high renewable output levels, power must flow southeast across and out of this region towards MISO load centers. In the LRTP models as well as in previous MISO planning studies, we have seen overloads and congestion across Iowa's central corridor. This project is intended to provide an additional 345 kV path southeast across the state, linking the high renewable region in the west with the Quad Cities load center and 345 kV outlets towards the rest of MISO. In doing so, we form a corridor both west-east and north-south across central Iowa.

Issues Addressed:
The Central Iowa projects between Webster and Sub 92 relieve a number of related issues. Table 6-6 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 projects and attributed to the Central Iowa set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-11.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	21	95-128%	34	96-132%
345 kV Lines	6	96-128%	7	97-128%
345/xx kV Transformers			4	96-127%

Table 6-6: Elements relieved by the Central Iowa projects in Future 1 power flow cases

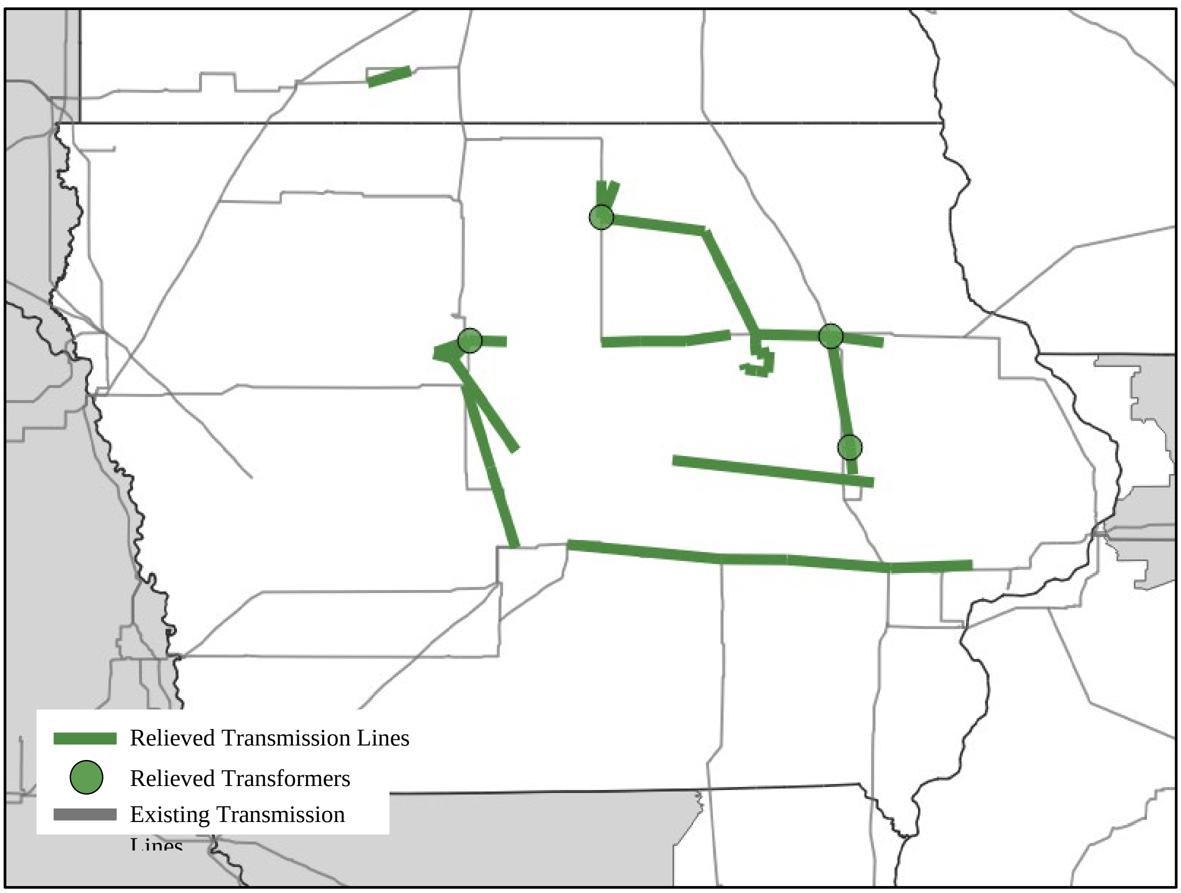


Figure 6-11: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Webster – Franklin – Marshalltown – Morgan Valley 345 kV forms a new connection from the 345 kV network in northwest Iowa (roughly west and north of Lehigh) to the north-south corridor across eastern Iowa (Adams – Hazleton – Hills – Maywood 345 kV). A previously approved line from Morgan Valley to Beverly stretches a few miles to the east, from which a new line can connect south from Beverly to Sub 92 345 kV. With that added segment, the overall path also completes a link from the northern 345 kV across central Iowa (Ledyard – Colby – Killdeer – Blackhawk – Hazleton 345 kV) down to a southern corridor (Bondurant – Montezuma – Hills – Sub 92 345 kV). By reinforcing the system in both directions, the project relieves loading on both west-east and north-south transmission facilities paralleling it. This loading is primarily seen in high renewable output cases, when renewable resources across western Iowa and southern Minnesota are producing high output. Lines seeing the greatest relief include Hazleton – Arnold 345 kV, Lehigh – Beaver Creek – Grimes 345 kV, and Montezuma – Diamond Trail – Hills 345 kV.

Alternatives Considered:

MISO reviewed several project alternatives and variations of the proposed central Iowa project set.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included the proposed version of this project (Webster – Franklin – Marshalltown – Morgan Valley 345 kV and Beverly – Sub 92 345 kV), as well as some additional facilities. These included a new line between Marshalltown and Montezuma, with both the Franklin – Marshalltown and Marshalltown – Montezuma lines built as double circuit 345 kV. Two transformers were also sited at Franklin and Marshalltown. MISO found that the double circuit line sections did not relieve an appreciable number of additional facility overloads. MISO saw that the inclusion of a line from Marshalltown to Montezuma contributed minimal reliability benefit. Of the proposed transformers, MISO found no clear benefit to including 345/161 kV transformers at Franklin. At Marshalltown, a single 345/161 kV transformer can relieve some local loading on the lower kV system, but a second 345/161 kV transformer did not appear necessary.

MISO also reviewed a roadmap project in western Iowa that was submitted as a stakeholder alternative as well. Ida County – Avoca 345 kV would create a new line between Ida County in NW IA and a new 345 kV substation in SW Iowa adjacent to the existing Avoca 161 kV station. In comparison to the proposed project, this project was similarly successful at relieving loading on Lehigh – Beaver Creek – Grimes 345 kV and parallel facilities, but ineffective at relieving constraints east of that corridor, or generally east of the Des Moines metro area.

MISO reviewed portions of the Iowa – Michigan corridor project and the Iowa – Missouri project, in comparison to the proposed project. These facilities were not effective at relieving most of the facilities north and east of Des Moines that are relieved by the proposed project. They did relieve overloads in the Des Moines metro area and in southeastern Iowa and reduced some of the loading that the proposed project moved into southeastern Iowa. Within Iowa, MISO sees the reliability benefit of these two additional project groups as additive, in addition to the benefits of the central Iowa project.

East-Central Corridor

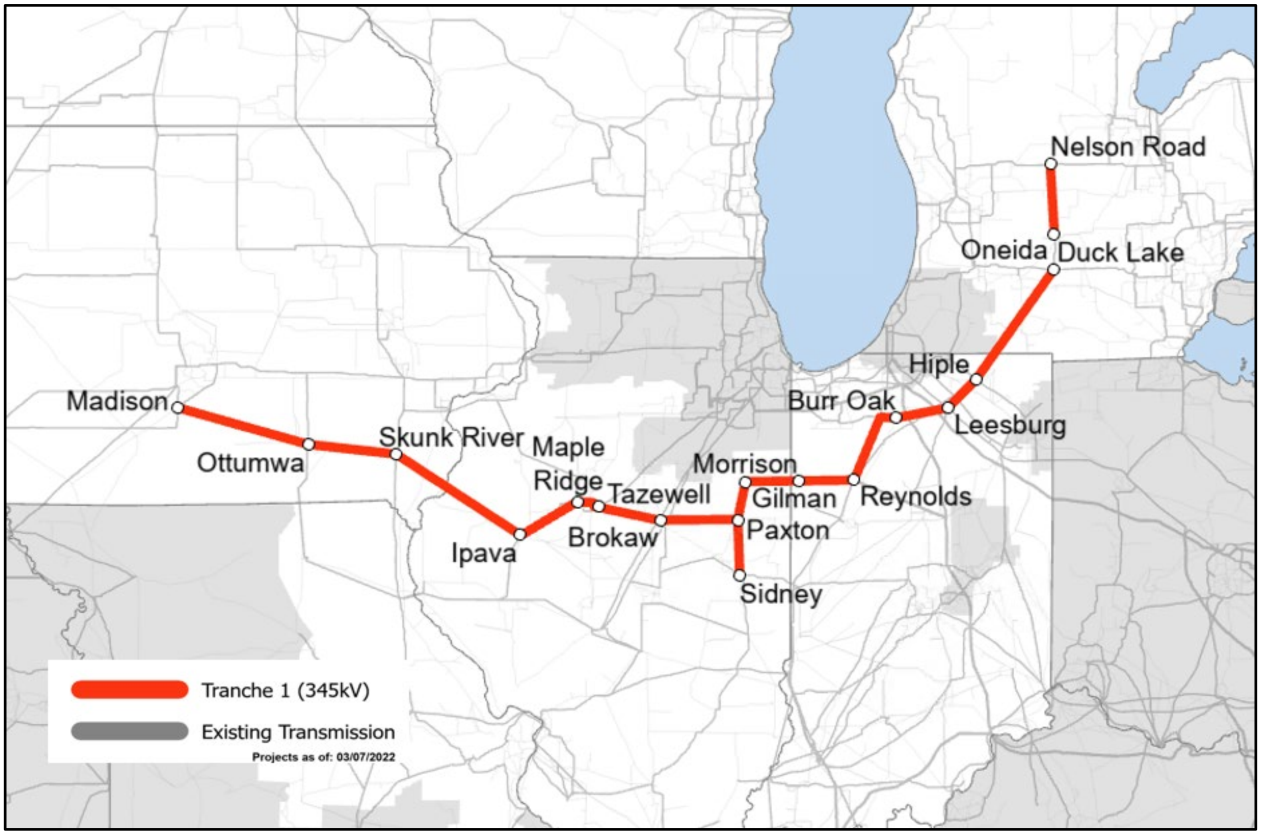


Figure 6-12: East-Central Corridor (Iowa to Michigan) Final Solution

Projects:
Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345 kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345 kV
Paxton – Sidney 345 kV
Oneida – Nelson Road 345 kV

Rationale:
MISO performed steady-state and voltage stability analyses on the proposed Iowa to Michigan LRTP projects. The steady-state results show the projects can mitigate severe thermal issues in Michigan, Indiana, Illinois, Missouri, and Iowa, with 77 monitored facilities addressed. The top 20 monitored facilities with worst-case contingencies are shown in Table 6-7.

The voltage stability results further demonstrate the effectiveness of the projects in improving voltage profiles and increasing transfer levels from West-East/East-West (Figures 6-14, 6-15, 6-16).

Issues Addressed:
The Iowa to Michigan projects addresses 600 thermal violations associated with 77 unique monitored facilities (Figure 6-13). For this metric, a constraint was considered relieved if its worst

pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the projects.

- 28 issues resolved in Michigan
- 16 issues resolved in Indiana
- 19 issues resolved in Missouri and Illinois
- 14 issues resolved in Iowa

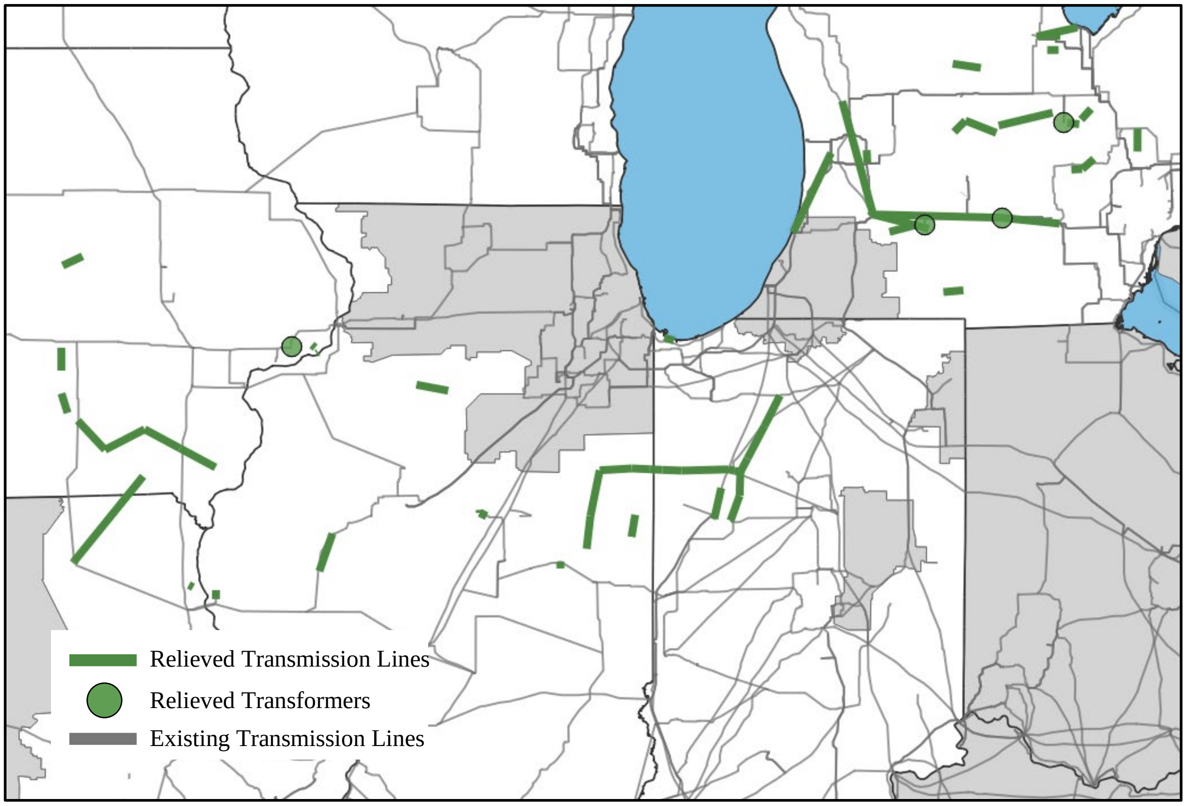


Figure 6-13: East-Central Corridor (Iowa to Michigan Line) map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

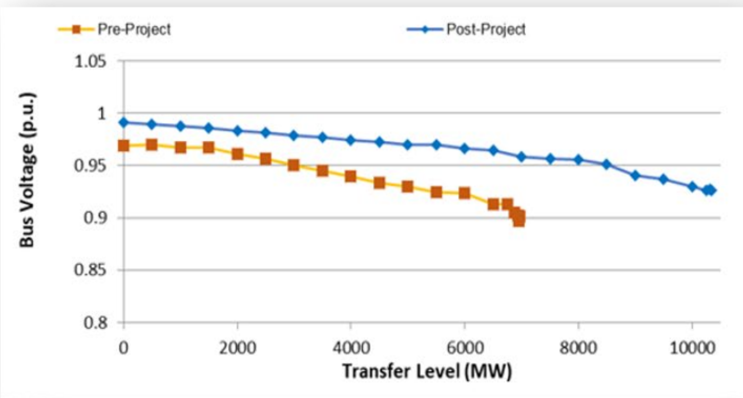
		% Loading	
Monitored Facility	**Area**	**Base + West LRTP***	**+ IA to MI Projects**
Goodland – Reynolds 138 kV Ckt. 1	NIPS	383	< 65
Reynolds 345/138 kV Transformer	NIPS	278	86
Reynolds – Magnetation 138 kV Ckt. 1	NIPS	264	67
Monticello – Magnetation 138 kV Ckt. 1	NIPS	263	67
Springboro – Monticello 138 kV Ckt. 1	DEI/NIPS	230	72
Lafayette 2 – Springboro 138 kV Ckt. 1	DEI	186	< 65
Morrison Ditch – Sheldon South 138 kV Ckt. 1	NIPS/AMIL	181	< 65
Gilman – Paxton East 138 kV Ckt. 1	AMIL	171	< 65
East Winamac – Headlee 138 kV Ckt. 1	NIPS	163	79

Westwood – South Prairie 138 kV Ckt. 1	DEI/NIPS	163	<65
Sheldon South – Watseka 138 kV Ckt. 1	AMIL	157	< 65
Burr Oak – East Winamac 138 kV Ckt. 1	NIPS	155	72
Island Rd 138 kV Bus	METC	155	67
Ottumwa 345/161 kV Transformer	ALTW	150	96
Poweshiek – Irvine 161 kV Ckt. 1	ALTW	144	98
Monticello – Headlee 138 kV Ckt. 1	NIPS	144	< 65
Gilman – Watseka 138 kV Ckt. 1	AMIL	136	< 65
Goodland – Morrison Ditch 138 kV Ckt. 1	NIPS	135	< 65
Tompkin – Majestic 345 kV Ckt. 1	METC/ITCT	133	82
Mahomet 138 kV Bus	AMIL	127	93

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-7: Top 20 thermal issues addressed by East-Central Corridor

Transfer levels increase and voltage profiles improve in Indiana, Missouri, and Michigan with the IA – MI projects (Figures 6-14, 6-15, and 6-16).



Pre-Project = No LRTP Projects
Post-Project = + IA to MI Line

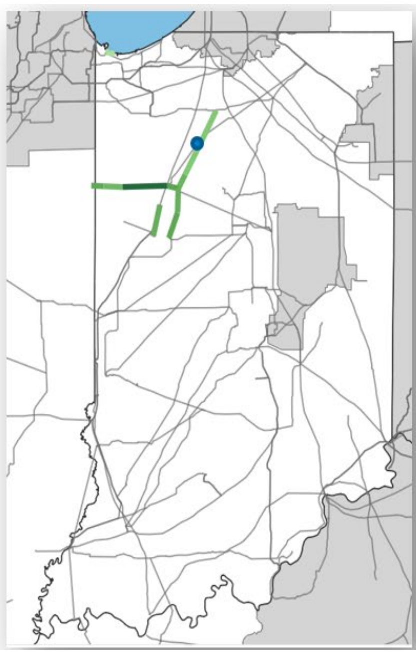


Figure 6-14: Improved voltage profiles in Indiana and Increased transfer levels with the Iowa to Michigan Projects

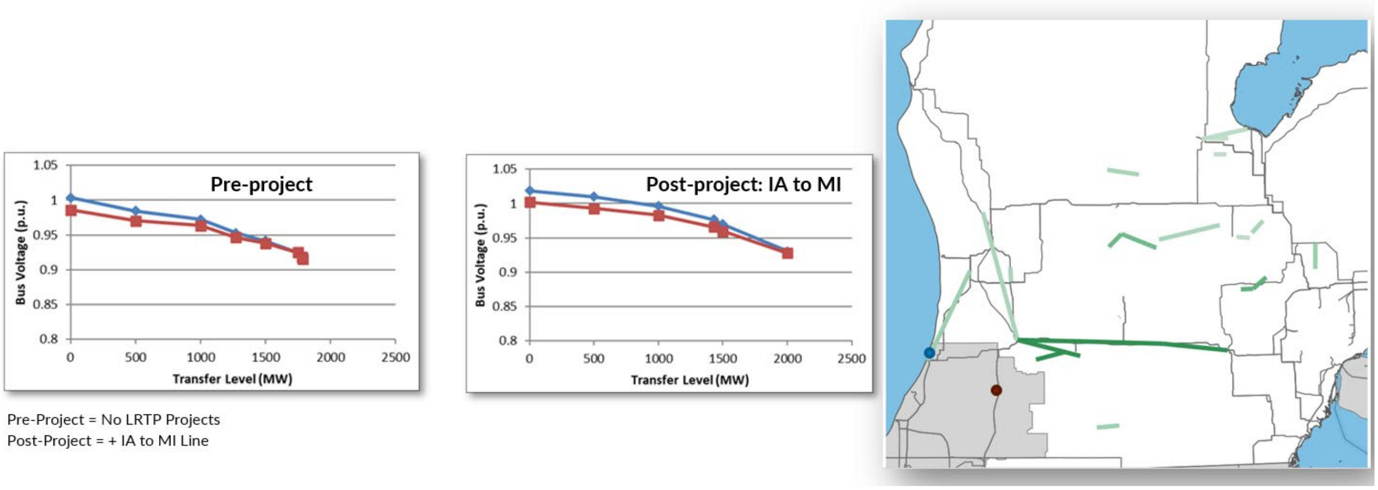


Figure 6-15: Improved voltage profiles in Michigan and Increased transfer levels with the Iowa to Michigan Projects

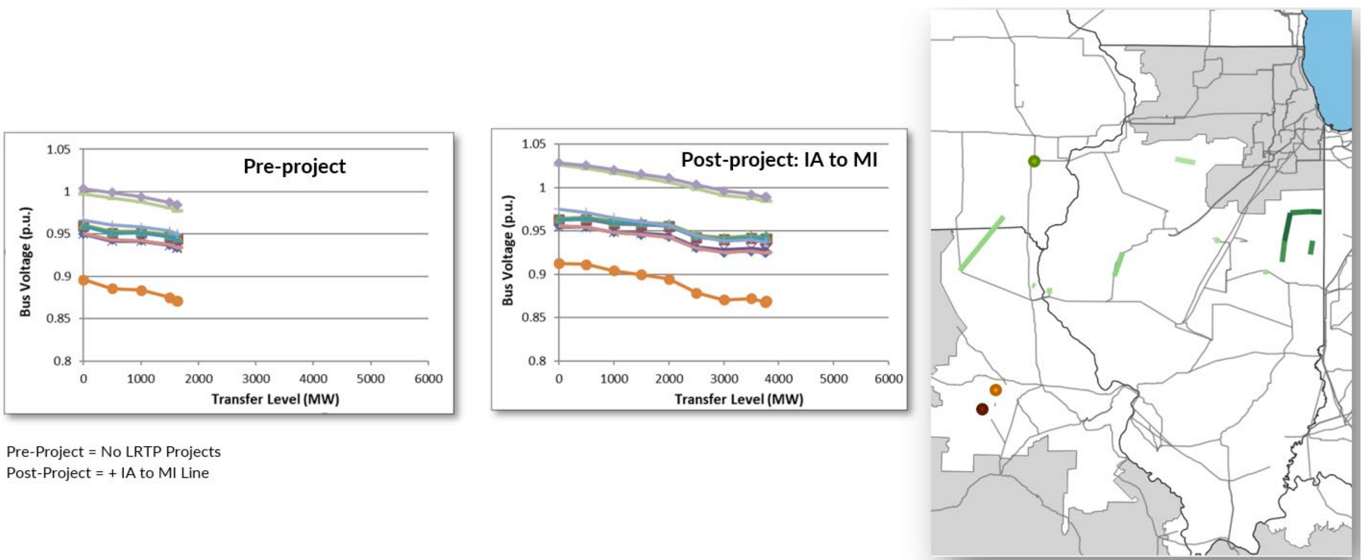


Figure 6-16: Improved voltage profiles in Missouri and Increased transfer levels with the Iowa to Michigan Projects

Alternatives Considered:

Two alternative solutions were received during the alternative submittal period, Duck Lake to Weeds Lake and Hiple to Duck Lake (MISO Main Proposal). Four additional alternatives were also evaluated. The alternative solutions resolve issues in Michigan, but fewer unsolved contingencies are associated with the road map project or MISO Main Proposal.

- Duck Lake to Weeds Lake, resolves 28 thermal issues:
- Hiple to Duck Lake (MISO main proposal), resolves 28 thermal issues
- Tie One Circuit in Argenta (resolves 28 thermal issues)
  - Argenta – Hiple
  - Argenta – Duck-Lake
- Oneida to Madrid (double-circuit), resolves 36 thermal issues
- Iowa to Indiana with Duck Lake Configuration, resolves 15 thermal issues

Northern Missouri Corridor

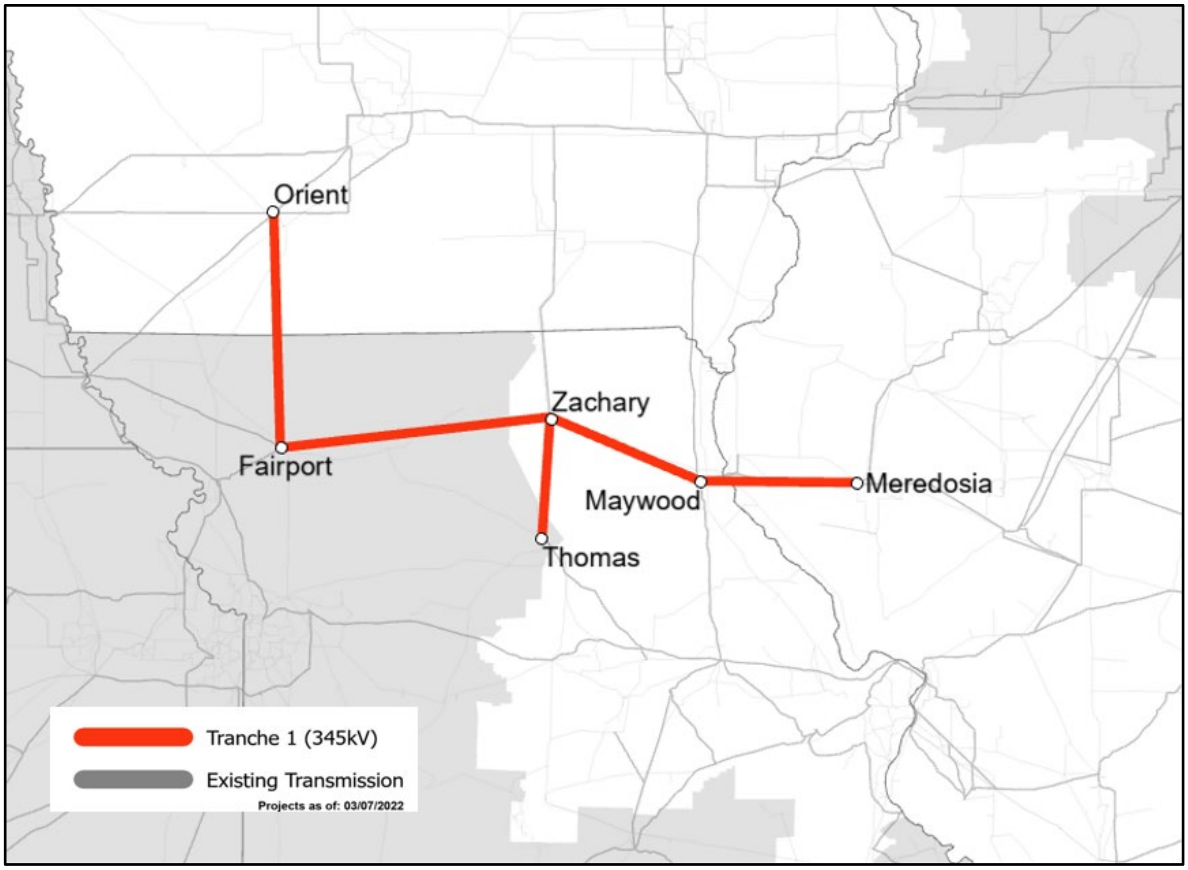


Figure 6-17: Northern Missouri Corridor Final Solution

Projects:
Orient – Fairport – Zachary – Maywood – Meredosia 345 kV
Zachary – Thomas 345 kV

Rationale:
The northern Missouri Corridor relieves loading on transmission elements in Iowa, Missouri, and Illinois. Increased transfer levels and improved voltage profiles are associated with the Missouri projects (Figure 6-17).

Issues Addressed:
The Missouri Corridor addressed thermal issues (Figure 6-18). Facilities mitigated by the Missouri Corridor are listed in Table 6-8. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

- 14 issues resolved in Missouri and Illinois
- 5 issues resolved in Iowa

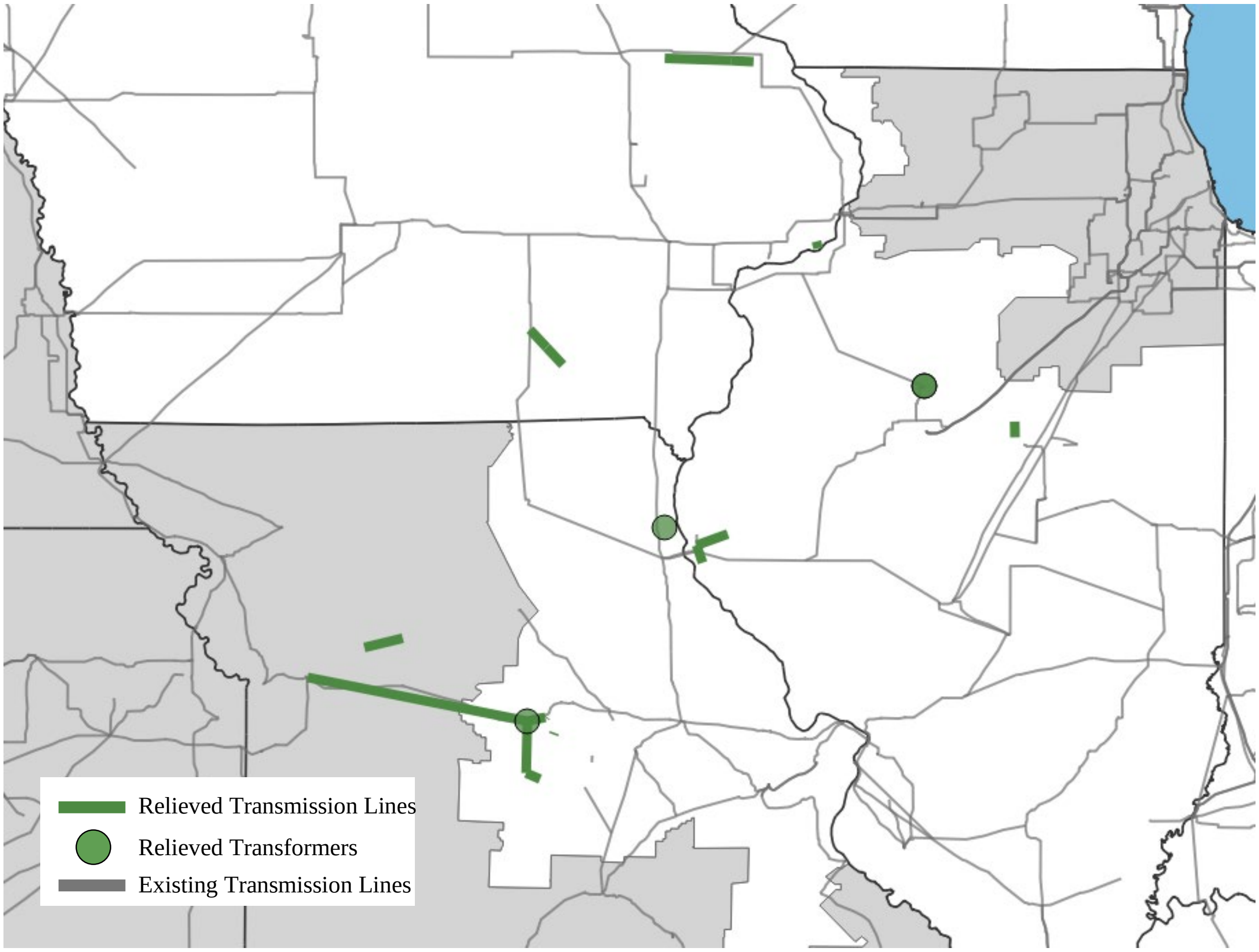


Figure 6-18: Northern Missouri Corridor map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

		% Loading	
Monitored Facility	**Area**	**Base + West LRTP***	**+ IA to MI Project + MO Projects**
Marblehead 161/138 kV Transformer	AMIL	137	85
Fargo 345/138 kV Transformer 1	AMIL	122	98
Fargo 345/138 kV Transformer 2	AMIL	122	98
Herleman 3 – Quincy S. 138 kV Ckt. 73	AMIL	120	79
Herleman 1 – Quincy N. 138 kV Ckt. 50	AMIL	120	79
Diamond Start Tap – White Oak Wind Bus 138kV Ckt. 1	AMIL	114	100
Overton 345/161 kV Transformer	AMMO	109	97
Overton – Sibley 345 kV Ckt. 1	AMMO	102	88
Huntsdale – Overton 1 161 kV Ckt. 1	AMMO	101	91
California 161 kV Bus 1 – Overton 2 161 kV Ckt. 1	AMMO	98	88
Huntsdale – Perche Creek 161 kV Ckt. 1	CWLD	97	87
McBaine Bus #2 – McBaine Tap 161 kV Ckt. 1	AMMO	97	85

Maurer Lake 161 kV Bus 1 – Carrollton 161 kV Ckt. 1	AMMO	96	70
California 161 kV Bus	AMMO	95	85
Sub 71 – Sub 88 161 kV Ckt. 1	MEC	109	98
Heights – Ottumwa 161 kV Ckt. 1	ALTW	103	95
Heights – Woody 161 kV Ckt. 1	ALTW	101	93
Liberty – Hickory Creek 161 kV Ckt. 1	ALTW	98	91
Liberty – Dundee 161 kV Ckt. 1	ALTW	98	91

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-8: Facilities mitigated by the Missouri Corridor

The Missouri projects can help power delivery, in addition to increasing transfer levels from East-West/West-East. Moreover, the projects address voltage instability in Missouri (Figure 6-19).

- In the Pre-project case (without LRTP projects), with the transfer level reaching 1640 MW, one 345 kV bus in Missouri shows voltage dropping to 0.87 p.u. following loss of a large generating plant, which demonstrates voltage instability in this source area
- With the proposed IA – MI 345 kV line, the transfer level is increased to 3773 MW
- With the addition of the MO Project, the transfer level is further increased to 6000 MW

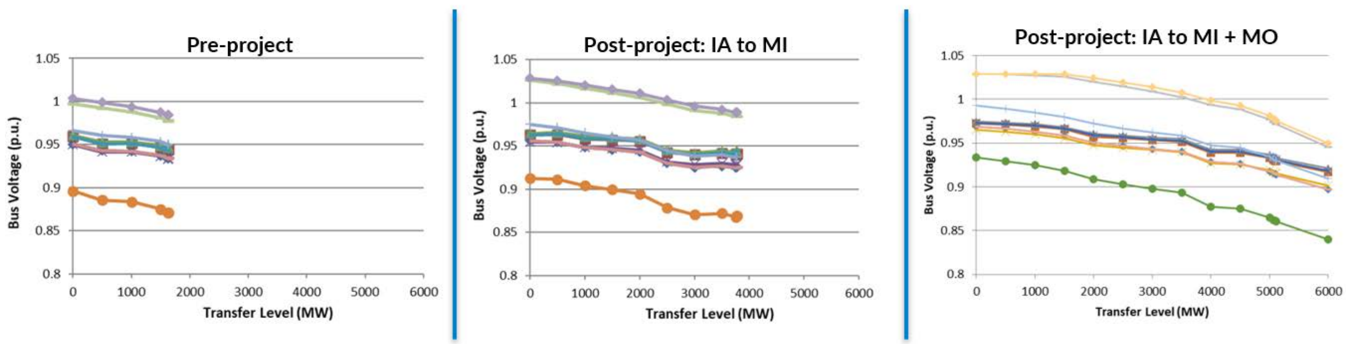


Figure 6-19: Bus Voltage Profiles

Alternatives Considered:

Segments of the Missouri corridor were considered separately, the full Missouri path (Orient – Fairport – Zachary – Maywood – Meredosia 345 kV / Zachary – Thomas 345 kV) is a better solution, with 19 issues addressed by the full path compared to:

- Zachary – Thomas – Maywood – Meredosia, resolves 11 issues
- Thomas – Zachary, resolves 4 issues
- Zachary – Maywood, resolves 6 issues
- Zachary – Maywood – Meredosia, resolves 9 issues
- Zachary – Maywood – Thomas, resolves 5 issues

7 LRTP Tranche 1 Portfolio Benefits

In accordance with the guiding principles of the MISO planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility of LRTP projects is established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

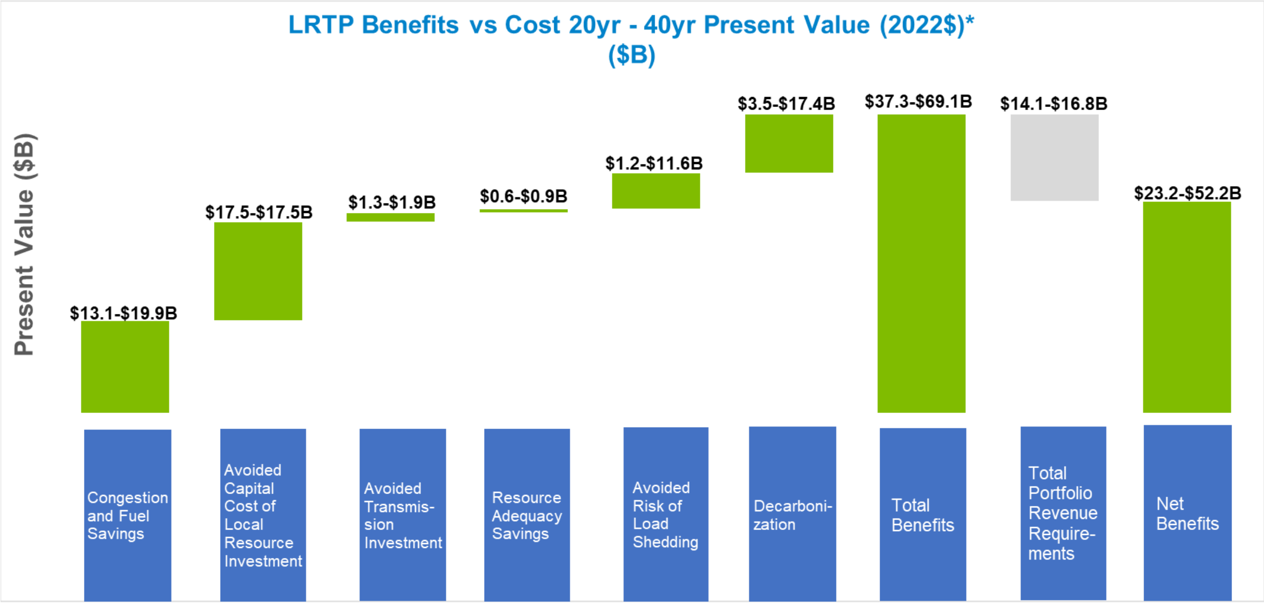


Figure 7-1: Financially Quantifiable Benefits of LRTP Tranche 1 Portfolio (values as of 6/1/22)

Guided by the allowable economic benefits defined in the tariff for MVP projects, the following benefit components were evaluated to determine the amount of value delivered by the LRTP Tranche 1 Portfolio:

- Congestion and fuel cost savings
- Avoided capital costs of local resource investment
- Avoided future transmission investment
- Reduced resource adequacy requirements
- Avoided risk of load shedding
- Decarbonization

Each benefit metric represents a distinct piece of the overall value resulting from either the transmission investments or the generation changes enabled by the transmission projects. Each benefit component is discussed in more detail, explaining what is captured in the metric, how LRTP projects impact the value being measured, and the methodology used to calculate the benefit. Starting from their assumed in-service year of 2030, benefits were calculated over a twenty-year horizon to evaluate eligibility as a multi-value project, and over a forty-year period to demonstrate the additional value provided over the expected useful life of the assets.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. All benefit values are expressed in 2022 dollars. An inflation rate of 2.5% is assumed when adjusting for the benefit period. A rate of 3 percent is used to represent the value a ratepayer would typically receive on a risk-adjusted investment. A discount rate of 6.9 percent is used to calculate the minimum value used to assess the benefit to cost ratio and based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. The benefits analysis also includes evaluation of a natural gas price sensitivity to determine how benefits change with respect to swings in natural gas prices. While the benefits of the LRTP Tranche 1 Portfolio business case are analyzed for a Future 1 resource expansion scenario based on a specific gas price assumption, the sensitivity analysis offers additional insights into the value of LRTP under a broader set of assumptions.

Congestion and Fuel Cost Savings

In the MISO Futures[4], transmission limitations require robust solutions that not only reduce system congestion but also facilitate access to the diverse, ever-changing resource mix. The LRTP Tranche 1 Portfolio helps deliver economic benefits by providing more transmission infrastructure to distribute loading on other facilities and by enabling the connection of more low-cost resources.

Congestion and Fuel Savings benefit analysis is determined by calculating Adjusted Production Cost (APC[5]) savings between a reference case and a change case production cost model. The makeup of the reference case includes sufficient resources to meet Future 1 energy requirements, without applying the limitations of the transmission system, as well as Future 1 Regional Resource Forecast (RRF) resources that do not require the LRTP Tranche 1 Portfolio to connect to the system. The change case includes the LRTP Tranche 1 Portfolio and Future 1 RRF resources enabled by regional transmission to connect to the system. To determine which RRF resources are included in the reference and change case models, MISO performed a distribution factor (DFAX[6]) analysis on reliability constraints addressed by the LRTP Tranche 1 Portfolio. Only renewable RRF resources with ≥ 5% DFAX are included in the change case and renewable RRF resources with < 5% DFAX will be included in both the reference and change cases (Figure 7-2).

[4] MISO Futures Report

[5] MISO APC White Paper

[6] The DFAX analysis utilized LRTP Powerflow models and identified LRTP reliability issues addressed by the LRTP Tranche 1 Portfolio and involves the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located which determines the amount of generator impact on facility loading.

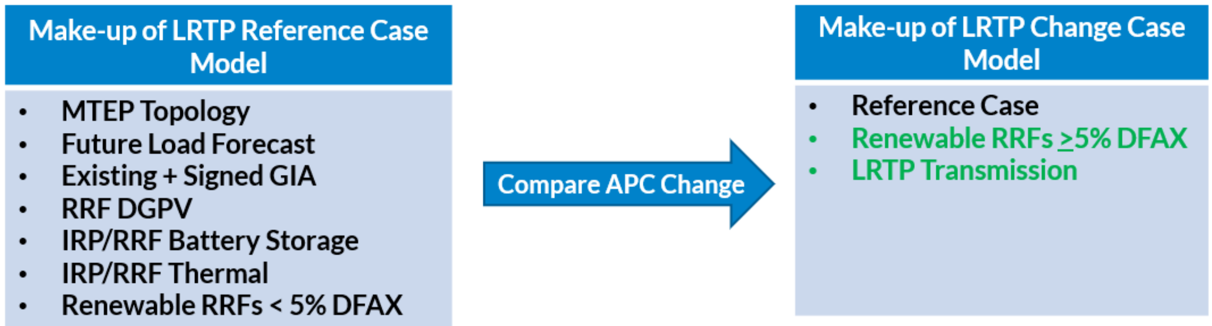


Figure 7-2: LRTP Reference and Change Case Criteria

As seen in Figure 7-3, application of this criteria resulted in 136.6 GW of resources being added to the LRTP Reference Case to meet Future 1 energy requirements and left 20.4 GW of renewable RRF resources available for DFAX analysis. This assessment resulted in the enablement of 20.1 GW of renewable RRF resources being added to the change case. Reference Figure 7-4 for geographical representation of the enabled renewable RRF resources in relation to the LRTP Tranche 1 portfolio.

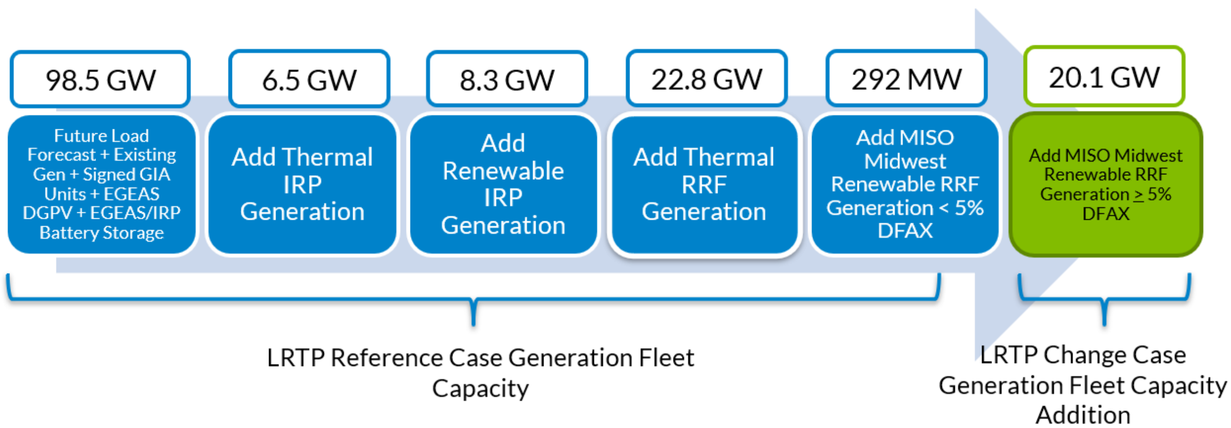


Figure 7-3: LRTP Reference and Change Case Criteria Capacity Result

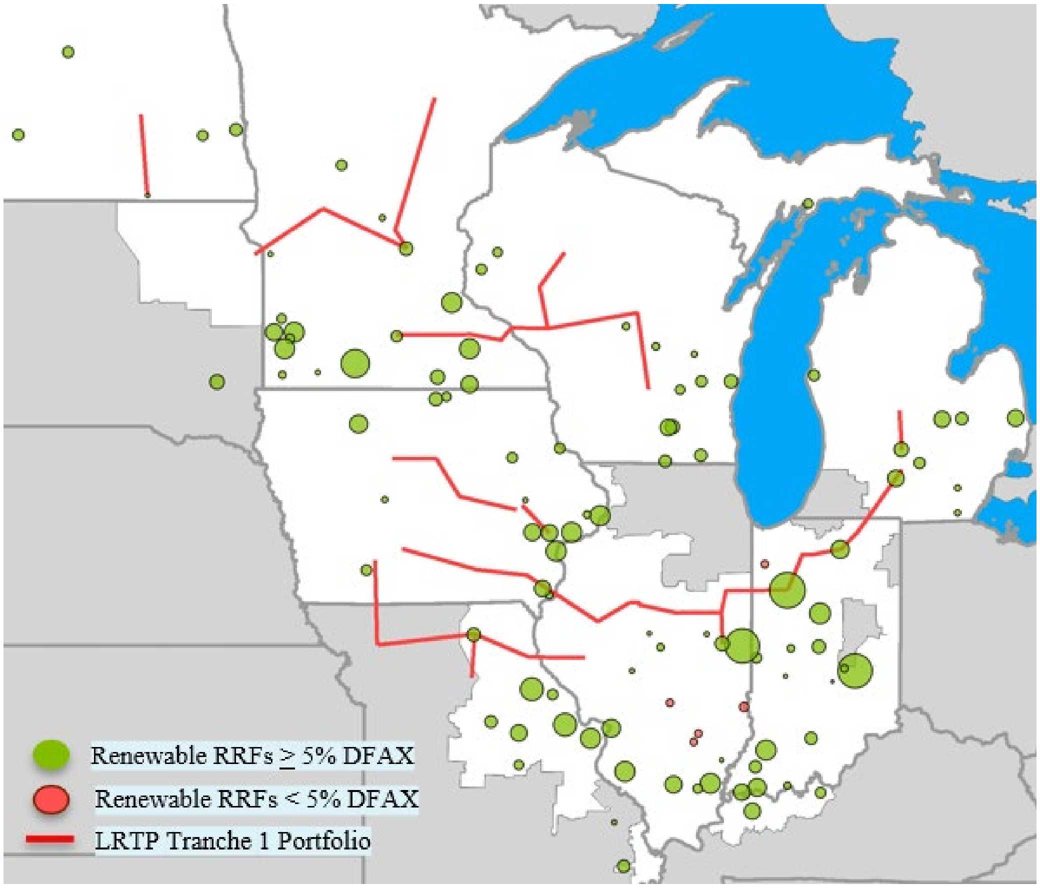


Figure 7-4: Geographic Map of RRF Resources Enabled by LRTP Tranche 1 Portfolio

The APC savings created by the LRTP Tranche 1 Portfolio generated $13.1 billion in congestion and fuel savings benefits over a 20-year period at a 6.9% discount rate. See Table 7-1 for additional benefit details on a Cost Allocation Zone (CAZ) granularity.

Present Value		**20-year PV (Millions-2022$)**		**40-year PV (Millions-2022$)**	
Discount Rate		**6.9%**	**3.0%**	**6.9%**	**3.0%**
CAZ	**1**	$3,169	$4,455	$4,668	$8,797
	2	$1,049	$1,511	$1,667	$3,313
	3	$2,195	$3,060	$3,151	$5,823
	4	$1,352	$1,934	$2,107	$4,133
	5	$1,471	$2,078	$2,205	$4,210
	6	$2,884	$4,133	$4,517	$8,890
	7	$1,006	$1,432	$1,543	$2,993
		$13,125	**$18,603**	**$19,858**	**$38,160**

Table 7-1: LRTP Tranche 1 Portfolio Congestion and Fuel Savings Benefits

Avoided Capital Costs of Local Resource Investments

The Avoided Capital Costs of Local Resource Investments metric captures the cost savings realized from a more cost-effective regional resource buildout that is enabled by regional transmission investment instead of depending on a more costly local resource buildout that is required due to local transmission limitations. In this specific case, the cost savings created by the LRTP Tranche 1 Portfolio will be determined by calculating an increase in costs for the resources enabled by the LRTP Tranche 1 Portfolio using a local versus regional capacity ratio.

To determine what the local resource investments would be, MISO had to first build local resource expansion models in EGEAS utilizing the same Future 1 assumptions[7] used in the regional expansion plan.

The local expansion plan EGEAS model assumptions are as follows:

- Local representation would be represented by Local Balancing Authority (LBA) granularity.
- Each LBA is treated as its own pool, self-constructing resources necessary to meet simulation constraints such as Planning Reserve Margin (PRM) and emissions.
- MISO PRM value of 18% was scaled for each LBA based upon its alignment to the MISO coincident peak.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are attributed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM due to limitations driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

[7] MISO Futures Report

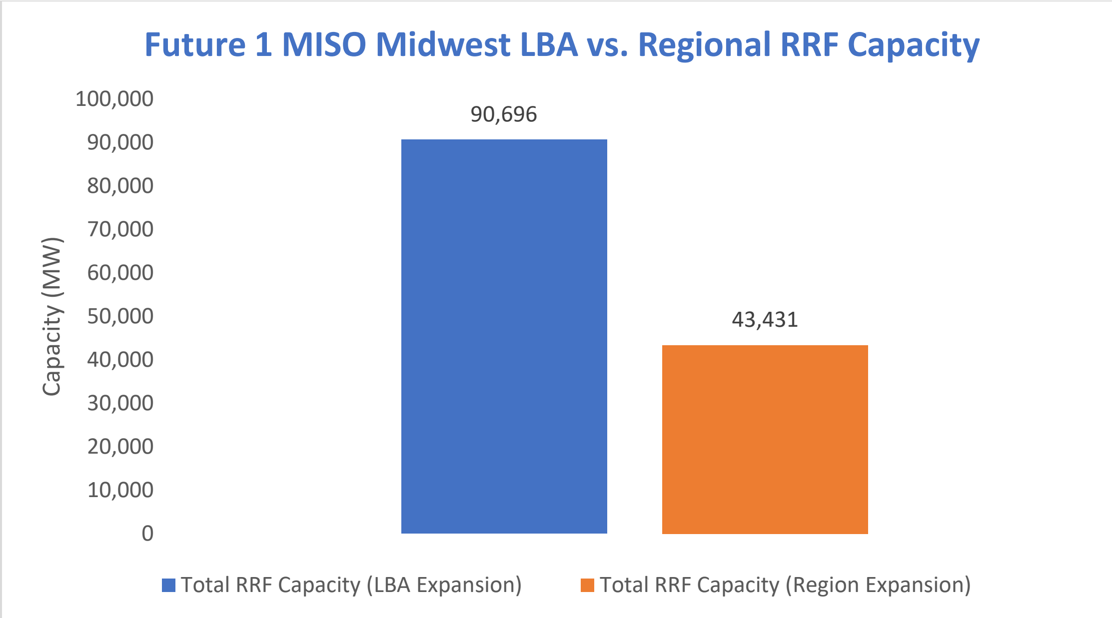


Figure 7-5: Future 1 LBA vs. Regional RRF Expansion Plan

As indicated in Figure 7-5, the LBA-specific scenario requires a much greater amount of localized resource expansion due to limited transmission capability, which is represented by isolating each LBA into its own EGEAS (transmission-less) model, compared to the equivalent regional expansion.

While Future 1 assumptions[8] were modeled consistently between the regional and LBA EGEAS models, the avoided capital cost benefit cannot be calculated by directly subtracting the regional expansion capital costs from local LBA expansion capital costs, as this would over-state the benefit created directly by regional transmission. To avoid this situation MISO had to consider what cost savings the Tranche 1 Portfolio would create. After evaluating several different options[9] with stakeholders to link the LRTP Tranche 1 Portfolio to the regional and local expansion, MISO proposed revised calculations and reviewed the details of the changes with stakeholders in the LRTP workshop discussions.[10] The ultimately decided on calculations are shown in equations (1) and (2) below:

$$Adjusted\ Capital\ Cost_{LBA\ Expansion} = \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})} \quad (1)$$

[8] MISO Futures Report
[9] January 21, 2022, LRTP Workshop
[10] February 25, 2022 LRTP Workshop

$$\textit{Avoided Capital Cost of Local Resource Investments} = \textit{Adjusted Capital Cost}_{LBA\ Expansion} - \textit{Enabled RRF Capital Cost}_{Region\ Expansion} \quad (2)$$

Equation (1) is used to determine what the assumed local resource expansion cost would be by increasing the cost of the enabled resources by a ratio set by the LBA and regional EGEAS expansion results.

- $\textit{Adjusted Capital Cost}_{LBA\ Expansion}$ represents the assumed capital cost of a local (LBA) resource expansion for MISO Midwest
- $\textit{Enabled RRF Capital Cost}_{Regional\ Expansion}$ is the capital cost associated with the enabled[11] Regional Resource Forecasting (RRF) units determined by EGEAS using Future 1 assumptions[12], reduced to MISO Midwest
- $\textit{Total RRF Capacity}_{LBA\ Expansion}$ is a summation of MISO Midwest's LBA RRF capacity determined through EGEAS by applying Future 1 assumptions on a LBA level
- $\textit{Total RRF Capacity}_{Regional\ Expansion}$ is a summation of MISO Midwest's regional RRF capacity determined through EGEAS by applying Future 1 assumptions on a regional level

Equation (2) is used to determine what the Avoided Capital Costs of Local Resource Investments would be by subtracting the $\textit{Enabled RRF Capital Cost}_{Regional\ Expansion}$, that is already accounted for, from the assumed LBA expansion capital cost calculated in equation (1).

As a result of being able to utilize the regional transmission buildout of the LRTP Tranche 1 Portfolio, approximately $17.5 billion of savings can be realized through the avoidance of local resource investment (Figure 7-6).

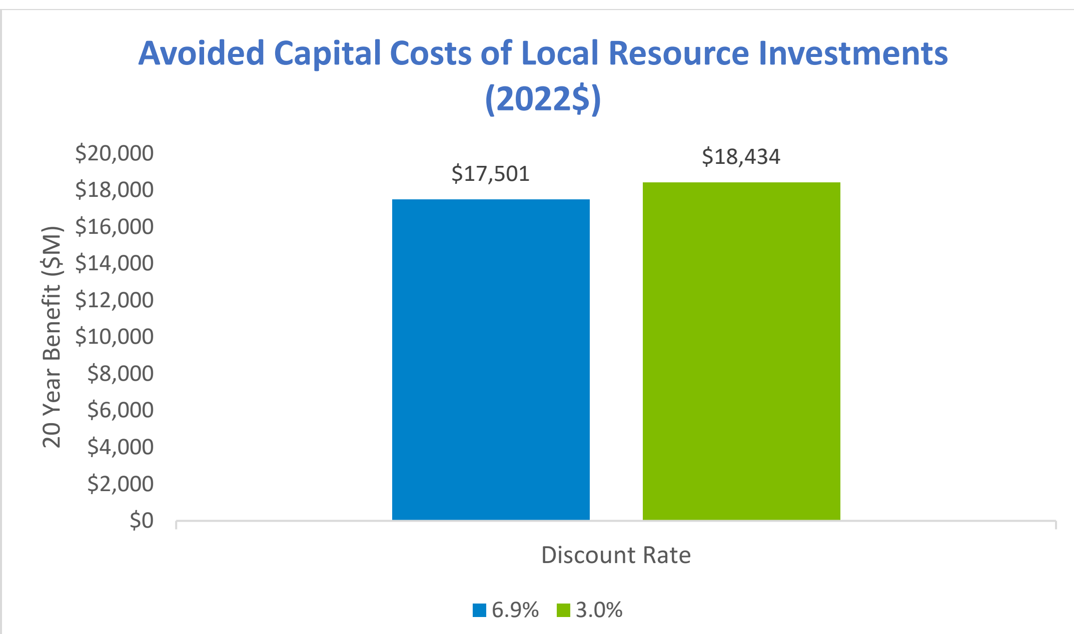


Figure 7-6: Avoided Capital Cost of Local Resource Investments Created by LRTP Tranche 1 Portfolio

[11] Renewable RRFs located in MISO Midwest Subregion which have >5% DFAX on reliability constraints addressed by LRTP Projects
[12] MISO Futures Report

Avoided Transmission Investment

The development of the LRTP Tranche 1 Portfolio provides a regional solution to addressing the future energy needs rather than an incremental approach to reliability planning. Avoided Transmission Investment captures the benefit provided by LRTP regional projects that address both avoided reliability projects and avoided age and condition replacement projects on right-of-way shared by LRTP projects.

LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the LRTP Tranche 1 Portfolio. Benefits of avoided future reliability upgrades are based on potential overloads in the future rather than issues observed within the LRTP study period, in order to avoid double counting of benefits.

Identification of future upgrades considers facilities with high thermal loading but not overloaded in the 20-year reference case without LRTP reinforcements, and uses the thermal loading observed in the 10-year reference case to calculate the projected overload (equation below).

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

These projected overloads are analyzed in the LRTP case to determine if the LRTP Tranche 1 Portfolio mitigates the overload condition and are included as candidates for avoided future upgrades.

For future avoided transmission facilities >=345 kV a cost adjustment is applied to reduce the value by 50% to offset future production cost benefits that may be realized. These upgraded extra high voltage (EHV) facilities will reduce future congestion and offset production cost savings in the long term and discounting reduces potential for double counting of benefits. EHV facilities support regional energy delivery and generally have greater influence on production cost than lower voltage facilities that provide local reliability.

LRTP solutions in some cases make use of existing transmission corridors to reduce the need for new right-of-way and often the existing facilities have long been in service and in need of replacement. The avoided transmission investment benefit component also includes the avoided cost of upgrades where LRTP Tranche 1 projects are constructed on existing right-of-way with facilities that would have required upgrades as a result of facility age and condition. Where LRTP Tranche1 projects require rebuilding the structures and facilities of the aging circuits to accommodate the new transmission line, the future cost of the replacement is eliminated.

Facilities included in the Avoided Transmission Investment metric were verified with Transmission Owners to determine if facility upgrades are already planned or existing circuits on shared right-of-way are not candidates for age and condition replacement and were excluded from further consideration. Costs for avoided transmission investment use exploratory cost estimates that are based on the type of upgrade or replacement required. MISO estimated costs are derived from the MISO *Transmission Cost Estimation Guide for MTEP21* and are show in Table 7-2 below.

Upgrades are assumed to be needed prior to the end of the LRTP 20-year study period, and capital investment is assumed to be spread equally over the 5-year period prior to the in-service date of 2040.

Facility Improvement Type	Unit Cost($M)	Quantity/Miles	Cost ($M)
Bus-tie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

Table 7-2: Estimated Costs of Avoided Transmission Investment (values as of 6/1/22)

Analysis Results

Cost savings associated with avoided future upgrades and future facility replacement for age and condition yields 20-40 year present value benefits from $1.3B to $1.9B (2022$).

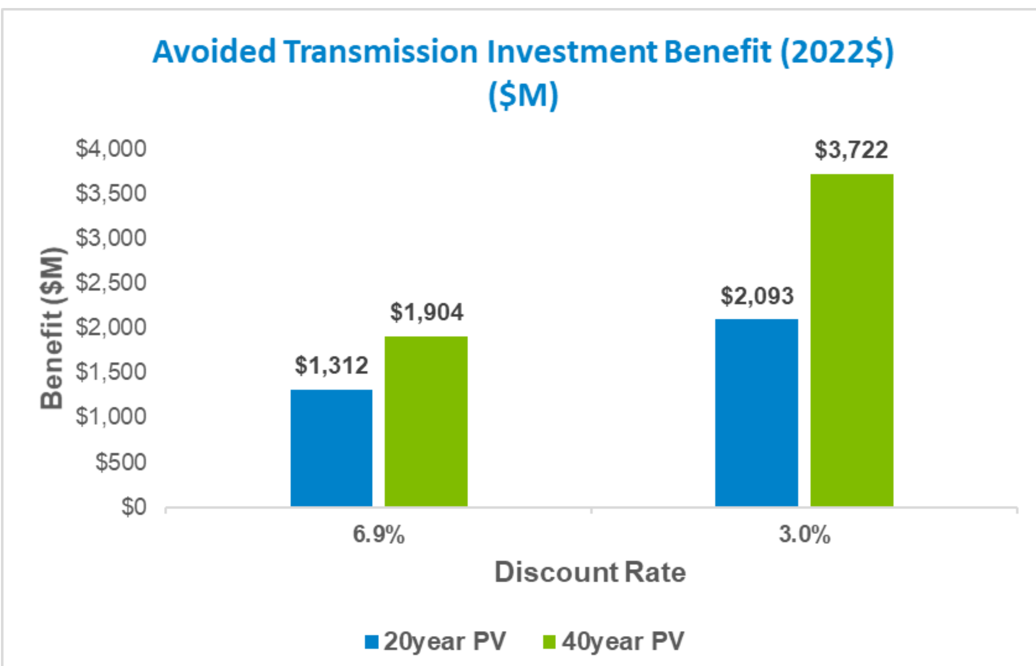


Figure 7-7: Avoided Transmission Investment Benefit (values as of 6/1/22)

Reduced Resource Adequacy Needs

The Reduced Resource Adequacy benefit metric represents a deferral of capacity that would be needed to address resource adequacy requirements due to increased zonal import limits. The transmission enhancements provided by the LRTP Tranche 1 Portfolio increases import capability and enables access to resources across the subregion. This decreases the need to procure capacity locally to meet resource adequacy needs.

The load serving entities (LSEs) that are located within the Local Resource Zones (LRZ) in MISO are required to meet two planning reserve margins in the Planning Resource Auction (PRA): the zonal planning reserve margin requirement (PRMR), which is based on the MISO-wide coincident peak load and MISO-wide PRM, and the local clearing requirement (LCR), which is based on each zone's non-coincident peak load and the local reliability requirement (LRR). The resource adequacy benefits presented in this section are related to the LCR.

Modeling and Assumptions

The modeling includes two parts; the first one involves a transfer analysis and the second one includes the monetization of the benefit.

1. Transfer Study: The CIL analysis generally aligns with the study methodology used in the Planning Resource Auction (PRA). The transfer analysis starts with the Future 1-2040 "peak load day" power flow model and associated input files (monitored elements and contingencies and sub-systems). These are then used in the TARA simulation tool to determine the incremental amount of power that can be transferred from source to sink. The First Contingency Incremental Transfer Capability (FCITC) is determined and the CIL is calculated for a base case (without LRTP Tranche 1 Portfolio) and change case (including LRTP Tranche 1 Portfolio). The definition of each case, in terms of the resource dispatch and demand levels, is consistent with the LRTP Future 1 reliability models.

2. Economic value of LCR reductions: The economic value of the LCR reduction is estimated as a function of the total unforced capacity (UCAP), CIL, and the LRR. The 2040 unforced capacity for each LRZ is determined using forced outage rates for thermal resources and the effective load carrying capability for non-thermal resources.

   The excess capacity within each LRZ is calculated as follows:

   Excess Capacity (LRZ_i) = 2040 UCAP (LRZ_i) – 2040 LCR (LRZ_i; without LRTP),
   where "i" represents the LRZ number (from 1-7).

   The RA benefits are estimated as follows:

   If Excess Capacity < 0 → Benefit = (Cost of new entry) x (-Excess Capacity)
   If Excess Capacity > 0 → Benefit = $0/year

   The LRR-UCAP percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ. The cost of new entry (CONE) assumptions is also consistent with the PY22-23 MISO LOLE study.

Analysis Results
The resulting CIL, with and without the LRTP Tranche 1 Portfolio, are shown in Table 7-3. The CIL values include the net-area interchange (e.g., the base transfer) gathered from the power flow model. Although their impact on the LCR benefit is negligible, the other components used in the CIL equation, e.g., border external resources (BER), coordinated owner (CO), and exports are kept unchanged in the base and reference cases.

Local Resource Zone	CIL (Base)	CIL (Change-With LRTP)	Delta CIL(MW)
1	5412	6070	658
2	4188	5223	1035
3	5062	6453	1391
4	7117	7609	492
5	6131	6183	52
6	6005	6171	166
7	3367	4659	1292

Table 7-3: Change in Capacity Import Limits (CIL)

A summary of the UCAP, LCR, LRR, and the Excess Capacity calculated for each LRZ is included in Table 7-4. The excess capacity shown in row 7 reflects the pre-LRTP scenario and a negative value represents a potential shortfall situation. The excess capacity shown in row 8 reflects the case with LRTP and confirms the ability of Tranche 1 projects to hedge against potential shortfall situations. The total 20-year and 40-year net present values are shown in Figure 7-8.

Row Number	Summary of resource adequacy benefits								
	LRZ	1	2	3	4	5	6	7	Formula Key
1	2040 Unforced Capacity (MW)	22,981	15,458	12,079	11,111	8,274	20,659	23,982	A
2	2040 Local Reliability Requirement Unforced Capacity (MW)	23,672	16,431	12,405	14,230	12,391	24,196	27,814	B
3	Without LRTP CIL (MW)	5,412	4,188	5,062	7,117	6,131	6,005	3,368	C
4	With LRTP CIL (MW)	6,070	5,223	6,453	7,609	6,183	6,171	4,659	D
5	Without LRTP LCR (MW)	18,260	12,243	7,343	7,113	6,260	18,191	24,446	E=B-C
6	With LRTP LCR (MW)	17,602	11,208	5,952	6,621	6,208	18,025	23,155	F=B-D
7	Excess capacity after LCR	4,721	3,216	4,737	3,998	2,014	2,468	-465	G=A-E

	without LRTP (MW)								
8	Excess capacity after LCR with LRTP (MW)	5,379	4,251	6,128	4,490	2,066	2,634	827	H=A-F
9	Deferred capacity value (M$)	0	0	0	0	0	0	-44	I=G*CONE

Table 7-4: Summary of resource adequacy benefits

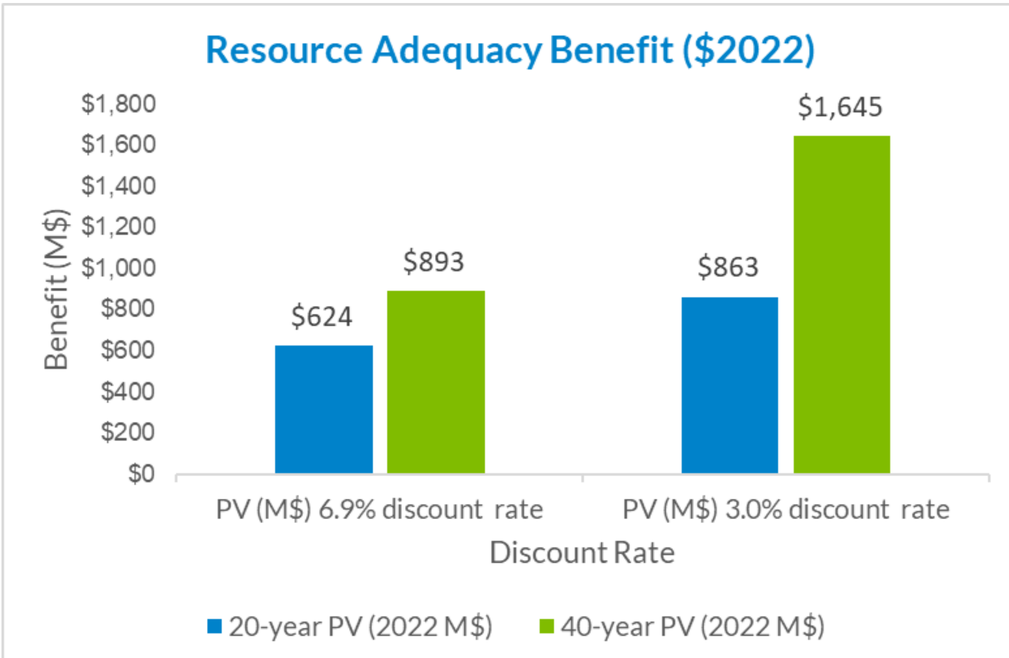


Figure 7-8: Resource Adequacy Benefit Total 20-year and 40-year Present Value

Avoided Risk of Load Shedding

Avoided Risk of Load Shedding is one of several metrics that is used to quantify the benefits provided by the LRTP Tranche 1 Portfolio. The method for determining this resiliency value considers high impact events with an expectation of a significant amount of controlled load shedding to ensure reliable system performance and/or prevent system collapse. While smaller, more common contingencies can result in the need for load shedding actions to maintain reliability, these events are often local in nature and beyond the scope of this analysis, which examines the impact of large-scale generation loss events caused by changing weather conditions or under extreme weather events. In a future with extensive penetration of renewable resources, the variability in weather introduces the potential for loss of renewable production. Additionally, extreme winter weather patterns can cause fuel supply disruptions that may result in extensive thermal generation outages. LRTP projects help to enable regional transfers mitigating the risk associated with these high impact generation outage events.

Analysis of load shedding risk was performed using 2040 winter peak reliability powerflow models, which represent system conditions under which the severe winter weather generation loss event is expected to occur. Weather events may be limited in scale to smaller areas that can affect a single resource zone or may be extreme in nature and have widespread impacts across the footprint. Study scenarios are defined for zonal and system-wide events that specify the generation outages resulting from severe winter weather impacts. Analysis of severe winter weather impacts on generation performance is generally straightforward but captures only one area of the risk associated with loss of load. This narrow focus results in a conservative estimate of the value of avoided risk of load shedding.

Historical weather event data is used to understand and develop assumptions about the frequency of significant winter weather events that could lead to large scale generation loss. MISO analyzed information on significant freeze and storm events over the past 40 years that have resulted in significant economic impact in order to establish the frequency of occurrence for evaluating risk (Figure 7-9).

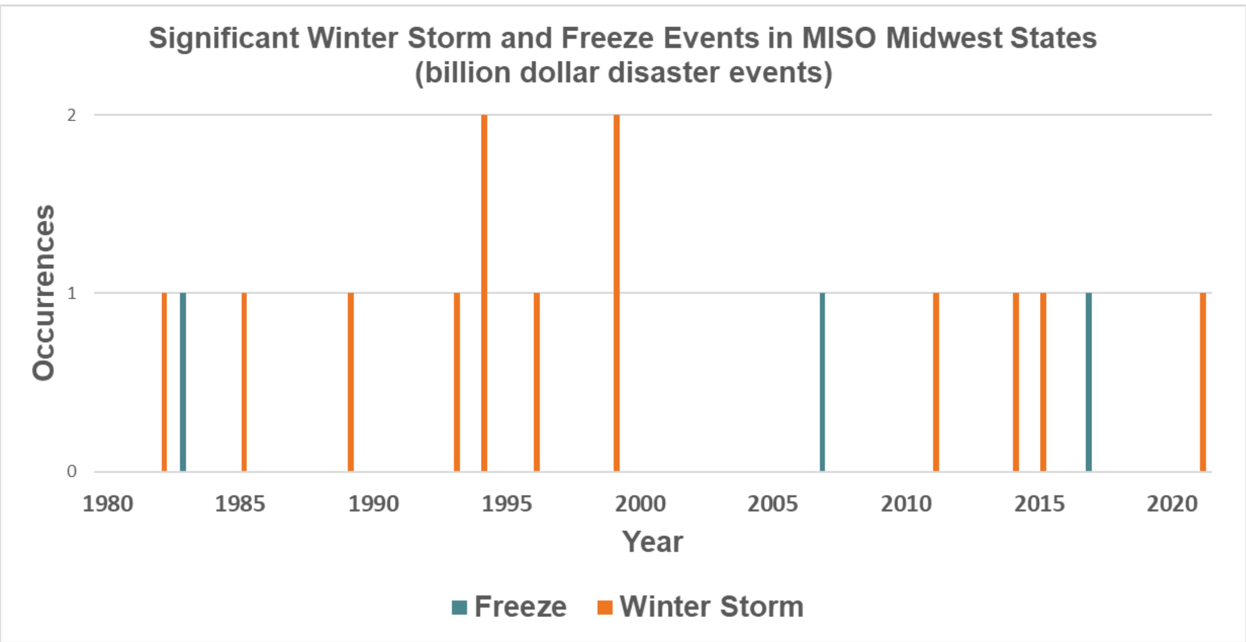
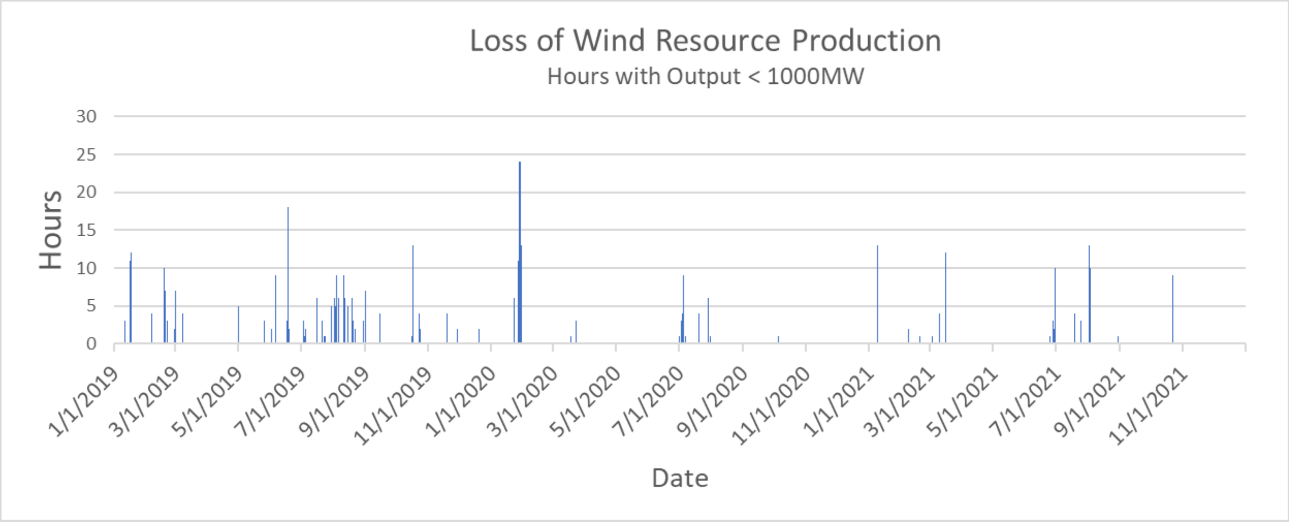


Figure 7-9: Winter storm and freeze events have been occurring every three years on average

Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Additionally, operational event data was analyzed to examine trends in resource availability events over time when severe winter weather conditions occur, which provides insights into how fleet composition affects the risk of generation deficiency. While many of these weather events have not caused major disruption of generation supply in the past, recently there have been a growing number of instances where weather conditions caused the need to implement emergency measures to maintain adequate supply. In the last five years, tight generation supply during winter conditions presented operational challenges that will continue with growing dependency on renewable resources and gas-fired generation. The MISO response to the Reliability Imperative report[13] notes a key indicator of the change in risk profile for the region is seen in the 41 MaxGen emergencies that have been declared since 2016.

Historical generation output data highlights recurring risks associated with periods of low renewable production which can occur during any season and any time of the day (Figure 7-10). Such events can leave a significant amount of generation capacity unavailable to meet load requirements and where the duration of generation shortfall can last several hours.



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

Figure 7-10: Periods of low wind production may last several hours

The interruption of load may have far reaching impacts that include risk to public health and safety, financial loss, and regulatory/legal burdens, which are difficult to accurately quantify. The monetization of value of lost load is often considered in the context of customer willingness to pay to avoid interruption. While the application of the MISO Tariff defined Value of Lost Load (VOLL) in the LRTP business case does not suggest that VOLL represents the full value of risk, it does provide a reasonable measure that is indicative of the LRTP benefits and closely aligns with other business processes. The value of avoided risk of load loss of the LRTP Tranche 1 Portfolio considers a range of VOLL from $3,500/MWh to $23,000/MWh. The $3,500/MWh is currently defined by the MISO Tariff for use in market pricing while $23,000/MWh is a value recommended by the MISO Independent Market Monitor to be more representative of the value. This value of VOLL is applied to the calculated MW value of load loss determined by the zonal and system-wide studies in order to capture the benefits associated with the LRTP Tranche 1 Portfolio.

[13] MISO's Response to the Reliability Imperative

<u>Method for Calculating Value of Avoided Risk of Load Shedding</u>

Scenario Development

Analysis of historical winter storm and freeze event data from the past 20 years and recent extreme winter weather events indicates that significant winter storms are recurring every three years on average with extreme winter storms and temperature conditions observed periodically (polar vortex, Uri). The increased influence of weather due to the variability of renewable resources and impact of cold temperatures on fuel supply and availability of gas-fired generation will result in more periods of risk for load loss. Thus, each occurrence of a severe winter event every one out of three years represents a risk of load shedding due to the widespread generation outages. This risk persists beyond a single day since winter storms often occur over multiple days.

Duration of the load loss was derived using hourly wind production data to examine periods of low wind output since variability in wind output will have a large influence on the risk of an event. While the duration of low wind output events can range from 1 hour to 24 hours for a given day (Figure 7-10), approximately half of the events occurring in winter season are greater than 10 hours and period of risk for load loss is assumed to be eight hours per day over a two-day period for the purpose of assessing the risk of load shedding caused by a severe winter weather event.

A series of event scenarios were developed to represent significant generation loss due to weather related conditions. Events were created to reasonably reflect the loss of future renewable and thermal resources within defined zones or groups of zones. Loss of wind resources was modeled to represent a 90% drop in output from the maximum capacity and loss of solar output was modeled as a 50% reduction from maximum capacity. For regional and zonal event analysis, loss of thermal generation was derived by using outage information from the recent extreme winter storm event to establish a 50% outage rate in regional scenarios and 40% outage rate in zonal scenarios to capture the higher impact from future growth in gas-fired resources. Where modeled wind output is less than 10% of maximum capacity or solar output less than 50% in either zonal or regional scenarios, no adjustment is applied to the wind or solar output.

Load Loss Analysis

In zonal load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given local resource zone. Load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis. Reliability analysis models normally apply a 50/50 load forecast, which reflects the normal peak load expected in the planning horizon. However, during extreme weather conditions, the peak load is expected to reach a 90/10 peak load forecast level, which is typically 5% higher. Resources were grouped within a single zone and event generation outage scenario applied to determine the amount of generation remaining. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total zone load and losses and adding any net imports into the zone. The future CIL calculated in the resource adequacy analysis is used to determine if sufficient import capability exists to support any shortfall and any change in CIL due to the addition of the

LRTP projects is used to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

$$\textbf{LoadLossMW} = GenMW_{net} - 1.05 * LoadMW - TxLossMW + \text{Capacity Import Limit (MW)}$$
$$\text{where } GenMW_{net} = GenMW_{cap} - GenMW_{loss}$$

In regional load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given group of local resource zones. Similar to zonal analysis, the load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis due to the extreme weather. Resources were grouped within a set of zones and event generation outage scenario applied to determine the amount of generation remaining. In the regional analysis scenarios, the amount of thermal generation loss is escalated to 50% of capacity to represent a more extreme condition with regional scale impacts. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total load and losses and adding any net imports into the study group. The incremental transfer capability is calculated using the power flow model and added to the existing group net imports to determine the total transfer capability to support any shortfall and the change in total transfer capability due to the LRTP projects is calculated to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Two scenarios are included for evaluating risk of load loss for regional scale events:

Scenario 1 assesses the impact of an extreme winter storm primarily on the western part of the MISO footprint causing large scale loss of generation in MISO upper Midwest areas and Southwest Power Pool (SPP) with SPP imports assumed to be 7,500 MW.

Scenario 2 assesses the impact of extreme winter storm activity in the MISO central areas and Ohio Valley with PJM exports curtailed to 0 MW.

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

LoadLossMW = $GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability (MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

The value of avoided risk of load shedding is monetized by the use of the Value of Lost Load (VOLL) to represent a portion of the outage costs associated with load curtailment during generation deficiency events. While VOLL is based on outage costs, it is a market pricing mechanism that considers a customer's willingness to pay for energy to avoid load curtailment under emergency conditions and does not fully consider the related impacts or the effects of extended outages in more extreme scenarios. Furthermore, there is a wide range of opinion concerning the appropriate value that should be used with $3,500/MWh currently being used in the MISO market pricing structure while MISO's Independent Market Monitor has recommended a value of $23,000/MWh to be used in the MISO market. Thus the $3,500/MWh figure is a conservative estimate for capturing the benefit of avoided risk of load loss with the $23,000/MWh value used to establish the upper bound of the value.

The load loss hours are summed for all scenarios to obtain the load risk of load loss in MWhr and the range of values for VOLL is applied to obtain the monetary value.

Avoided Load Loss Value ($) = VOLL * LoadLossMW * duration(hrs.)
where VOLL – Value of Lost Load: $3,500- $23,000[14]

[14] IMM Quarterly Report: Summer 2020,

Analysis Results

The additional transfer capability provided by the LRTP Tranche 1 Portfolio enables power transfers to address supply deficiency caused by weather related generation outages and delivers 20- to 40-year present value benefits of $1.2 billion to $11.6 billion (2022$).

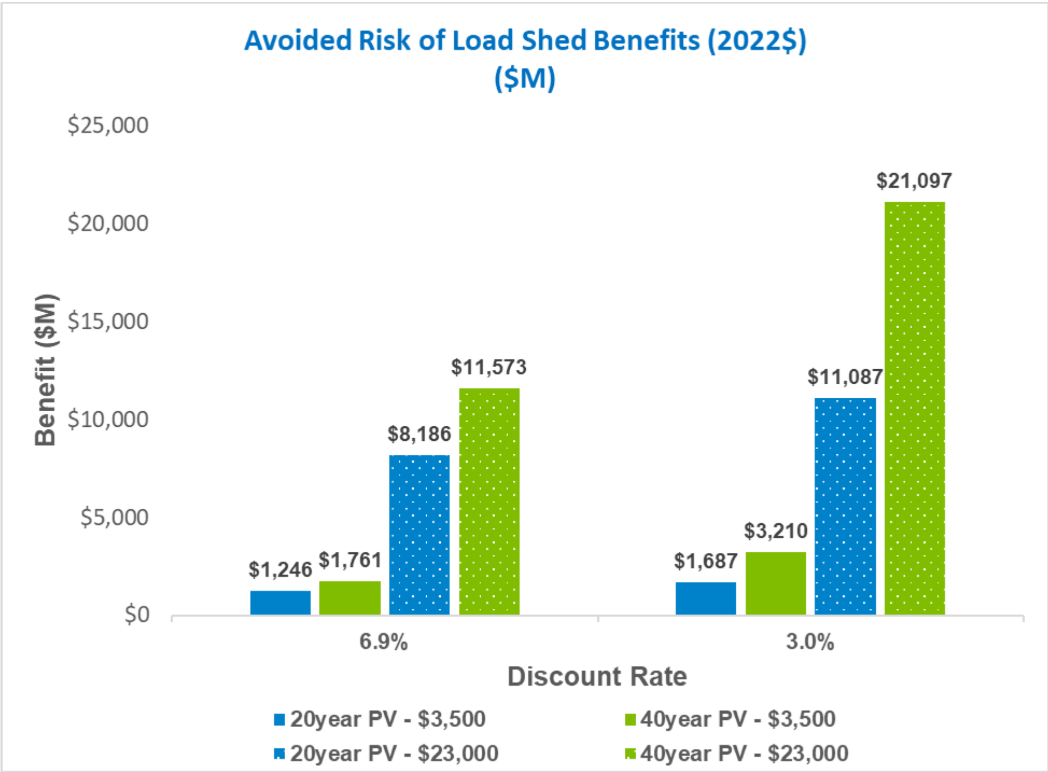


Figure 7-11: Benefits of Avoided Risk of Load Shedding (values as of 6/1/2022)

Decarbonization

MISO continues to explore how the rapid growth of members' decarbonization goals creates additional needs and opportunities to provide value. The robust transmission planning embodied by the LRTP initiative can signal better locations that deliver decarbonization, among other benefits. This item captures a range of potential cost savings from LTRP-enabled Decarbonization.

MISO acknowledges there is no cost of carbon applicable to the entire footprint currently. However, with the energy transition and changing landscape, it is possible that additional emissions standards may be placed on the electric industry. Since the 1990s, sulfur dioxide has decreased by 94%, nitrogen oxides by 88% and mercury emissions by 95% across the U.S. electric power sector.[15] Many of the benefits associated with these emission reductions have already been captured throughout the footprint.

[15] Edison Electric Institute: Climate and Clean Air

Over the past several years, MISO members have announced large carbon emission reduction goals that will rely on intermittent low-cost energy. The LRTP initiative aims to help ensure an efficient dispatch of energy across MISO during this fleet transition. With the rationale above, MISO conducted research to develop a price range to express Decarbonization's value. MISO chose sources within the U.S., at state and federal levels, within and outside of the MISO footprint. The range in prices draws from regulatory and market-based approaches, both of which are influenced by policy. From MISO's PROMOD analysis, carbon emissions are reduced by 399 million metric tons over 20 years and 677 million metric tons over 40 years of LRTP Tranche 1 project life (Figure 7-11).[16]

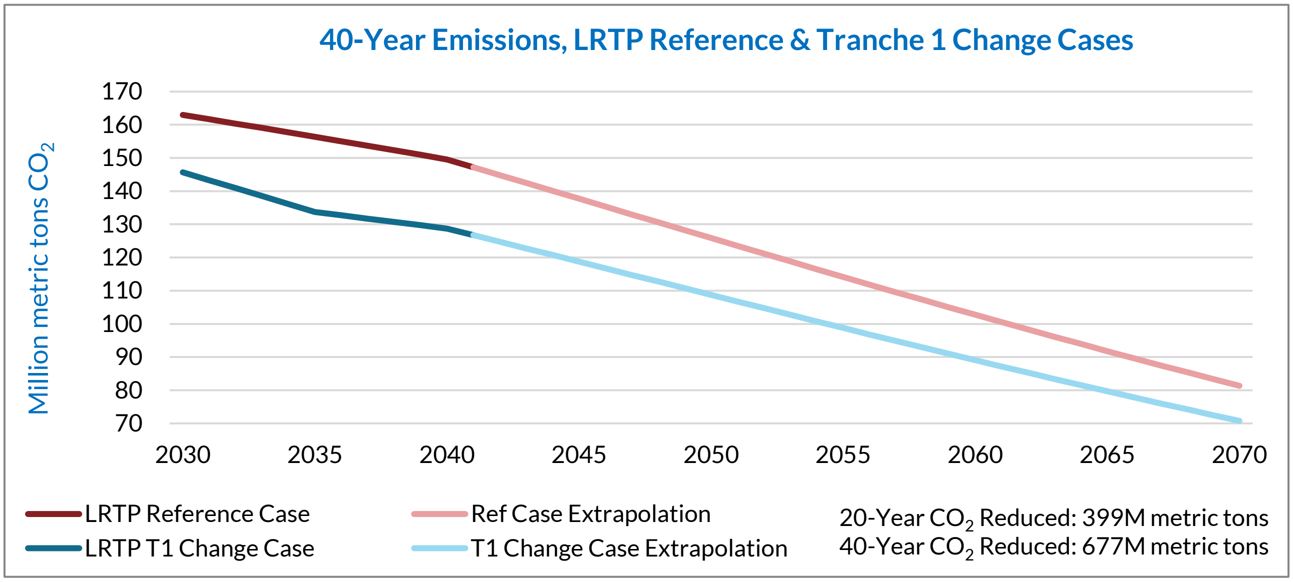


Figure 7-12: 40-Year CO_2 Emissions of LRTP Reference and Tranche 1 Change Cases

MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons.[17] Second, MISO converted prices from nominal dollar-years of origin into 2022 dollars using the Consumer Price Index Inflation Calculator.[18] For consistency, the month of January was used for dollar-year conversions except in cases related to market prices, which used the month of auction settlement as the origin date. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Minnesota Public Utility Commission (MN PUC) price began with the 2022 Low[19] price of $9.46 per short ton in 2015 dollars and yielded $10.43 per metric ton; $12.55 per metric ton in 2022 dollars.

[16] MISO interpolated emissions data among PROMOD model years 2030, 2035, and 2040 and used linear extrapolation for post-2040 emissions reductions. 20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
[17] U.S. Energy Information Administration
[18] U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator
[19] Minnesota Public Utility Commission

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean)[20] price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.
- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement[21] price of $28.26/metric ton is $28.59 in 2022 dollars.
- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon.[22] The 45Q Tax Credit follows a prescribed price schedule; starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

The Decarbonization assessment employs the following overall methodology:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case
- Convert the reduced emissions to metric tons
- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable
- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits
- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits along the price range (Figure 7-12, Table 7-4, Table 7-5)

Detailed assumptions, calculations and formulas are found in the supplementary LRTP Business Case Analysis workbook.

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Table 7-4: Full Range of Carbon Prices and Tranche 1 Decarbonization Benefits at 6.9% Discount Rate

[20] Regional Greenhouse Gas Initiative (Q4 2021 average [mean] price)
[21] California-Quebec Carbon Allowance Price (November 2021)
[22] Federal: 45Q Tax Credit, Social Cost of Carbon

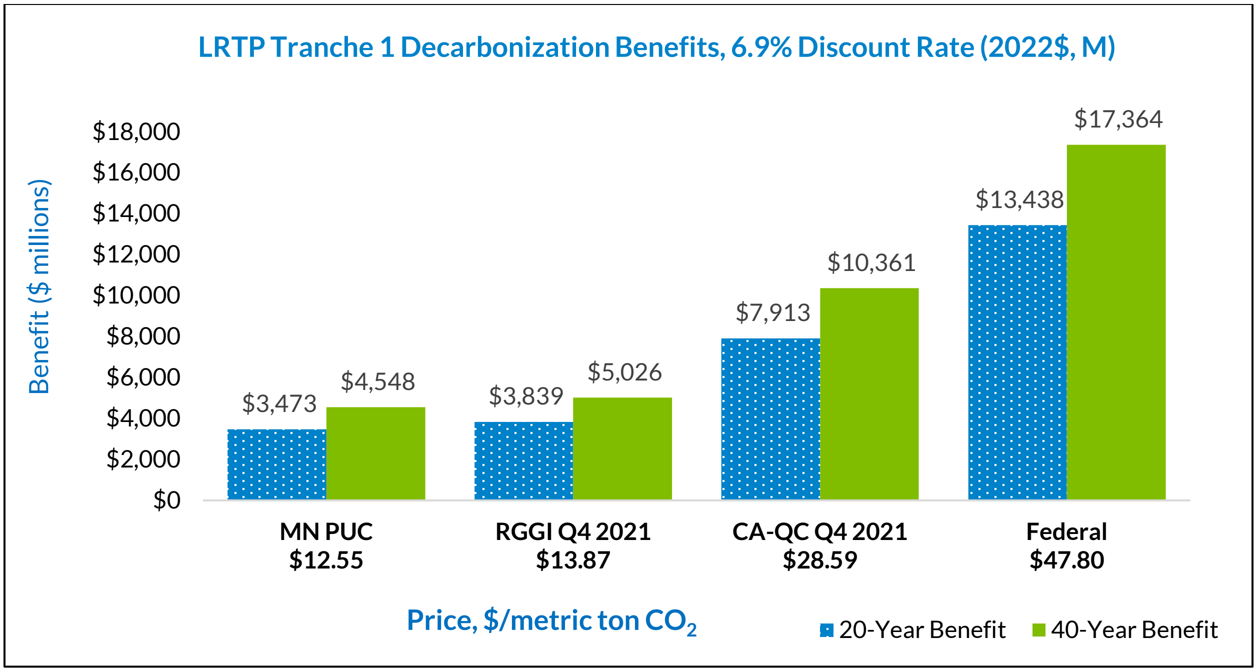


Figure 7-13: LRTP Tranche 1 Decarbonization 20- and 40-Year Benefits Using Full Carbon Price Range, Applying 6.9% Discount Rate (2022$, M)

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M):	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M):	$4,548	$17,364	$7,818	$29,498

Table 7-5: Min/Max Carbon Prices and Tranche 1 Decarbonization Benefits at Two Discount Rates

8 Benefits Are Spread Across the Midwest Subregion

The LRTP Tranche 1 Portfolio of projects was developed to address regional energy delivery needs for the MISO Midwest subregion. As Multi-Value-Projects, the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. Analysis of benefits examined how much each benefit accrued to the Midwest Subregion Cost Allocation Zones in order to compare the relative impacts between zones and the relationship with cost allocation. The distribution of benefits of the LRTP Tranche 1 Portfolio is shown to yield significant benefits for all Cost Allocation Zones (CAZs) well in excess of the share of portfolio costs.

Distribution of Benefits

Congestion and fuel savings are distributed to CAZs based on the production cost simulations used to calculate the savings and aggregated to the CAZs.

Avoided capital cost of local resource investment benefits are assigned based on load ratio share of each CAZ and aligns with the goal of the resource expansion to meet the future energy needs of the Midwest Subregion.

Avoided transmission investment benefits are allocated to the CAZ in which the baseline transmission upgrades, and age and condition replacement facilities are located. Costs for these avoided projects would otherwise be borne by the local pricing zone which yields a benefit to those specific CAZs.

Reduced Resource Adequacy savings are assigned directly to the CAZs in which the cost savings are realized since each CAZ has a responsibility for their own resource adequacy needs, and the CAZs in the Midwest Subregion align with the Local Resource Zones used for resource adequacy.

Avoided Risk of Load Shedding benefits are distributed to CAZs based on load ratio share to reflect the widespread protection against load loss in the interconnected electric system.

Decarbonization captures the benefits of reduced carbon emissions in energy production that is used to serve load across the Midwest subregion and is allocated by load ratio share to CAZs.

Distribution of LRTP Tranche 1 Portfolio Costs

The cost for Multi-Value Projects are allocated to load in the Midwest Subregion according to load ratio share of energy withdrawals. To determine the benefit/cost ratios by Cost Allocation Zone the energy withdrawals by the applicable LBAs included in each zone have been aggregated for Figure 8-1. Additionally, indicative annual MVP usage rates for the LRTP Tranche 1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. This information on the estimated MVP usage rates is provided in Appendix A-3.

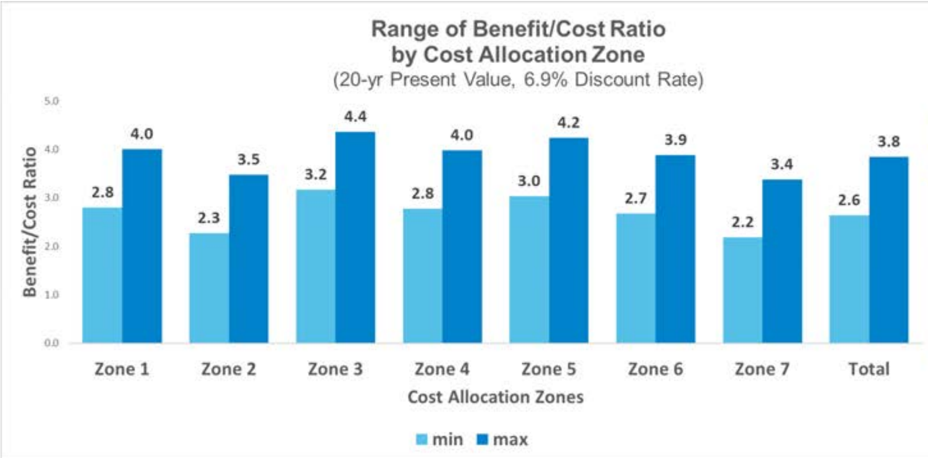


Figure 8-1: Distribution of benefits to Cost Allocation Zones in Midwest Subregion (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP Tranche 1 Portfolio provides broad distribution of benefits across the Midwest subregion zones and delivers a benefit to cost ratio of at least 2.2 for every CAZ. Analysis of the zonal benefit distribution indicates that the spread of benefits is roughly commensurate with the allocation of portfolio costs.

9 Natural Gas Price Sensitivity

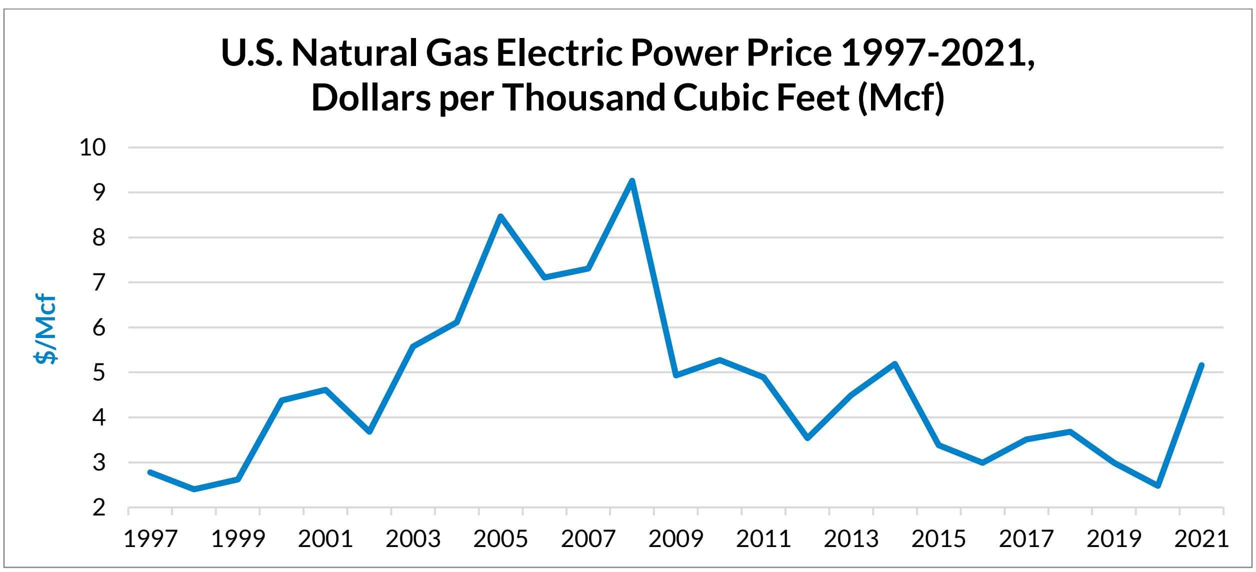


Figure 9-1: Historic U.S. Natural Gas Electric Power Prices

Beginning in 2021, natural gas prices increased sharply, reversing the general price decline seen over the last decade as production grew dramatically from the shale revolution (Figure 9-1).

U.S. export capacity of liquefied natural gas (LNG) has grown rapidly since beginning in 2016, from 0.55 billion cubic feet per day (Bcf/d) to an estimated peak of 11.6 Bcf/d as of November 2021. The U.S. Energy Information Administration estimates U.S. LNG peak export capacity will reach 16.3 Bcf/d by the end of 2024.[23]

Considering the expansion of LNG exports along with the growing prevalence of extreme weather events and current geopolitical developments, U.S. gas price exposure to the global market has increased as well. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than gas.

Two sensitivity analyses were performed on the LRTP Tranche 1 Congestion and Fuel Savings Reference and Change Case PROMOD models to quantify the impact of changes in gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the business case analysis, except for the gas prices. The sensitivity assumed gas price increases of 20 and 60 percent, respectively. For both analyses, the prices increased starting in the year 2030 and escalated by inflation thereafter.

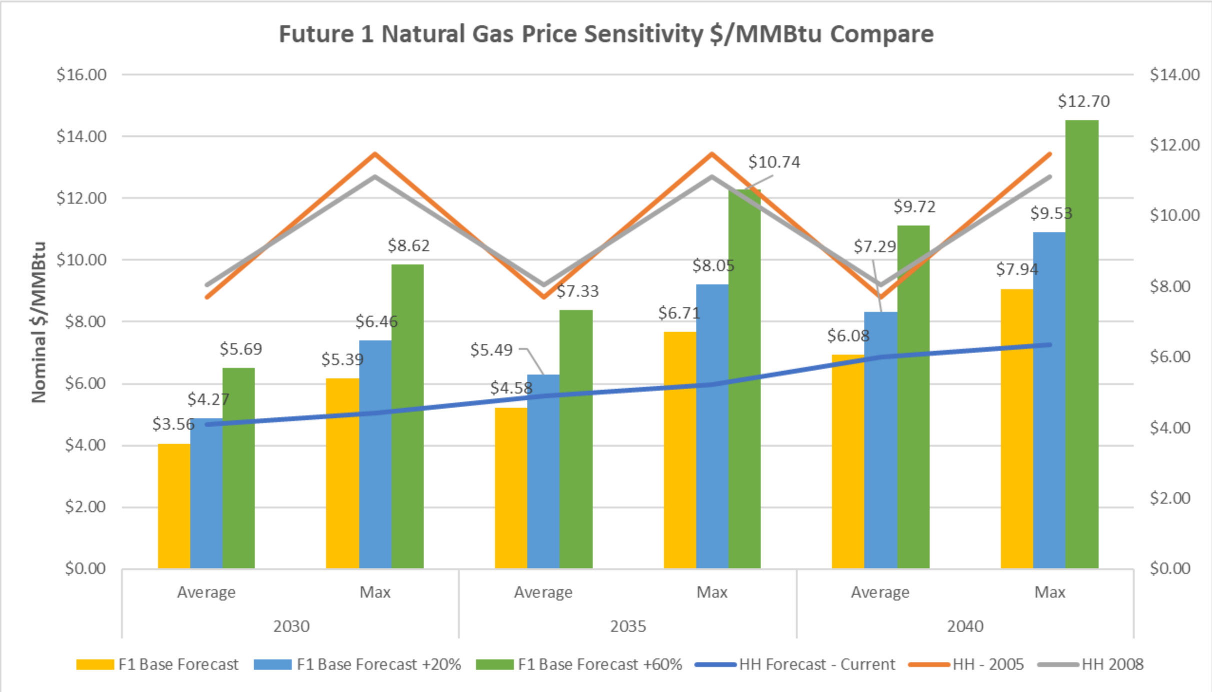


Figure 9-2: Future 1 Natural Gas Price Sensitivity $/MMBtu per LRTP PROMD Study Year

The resulting natural gas price increases achieved (Figure 9-2) created a gas price increase that ensures each study year's average fuel cost is greater than current Henry Hub (HH) projections as

[23] https://www.eia.gov/todayinenergy/detail.php?id=50598

well as representing HH highest historical sale prices from 2005 and 2008. This sensitivity concluded that the LRTP Tranche 1 Portfolio offsets gas price volatility by providing additional Congestion and Fuel Savings benefits by enabling access to renewable energy, as shown in Figure 9-3.

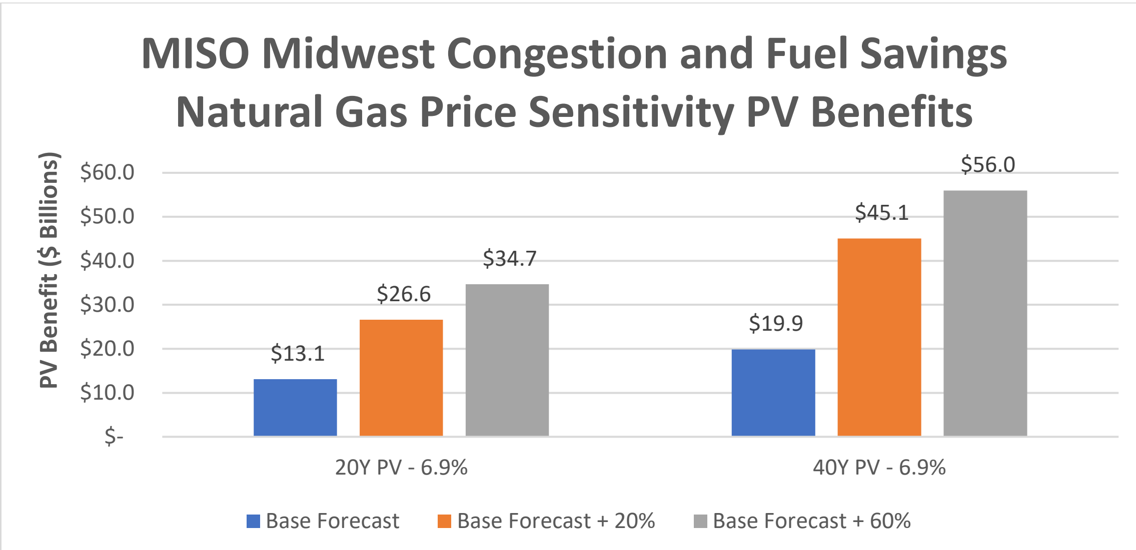


Figure 9-3: Natural Gas Price Sensitivity Results

10 Other Qualitative and Indirect Benefits

In addition to the quantifiable economic and reliability benefits, the LRTP Tranche 1 Portfolio enables other value streams that are reflected qualitatively.

Transmission reinforcements strengthen the grid to support the stability of the larger interconnection and provide greater resilience to recover from unexpected system events without adverse impacts. The interconnected nature of the power system provides support between neighboring systems during severe system disturbances. Regional transmission projects bolster the network, enabling greater bulk power transfers to address the developing conditions and avoid further degradation of the system performance.

Investment in regional transmission projects expand access to a greater diversity of lower-cost resources across the footprint, allowing more options for customer choice of fuel mix. Transmission allows for leveraging of the wide geographic and fuel diversity offered by the MISO region. The stronger regional ties offer more flexibility to handle the variability of renewable output caused by differences in weather patterns across different areas of the MISO footprint. This capability offers greater protection against both market price risk and possible load curtailment measures.

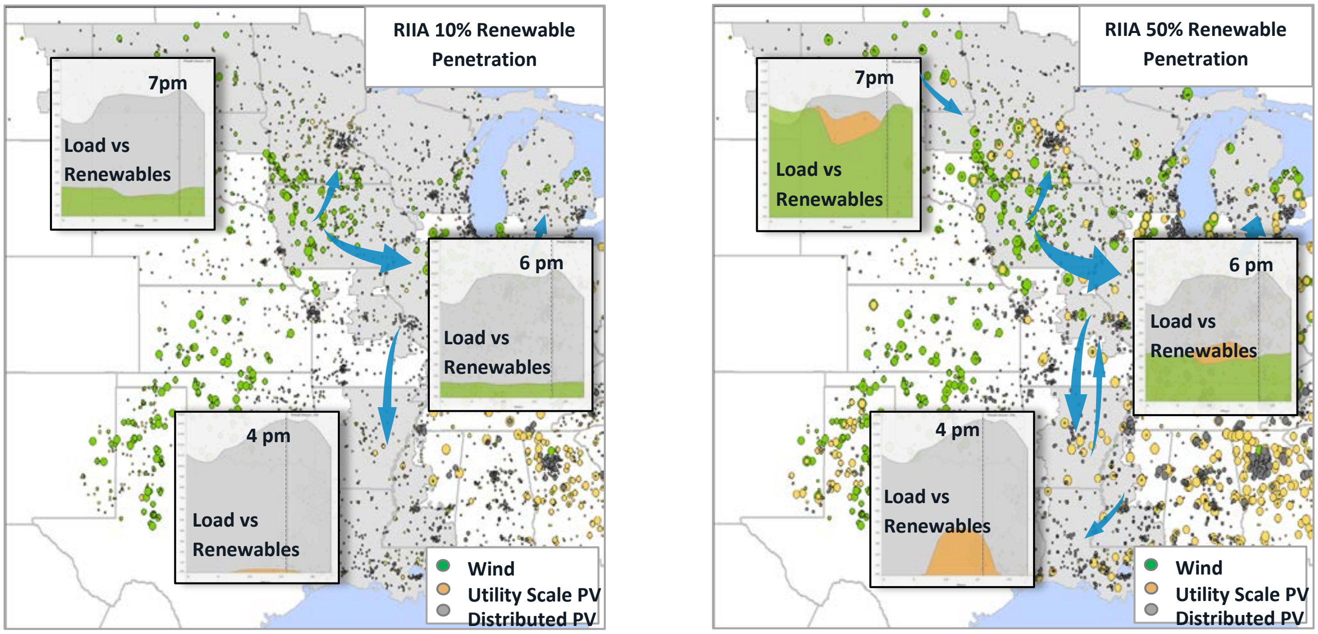


Figure 10-1: Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

The addition of transmission facilities allows greater operational flexibility related to unplanned and planned transmission facility outages. While the Congestion and Fuel Savings metric described earlier captures economic value related to reduced congestion, it represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits. Furthermore, as the grid moves to a higher penetration of renewables and seasonal load curve flattens, outage scheduling becomes more challenging. Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages.

The LRTP Tranche 1 Portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environment and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

The LRTP Tranche 1 Portfolio gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

SCHEDULE 3:
2021 MISO FUTURES REPORT

MISO Futures Report

- Published April 2021 -

Updated December 2021

Highlights

- Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

- The three MISO Futures encompass scenarios that bookend the fleet resource mix over the next twenty years and are intended to be used for several years with minimal updates.

- Analysis of three scenarios allows for insights to the MISO system once it transforms to dual summer and winter peaking as renewable energy and projected demand increase.

- December 2021 updates include revised expansion results for Futures 2 and 3. Explanation and details of these results can be found in the September, October, and November 2021 PAC presentations in the Presentation Materials section of this report.

Executive Summary

MISO is tasked with delivering safe, reliable, and cost-effective power across 15 states and the Canadian province of Manitoba. Within MISO's diverse regional footprint, utility members are making future plans, committing to near and long-term retirements and investments, and announcing increasingly advanced decarbonization goals. Although MISO's role is to remain policy- and resource-agnostic, there is a clear fleet transition underway that has implications for system operations.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving what MISO refers to as a regional "Reliability Imperative." MISO, our member utilities, and state regulators all share the responsibility to address this Reliability Imperative. A key element of MISO's response to the Reliability Imperative is our Long-Range Transmission Planning (LRTP) initiative. The "Futures" defined in this document will be a key driver of those efforts and other elements of the Reliability Imperative.

How can MISO, as a regional grid operator, support its member utilities and state policy makers as they continuously refine how to serve the 42 million people in the MISO footprint? One tool at MISO's disposal is the use of forward-looking planning scenarios to provide outlooks of the future. These Future planning scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period. This information is used to model a capacity expansion, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives. Using the range of resource generation modeled, MISO will then apply the Futures' expansion results to the development of transmission plans, the LRTP, and other MISO initiatives that ensure continued reliability and economic energy delivery.

This report captures an eighteen-month collaboration between MISO and stakeholders to develop three Future scenarios that bookend the uncertainty over the next twenty years. When carried forward into the transmission planning models, this set of Futures will enable the diverse goals and policies of MISO's states and utilities.

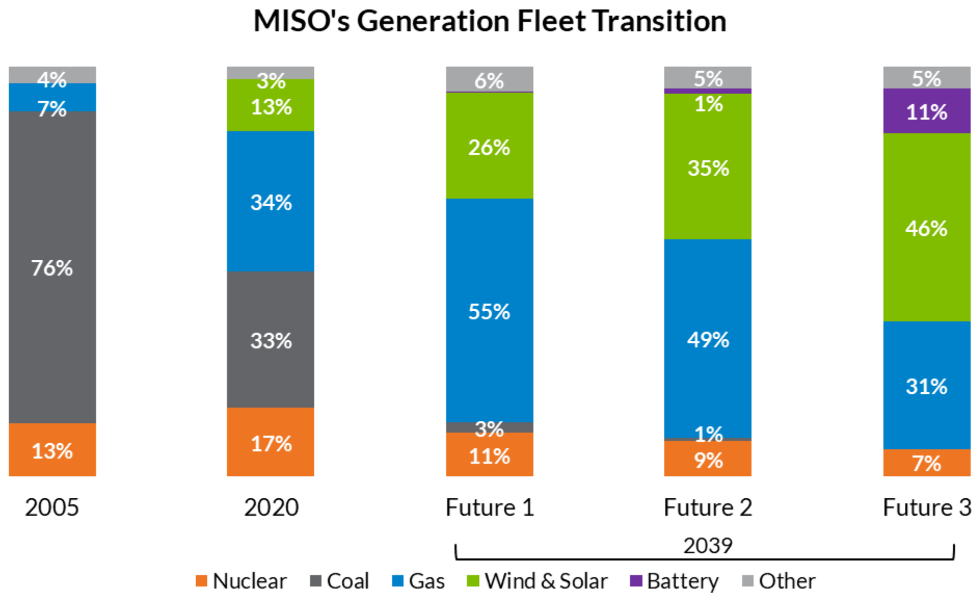


Figure 1: Overview of MISO's Generation Fleet Mix Transition [82]

Future 1 Assumptions – This Future reflects substantial achievement of state and utility announcements and includes a 40% carbon dioxide reduction trajectory.[1] While Future 1 incorporates 100% of utility integrated resource plan (IRP) announcements, state and utility goals that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these announced goals and respective timelines. Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate[2] of 0.5%.

Future 2 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including a 60% carbon dioxide reduction. Future 2 introduces an increase in electrification, driving an approximate 1.1% annual energy growth rate.

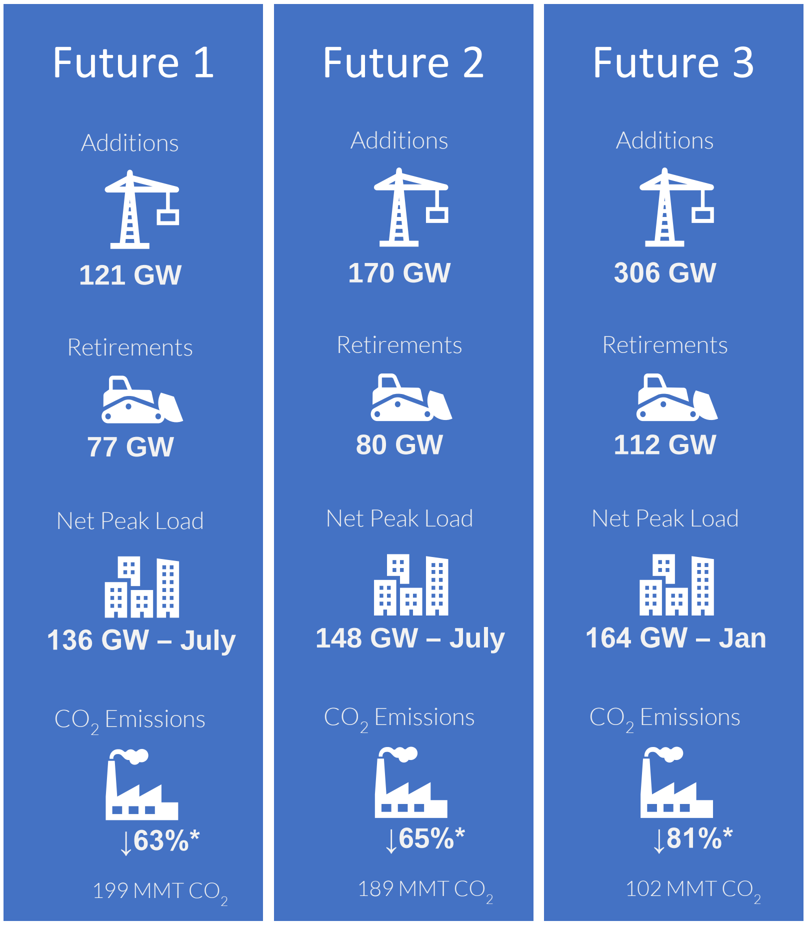


Figure 2: Summary of Future Scenario Impacts, 2039

Future 3 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.7% annual energy growth rate.[82]

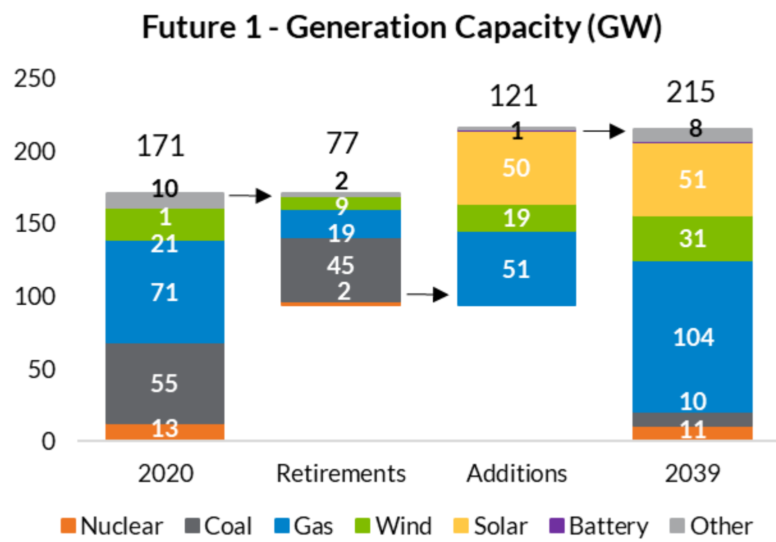
The Futures utilized announced goals and other input assumptions through September 2020 to represent a snapshot in time. Since the modeling of the Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures Assumptions above summarize each scenario's inputs, Figure 2 details several key results of the modeling. For example, Future 1 included a 40% carbon reduction trajectory, and the model resulted in 63% carbon reduction. Additionally, "net peak load" results refer to peak load values, net of load modifying resources.

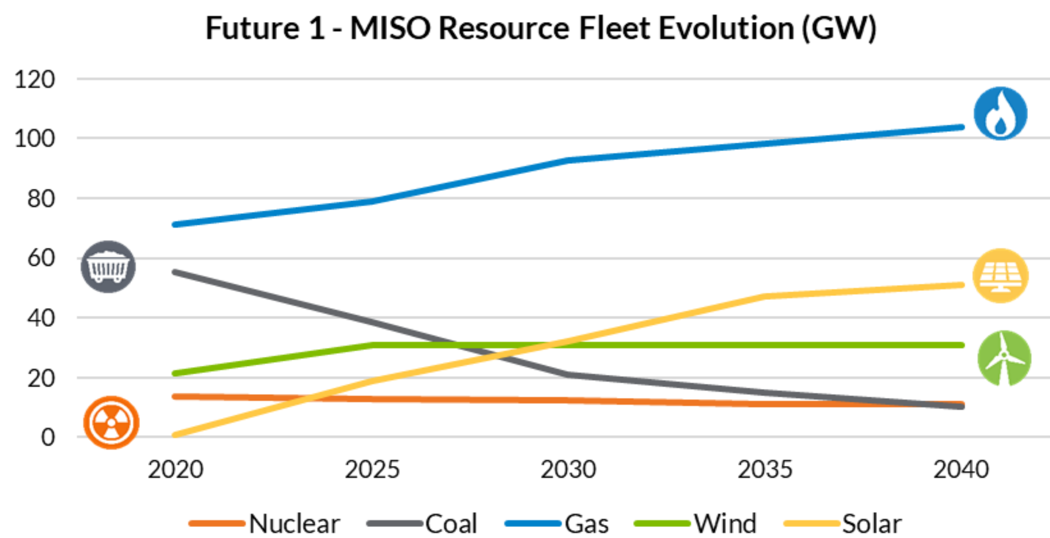
[1] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.

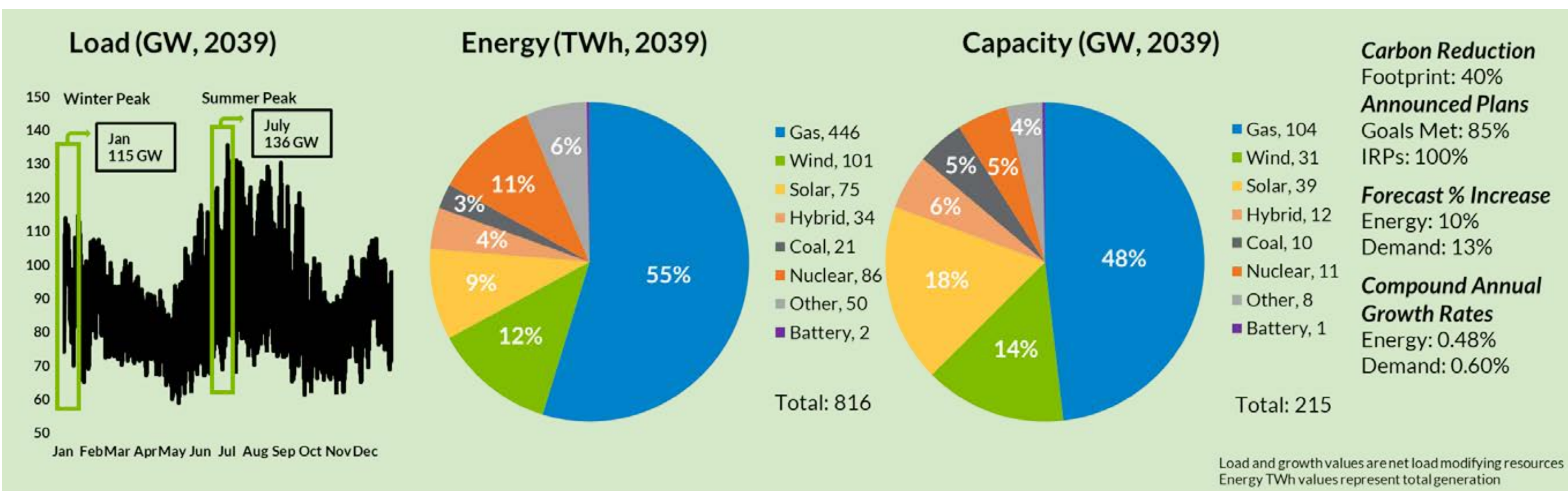
[2] Futures energy growth rates are compound annual growth rates (CAGR).

Future 1 Results

This Future assumes demand and energy growth are driven by existing economic factors, with small increases in EV adoption. Modeling for Future 1 results in the retirement of 77 GW and the addition of 121 GW of resources to the MISO footprint.

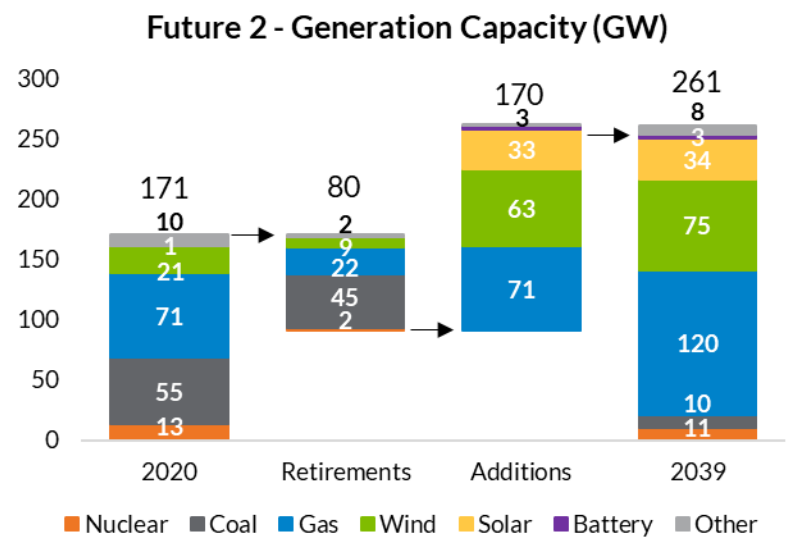


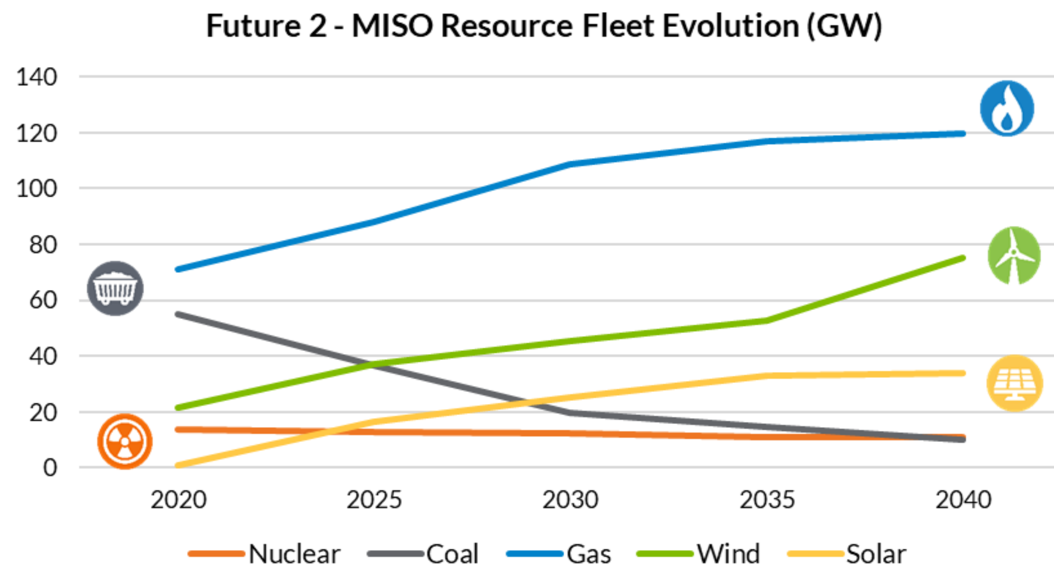


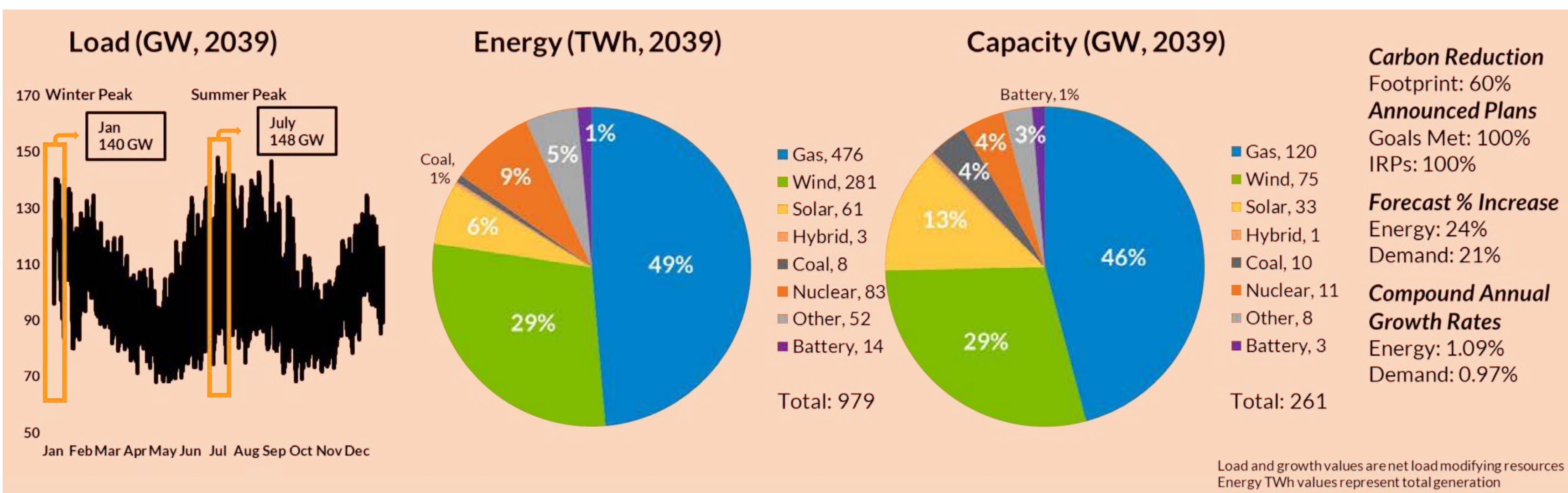


Future 2 Results

Due to retirements and increased electrification, moderate increases in demand and energy cause Future 2's load shape to have a larger peak in the summer but remain relatively dual peaking. Modeling of Future 2 results in the retirement of 80 GW and the addition of 170 GW of resources to the MISO footprint.

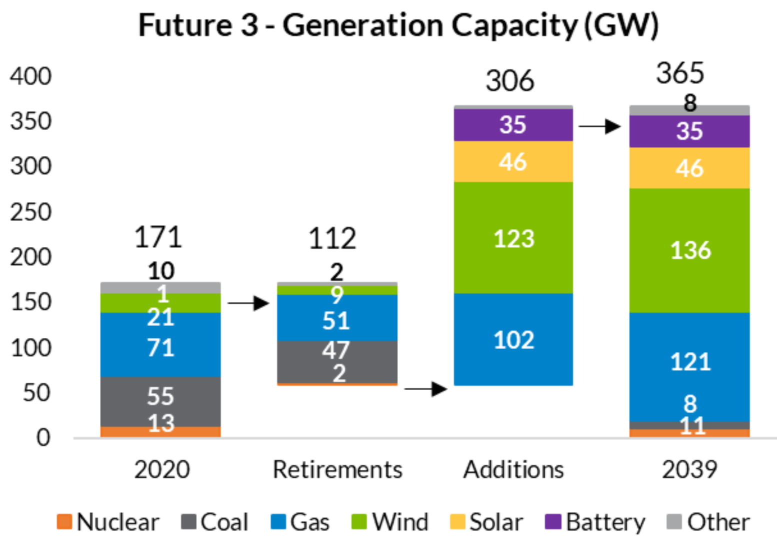


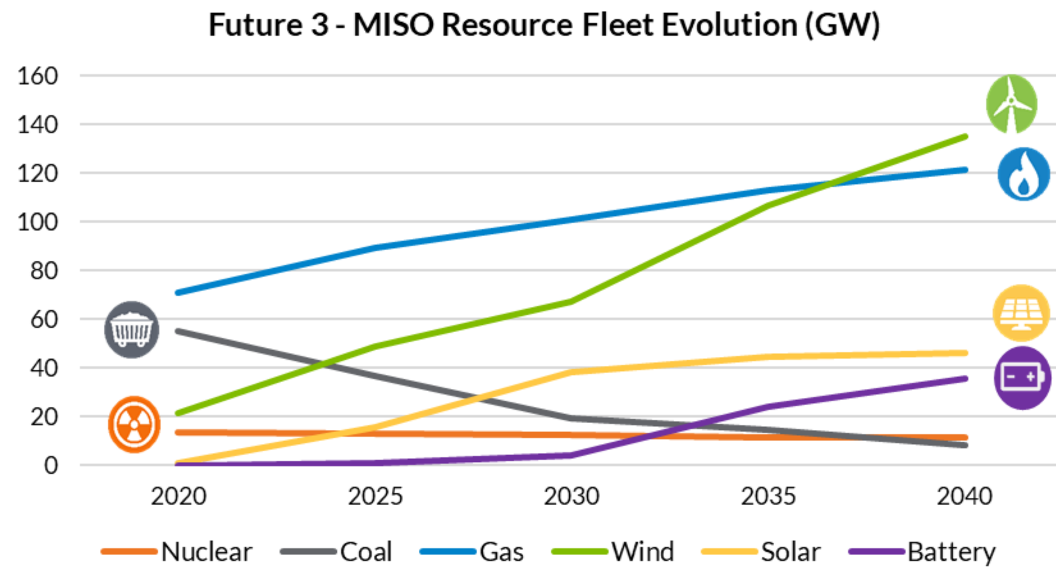


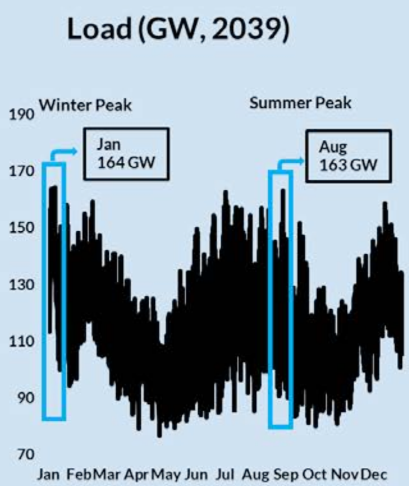


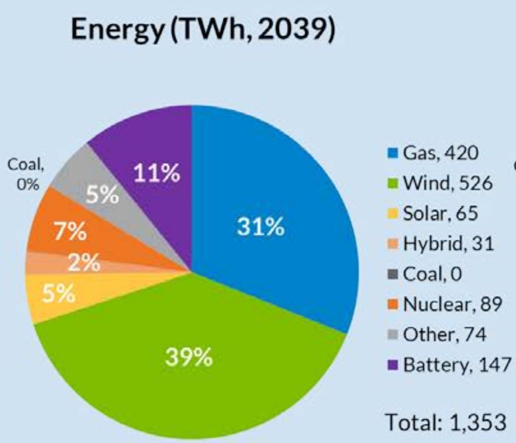
Future 3 Results

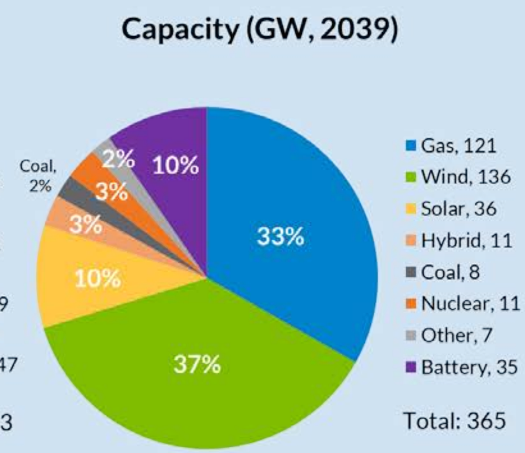
Due to retirements, decarbonization, and electrification, large increases in demand and energy produce a prominent dual peaking load shape in the later years of the study period. Modeling of Future 3 results in the retirement of 112 GW and the addition of 306 GW of resources to the MISO footprint.











Carbon Reduction
Footprint: 80%
Announced Plans
Goals Met: 100%
IRPs: 100%

Forecast % Increase
Energy: 40%
Demand: 32%

Compound Annual Growth Rates
Energy: 1.71%
Demand: 1.41%

Load and growth values are net load modifying resources
Energy TWh values represent total generation

MISO Futures Purpose and Assumptions

In order to perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be in the future. Complicating matters is the uncertainty of future developments.

A tool that MISO has developed to address this uncertainty is the use of multiple forward-looking scenarios to provide a range of future outlooks. Within MISO, the collection of assumptions defining these multiple forward-looking scenarios are called the "Futures". These Future scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period.

One of the core components of analyzing the grid twenty years into the future is an understanding of what the electric generation resource fleet will be. Since MISO is not an integrated resource planner, MISO relies on its stakeholders, policy direction, and industry trends to bridge the gap between what the generation fleet is today and what it will be in the future. The Futures are used to hedge uncertainty by utilizing an economic resource expansion analysis, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving changes within the Futures process, and throughout MISO more broadly as part of the Reliability Imperative. As the 2019 MISO FORWARD Report identified, three major trends that are changing the energy landscape have emerged – demarginalization, decentralization, and digitalization. Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

MISO received a clear message of urgency from its stakeholders including member utilities, policy makers, and large end-users asking MISO to move quickly from identifying high-level needs to providing solutions that allow states and utilities to reach their energy transition goals. In response, MISO initiated a public stakeholder process to update the Futures process to align with the ongoing rapid transformation and to better incorporate the plans of MISO's members and states, while also creating a bookended range of future scenarios that could be utilized in multiple study cycles. The public stakeholder process kicked off in August 2019, included thirteen different public stakeholder meetings, and concluded in December 2020.

MISO is not an integrated resource planner. The MISO Futures reflect resource plans announced by member utilities and states and forecast additional resources to meet forecasted energy demand, policy objectives, and reserve margins.

The Future scenarios in this document are a product of continued collaboration between MISO and its stakeholders. They represent challenges and compromises enabling member utilities to achieve significant fleet transition goals with diverse approaches or a more traditional resource portfolio. This report describes three Futures that are intended to be used as inputs for multiple MISO Transmission Expansion Plan (MTEP) cycles, the Long-Range Transmission Plan (LRTP) initiative, and other planning studies. These Futures will form the basis for all components of the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations.

Assumptions within the three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next twenty years. Future 1 represents a scenario driven by state and members' plans, with demand and energy growth driven by existing economic factors. Future 2 builds upon Future 1 by fully incorporating state and members' plans and includes a significant increase in load driven by electrification (discussed in the Electrification section of this report). In the final scenario analyzed, Future 3 advances from Future 2, evaluating the effects of large load increases due to electrification, 50% penetration of wind and solar, and an 80% carbon reduction across the footprint by 2039.

MISO conducted the Renewable Integration Impact Assessment (RIIA) to evaluate the impact of large installations of wind and solar to the system. This assessment found that managing MISO's grid, particularly beyond the 30% system-wide renewable level, will require transformational change in planning, markets, and operations. RIIA concludes that renewable penetration of at least 50% can be achieved through additional coordinated action. MISO members have continued to update their goals and look to MISO to help integrate these resources within the grid. With the analysis of the Future scenarios, wind and solar penetrations reach 26% in Future 1 and 46% in Future 3.[82]

Figure 3 shows the resulting wind and solar energy generation in each Future. Since load forecasts differ, the energy required of wind and solar to reach these penetrations is larger in each scenario. Futures 1, 2, and 3 reach maximum wind and solar penetrations of 26%, 35%, and 46% respectively.

Resulting Wind and Solar Penetration Levels

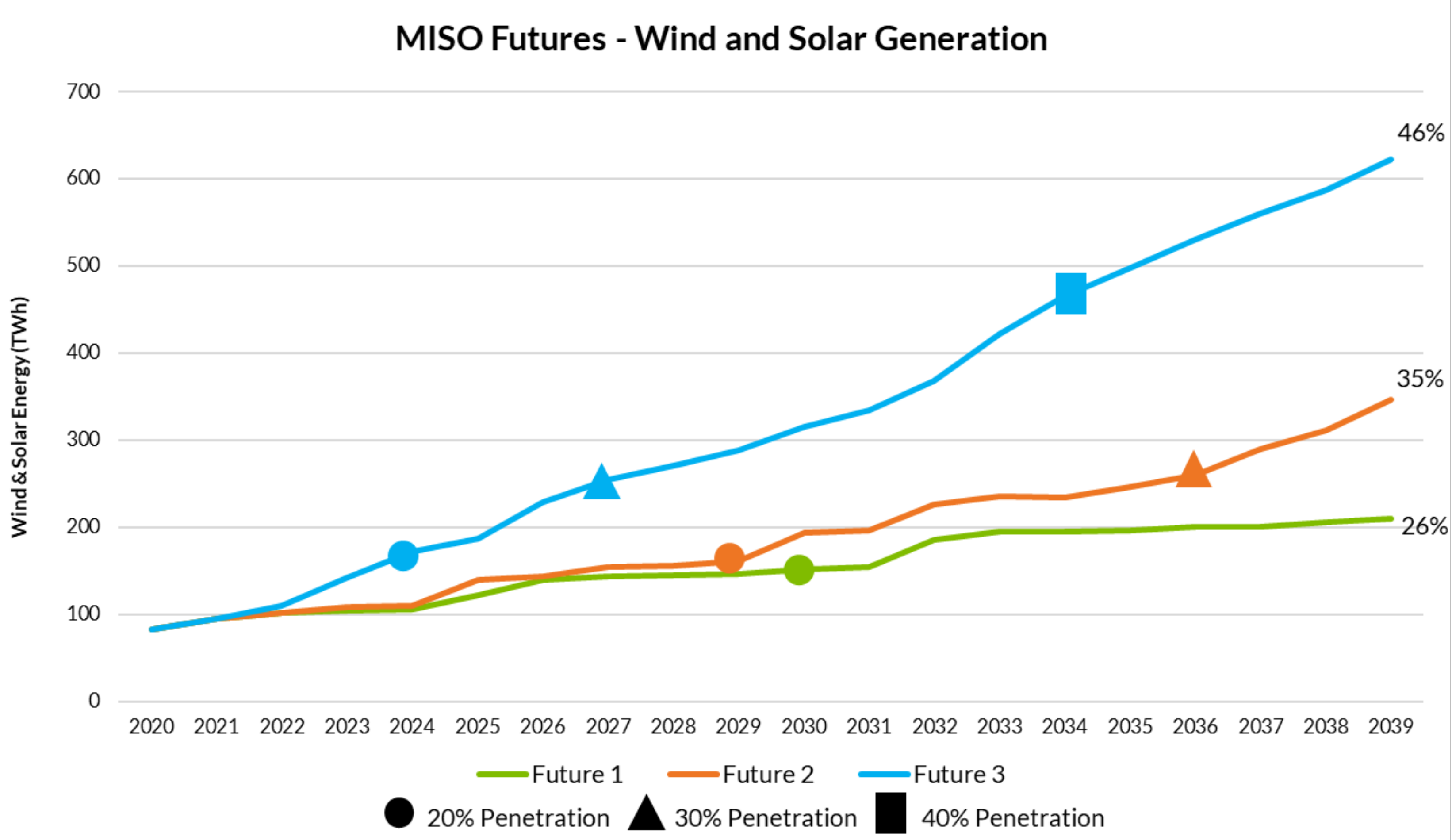


Figure 3: Wind and Solar Energy Generation Throughout Study[82]

Changing Energy Across MISO

Cities, states, large commercial and industrial corporations, and utilities are exploring and setting decarbonization goals that often include reaching 100% renewable energy supply or net zero carbon by 2050. Although not all states and utilities share these clean energy goals, a fleet transition of this magnitude will have implications on what resources will be needed across the MISO footprint to ensure reliability of the grid. The role of MISO is to remain resource-agnostic and to ensure a reliable and economic Bulk Electric System in an ever-changing energy, regulations, and economics environment.

Throughout the analysis of each Future scenario, MISO incorporated specific state and utility goals relative to carbon and renewable energy percentages into the models. Carbon was broken out into two segments per Future: a footprint-wide reduction applied to all resources and site-specific reductions applicable to carbon-emitting resources within states and utilities with announced carbon goals.

Renewable goals were modeled differently than those of carbon emissions. This was done by converting utility/state goals into relative percentages of MISO and taking the summation of these values to create footprint trajectories. As costs for wind and solar have decreased, the model surpassed these goals in Futures 1 and 2. Resources were assigned to their respective areas in the siting process.

Internal analysis indicates the MISO footprint has decarbonized by 29% since 2005. Early thermal retirements, public announcements, and evolving IRPs support MISO's preparation for a broad range of Future scenarios, enabling continual adaptation to the changing energy landscape while ensuring better grid reliability.

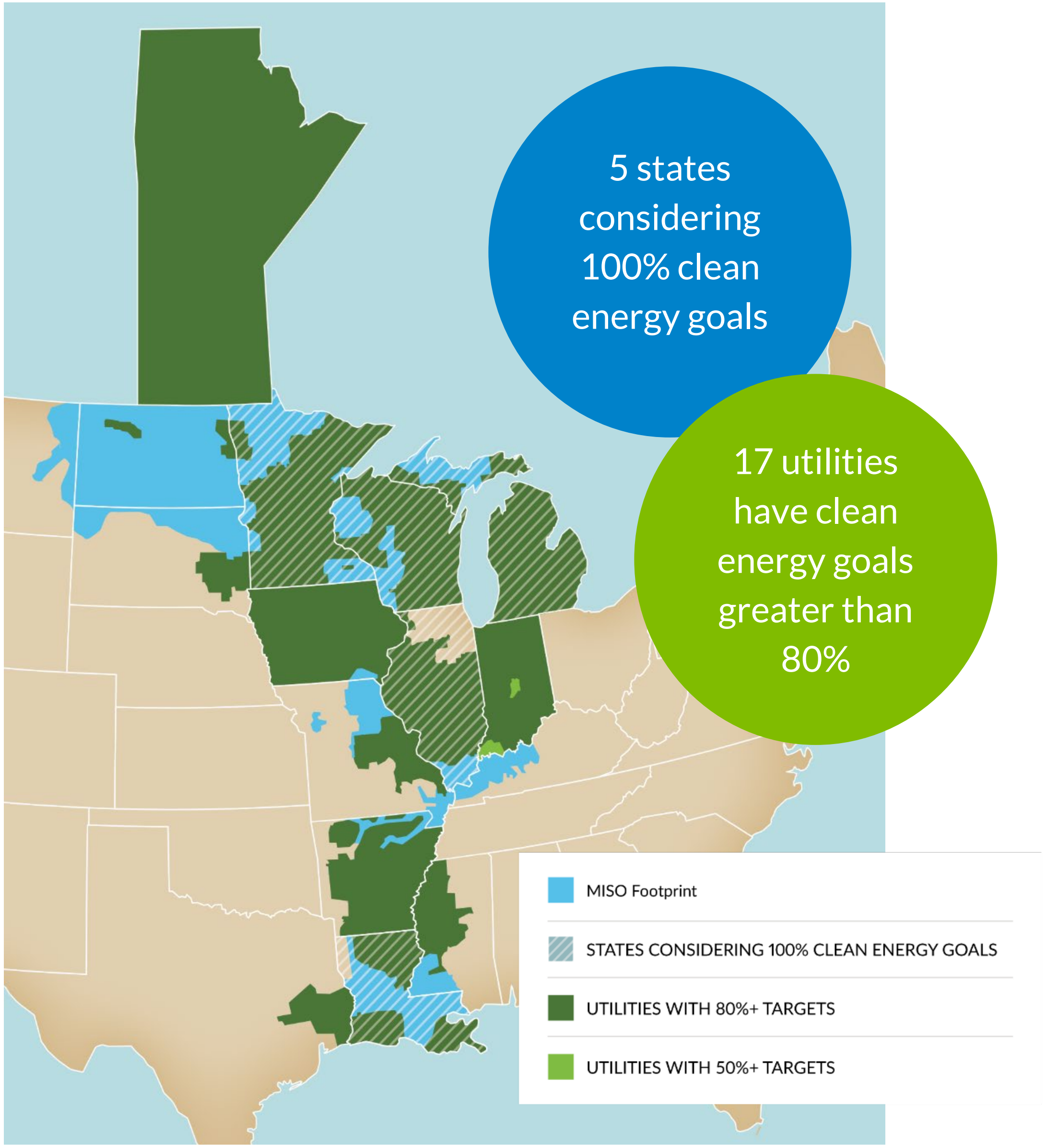


Figure 4: Clean Energy Goals above 50% Across Footprint[3]

State and Utility Clean Energy Goals

Today, state and utility policies and goals are changing rapidly and continued to do so during the Futures process, regarding carbon reductions, renewable energy targets, and unit retirement assumptions. To best account for these changes, MISO continuously updated these announced goals until the final Future scenario models were complete in October 2020. Since then, several members have updated or announced their plans, noted with asterisks in Table 1.

When collecting goal announcements, MISO staff examined companies' IRPs, state publications, and results from the MISO/OMS State Data Survey. (OMS refers to the Organization of MISO States). Once this information was compiled, MISO compared unit addition announcements with signed generation interconnection agreements (GIA) in its queue to ensure that these units would not be double counted. MISO then added IRP units into the base model to account for the announced goals of states and utilities. These units had a variety of fuel types and contained announced additions throughout the study period (2020-2039).

From Figure 4, it is apparent that much of the footprint has a clean energy goal greater than 50% (either from a carbon reduction or renewable energy target).[3] Some goals displayed in the table below were not included in the Futures analysis because their announcement came after the models were complete in October of 2020.[4,5] Table 1 displays state and utility goals within the model, overlapping by service area. In this analysis, MISO considered current trends but also had the opportunity to look beyond and plan for a range of Future scenarios to bookend plausible possibilities over the next 20 years.

[3] Utility goals are represented with green shading while state goals of 100% are given white stripes.

[4] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

[5] Entities who announced or updated their goals after Future scenario modeling was complete are listed here in their respective categories. Carbon reduction goals not modeled: Madison Gas, Vectren, Vistra, IPL, and OTP. Renewable energy targets not modeled: Alliant, CLECO, Vistra, IPL, and Entergy. Entities whose carbon reduction was modeled but a modification to the goal was made: Michigan (28% by 2025), Ameren (80% by 2050), and Minnesota Power (50% by 2021).

<table>
<thead>
<tr><th>State Clean Energy Goals & RPS[6]
(source linked)</th><th>State</th><th>Utility</th><th>Utility Carbon Reduction Goals (2005 Baseline)[7]</th><th>Utility Renewable Energy Goals</th></tr>
</thead>
<tbody>
<tr><td>RPS: 15% RE by 2021 (IOUs)</td><td>Missouri</td><td rowspan="2">Ameren</td><td rowspan="2">Net Zero by 2050*</td><td rowspan="2">100% by 2050</td></tr>
<tr><td rowspan="2">100% Clean Energy by 2050 (Governor)
RPS: 25% by 2025-2026</td><td rowspan="2">Illinois</td></tr>
<tr><td rowspan="2">MidAmerican Energy</td><td rowspan="2">-</td><td rowspan="2">100% by 2021</td></tr>
<tr><td rowspan="3">RPS: 105 MW (completed 2007)</td><td rowspan="3">Iowa</td></tr>
<tr><td>Alliant Energy</td><td>Carbon Free by 2050</td><td>30% by 2030*</td></tr>
<tr><td rowspan="2">Dairyland Power</td><td rowspan="2">-</td><td rowspan="2">29% by 2029</td></tr>
<tr><td rowspan="3">Carbon Free by 2050 (Governor)
RPS: 10% by 2020</td><td rowspan="3">Wisconsin</td></tr>
<tr><td>WEC Energy Group</td><td>Carbon Neutral by 2050</td><td>-</td></tr>
<tr><td>Madison Gas & Electric</td><td>Net Zero by 2050*</td><td>30% by 2030</td></tr>
<tr><td rowspan="3">Carbon Neutral by 2050*
RPS: 15% by 2021 (standard), 35% by 2025 (goal, including EE & DR)</td><td rowspan="3">Michigan</td><td>Consumers Energy</td><td>Net Zero by 2040</td><td>56% by 2040</td></tr>
<tr><td>DTE Energy</td><td>Net Zero by 2050</td><td>25% by 2030</td></tr>
<tr><td>Upper Peninsula Power</td><td>-</td><td>50% by 2025</td></tr>
<tr><td rowspan="4">Voluntary clean energy PS,
10% RE by 2025</td><td rowspan="4">Indiana</td><td>Duke Energy</td><td>Net Zero by 2050</td><td>16,000 MW by 2025</td></tr>
<tr><td>Hoosier Energy</td><td>80% by 2040</td><td>10% by 2025</td></tr>
<tr><td>Vectren</td><td>75% by 2035*</td><td>62% by 2025</td></tr>
<tr><td>NIPSCO</td><td>90% by 2028</td><td>65% by 2028</td></tr>
<tr><td rowspan="4">Carbon Free by 2050 (Governor)
RPS: 26.5% by 2025 (IOUs),
25% by 2025 (other utilities)</td><td rowspan="4">Minnesota</td><td>Xcel Energy</td><td>Carbon Free by 2050</td><td>100% by 2050</td></tr>
<tr><td>SMMPA</td><td>90% by 2030</td><td>75% by 2030</td></tr>
<tr><td>Minnesota Power</td><td>100% Clean Energy by 2050*</td><td>50% by 2021</td></tr>
<tr><td>Great River Energy</td><td>95% by 2023</td><td>50% by 2030</td></tr>
<tr><td>Net Zero GHG by 2050 (Governor)</td><td>Louisiana</td><td>Entergy</td><td>Net Zero by 2050
(2000 baseline)</td><td>12% by 2030*</td></tr>
</tbody>
</table>

Table 1: State & Utility Goals – Service Area Overlay

System-Wide Carbon Modeling

In addition to state and utility renewable goals, each Future scenario had a carbon emission reduction (CER) applied across the entire footprint. Carbon reduction trajectories were made from a total MISO 2005 CO_2 baseline, with linear reductions of 40%, 60%, and 80% (for Futures 1, 2, and 3, respectively) applied through the end of the study period. These trajectories were modeled within EGEAS (Electric Generation Expansion Analysis System). As well as the footprint-wide total CER for each Future, MISO also entered more specific trajectories for states and utilities as applicable.

[6] DR: demand response; EE: energy efficiency; GHG: greenhouse gas; IOU: investor-owned utility; PS: portfolio standard; RE: renewable energy; RPS: renewable portfolio standard

[7] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

All utility and state carbon trajectories used a 2005 CO_2 emissions baseline except for Entergy, which used a 2000 baseline in accordance with utility-specific goals. Each CER trajectory was given an approximate 2020 CO_2 starting value and then decreased to a target reduction percentage of the baseline. Consistent with Futures assumptions, CER trajectories reflected 100% of IRPs and 85% of other announced goals for Future 1, while trajectories for Futures 2 and 3 reflected 100% of both.

From analysis of the current fleet in 2005, MISO emitted 543 million (M) tons of CO_2. Figure 5 below illustrates CER for each Future scenario, displaying the tons of carbon emitted (bars) and the percentage of carbon reduction from the 2005 baseline (lines). The dotted line projects the historical trend of carbon emissions that MISO is assumed to have for comparison. From the trend of MISO, it is evident that the carbon emissions of the system will continue to decrease and will be accelerated as members' goals continue to change. Futures 2 and 3 emit more carbon than Future 1 in 2020 due to the increased load assumptions met by the existing fleet. The Future scenarios in this document allow for insights on how quickly carbon reduction across the footprint may occur. By the end of the study period, emissions reduced by 63% in Future 1, 65% in Future 2, and 81% in Future 3.

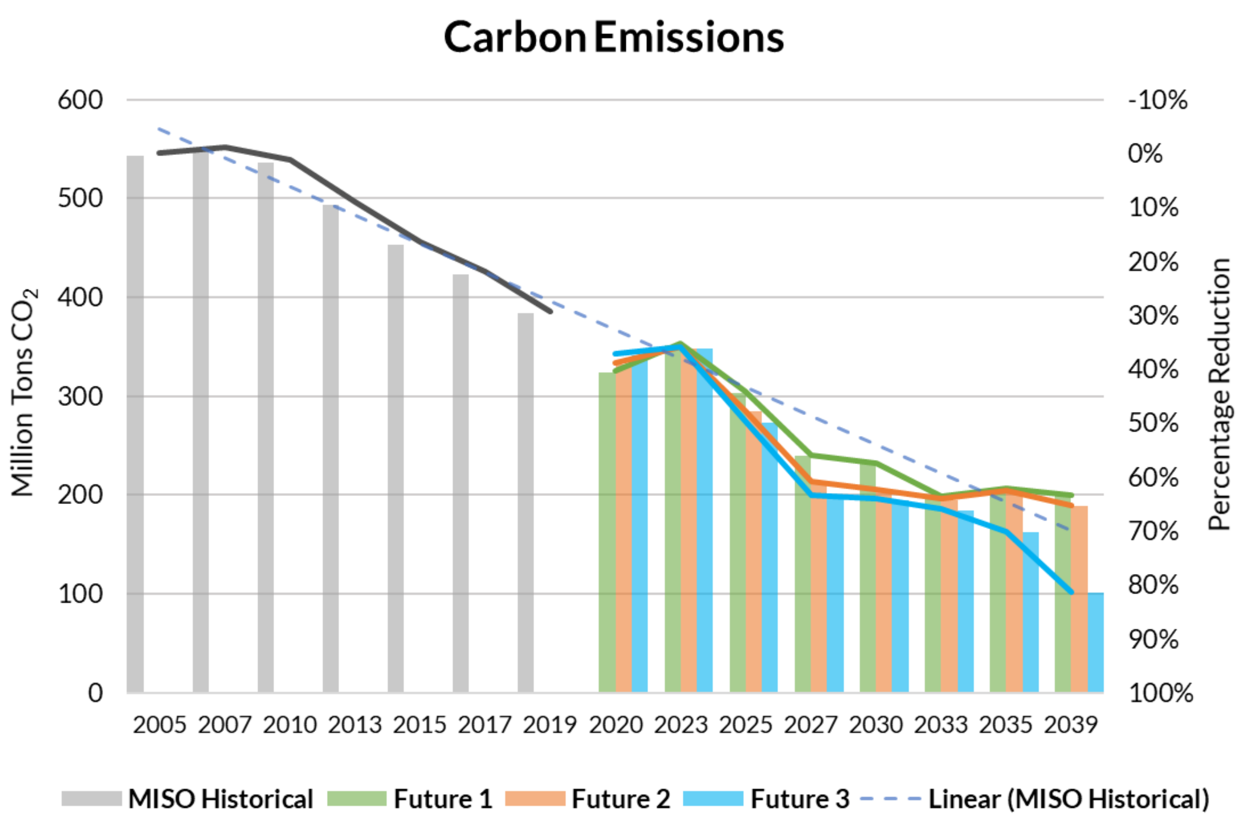


Figure 5: CO_2 Reduction Results (from 2005 Baseline)

Retirement and Repowering Assumptions

Base Retirement Assumptions

Nuclear and Hydroelectric – Retirement of nuclear and hydroelectric units will occur when a unit has a publicly announced retirement plan or is listed to retire in an IRP. Otherwise, these units will remain active throughout the study across all Futures.

Age-Based Retirement Assumptions

Age-based assumptions will be applied to all the units that fall into any of the categories listed below. However, in cases where these assumptions cause older units in the MISO system to retire before the start of the study period (2020), units will be retired by 2025.

Coal – Retirement ages of coal units progressively decrease with each Future. It is assumed that with changing policies and emission standards, coal usage will decline further. The coal retirement ages modeled in the three Futures respectively are: 46, 36, and 30 years. The Future 1 retirement age of 46 years is based on the average age of coal units noted by the Energy Information Administration (EIA).

- Coal retirements in each Future are approximately a 50/50 split between base and age-based retirement assumptions. The amount of coal retired results in similar capacity due to the average coal unit within the MISO fleet being 46 years of age.

Gas – Retirements for gas units were split into two categories, Combined Cycle (CC) and Other-Gas (e.g., Combustion Turbine [CT], IC [Internal Combustion] Renewable, and Integrated Gasification Combined Cycle [IGCC]). Both unit types were given retirement ages that decreased across the Futures scenarios; retirement ages for CC gas units are: 50, 45, and 35 years and retirements for Other-Gas units are: 46, 36, and 30 years respectively.

Oil – Retirement ages of oil units decrease across each Future scenario and are 45, 40, and 35 years respectively.

Wind and Solar – Retirements for utility-scale wind and solar will occur once a unit reaches 25 years of age. However, wind units will be repowered within the same year of retirement. These will be replaced by a new 100m hub height wind turbine with the same capacity as the previous unit but will receive new wind profiles, dependent on location. New profiles have updated capacity factors that are higher than existing wind turbines.

	Future 1	*Future 2*	*Future 3*
Coal	46	36	30
Natural Gas – CC	50	45	35
Natural Gas – Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar – Utility-Scale	25	25	25
Wind – Utility-Scale	25	25	25

Table 2: Age-Based Retirement Assumptions

Figure 6 through Figure 8 display the results of differing retirement assumptions across each of the three Future scenarios. Retirement totals were calculated by applying age-based assumptions, announced retirements, and adjusting generation units per stakeholder feedback provided to MISO. Age-based assumptions are the product of Future-specific retirement assumptions, while base retirements are announced by the generator owner, stated in an IRP, or filed with MISO's Attachment Y.[8]

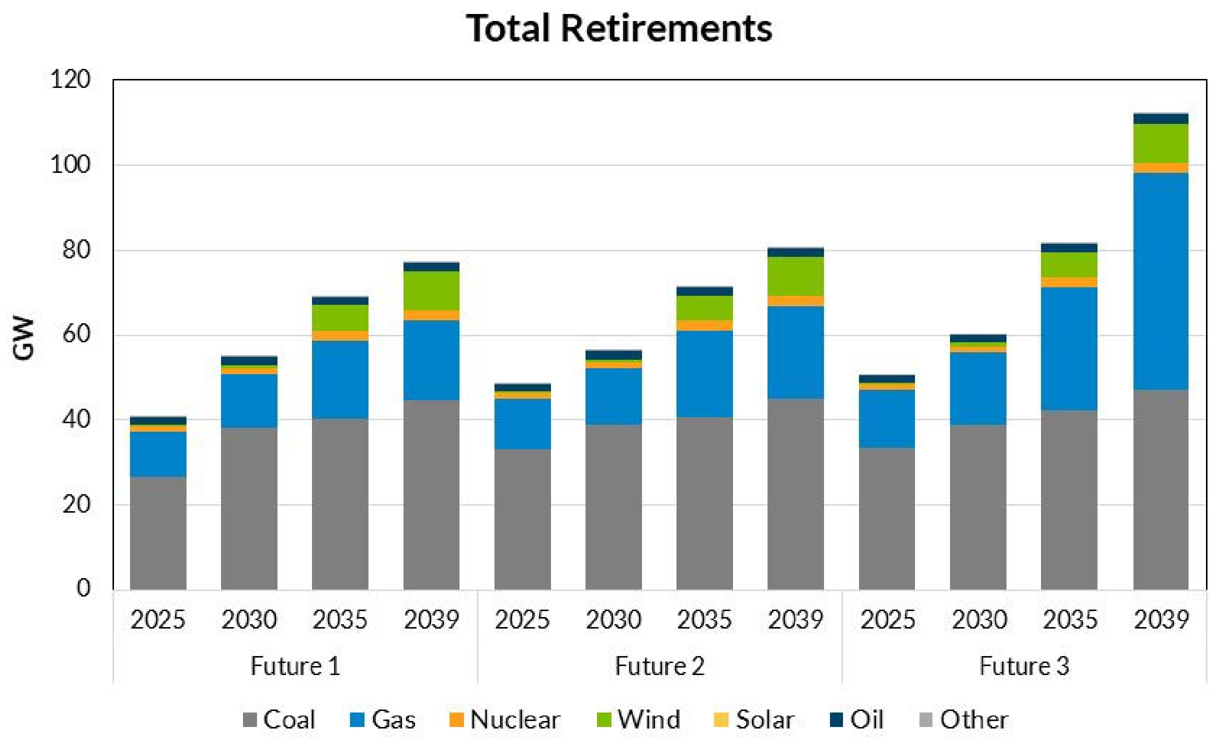


Figure 6: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[8] MISO's retirement notification process

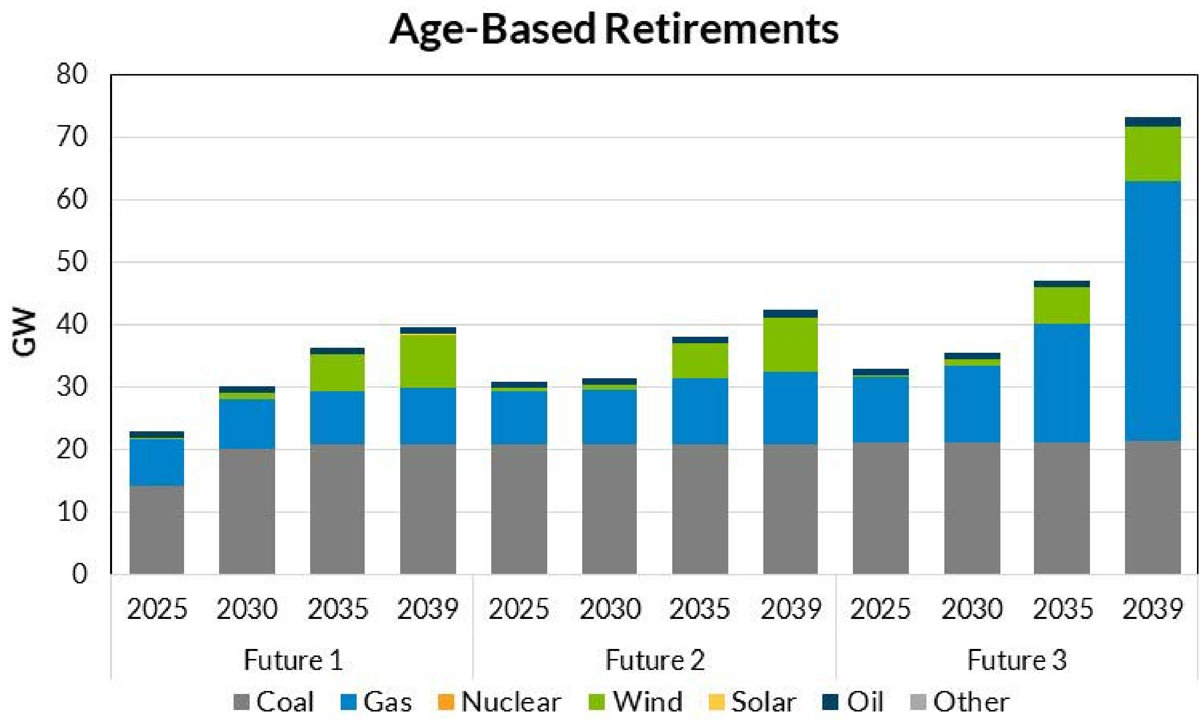


Figure 7: Age-Based Retirements per Future (Cumulative per Year)

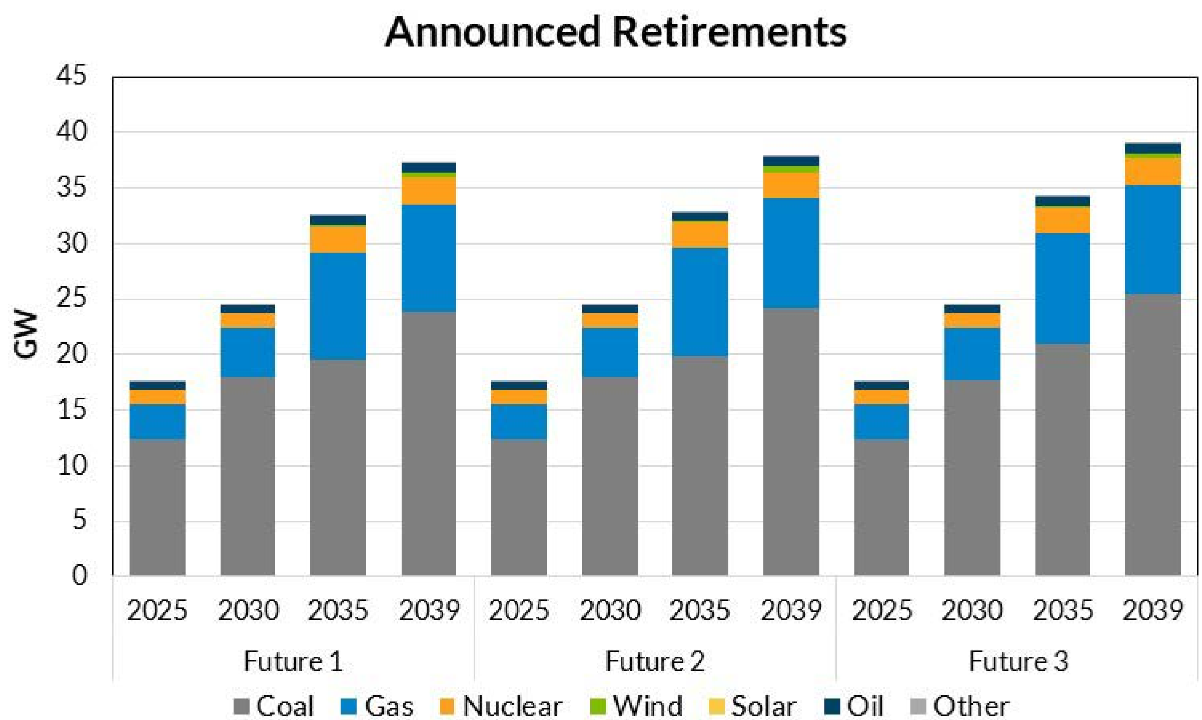


Figure 8: Base Retirements per Future (Cumulative per Year)

Figure 9 through Figure 11 display the results of the Future scenarios' retirement assumptions geographically throughout the MISO footprint. It is important to note that the wind units seen in these figures are assumed to be repowered with the same capacity, albeit with an updated profile that includes a higher capacity factor.

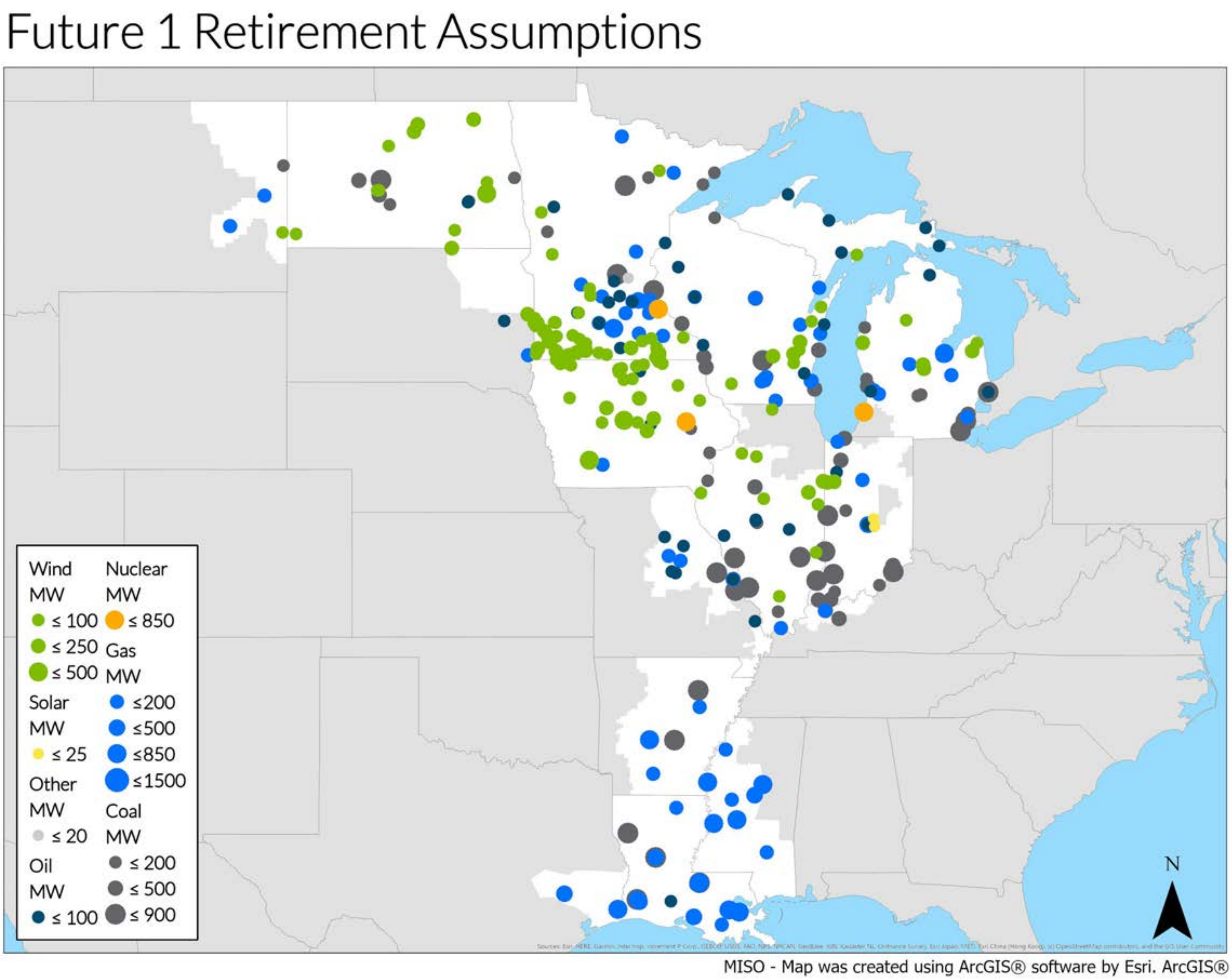


Figure 9: Future 1 Retirements by Fuel Type

Future 2 Retirement Assumptions

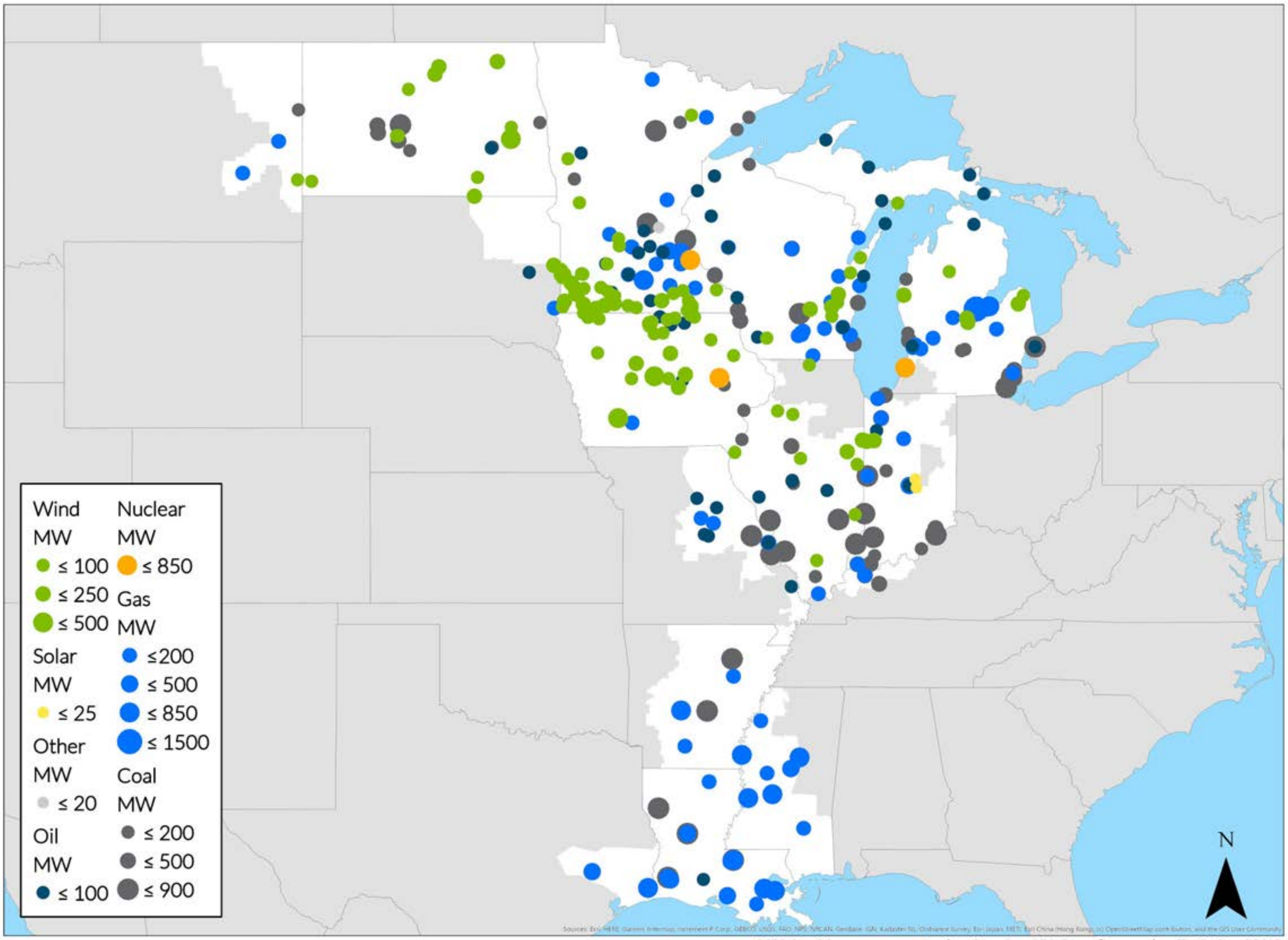


Figure 10: Future 2 Retirements by Fuel Type

Future 3 Retirement Assumptions

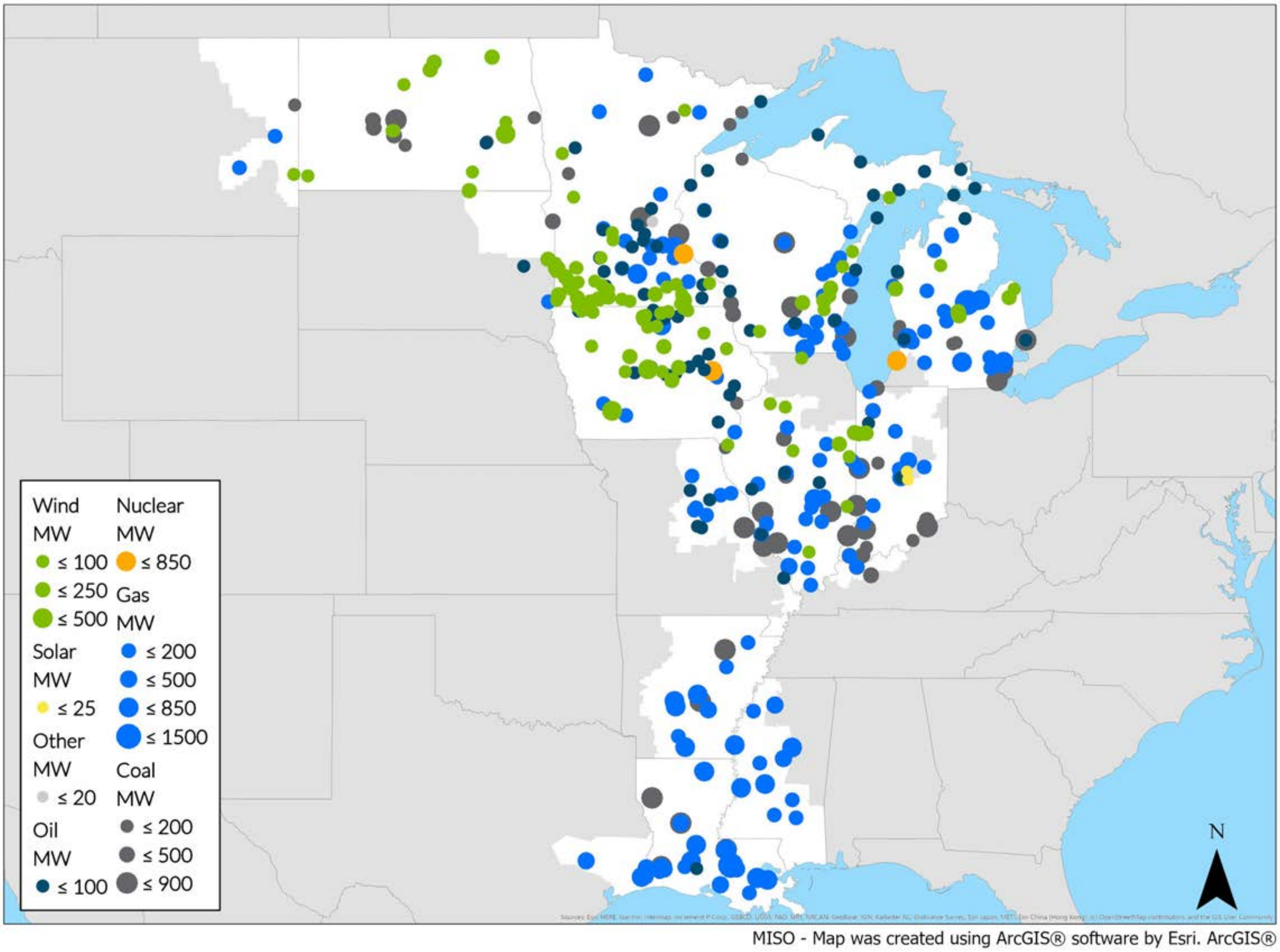


Figure 11: Future 3 Retirements by Fuel Type

Load Assumptions

To analyze what new generation and load modifying resources may be necessary 20 years into the future, assumptions were made regarding the load during that same 20-year period for each Future planning scenario. The three Futures each have differing assumptions representing a wide range of compound annual growth rates (CAGR) during the study period.

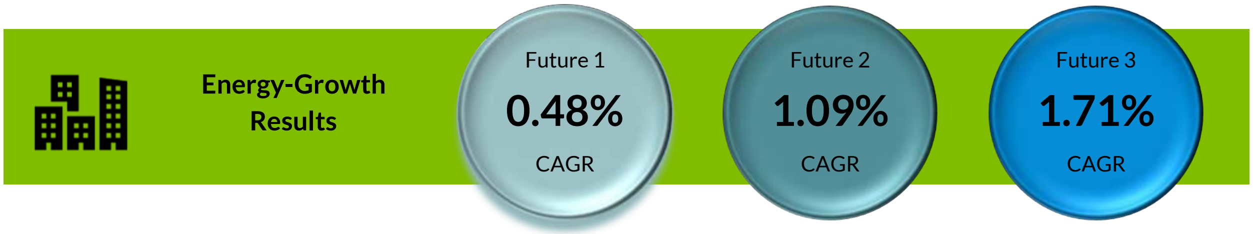


Figure 12: Annual Energy-Growth Rates

Future 1 assumed a load growth[9] consistent with recent trends; 0.48%, including currently low electric vehicle adoption as modeled by Lawrence Berkeley National Laboratory's (LBNL) 'Low' scenario projection.

Future 2 assumed an annual energy growth rate[9] of 1.09% to reach a targeted 30% energy increase by 2040, largely driven by electrification.

Future 3 assumed an annual energy growth rate[9] of 1.71% to reach a targeted 50% energy increase by 2040, driven by additional electrification.

A primary driver of load growth in Futures 2 and 3 is electrification. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). The increased energy assumptions of 30% and 50% were selected by MISO to create a wide but plausible range of growth scenarios. Although electrification drives the load increase in two of the Futures, it is not the sole source of each scenario's load growth. A more detailed discussion of each Future's load growth and electrification assumptions is provided below and in the Electrification Section of this report.

The resulting Future-specific Demand (MW) and Energy (GWh) forecasts are further detailed in the proceeding sections of this report.

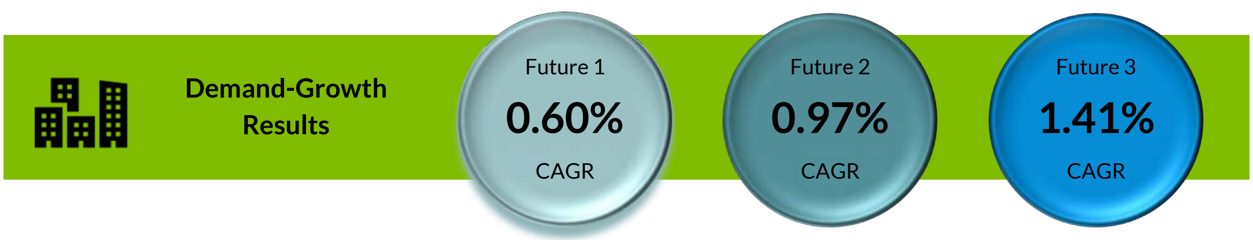


Figure 13: Annual Demand-Growth Rates

[9] Net annual energy and demand growth rates result from reducing the hourly load shape by the energy from energy efficiency (EE) programs.

MISO Forecast Development

The development of the EGEAS-Ready Coincident Peak (CP) Demand and Energy Forecasts for each Future began with MISO's load serving entities' 20-year demand and energy forecasts[10] and ended with the application of the various Future-driven assumptions, creating Future- and year-specific forecasts.

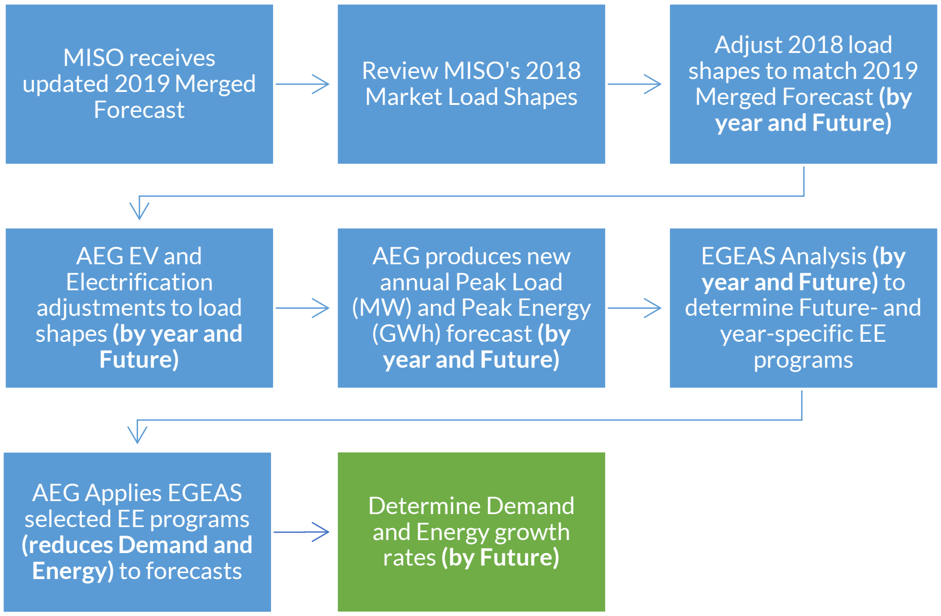


Figure 14: MISO's Forecast Development High-Level Process Flow Chart[11]

Base Forecast and Load Shapes

The 2019 Merged Load Forecast for Energy Planning forecast was reviewed for updates by stakeholders December 17, 2019 through January 10, 2020, and the updates received were incorporated. To accompany the forecast, MISO evaluated its 2018 load shapes for the impact of abnormal outages in operational load shape data due to weather anomalies. MISO evaluated the impact of Atlantic Tropical Cyclones which entered the MISO footprint according to the National Oceanic and Atmospheric Administration and determined that the 2018 shapes are suitable for MISO Futures.[12] MISO's 2018 load shapes also align with wind and solar shapes based on the most current data.

As a Futures process improvement, MISO used PROMOD to adjust each Load Balancing Authority's (LBA) 2018 load shape to meet Peak Load (MW) and Annual Energy (GWh) requirements set by the updated 2019 Merged Load Forecast for Energy Planning forecast. The benefit of this improvement was to create 20 years' worth of unique load shapes for the EGEAS analysis, as well to establish a common load shape for the EGEAS and Market Congestion Planning Studies (MCPS) analyses.

[10] If a particular MISO Load-Serving Entity (LSE) did not provide a 20-year demand and energy forecast, data from the State Utility Forecasting Group's Independent Load Forecast was used for it, creating the 2019 Merged Load Forecast for Energy Planning CP.

[11] Demand and Energy forecast process currently at box highlighted green.

[12] https://www.nhc.noaa.gov/data/tcr/index.php?season=2018&basin=atl

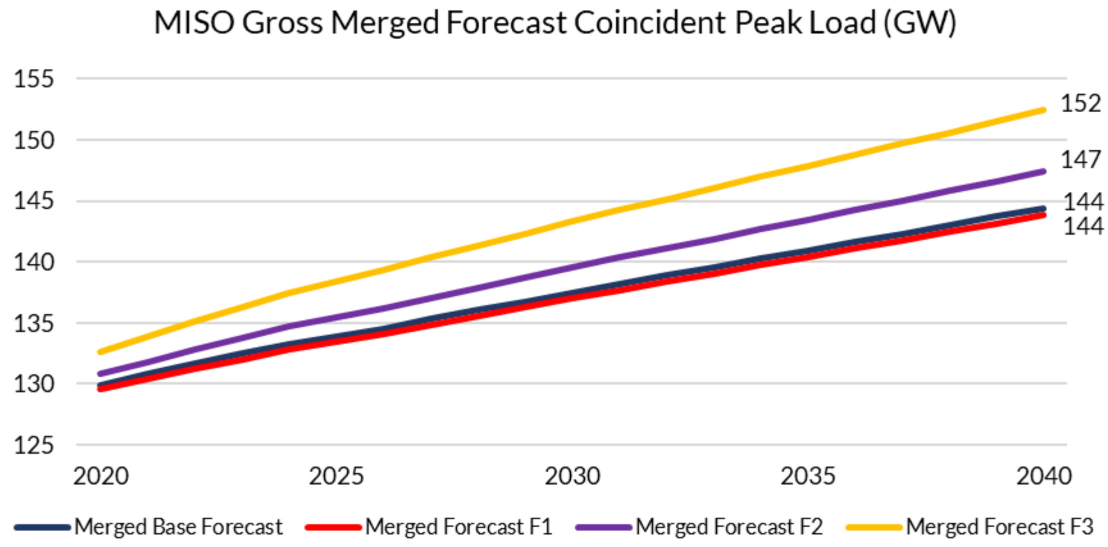


Figure 15: 2019 Merged Load Forecast Peak Load (GW)

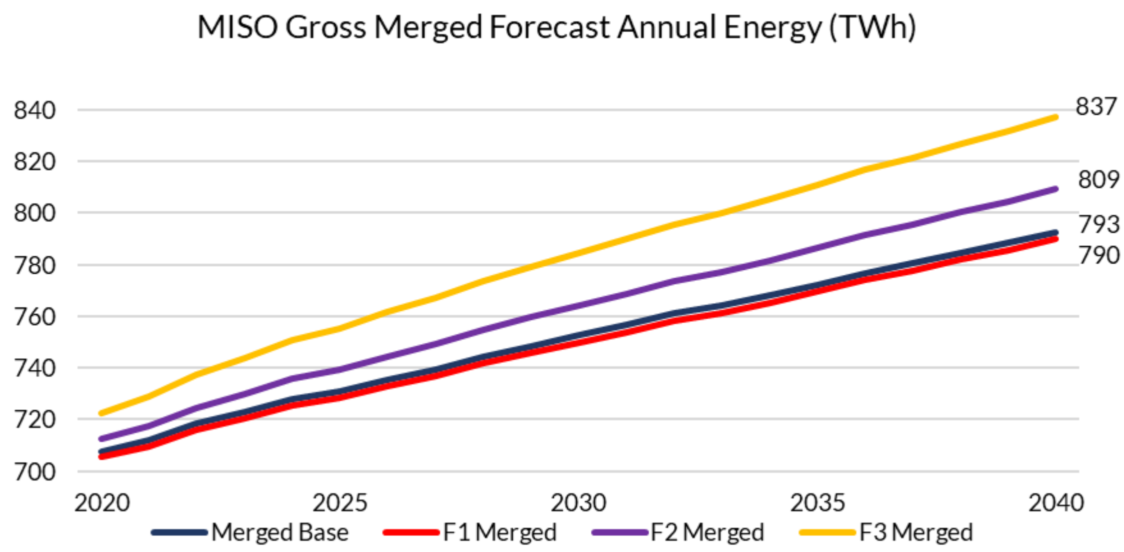


Figure 16: 2019 Merged Load Forecast Annual Energy (TWh)

Future-Specific Forecasts and Load Shapes

Applied Energy Group (AEG) used PROMOD-adjusted load shapes for their base input assumptions and then further modified these load shapes to achieve Future-specific electrification assumptions (EV growth and charging assumptions, residential electrification, and commercial and industrial electrification), ultimately creating 20 years of load shapes for each Future. A representation of the load shape modification is shown in Figure 24.

These Future-specific load shapes were used to calculate the associated Peak Load (MW) and Annual Energy (GWh) forecast for each year to be used in the EGEAS analysis. Refer to the following figures for MISO Footprint and Local Resource Zone (LRZ) representation of this forecast.

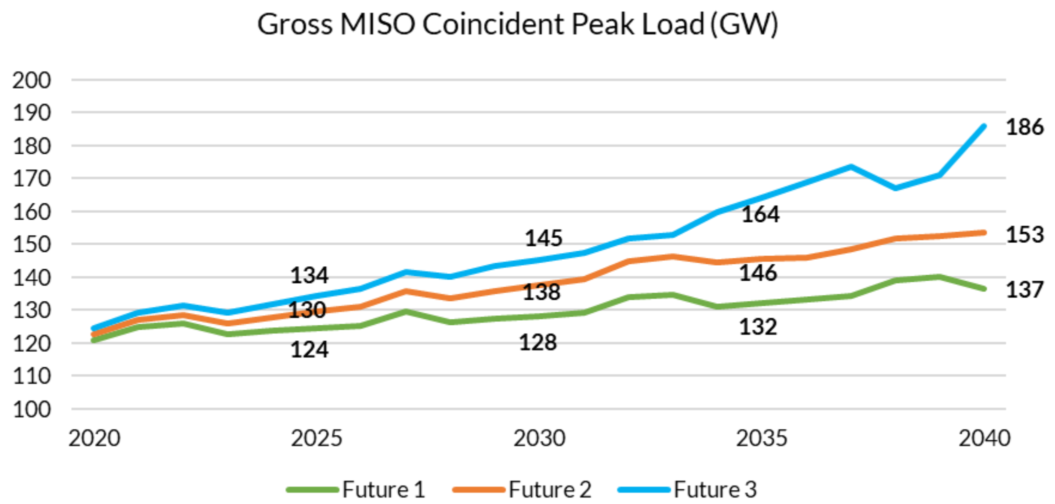


Figure 17: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[13,14]

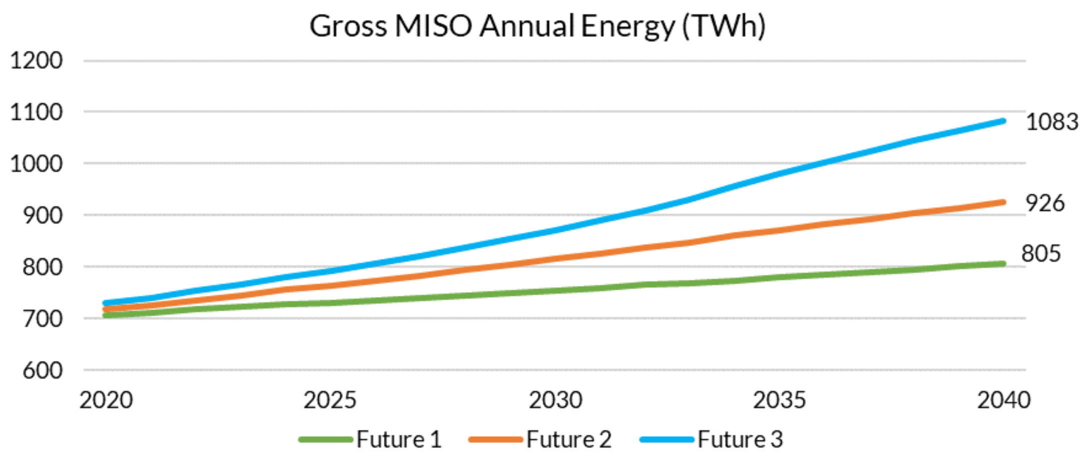


Figure 18: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future

[13] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[14] Dips in Future 3 are due to different peak times of reference, EV charging, and electrification load forecasts.

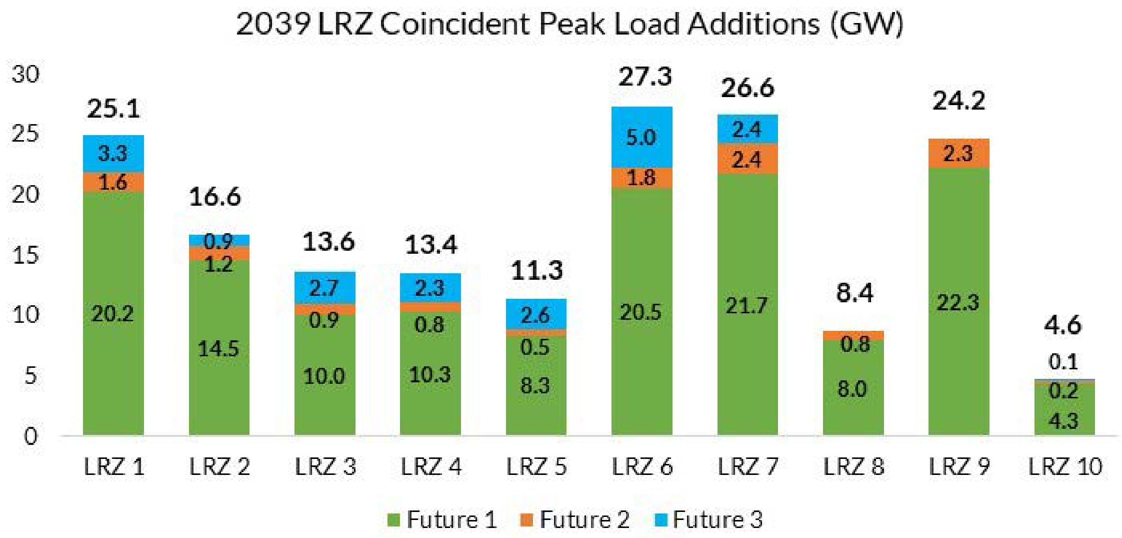


Figure 19: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast[15,16]

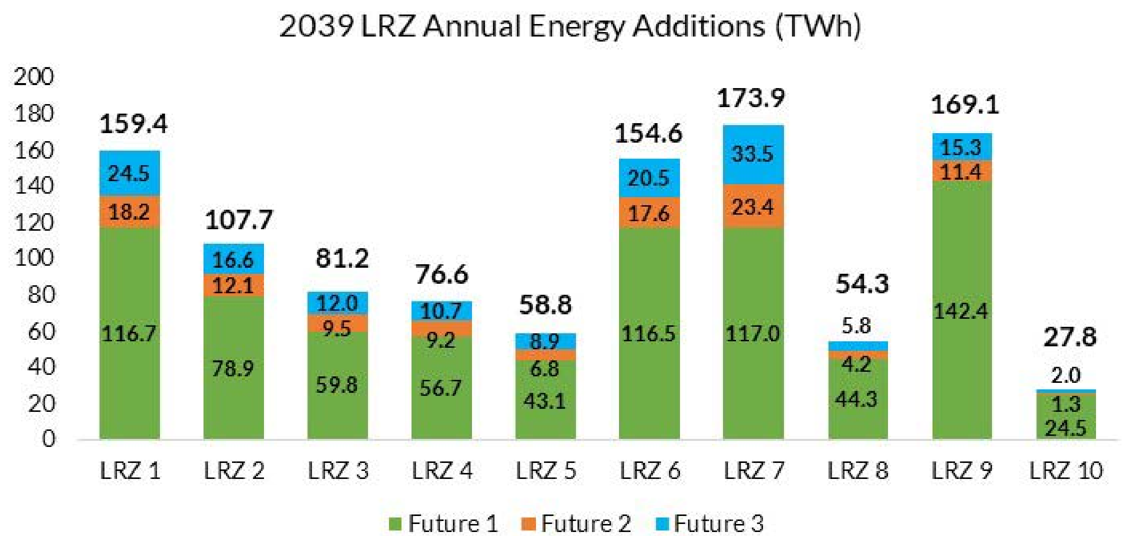


Figure 20: Final AEG Modified LRZ Annual Energy (TWh) Forecast[16]

[15] In LRZs 8 and 9, CP values decrease in Future 3, making the total shown less than the sum of values for Futures 1 and 2.

[16] Values shown do not include load and energy modifiers determined by EGEAS analysis.

Forecast Growth Assumptions

Demand and energy growth values are based on Futures assumptions and were determined once the analysis was finalized; EGEAS having selected hourly load (MW) and energy (GWh) modifiers and programs applied to each Future scenario's Coincident Peak forecast. The following figures represent compound annual growth rates (CAGR) and forecast increases pre- and post-analysis.

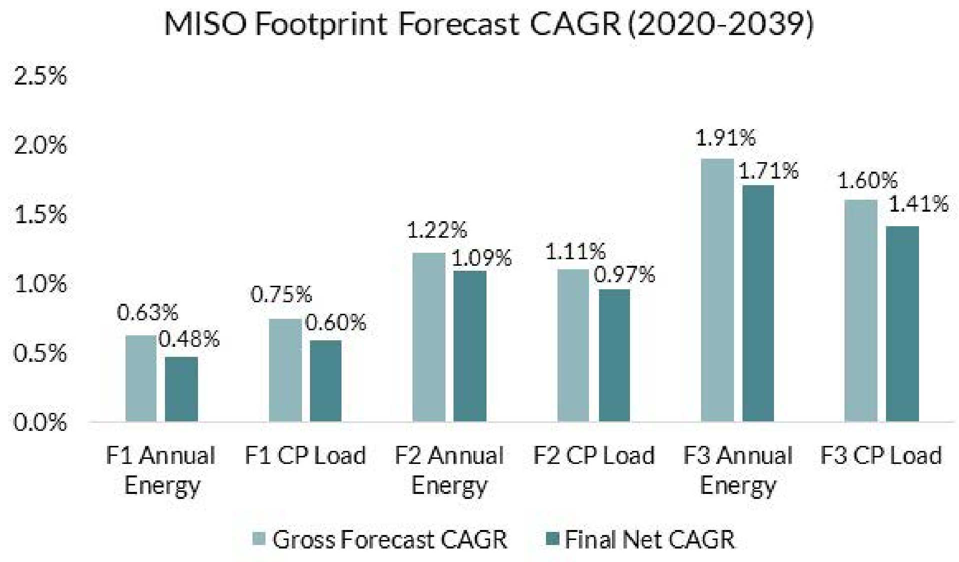


Figure 21: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

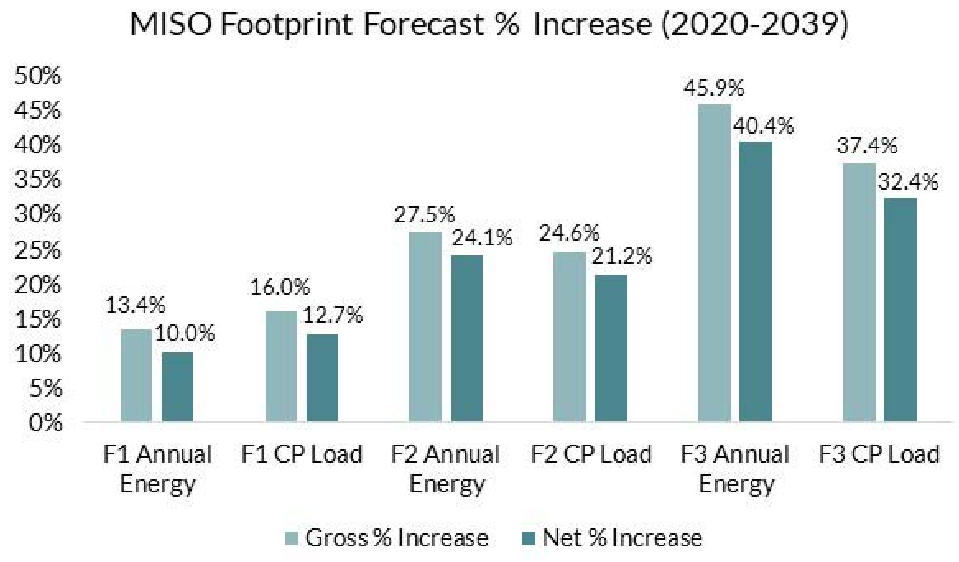


Figure 22: Final AEG Modified MISO Footprint Forecast % Increase[17]

[17] Gross values do not include load and energy modifiers determined by EGEAS analysis, while Net values include EE programs that were selected during modeling.

Forecast Evolution

To ensure the Futures update has effectively created broad and realistic bookends, especially with demand and energy assumptions as key drivers, MISO has compared the 2019 Merged Forecast (pre-application of EV and Electrification assumptions), MTEP21 Coincident Peak (CP) Future-specific forecasts (post-application of EV and Electrification assumptions), and MTEP19 Future forecasts.

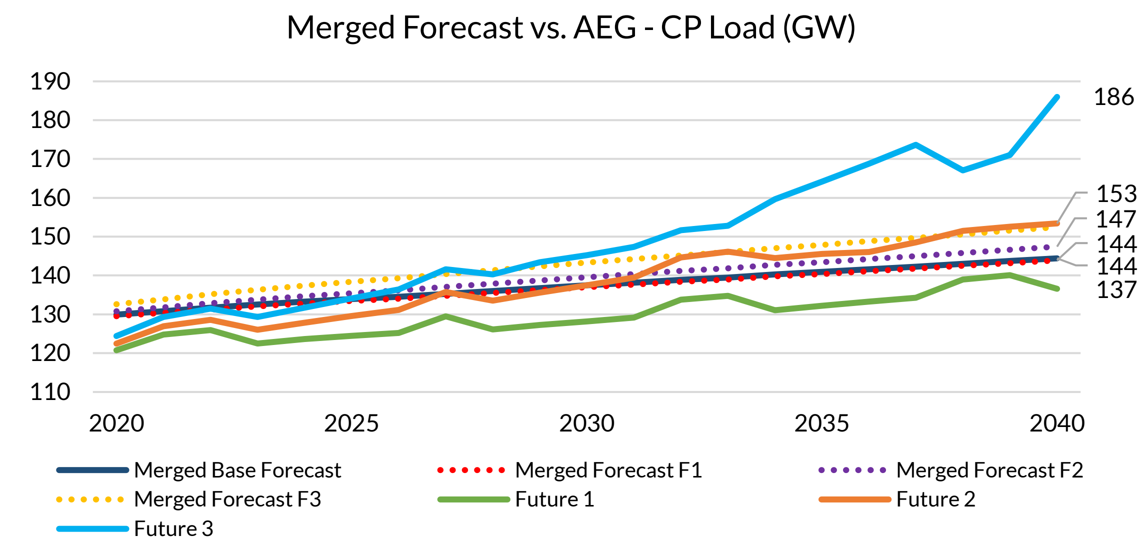


Figure 23: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW)[18,19]

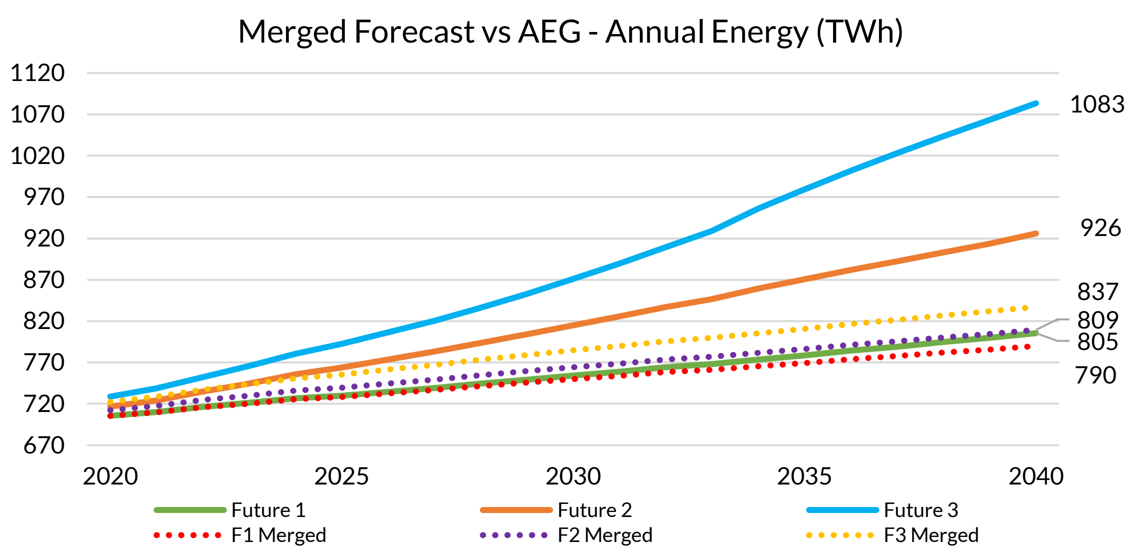


Figure 24: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[18] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[19] Merged Forecast CP Load (GW) values are calculated from monthly peak data while the AEG Peak Load (GW) values are calculated from hourly data. This has the illusory effect of the Merged Forecast CP Load (GW) being reduced.

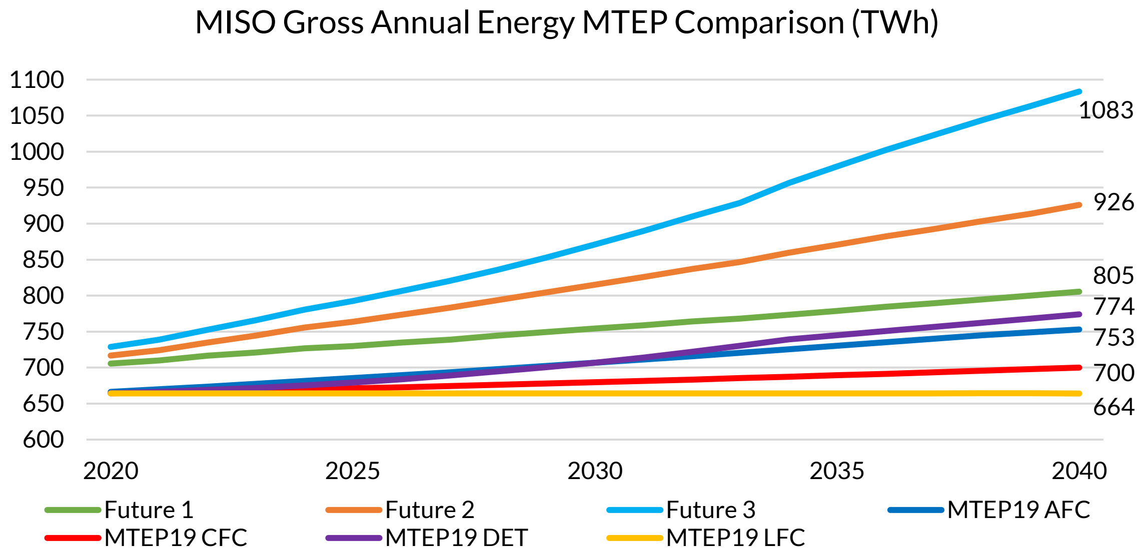


Figure 25: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare[20]

Final Load Shapes

Upon conclusion of the EGEAS analysis, MISO removed energy proportionate with selected energy efficiency programs in each Future scenario's load shape to produce final net load shapes. In Figure 27 through Figure 29, the evolution of each Future load shape is shown, starting with the initial 2020 load shape developed by SUFG,[21] the final input load shape for year 2039 from AEG that includes electrification assumptions, and then the 2039 load shape post modeling of each scenario that nets out EE programs selected. Figure 26 displays each Future scenario's post-modeling load shape in the final year of the study, for comparison.

[20] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[21] Purdue University's State Utility Forecasting Group

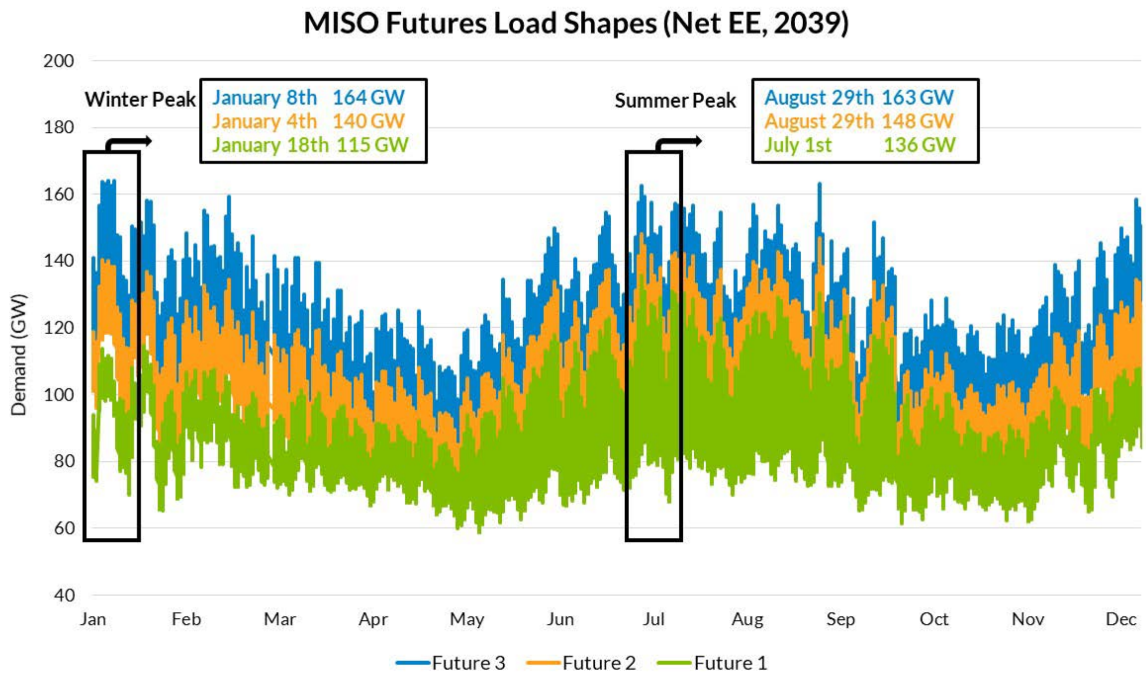


Figure 26: All Futures Final Load Shapes

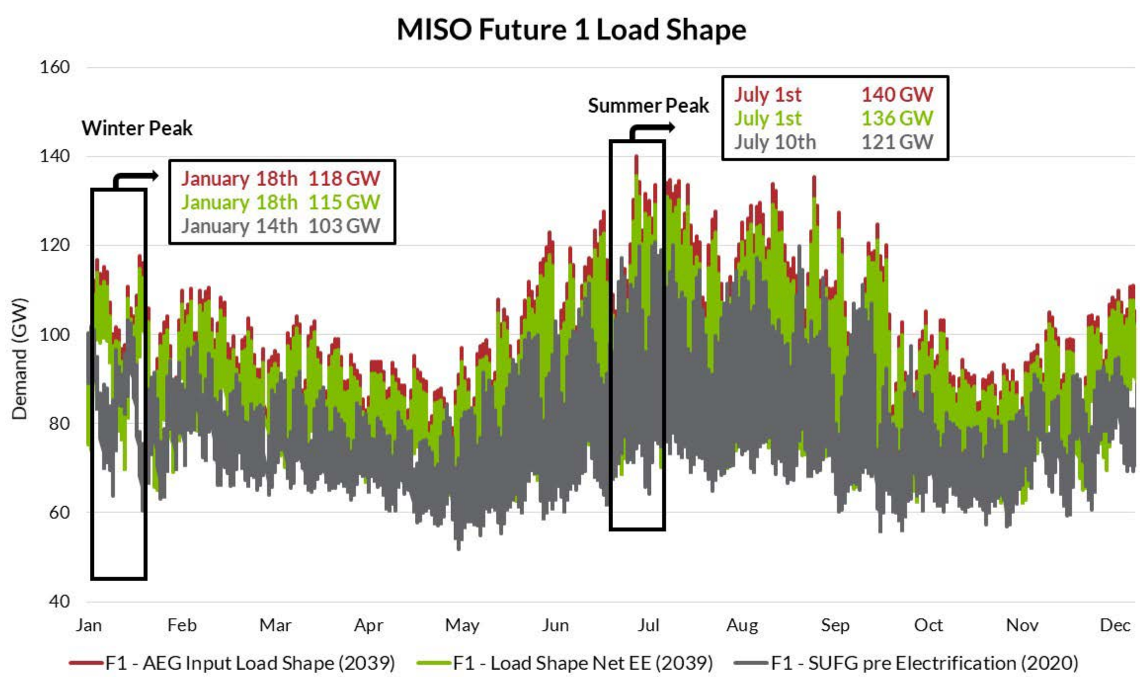


Figure 27: Future 1 Load Shape Evolution

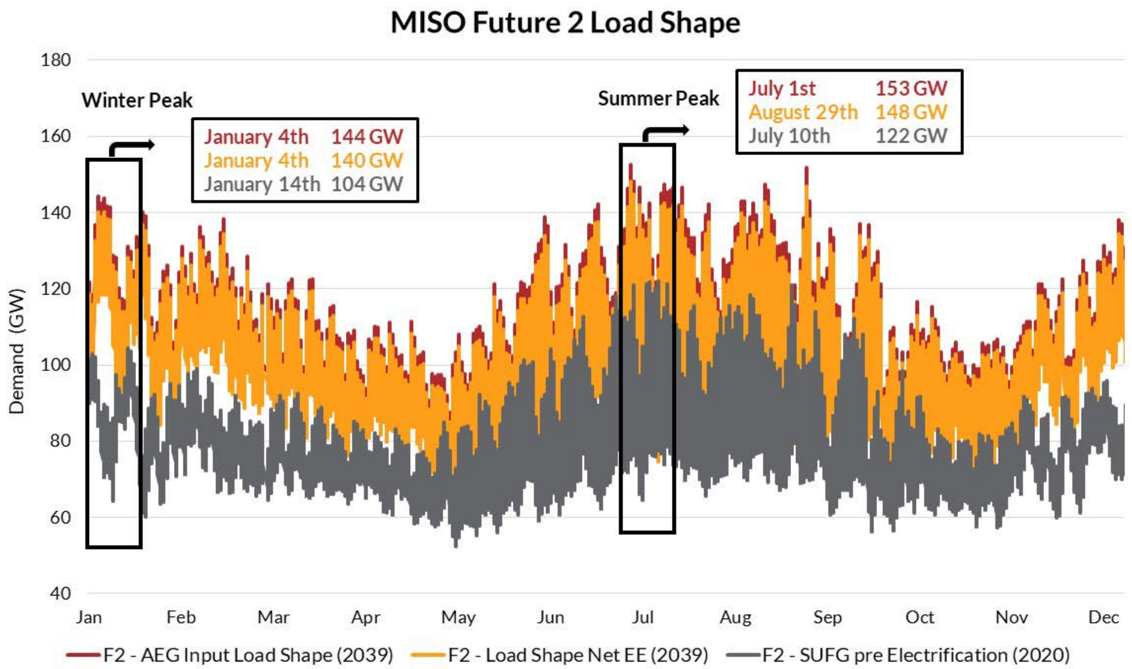


Figure 28: Future 2 Load Shape Evolution

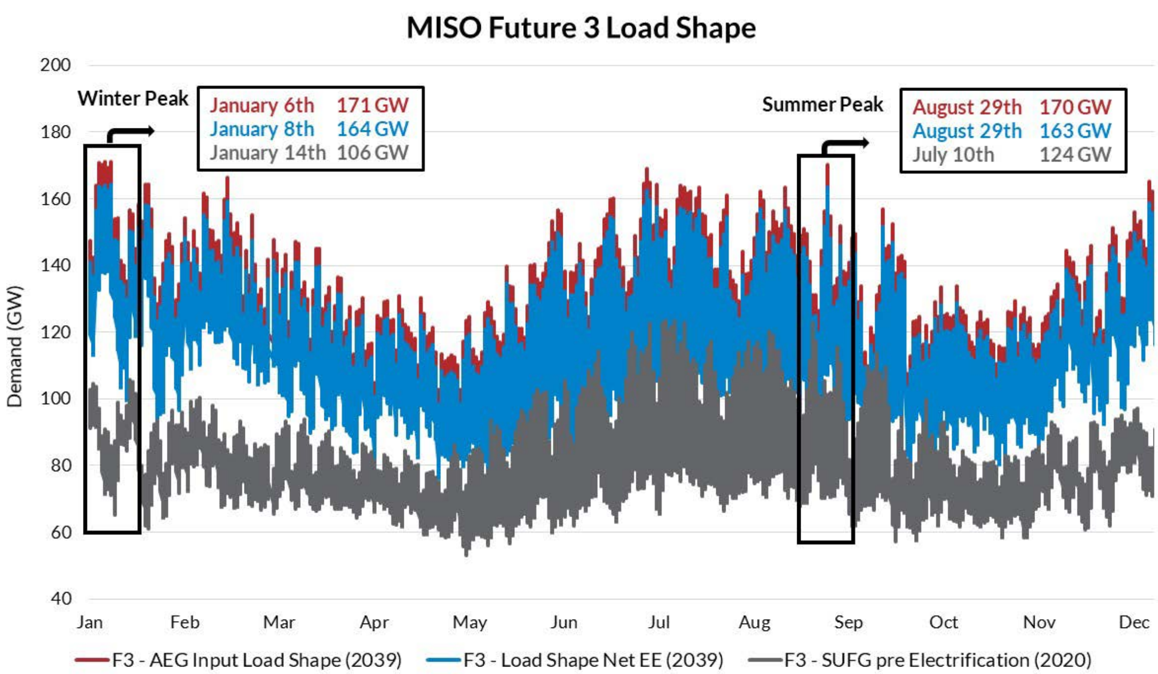


Figure 29: Future 3 Load Shape Evolution

Electrification

MISO contracted Applied Energy Group (AEG) to evaluate the MISO footprint on its potential to electrify. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). In this study, electrification is calculated as a percentage of technical potential that a given LRZ could achieve. The figure to the right shows the categories of electrification and what percentages of the technical potential they comprise. More details on the assumptions for the categories are included below.

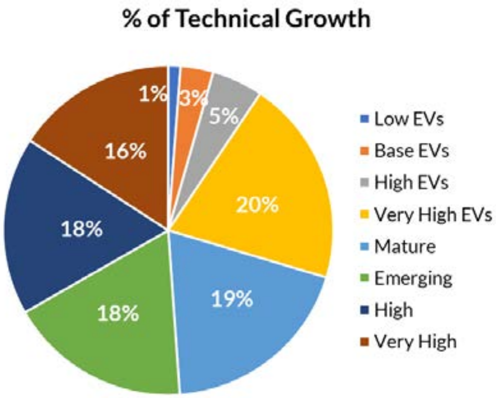


Figure 30: Electrification Categories

To estimate the available market for electrification, AEG started with the end-use load forecasting models developed for MTEP20 (previous set of MISO Futures), which include market data for each state in the MISO footprint. These market data included estimates of the penetration of many types of electric equipment. To estimate the total technical electrifiable load, AEG assumed that 90% of a particular end-use customer load was capable of being electrified, and then subtracted the electric equipment saturations (the load that is already electrified) from that value.

Electrification Categories

AEG identified each electrifiable technology and considered how likely or feasible it would be to be adopted before assigning it to one of four categories: mature technologies, emerging, high, and very high.[22] AEG considered how widespread the technology currently is, whether there are utility EE programs, and whether or not there are known market barriers. Since both mature and emerging versions of known technologies (e.g., traditional air-source heat pumps vs. cold-climate heat pumps) can coexist, AEG distributed the electrification potential for different technologies over more than one category. These are represented by the percentages below.

Additionally, AEG considered the certainty around each assumption. For example, industrial process loads are very customizable and would require a "bottom-up" approach to implementation, considering each industry and state individually. To capture this uncertainty, electrification of industrial process loads was assigned to higher electrification levels.

Each category is described below however, additional insights into the details of these categories may be found in MISO's Electrification Insights Report.

Mature Technologies

The "Mature Technologies" electrification category includes technologies that are widely available on the market today and are the most likely to electrify in the future. One example is an air-source heat pump, which is already found in many homes throughout the United States. Electric cooking equipment, such as induction ovens, is another example of an existing technology that is popular and relatively straightforward to install. Technologies in this category include:

- Air-Source Heat Pumps (50% of single-family [SF], 50% of multi-family [MF], 50% of Commercial and Industrial [C&I])
- Geothermal Heat Pumps (50% of SF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF)
- Clothes Dryers

[22] AEG's 2019 Presentation on Electrification

- Dishwashers
- Stoves

To better understand how much of these technologies are being electrified in each category, it is best to give an example. For air-source heat pumps, this section is saying that 50% of single-family, multi-family, and commercial and industrial heat pumps that can electrify will be electrified in this category.

Emerging Technologies

The "Emerging Technologies" category represents electrification load that is beginning to become available or is more mature but limited by known market barriers. For example, while air-source heat pumps are a mature technology, they may not be easily installable without reconfiguring the ductwork. Gas forced-air furnaces provide hotter air and require smaller ducts, requiring an invasive modification to expand the ductwork to keep a home warm in the winter. Process loads also begin to appear in this category. Technologies in this category include:

- Air-Source Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Geothermal Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF, 50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

High Electrification Scenario Technologies

This category represents the point where substantial market barriers exist or where technologies are new or still in development. An example is a large-scale air-source heat pump that would be necessary to replace a large gas boiler heating a hospital. These are not readily available—gas is the most common fuel source in large-scale applications. However, if high levels of electrification are to be achieved, electrification using these new and in-development technologies would need to take place. Technologies in this category include:

- Air-Source Heat Pump (50% of C&I)
- Geothermal Heat Pump (50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

Very High Electrification Scenario Technologies

This category represents the highest levels of uncertainty in the analysis and is only applied in the highest-growth cases. As noted above, much of the industrial process electrification is present in this category. The only technology in this category is noted below:

- Industrial Process (50% of C&I)

Technologies Electrified

HVAC Heat Pumps - Air-source and geothermal heat pumps

- Lower-growth scenarios electrify many residential homes and some businesses, where this technology is already available (rooftop units and residential systems)
- Higher-growth scenarios assume large-scale replacements are available for technologies like gas boilers

Heat Pump Water Heaters - Efficient water heaters with a vapor-compression refrigeration cycle

- Lower-growth scenarios electrify tanks in both the residential and commercial sectors
- Higher-growth scenarios include the electrification of large-scale gas water heaters

Residential Appliances - Clothes dryers, dishwashers, and stoves

- Dishwasher electrification occurs when no existing dishwasher is present

Industrial Process - High growth potential, but only certain processes can be electrified

- Due to the complexity involved in electrifying industrial processes, AEG assumed that most of this occurs in the higher-growth scenarios
- Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling
- Electric boiler, industrial heat pump, resistance heating industrial heat pump, induction furnace, etc.

LBNL PEV Forecasts[23] - All four forecasts were used in development of these scenarios

- These include combinations of uncontrolled and V2G versions of the: Low, Base, High, and Very High scenarios
- Merged PEV forecasts were selected for each growth scenario – adoption curves and load shapes specific to the selected forecast were used

Figure 32 through Figure 37 display the results of these electrification assumptions across each Future scenario in the MISO footprint. The charts present a detailed view of the results showing yearly cumulative increases in energy from electrification for the footprint, electrification totals for each Local Resource Zone for the entire study, and the proportion of electrification from each technology. Similar charts for external region electrification results are found in the Appendix, Figure 80 through Figure 87.

[23] Lawrence Berkeley National Lab EV Forecast Report

Electrification Potential Across MISO Footprint

This analysis was conducted at the state level in the MISO footprint then aggregated by LRZ. AEG's end-use forecasting and Demand-Side Management (DSM) potential model was used to conduct this analysis, providing estimates of electric equipment penetrations as well as consumption for MISO's fraction of each state. Since local weather and equipment penetration data were used in this analysis, each state will have different end-use consumption patterns and a different electrifiable load, as shown in Figure 31. These are high-level findings based on the end-use models and a result of the differences noted above. The three main drivers of technical potential for electrification are:

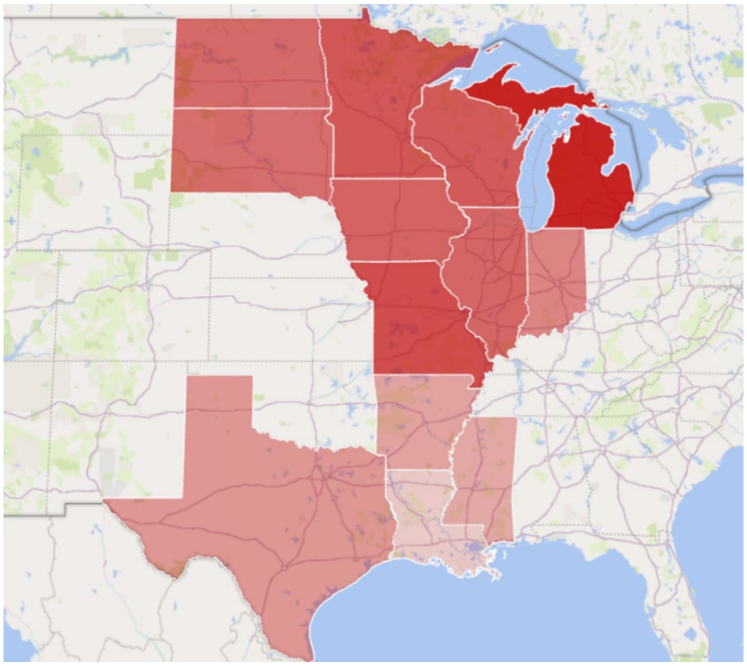


Figure 31: Electrification Potential by State

- **Latitude:** The northern states in the MISO footprint are generally colder than the southern states, resulting in larger space-heating loads. Since the heating end-uses represent some of the largest electrification potential, additional new loads are expected in the northern MISO states.
- **Gas Infrastructure:** Along with latitude, existing gas infrastructure heavily influences the electrifiable load. AEG utilized the state-level market data listed above to estimate gas equipment penetrations by state. If the load in a state is already mostly electric, there would be fewer non-electric units to convert, lowering potential.
- **Cooling Presence:** The final notable factor is the presence of existing cooling equipment. Similar to the gas infrastructure note above, high penetrations of existing cooling equipment limit electrification potential since the remaining non-electric market is smaller. In the warmer southern states, many homes already have cooling equipment installed, so their potential is lower.

Future 1 Electrification

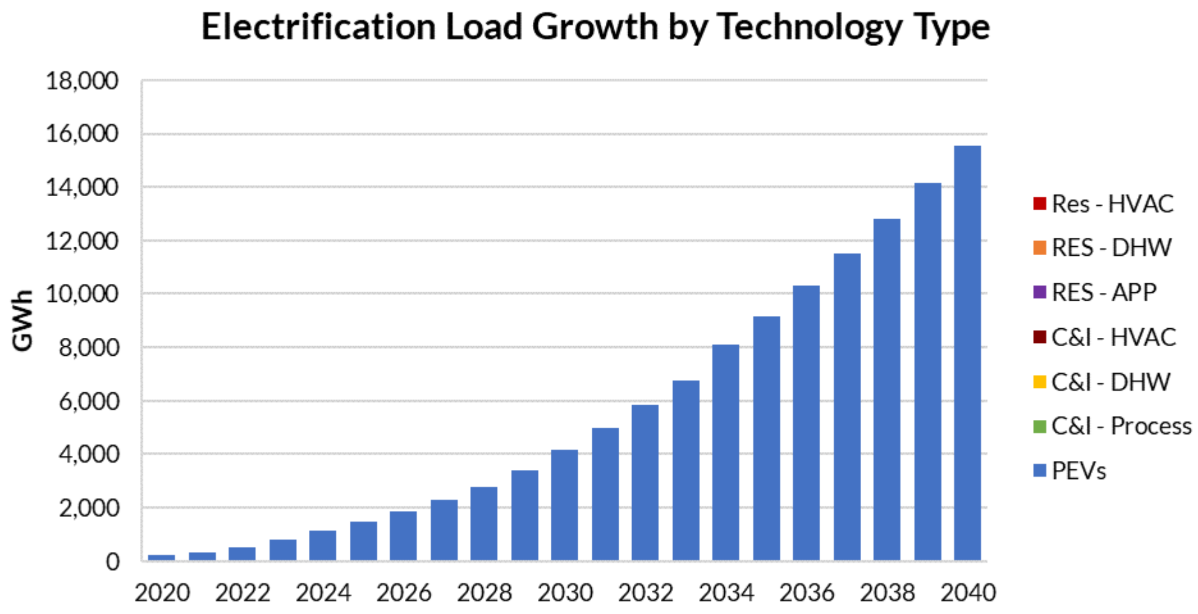


Figure 32: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

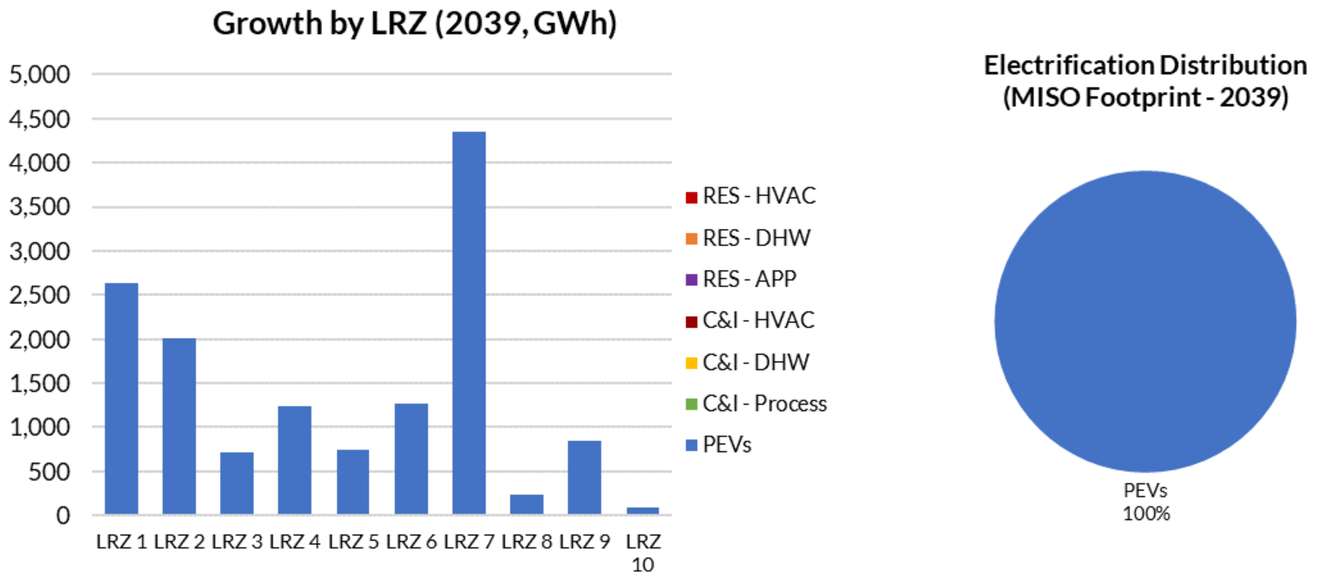


Figure 33: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

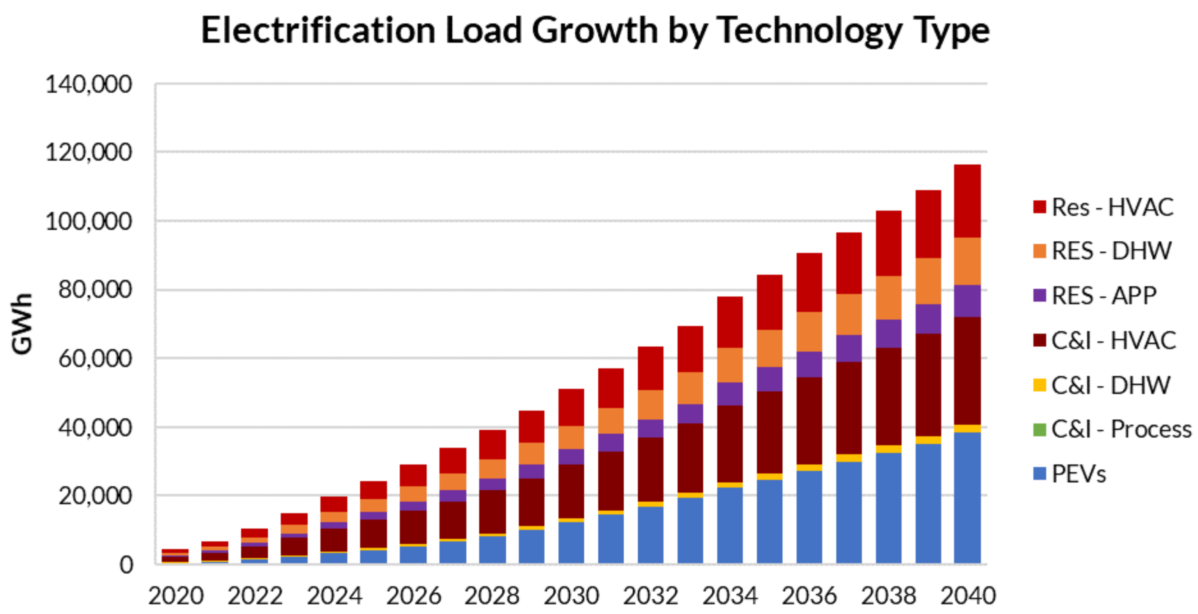
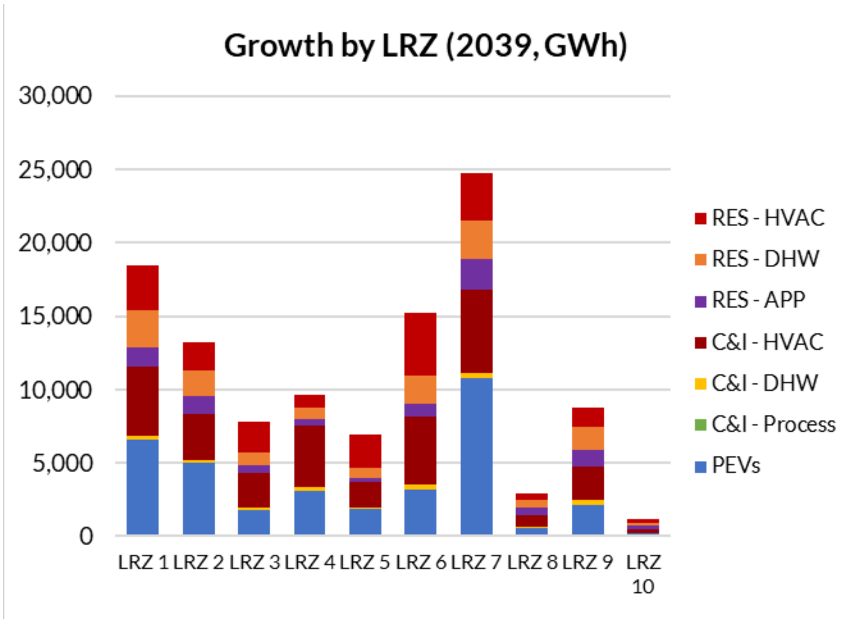


Figure 34: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



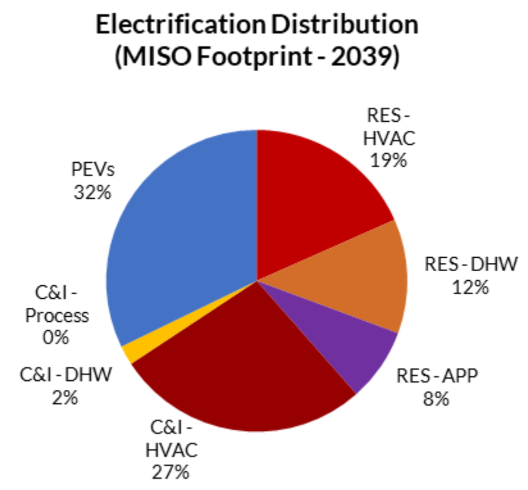


Figure 35: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

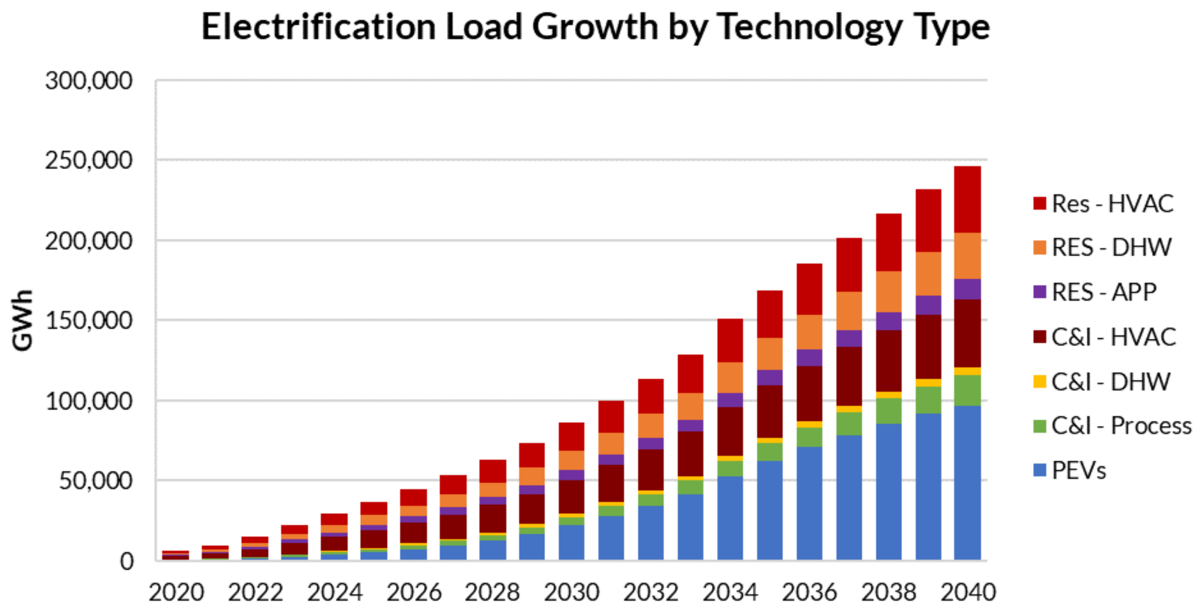


Figure 36: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

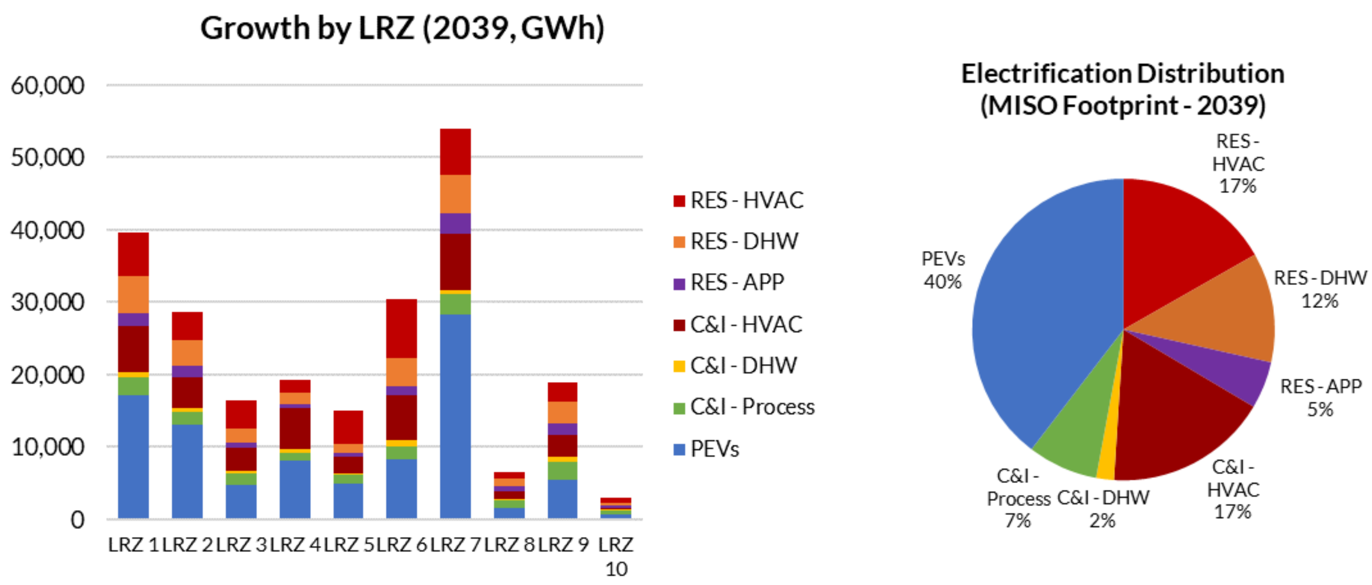
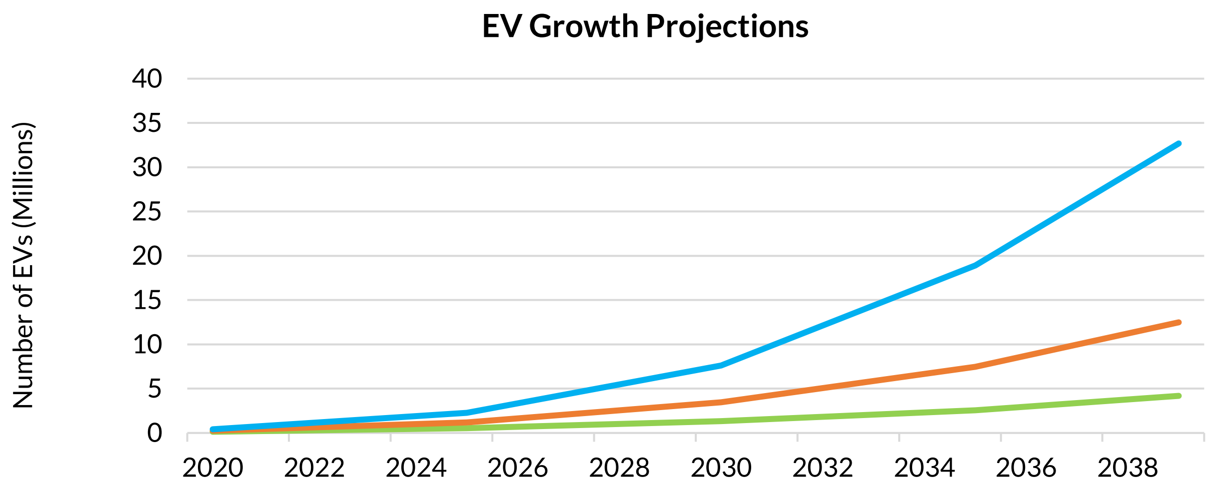


Figure 37: Future 3 Electrification Broken Down by End-Use

Electric Vehicle Forecasts

MISO collaborated with Lawrence Berkeley National Laboratory (LBNL) on a study to determine the potential for EVs within the MISO footprint. This study categorized the projected growth of EVs in into four scenarios: low, base, high, and very high. Each of the three Futures used merged forecasted EV growth scenarios to include different amounts of light-duty EVs. All Futures explored a variety of EV growth and charging scenarios within every LRZ across the 20-year study period.

Future 1 evaluated only uncontrolled charging methods, Future 2 included vehicle-to-grid (V2G) charging after 2035, and Future 3 incorporated V2G charging after 2030. Figure 38 through Figure 41 detail the number of EVs in each scenario, MISO footprint and LRZ.



	2020	2025	2030	2035	2039
Future 1	0.135	0.53	1.33	2.57	4.19
Future 2	0.26	1.205	3.47	7.455	12.49
Future 3	0.416	2.272	7.598	18.91	32.686

Figure 38: EV Growth per Future (MISO footprint)

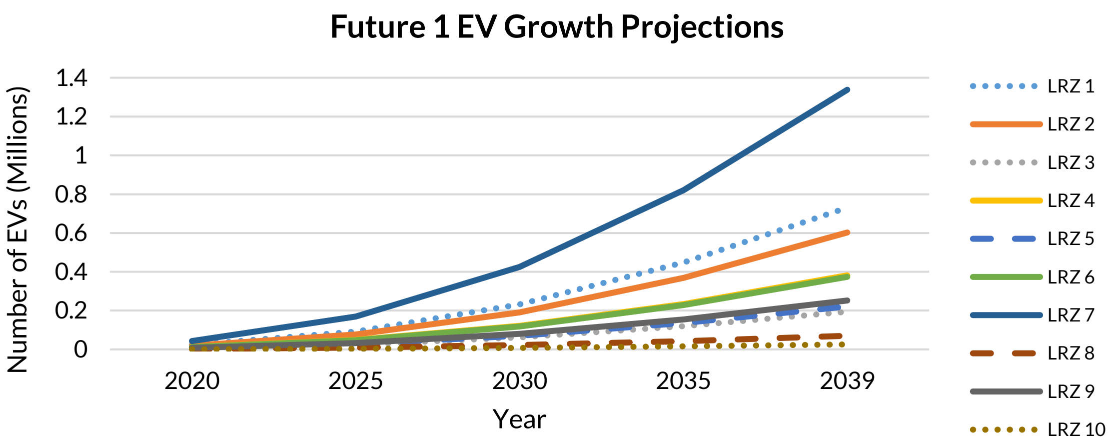


Figure 39: Future 1 EV Growth per LRZ

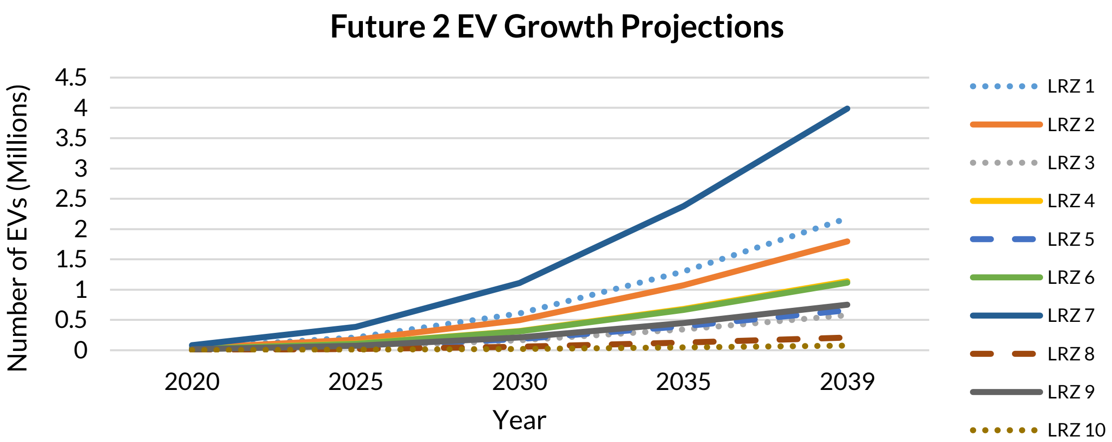


Figure 40: Future 2 EV Growth per LRZ

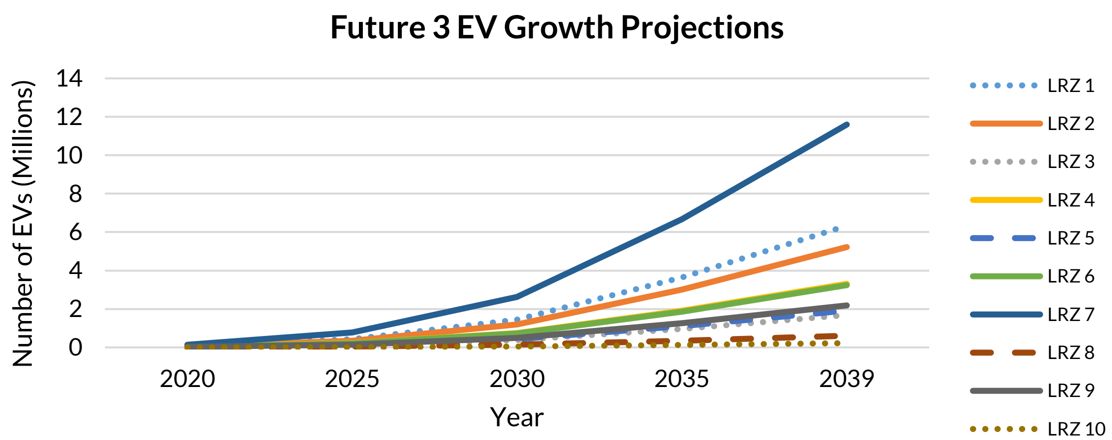


Figure 41: Future 3 EV Growth per LRZ

New Resource Additions

Regional Resource Forecast Units (RRF Units) are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO Futures are discussed in further detail below.

Wind

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. New RRF units were built at 100m hub height throughout the study period. Existing units used representative 80m hub height hourly profile and all wind units assumed 16.6% capacity credit.

Solar

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. Existing units used a representative hourly profile and all solar units assumed 50% capacity credit at the beginning of the study period and decreased by 2% starting in year 2026, until the capacity factor reached a minimum of 30%.

Hybrid: Utility-Scale Solar PV + Storage

Hybrid solar profiles were created by modifying VCE 2018 hourly profiles for solar units. Hybrid units were modeled as a 1200 MW inverter attached to 1500 MW of solar panels, resulting in an over-panel of 25%. When solar output exceeded the inverter capacity, the battery charged. Once solar output reached 20% or lower of the max capacity (max capacity is 1500 MW making 20%, 300 MW), the battery discharged until empty. Hybrid units assumed a 60% capacity factor.

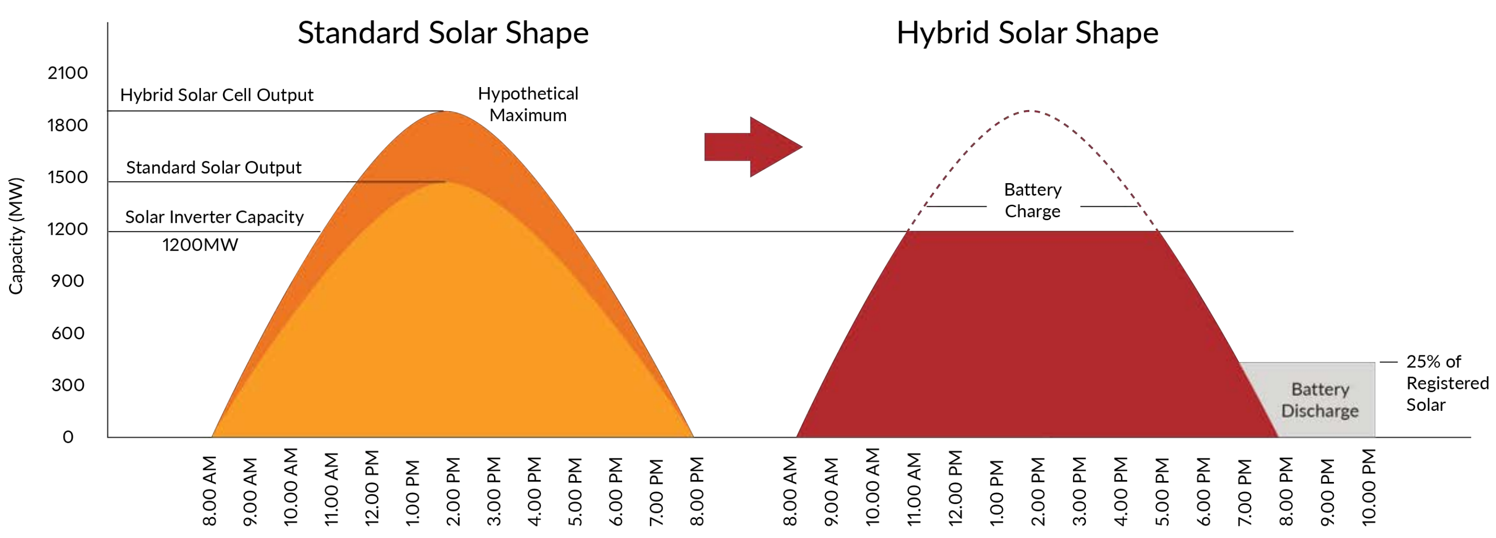


Figure 42: Solar + Storage Hybrid Profile

Storage: Lithium-Ion Battery (4-hour)

Batteries modeled in the capacity expansion were 4-hour duration lithium-ion batteries. Units were sited with a minimum capacity of 5 MW and a maximum capacity of 500 MW across all Future scenarios.

Distributed Energy Resources (DERs)

As in previous Futures cycles, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for EGEAS.

Previously referred to as demand-side additions or management (DSM), these resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). Programs also fall into two sectors: Residential and Commercial and Industrial (C&I).

During the program selection phase for the models, each block was offered against supply-side alternatives to determine economic viability. For all three Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Future 3 selected Residential Low-Cost Energy Efficiency. "Customer PV" indicates market-driven, naturally occurring solar panel adoption, whereas "Utility Incentive PV" indicates a utility incentive program for solar PV. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of detailed AEG programs mapped to EGEAS program blocks is below in Table 5.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder additions were implemented in the Futures models. Table 3 and Table 4 show total DER technical potential and additions modeled in MISO by the end of the study period.

MTEP21 DERs Capacity (GW) Technical Potential & Added	**Future 1**		**Future 2**		**Future 3**	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table 3: DER Capacity (GW): 20-Year Technical Potential & Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	**Future 1**		**Future 2**		**Future 3**	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Table 4: DER Energy (GWh): 20-Year Technical Potential & Additions in MISO

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

* Program was selected as economically viable and utilized by EGEAS in the resource expansion.

Natural Gas Resources

Combined Cycle (CC) and Combustion Turbine (CT) were the two gas resource types modeled. Site priority levels for these units remained the same when selecting a site. However, CC units were given a higher priority over CT units.

CC + Carbon Capture Sequestration

Futures analysis modeled Combined Cycle plus Carbon Capture and Sequestration (noted as CC+CCS in report documentation) due to the need for a low-carbon resource with a high-capacity factor. This was found to be the case when modeling the high carbon reduction in Future 3 (80%) after 2035 and in 2039 of Future 2 (60%). While there are no large-scale CC+CCS plants in operation today, there are several states and utilities testing this resource.

In modified Futures studies to come, MISO will continue to investigate other forms of energy that could include small modular reactors (SMRs) and green hydrogen, for example. Recent announcements show that members are looking into SMRs and hydrogen resources for electricity production.[24,25,26] Due to such recent developments and MISO's role to remain resource-agnostic, MISO used CC+CCS units in modeling to serve as a proxy for a high-capacity factor, low-carbon-emitting resource.

New Resource Addition Siting Process

RRF unit siting processes were developed to help identify where future generation would likely be located. While different RRF unit types need their own siting processes, there are universal criteria that apply to each resource type's unique siting process. These universal siting criteria and resource-specific processes are discussed below.[27]

Universal Siting Criteria

To help improve siting measures, the following criteria underlie all resource-specific siting processes.

1. The same sites were used for each Future and site differences only occurred due to Future-specific renewable capacity needs. This included only using sites that were found in both the Year 5 and Year 10 MTEP Powerflow models.
2. Radial lines and associated buses were identified in the MTEP Powerflow models and excluded from potential resource sites.
3. Sited capacity could not exceed a site's N-1 capacity amount. This means the summation of all the transmission elements, excluding the highest rated capacity element, could not have a lower capacity than the resource capacity.
4. Units were only sited on MISO-owned transmission elements.

Wind and Solar PV

Resources of this type were modeled as a collector system, representing an aggregated capacity potential that can be installed within 10-30 miles of each site. These collector sites were identified by two methods:

1. Compilation of Generation Interconnection (GI) queue projects:
   - 80% of Future-determined capacity was distributed to GI sites.
   - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher) and grouped by project state location, creating a capacity by state penetration percentage.
   - GI projects within 10 miles of each other were identified and combined into a collector system.
   - The capacity by state penetration percentage was applied to the 80% capacity expansion results, creating a state-up siting processes driven by GI Queue activity.
2. Vibrant Clean Energy[28] (VCE) results:
   - VCE sites receive the remaining 20% of Future-determined capacity.
   - Collector buses represent a 20- to 30-mile aggregated capacity potential.

[24] Mitsubishi Power and Entergy Collaboration

[25] Xcel Energy and INL

[26] Xcel Energy

[27] All capacities referenced on this page are (MW).

[28] VCE Report

Utility-Scale Solar PV + Storage (Hybrid)

Hybrid units were sited the same as Solar PV units and utilized the GI Queue only. Due to low GI queue activity for hybrid units not all Hybrid capacity (MW) was able to be distributed. As a result, the remaining balance was sited at unutilized Solar PV GI sites for the respective Future.

Distributed Solar PV Generation (DGPV)

Distributed solar PV resources (DGPV) siting methodology utilized the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand Model (dGen) and consisted of the following:

- Using dGen, identify top 25 counties by DGPV potential within each LRZ.
- Identify (up to) top 20 load buses for each county.
- Distribute county capacity using dGen results weighting.
- Use top 20 load buses' Load Ratio Share (LRS) to distribute dGen-weighted capacity to each bus.

Lithium-Ion Battery (4-hour)

Batteries were restricted to a minimum capacity of 5 MW and capped at a maximum capacity of 500 MW (PROMOD performance reasons) and sited in a way to create geographical distribution for each LBA. The geographical distribution process follows:

- Each LBA's LRS was determined using Future-specific forecast data; LRS was then used to determine each LBA's Battery Capacity (MW) allocation.
- Top load buses for each LBA were identified, and the nearest, highest N-1 capacity bus greater than 100kV was selected to site the capacity.
- If an LBA needed more than one battery site, the next bus selected would be at least 10-20 miles away from the previously used bus to maintain geographical distribution.

Combined Cycle and Combustion Turbine

Combined Cycle and Combustion Turbine siting largely remained the same as in past MTEP cycles with site rankings as follows:

- Combined Cycle units got higher priority sites over Combustion Turbine
- Priority 1: Active Definitive Planning Phase (DPP) Phase 1, 2, 3 Generator Interconnection Queue
- Priority 2: Brownfield – Existing and Retired Sites
    - Retired sites ranked by earliest commission date
    - Retired sites had to be 50 MW and greater
- Priority 3.1: SPA or Canceled/Postponed GI Queue
- Priority 3.2: Greenfield Siting Criteria

CC + Carbon Capture Sequestration

Combined Cycle plus Carbon Capture Sequestration (CC+CCS) sites were limited to sites suitable to this technology type. Desirable basins for these resources were determined using the results of the U.S. Geological Survey's (USGS) National Geologic CO_2 Storage Assessment. Potential sites were screened to ensure that their geographic location fell within the boundary of a geologic storage resource. Sedimentary basin locations were overlayed onto Priority Sites for Combined Cycle and Combustion Turbine. Priority sites were then ranked by suitability and reserved for CC+CCS resources.

MISO Expansion Results

While comparing the expansion results of the MISO footprint across each Future scenario, there are several key findings of note:

- All scenarios have relatively large amounts of gas additions; this is due to increasing amounts of coal and gas retirements and the system's need for base generation to replace retired units. CC and CT gas units emit approximately half the amount of CO_2 that coal units emit. Decarbonization and load growth allow for gas to comprise 40% of the total expansion in Future 1, while CC+CCS comprises 40% of the gas units built in Future 3's expansion, illustrating the model's need for a low-carbon, high-capacity factor proxy resource.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load, 80% carbon reduction, and dual peaking system.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across all scenarios. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- Distributed solar and energy efficiency (EE) resources are composed of both selected DER programs and specific member feedback. No demand response (DR) resources were selected in the model, but are present in the expansion due to member feedback.

Future Resource Additions (MW)												
	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	Hydro	EE	DR	Totals
Future 1	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	7,824	939	129,540
Future 2	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	8,053	939	179,368
Future 3	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	11,722	939	318,530

Future Resource Retirements (MW)								
	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
Future 1	44,827	18,627	2,359	1,996	9,223	21	36	77,089
Future 2	45,109	21,611	2,359	2,027	9,223	21	36	80,386
Future 3	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 6: MISO Resource Additions and Retirement Totals

Figure 43 details the results from each Future scenario's resource additions as displayed in the table above. Solar resources are comprised of utility-scale solar PV, solar hybrid, and distributed solar resources. Wind totals include expansion wind units and repowered wind assumptions. The other resource categorey includes energy efficiency and demand side management programs selected within each future. Gas resources include both CC and CT units for Futures 1, while Future 2 and 3 additionally include CC+CCS expansion units. In Future 3, the CC+CCS resource proxy units (42 GW) are needed in the later years of the study period to serve base load with low CO_2 emissions.

Over the course of the following pages (Figure 44 through Table 12) the detailed expansion results of each Future scenario and the siting locations are displayed. Following the figures in each section are resource-specific additons and retirement (R&A) tables; each table details R&A capacities applicable for each LRZ and MISO per milestone year.

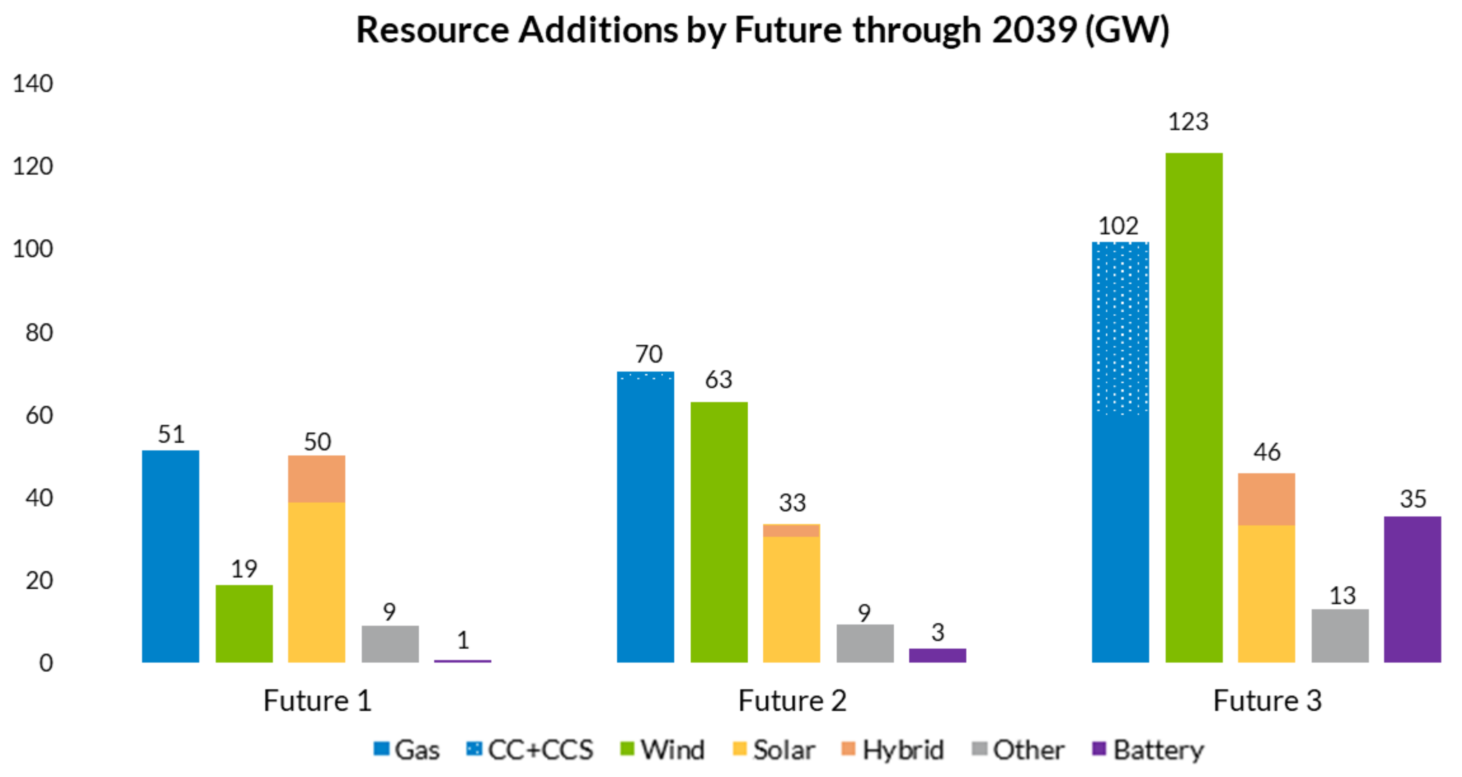


Figure 43: MISO Resource Addition Summary by Future

MISO – Future 1

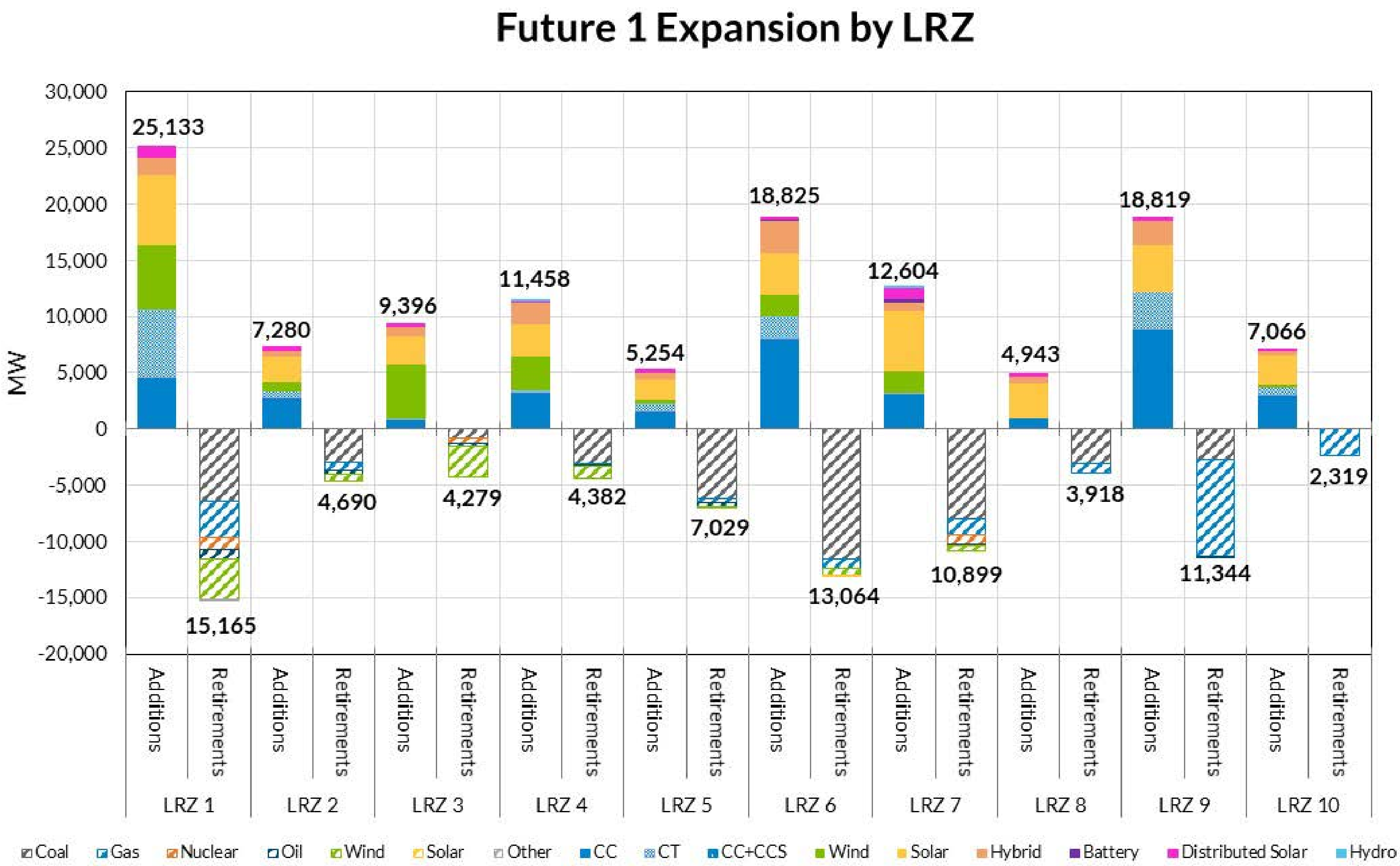


Figure 44: MISO Future 1 Resource Retirement and Addition Summary

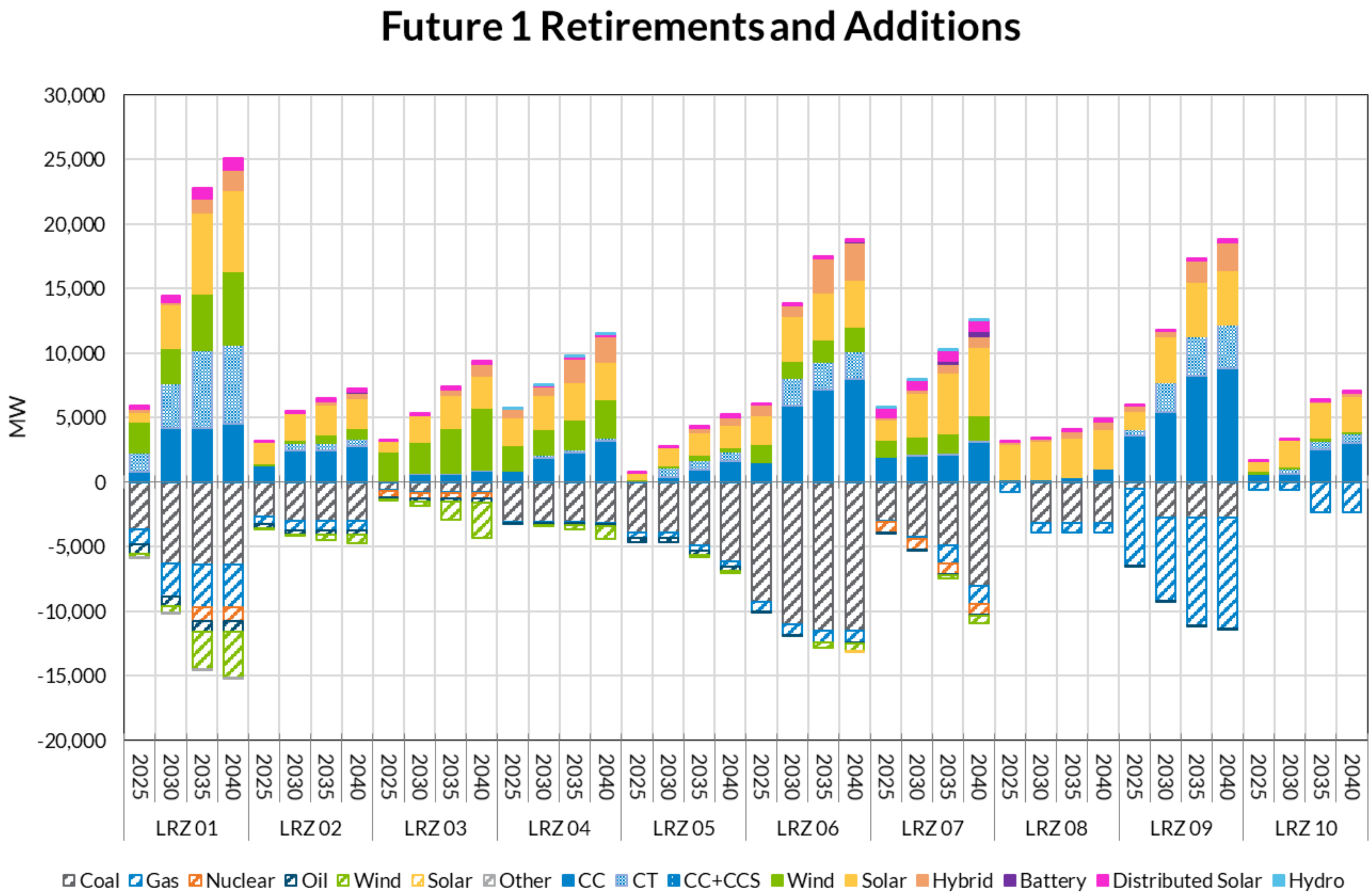


Figure 45: Future 1 Resource Additions per Milestone Year (Cumulative)

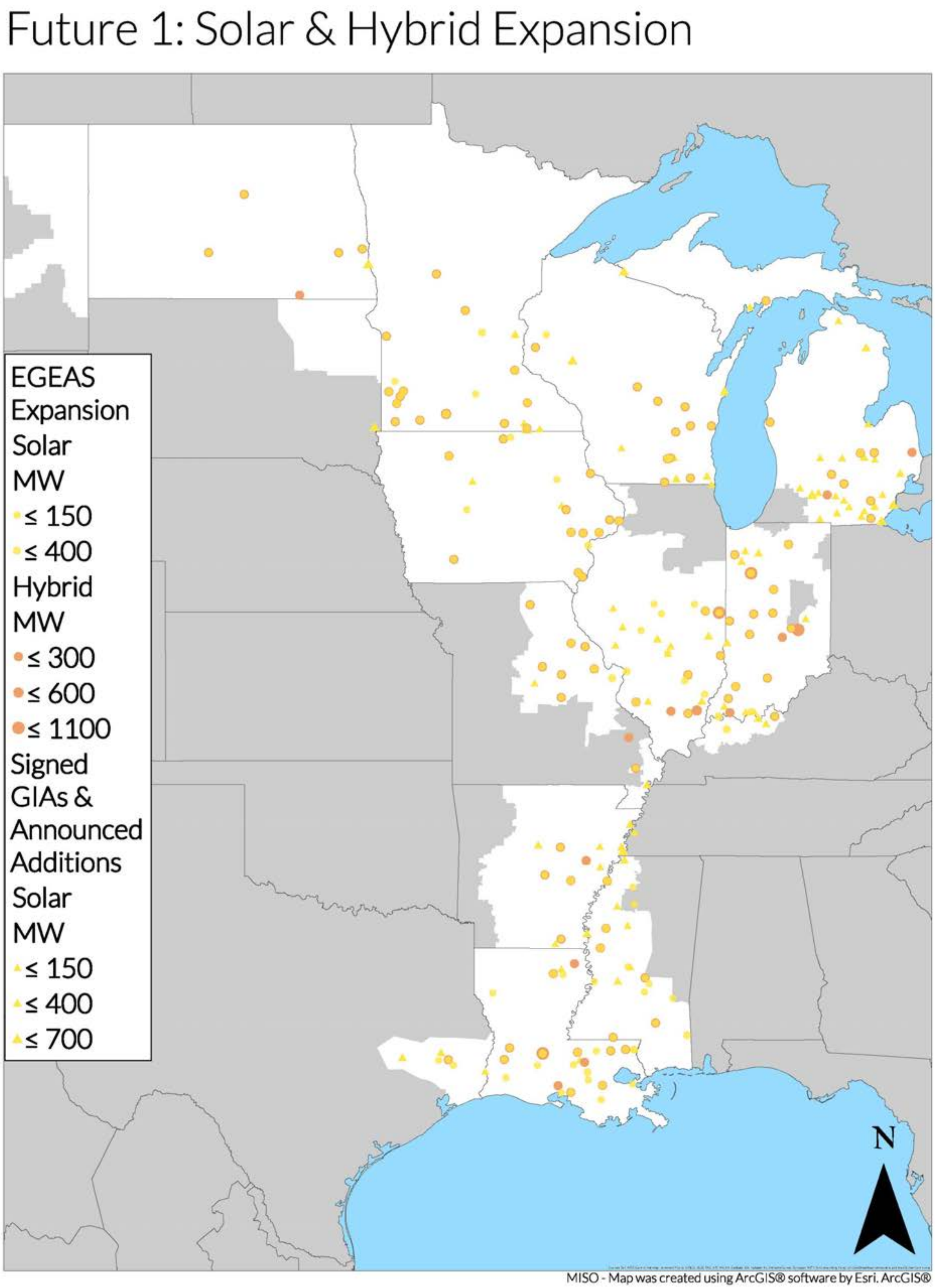


Figure 46: MISO Future 1 Solar and Hybrid Siting

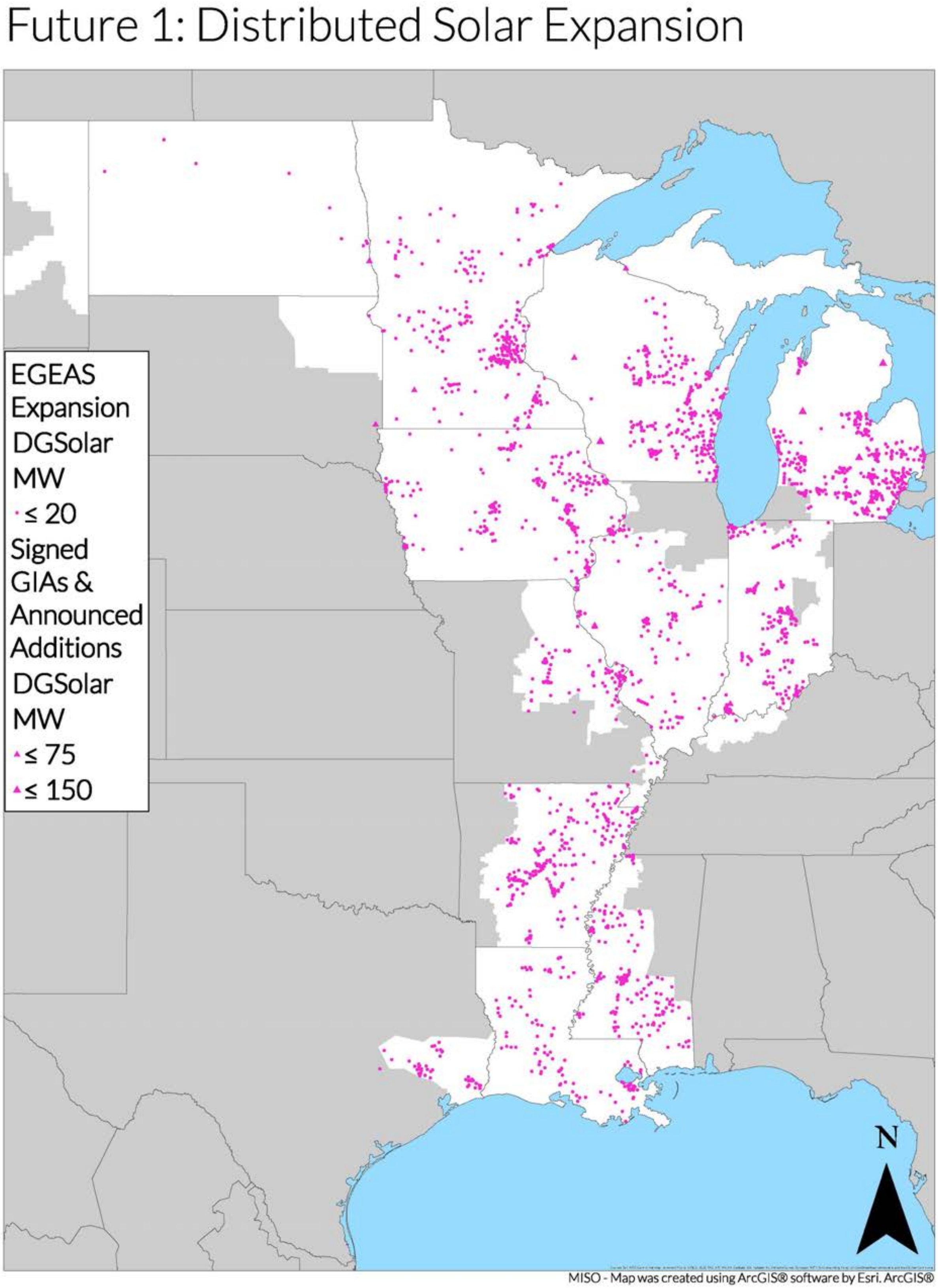


Figure 47: MISO Future 1 Distributed Solar Siting

Future 1: Wind Expansion

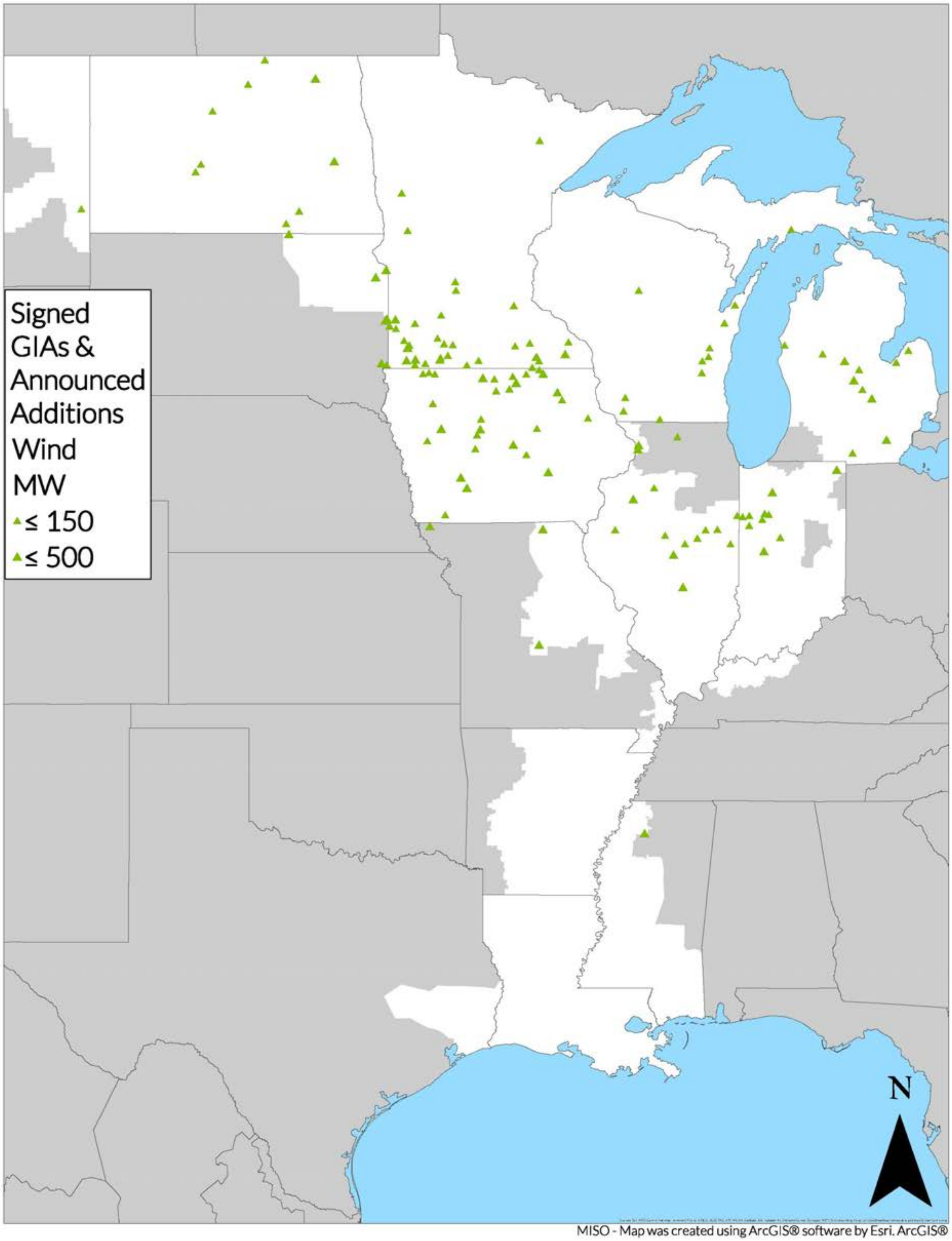


Figure 48: MISO Future 1 Wind Siting

Future 1: Battery Expansion

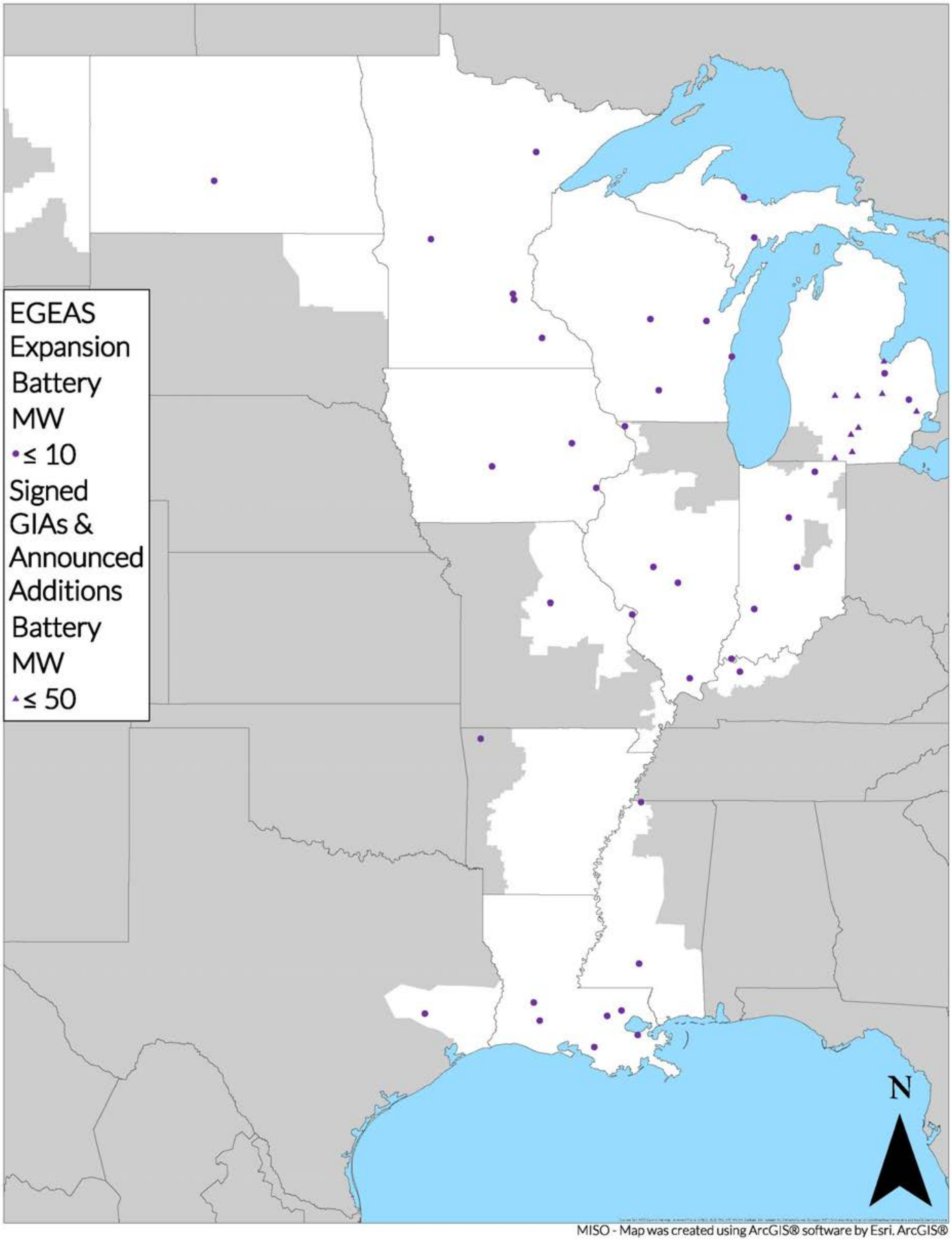


Figure 49: MISO Future 1 Battery Siting

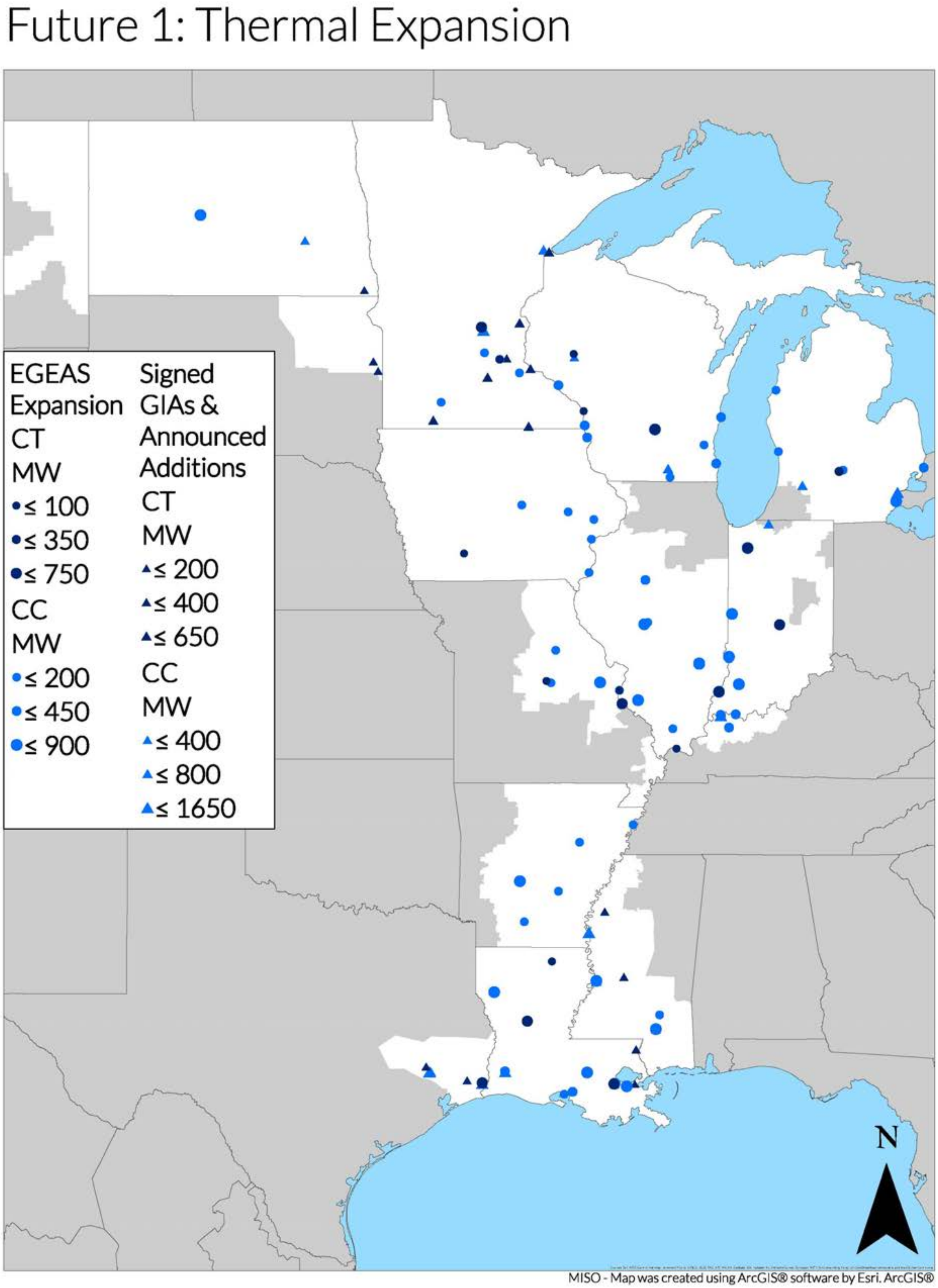


Figure 50: MISO Future 1 Thermal Siting

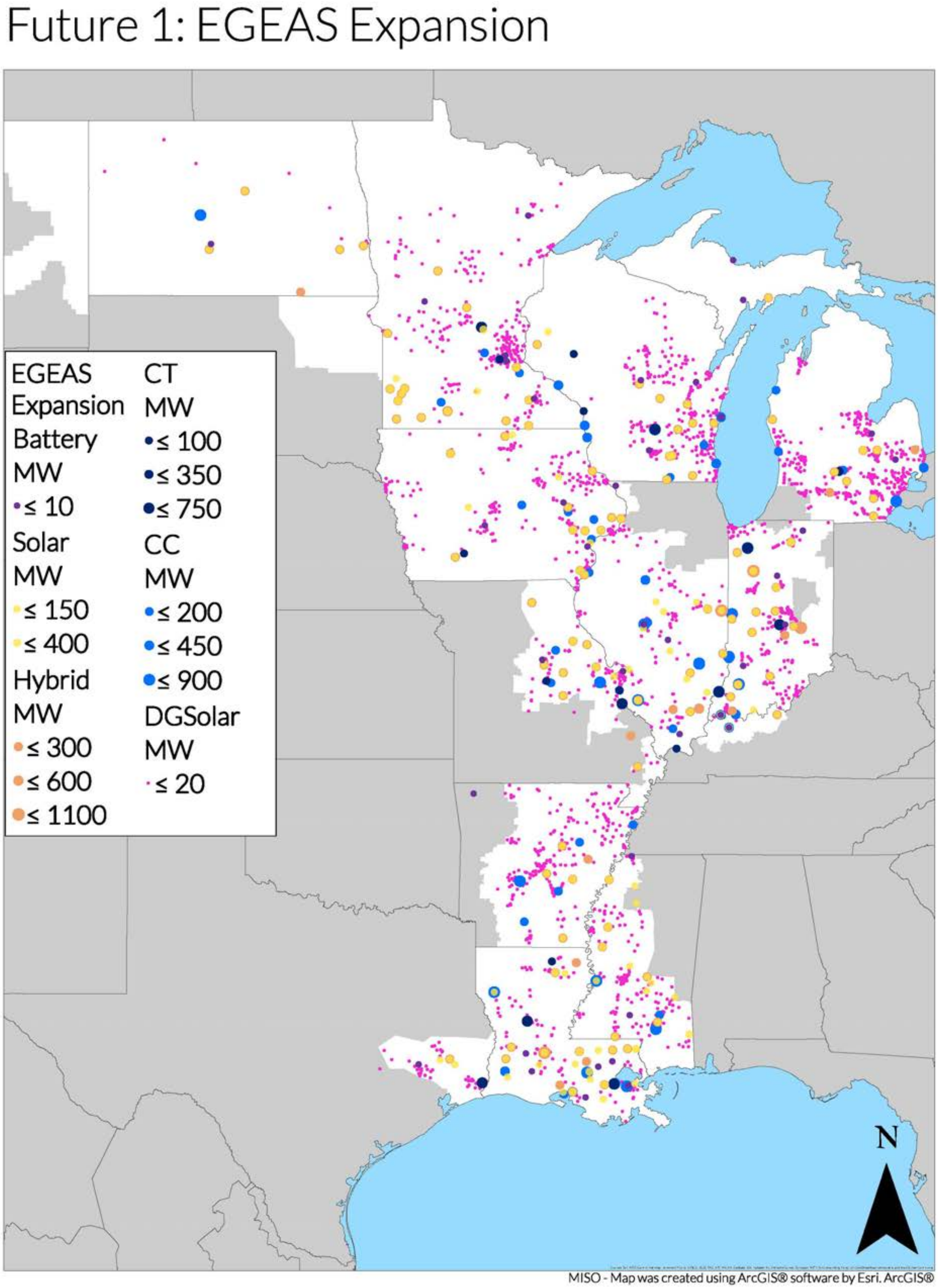


Figure 51: MISO Future 1 Complete EGEAS Expansion Siting

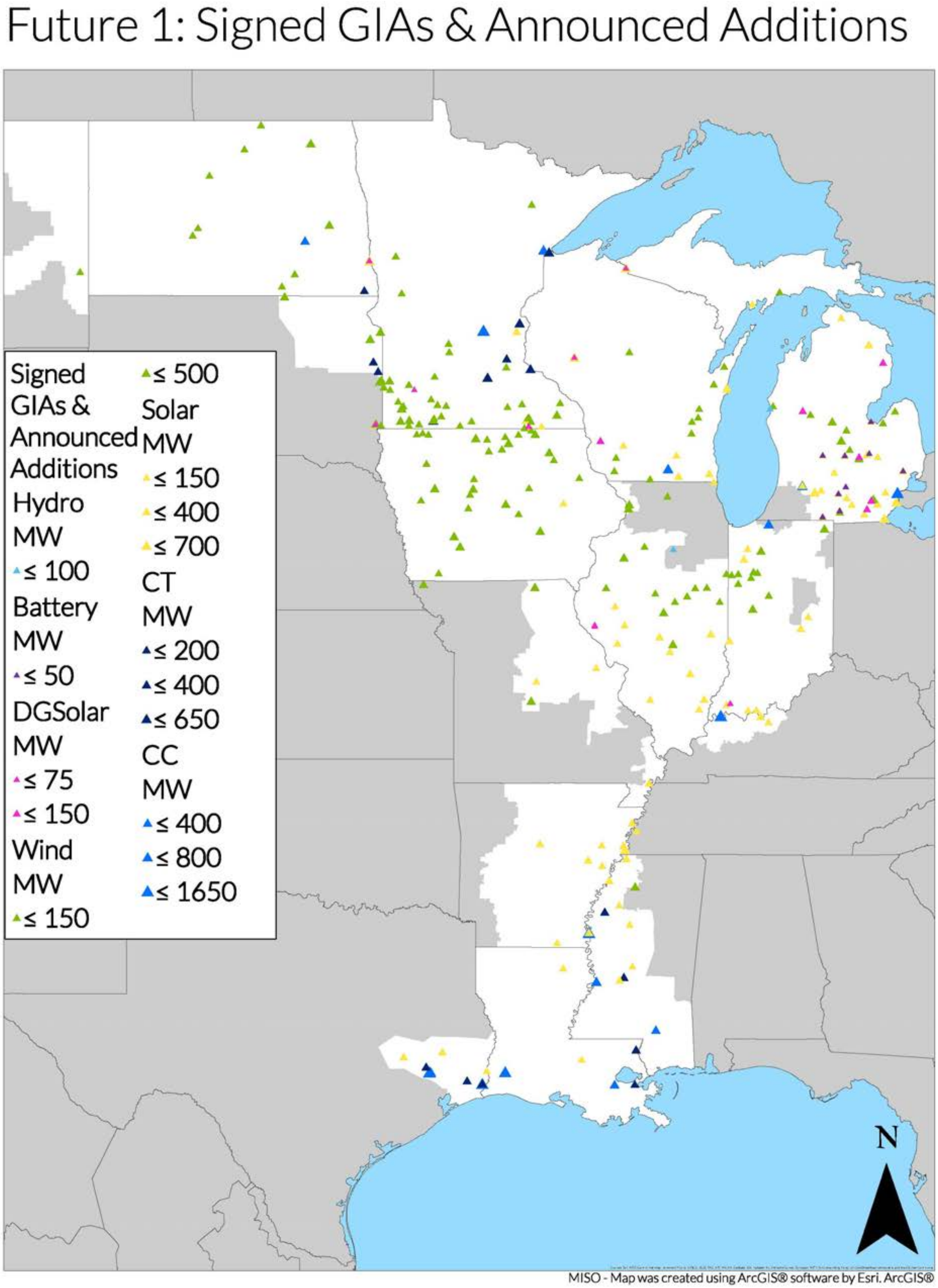
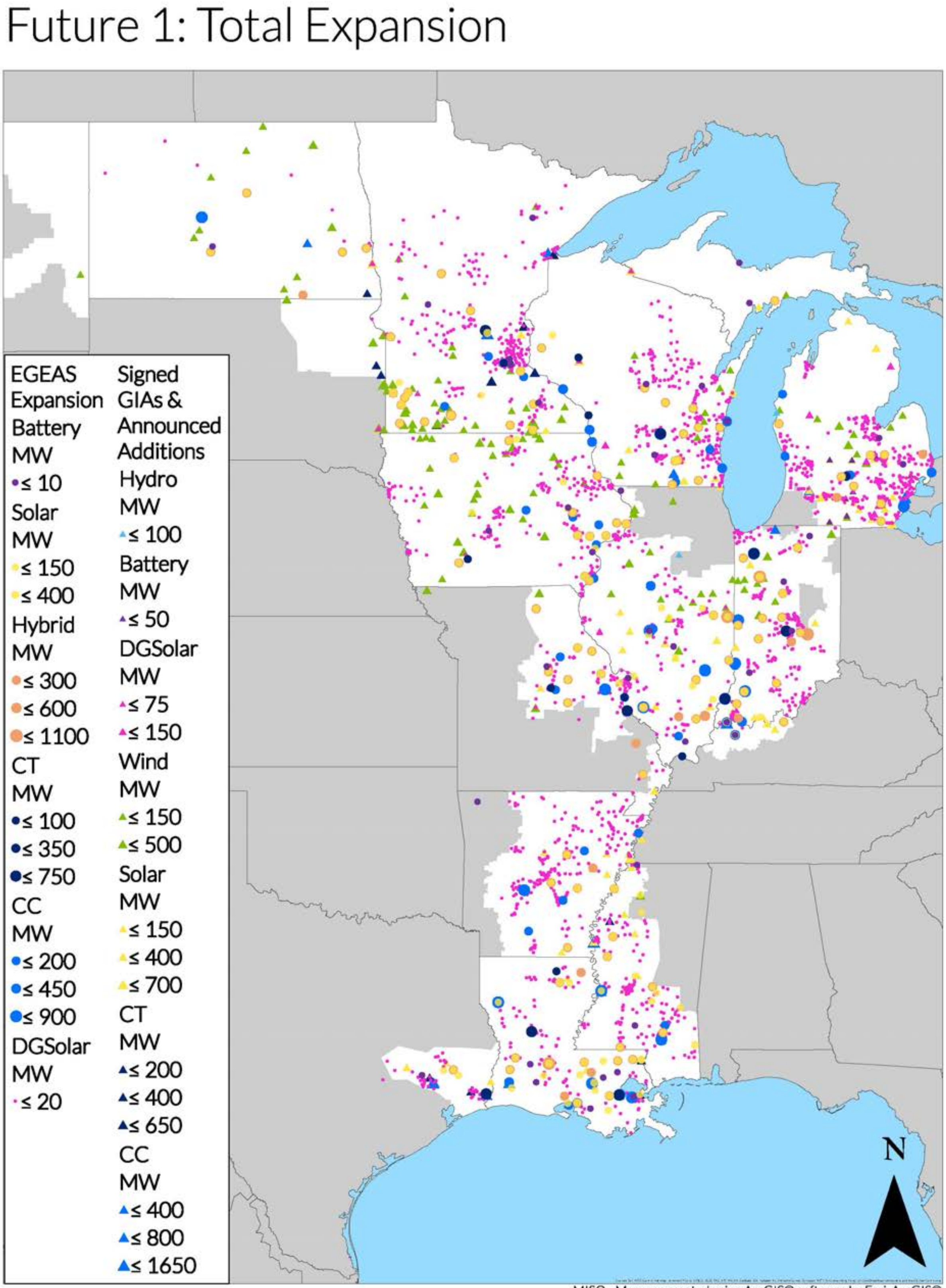


Figure 52: MISO Future 1 Non-EGEAS Expansion Siting



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 53: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

Future 1 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	1,453	0	2,402	771	198	0	283	0	5,957
	2030	4,171	3,520	0	2,669	3,384	198	0	499	0	14,442
	2035	4,171	6,088	0	4,379	6,225	1,129	0	772	0	22,764
	2039	4,560	6,088	0	5,734	6,225	1,547	36	942	0	25,133
LRZ 2	**2025**	1,268	0	0	240	1,585	0	0	38	0	3,131
	2030	2,432	572	0	270	2,099	0	0	122	0	5,495
	2035	2,484	572	0	636	2,304	242	0	246	0	6,484
	2039	2,795	572	0	846	2,304	422	30	311	0	7,280
LRZ 3	**2025**	150	0	0	2,198	875	0	0	33	0	3,256
	2030	608	92	0	2,424	2,103	0	0	104	0	5,331
	2035	608	92	0	3,510	2,522	475	0	210	0	7,417
	2039	881	92	0	4,783	2,522	838	15	265	0	9,396
LRZ 4	**2025**	900	0	0	1,966	2,152	628	0	52	10	5,709
	2030	1,868	240	0	1,986	2,693	628	0	80	10	7,504
	2035	2,285	240	0	2,345	2,871	1,839	0	120	10	9,710
	2039	3,231	240	0	2,979	2,871	1,971	15	141	10	11,458
LRZ 5	**2025**	64	0	0	200	500	0	0	25	0	789
	2030	382	747	0	200	1,381	0	0	80	0	2,790
	2035	979	747	0	369	1,755	322	0	162	0	4,333
	2039	1,596	747	0	369	1,768	560	10	205	0	5,254
LRZ 6	**2025**	1,594	0	0	1,325	2,282	853	0	69	0	6,123
	2030	5,956	2,136	0	1,325	3,466	853	0	103	0	13,839
	2035	7,189	2,136	0	1,702	3,685	2,626	0	153	0	17,491
	2039	7,989	2,136	0	1,907	3,685	2,899	30	179	0	18,825
LRZ 7	**2025**	1,954	0	0	1,322	1,550	189	0	749	72	5,835
	2030	2,051	153	0	1,322	3,421	189	0	781	72	7,988
	2035	2,116	153	0	1,551	4,715	638	200	829	72	10,274
	2039	3,156	153	0	1,887	5,315	755	412	854	72	12,604
LRZ 8	**2025**	250	0	0	0	2,688	155	0	26	0	3,119
	2030	250	0	0	0	2,985	155	0	83	0	3,473
	2035	384	0	0	0	3,059	536	0	168	0	4,147
	2039	1,038	0	0	0	3,059	628	5	212	0	4,943
LRZ 9	**2025**	3,601	493	0	0	1,465	378	0	28	0	5,965
	2030	5,439	2,328	0	0	3,540	378	0	91	0	11,776
	2035	8,287	3,020	0	0	4,238	1,640	0	184	0	17,369
	2039	8,833	3,366	0	0	4,238	2,113	37	232	0	18,819
LRZ 10	**2025**	672	0	0	200	730	0	0	16	0	1,619
	2030	672	350	0	200	2,070	0	0	52	0	3,345
	2035	2,531	700	0	200	2,709	153	0	106	0	6,399
	2039	3,046	700	0	200	2,709	267	10	134	0	7,066
MISO Total	**2025**	11,303	1,946	0	9,853	14,600	2,400	0	1,320	82	41,504
	2030	23,829	10,138	0	10,396	27,144	2,400	0	1,995	82	75,984
	2035	31,035	13,748	0	14,691	34,082	9,600	200	2,950	82	106,388
	2039	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	120,777

Table 7: MISO Future 1 Resource Additions by LRZ and Footprint

Future 1 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	3,619	1,214	0	698	240	0	36	5,807
	2030	6,303	2,567	0	698	519	0	36	10,123
	2035	6,413	3,281	1,092	771	2,946	0	36	14,539
	2039	6,413	3,281	1,092	771	3,572	0	36	15,165
LRZ 2	**2025**	2,650	599	0	351	11	0	0	3,611
	2030	2,981	736	0	351	41	0	0	4,109
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	741	0	351	617	0	0	4,690
LRZ 3	**2025**	596	92	448	196	122	0	0	1,454
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	196	1,434	0	0	2,927
	2039	757	92	448	275	2,707	0	0	4,279
LRZ 4	**2025**	3,056	134	0	90	0	0	0	3,281
	2030	3,056	134	0	117	20	0	0	3,327
	2035	3,056	134	0	117	379	0	0	3,686
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	9,268	788	0	50	0	0	0	10,106
	2030	11,002	853	0	50	0	0	0	11,905
	2035	11,537	853	0	50	377	0	0	12,816
	2039	11,537	853	0	71	582	21	0	13,064
LRZ 7	**2025**	2,956	155	819	45	0	0	0	3,974
	2030	4,223	161	819	59	0	0	0	5,261
	2035	4,878	1,444	819	59	230	0	0	7,429
	2039	8,013	1,444	819	59	565	0	0	10,899
LRZ 8	**2025**	0	788	0	0	0	0	0	788
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	515	5,919	0	7	0	0	0	6,441
	2030	2,746	6,438	0	7	0	0	0	9,191
	2035	2,746	8,361	0	7	0	0	0	11,114
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	26,553	10,648	1,267	1,782	373	0	36	40,658
	2030	38,091	12,727	1,267	1,822	928	0	36	54,871
	2035	40,397	18,397	2,359	1,896	5,960	0	36	69,044
	2039	44,827	18,627	2,359	1,996	9,223	21	36	77,089

Table 8: MISO Future 1 Resource Retirements by LRZ and Footprint

MISO – Future 2

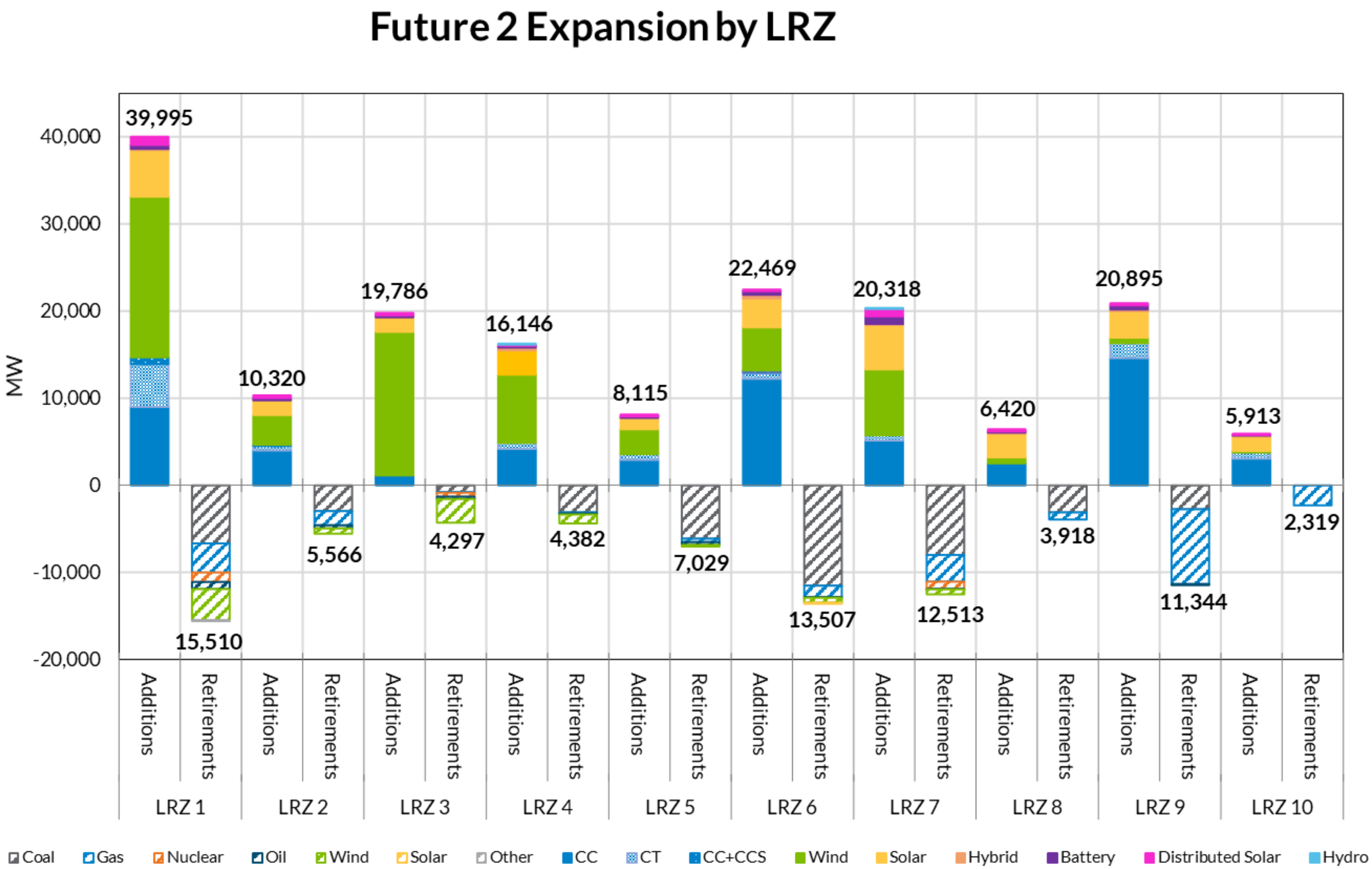


Figure 54: MISO Future 2 Resource Retirement and Addition Summary

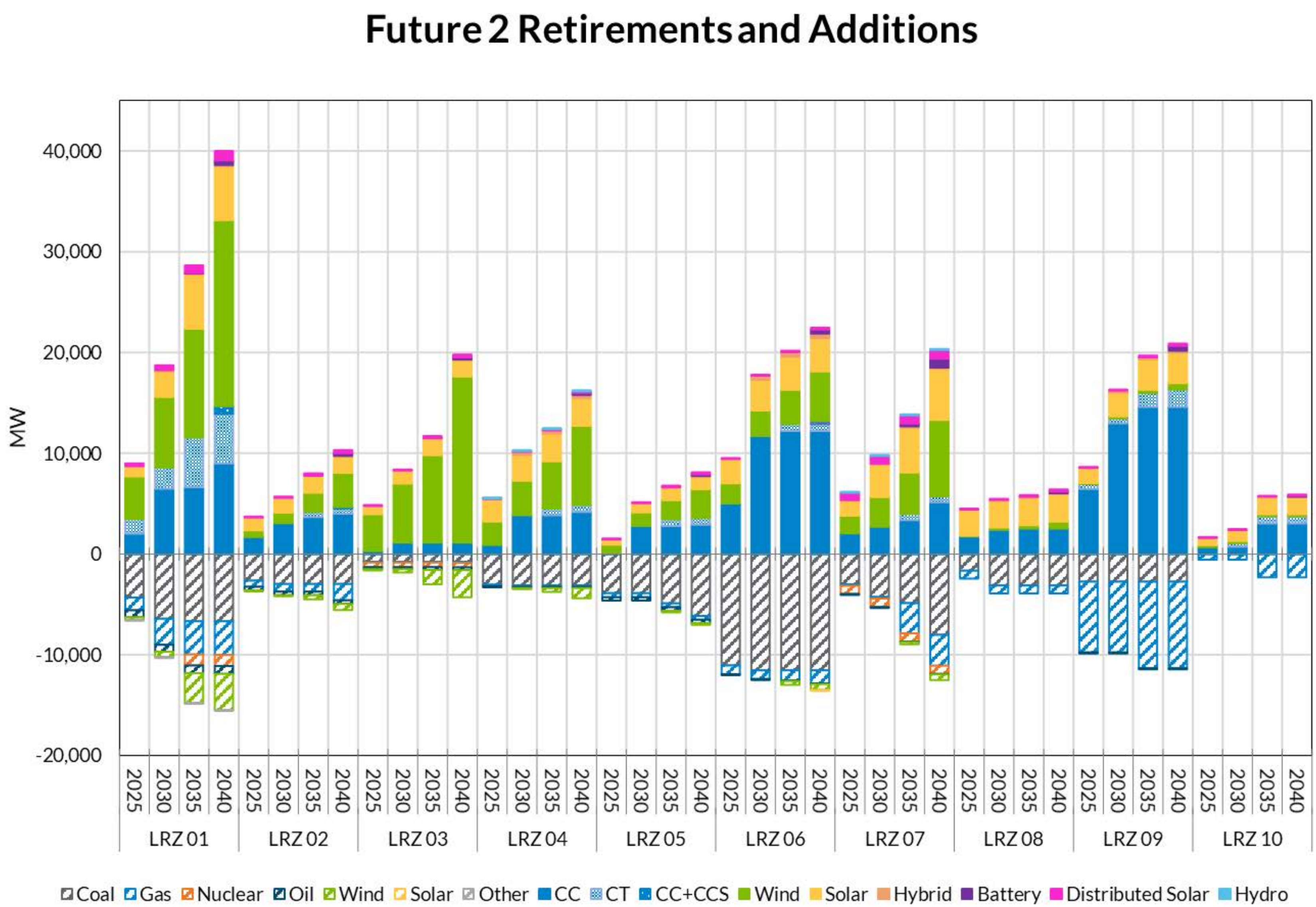


Figure 55: MISO Future 2 Resource Additions per Milestone Year (Cumulative)

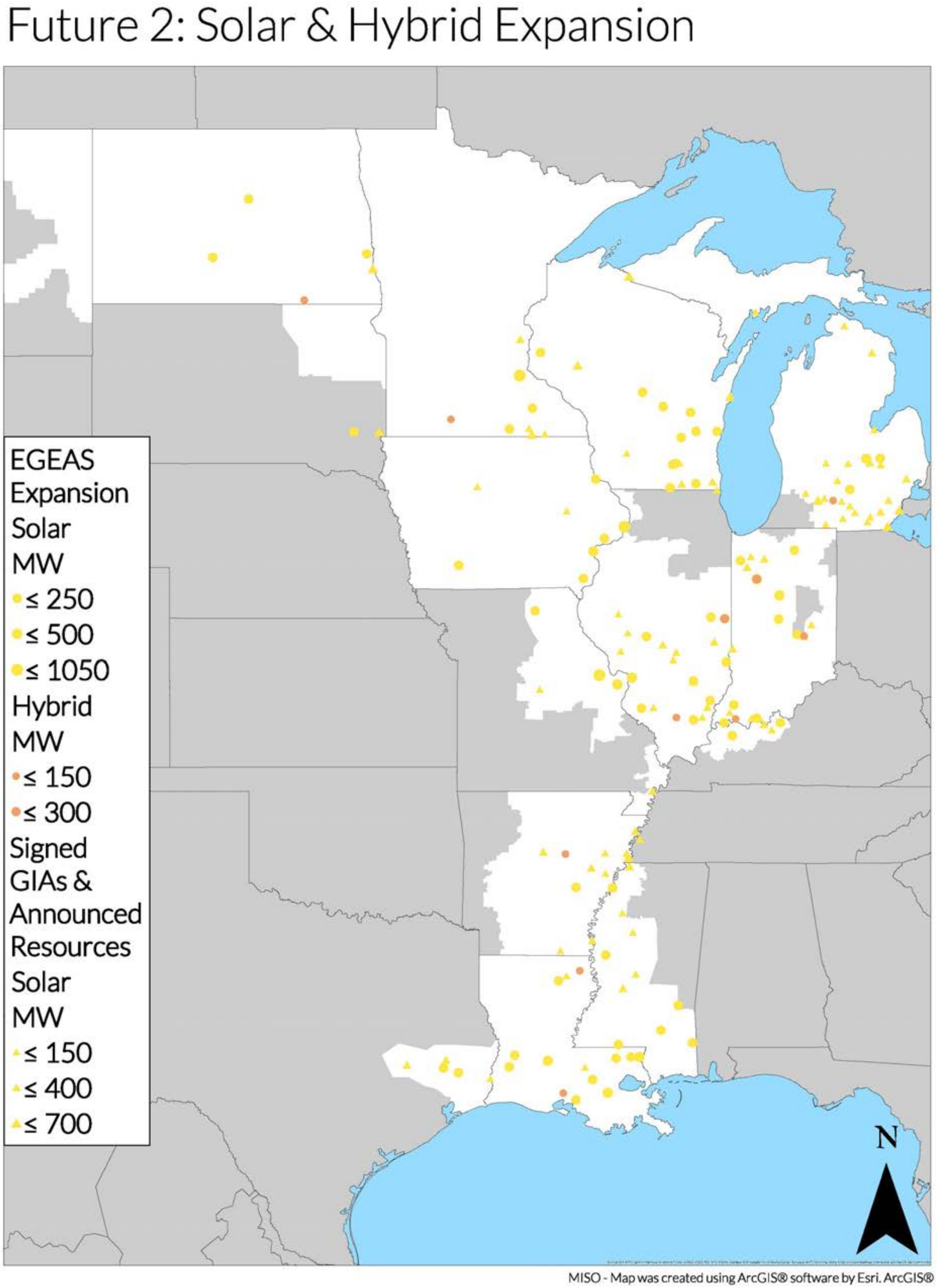


Figure 56: MISO Future 2 Solar and Hybrid Siting

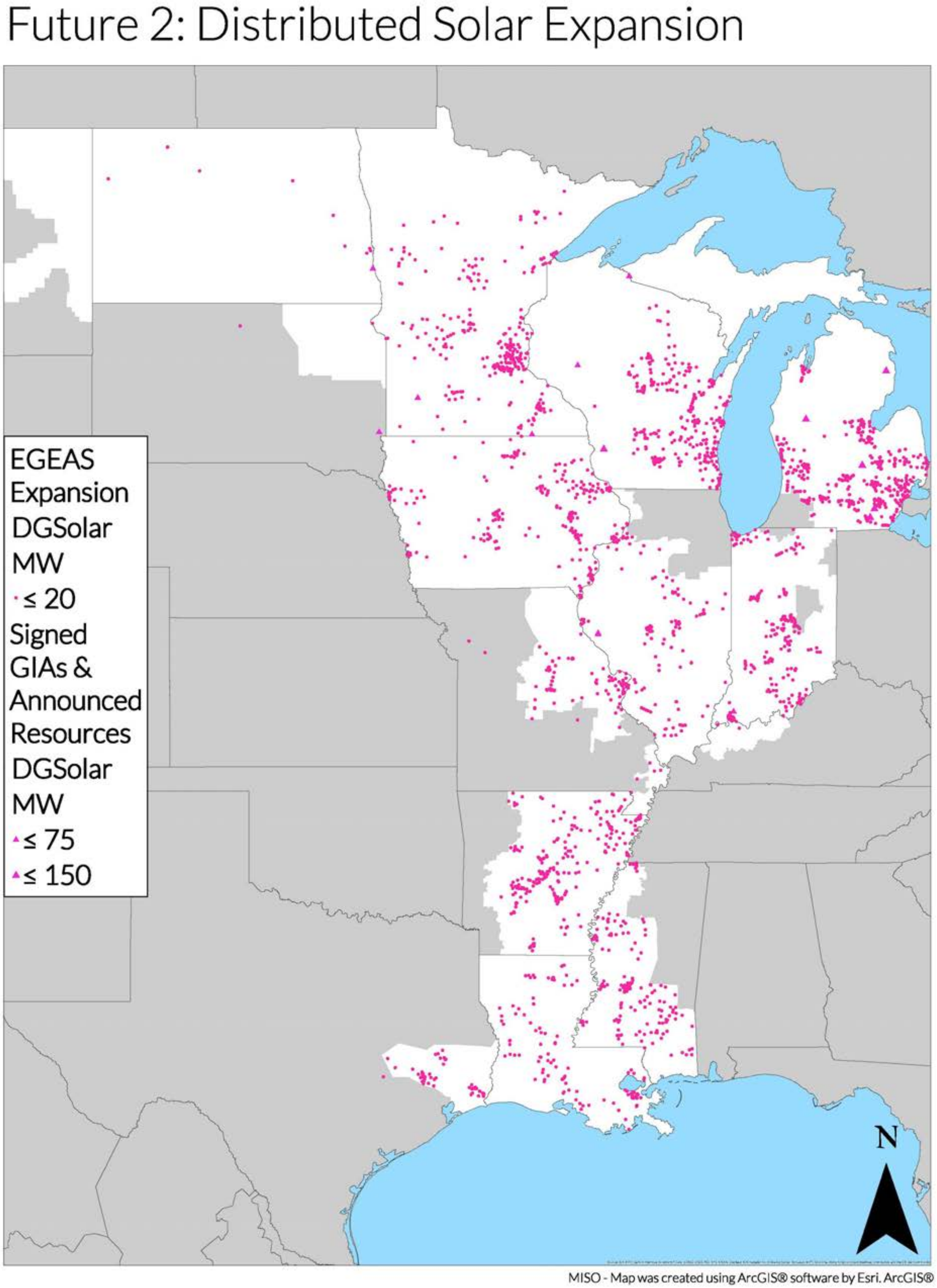
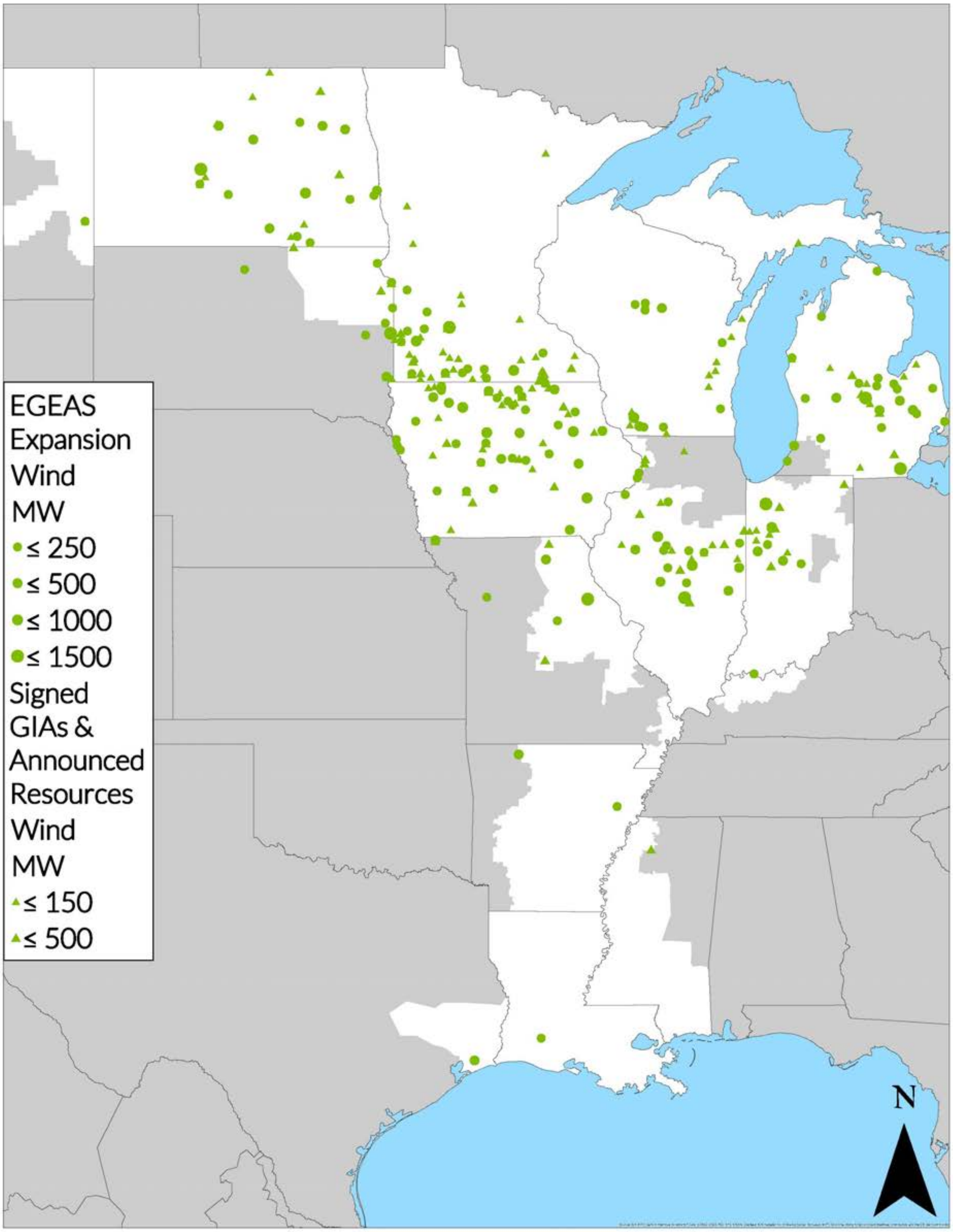


Figure 57: MISO Future 2 Distributed Solar Siting

Future 2: Wind Expansion



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 58: MISO Future 2 Wind Siting

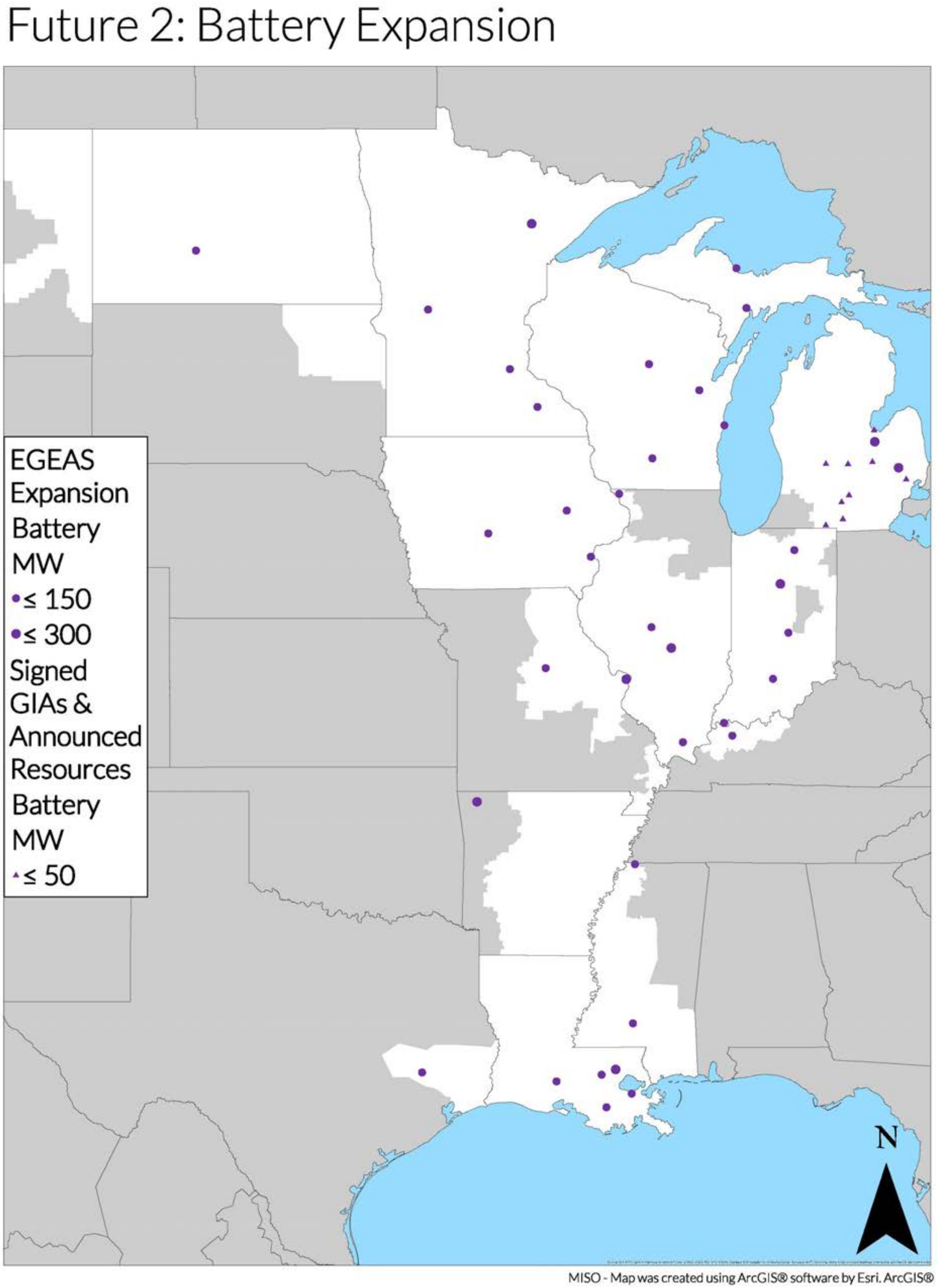


Figure 59: MISO Future 2 Battery Siting

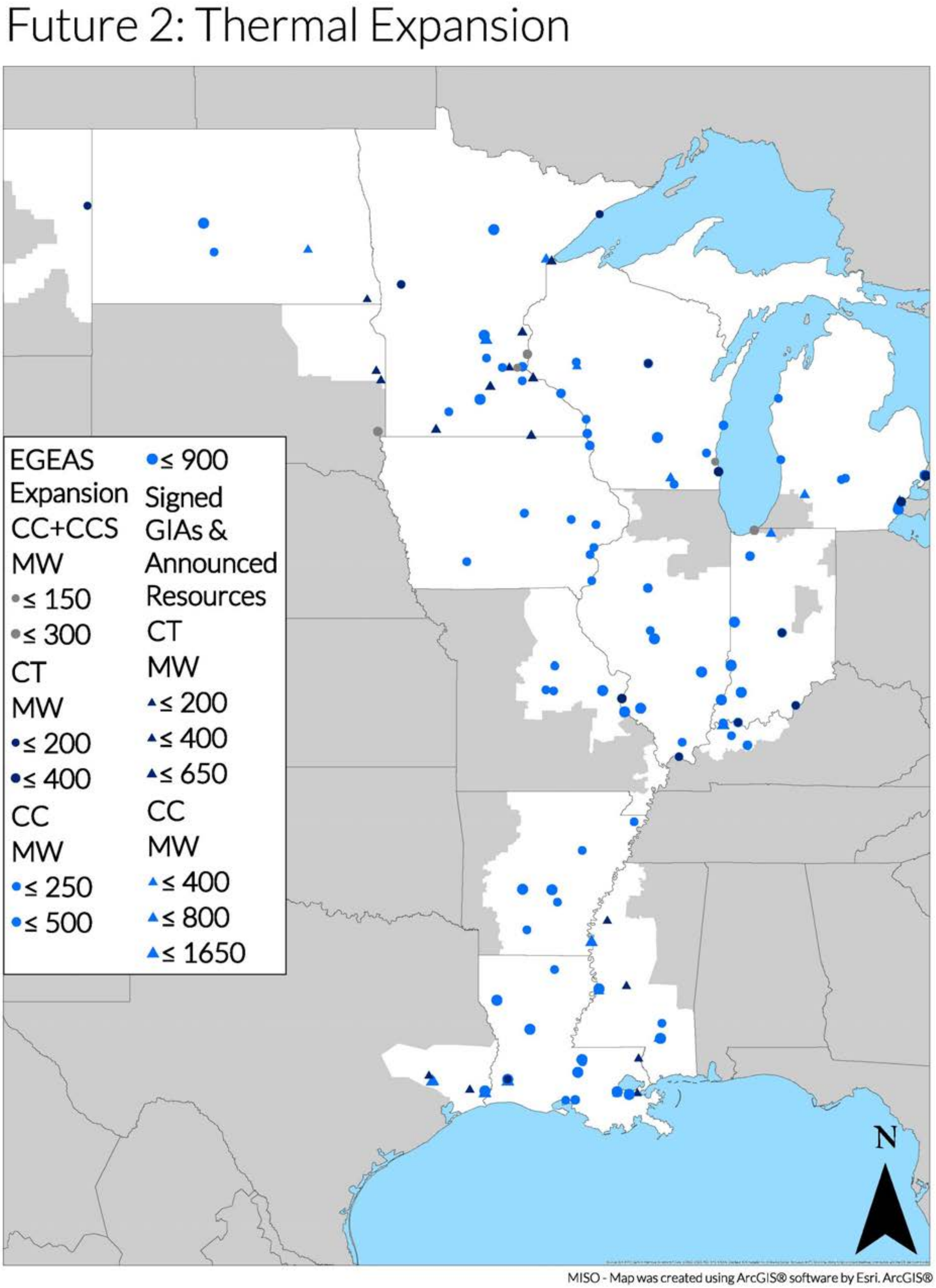
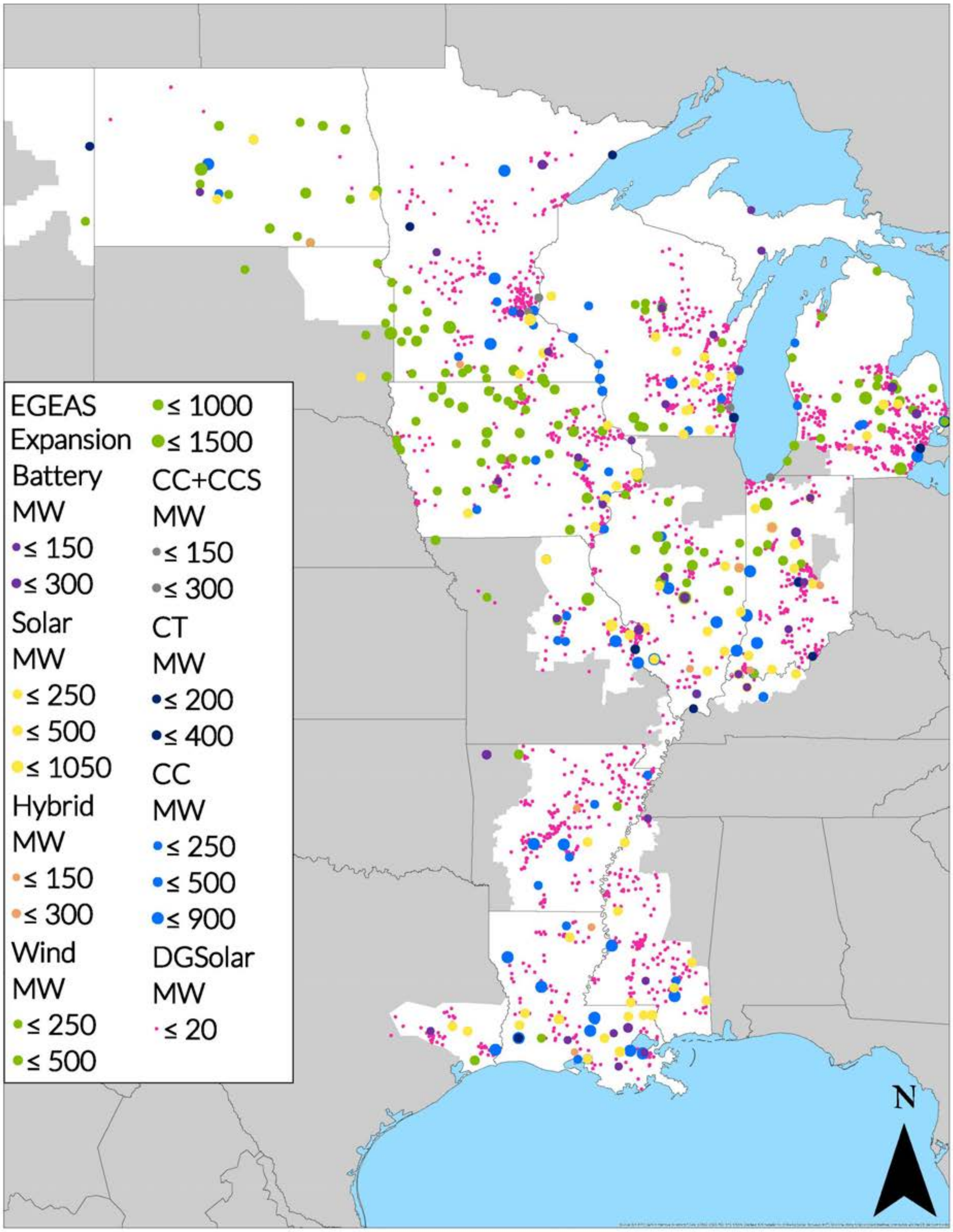


Figure 60: MISO Future 2 Thermal Siting

Future 2: EGEAS Expansion



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 61: MISO Future 2 Complete EGEAS Expansion Siting

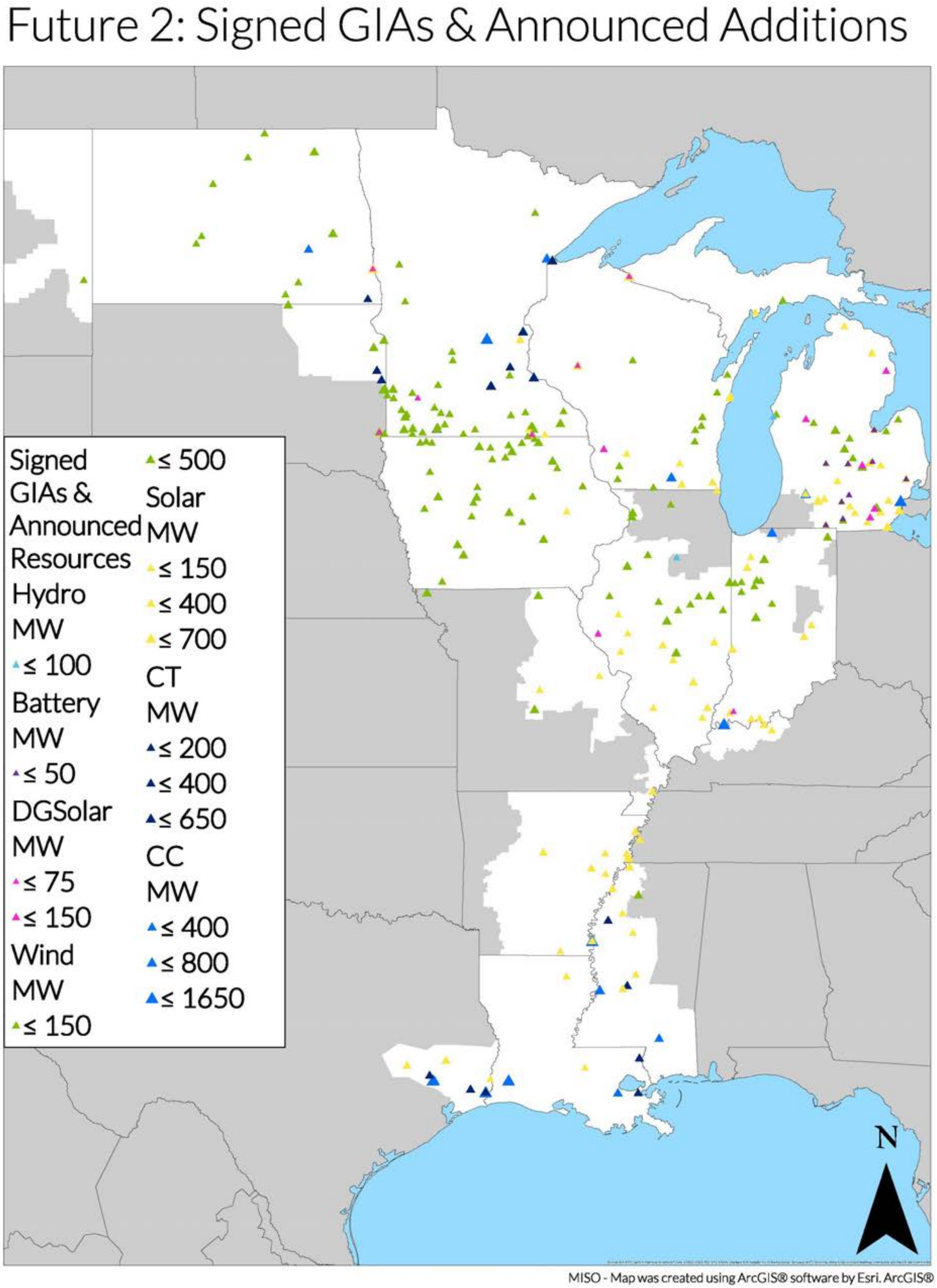
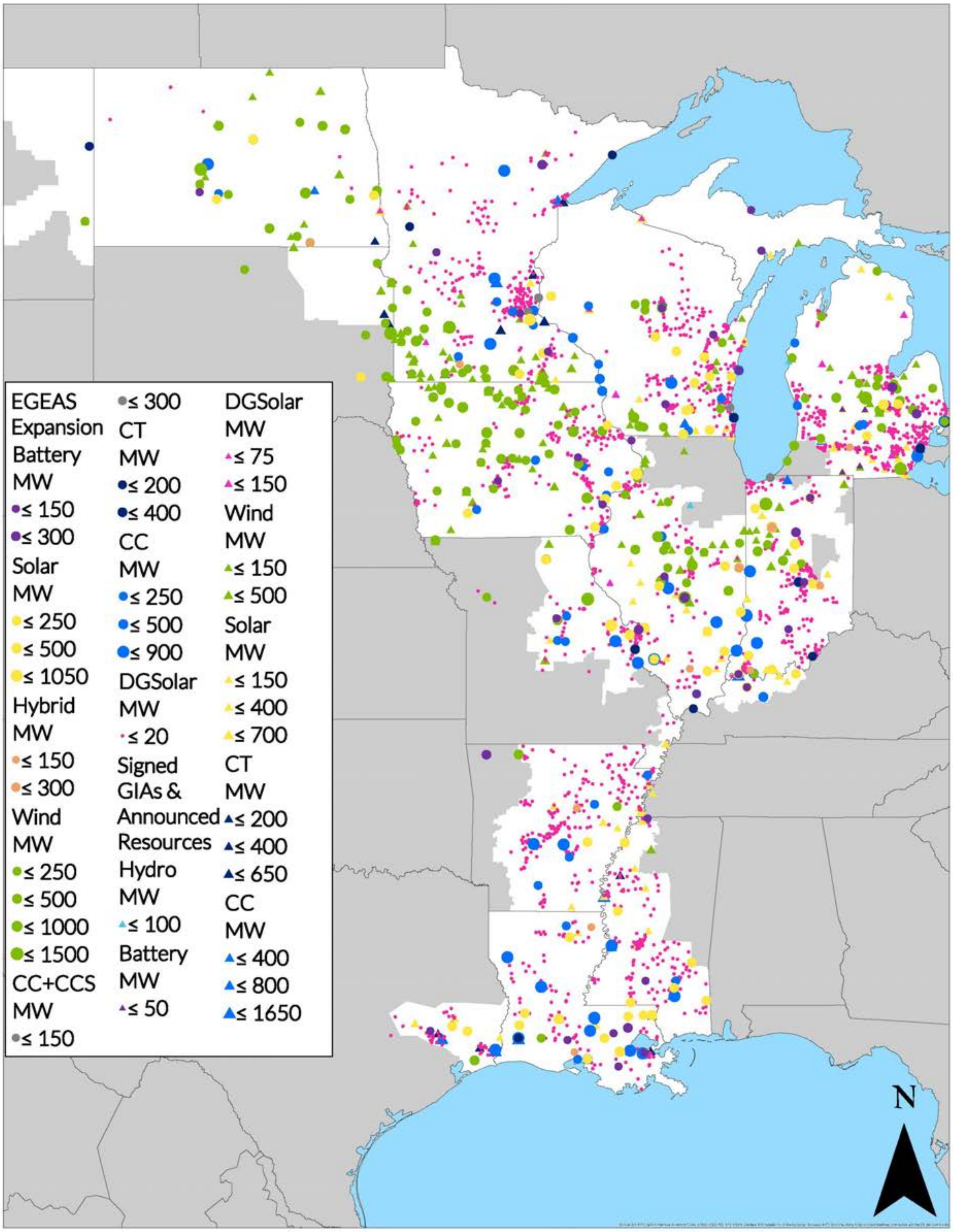


Figure 62: MISO Future 2 Non-EGEAS Expansion Siting

Future 2: Total Expansion



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 63: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

Future 2 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	2,020	1,453	0	4,219	1,032	0	0	283	0	9,007
	2030	6,491	2,095	0	7,006	2,550	99	0	499	0	18,740
	2035	6,641	4,928	0	10,797	5,380	99	33	772	0	28,650
	2039	8,986	4,928	774	18,435	5,380	99	451	942	0	39,995
LRZ 2	**2025**	1,686	0	0	657	1,270	0	0	38	0	3,650
	2030	3,056	0	0	1,041	1,471	0	0	122	0	5,689
	2035	3,673	511	0	1,903	1,680	0	0	246	0	8,012
	2039	4,004	511	138	3,408	1,680	0	268	311	0	10,320
LRZ 3	**2025**	311	0	0	3,630	821	0	0	34	0	4,796
	2030	1,134	0	0	5,850	1,295	0	0	109	0	8,388
	2035	1,134	0	0	8,682	1,666	0	0	220	0	11,701
	2039	1,134	0	0	16,484	1,666	0	224	277	0	19,786
LRZ 4	**2025**	900	0	0	2,328	2,225	0	0	51	10	5,514
	2030	3,850	0	0	3,424	2,557	314	0	75	10	10,230
	2035	3,850	668	0	4,671	2,771	314	0	111	10	12,396
	2039	4,184	668	0	7,862	2,771	314	207	129	10	16,146
LRZ 5	**2025**	64	0	0	881	498	0	0	25	0	1,468
	2030	2,783	0	0	1,358	901	0	0	80	0	5,122
	2035	2,783	660	0	1,905	1,273	0	0	162	0	6,783
	2039	2,909	660	0	2,879	1,287	0	174	205	0	8,115
LRZ 6	**2025**	5,009	0	0	2,002	2,410	0	0	69	0	9,490
	2030	11,699	0	0	2,552	3,027	426	0	103	0	17,807
	2035	12,209	699	0	3,384	3,309	426	0	153	0	20,180
	2039	12,209	699	289	4,935	3,309	426	423	179	0	22,469
LRZ 7	**2025**	2,051	0	0	1,758	1,537	0	0	749	72	6,166
	2030	2,718	0	0	2,937	3,211	94	0	781	72	9,813
	2035	3,378	601	0	4,106	4,498	94	267	829	72	13,845
	2039	5,133	601	0	7,576	5,098	94	889	854	72	20,318
LRZ 8	**2025**	1,734	0	0	93	2,578	0	0	26	0	4,431
	2030	2,400	0	0	222	2,681	77	0	83	0	5,464
	2035	2,522	0	0	334	2,750	77	0	168	0	5,851
	2039	2,522	0	0	686	2,750	77	172	212	0	6,420
LRZ 9	**2025**	6,457	493	0	86	1,512	0	0	28	0	8,577
	2030	12,965	493	0	207	2,360	189	0	91	0	16,305
	2035	14,597	1,381	0	310	3,031	189	0	184	0	19,692
	2039	14,597	1,727	0	638	3,031	189	481	232	0	20,895
LRZ 10	**2025**	672	0	0	200	718	0	0	16	0	1,606
	2030	731	350	0	200	1,091	0	0	52	0	2,425
	2035	3,046	700	0	200	1,723	0	0	106	0	5,776
	2039	3,046	700	0	200	1,723	0	109	134	0	5,913
MISO Total	**2025**	20,903	1,946	0	15,853	14,600	0	0	1,320	82	54,704
	2030	47,828	2,938	0	24,796	21,144	1,200	0	1,995	82	99,983
	2035	53,834	10,148	0	36,291	28,082	1,200	300	2,950	82	132,887
	2039	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	170,376

Table 9: MISO Future 2 Resource Additions by LRZ and Footprint

Future 2 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,255	0	698	240	0	36	6,553
	2030	6,413	2,584	0	698	519	0	36	10,250
	2035	6,676	3,281	1,092	771	2,946	0	36	14,802
	2039	6,676	3,332	1,092	803	3,572	0	36	15,510
LRZ 2	**2025**	2,650	2,650	0	351	11	0	0	5,663
	2030	2,981	741	0	351	41	0	0	4,114
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	1,617	0	351	617	0	0	5,566
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	275	1,434	0	0	3,006
	2039	776	92	448	275	2,707	0	0	4,297
LRZ 4	**2025**	3,056	134	0	117	0	0	0	3,307
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	134	0	117	379	0	0	3,748
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	853	0	50	0	0	0	12,439
	2035	11,537	1,008	0	71	377	0	0	12,992
	2039	11,537	1,296	0	71	582	21	0	13,507
LRZ 7	**2025**	2,991	161	819	59	0	0	0	4,029
	2030	4,258	168	819	59	0	0	0	5,303
	2035	4,878	2,973	819	59	230	0	0	8,958
	2039	8,013	3,059	819	59	565	0	0	12,513
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	2,746	7,013	0	7	0	0	0	9,766
	2030	2,746	7,013	0	7	0	0	0	9,766
	2035	2,746	8,591	0	7	0	0	0	11,344
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	33,132	13,904	1,267	1,822	373	0	36	50,534
	2030	38,833	13,331	1,267	1,822	928	0	36	56,217
	2035	40,722	20,311	2,359	1,996	5,960	0	36	71,383
	2039	45,109	21,611	2,359	2,027	9,223	21	36	80,386

Table 10: MISO Future 2 Resource Retirements by LRZ and Footprint

MISO – Future 3

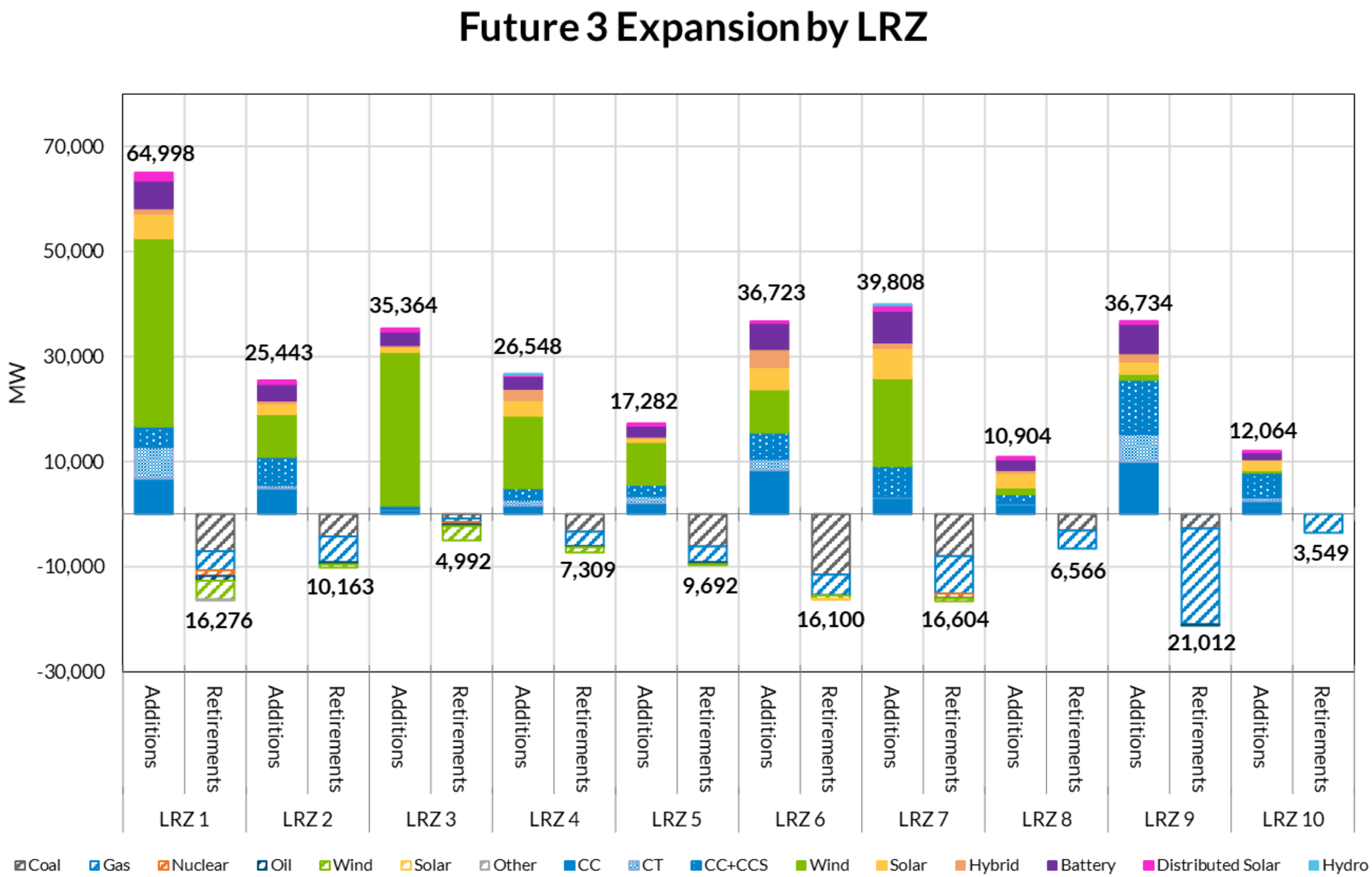


Figure 64: MISO Future 3 Resource Retirement and Addition Summary

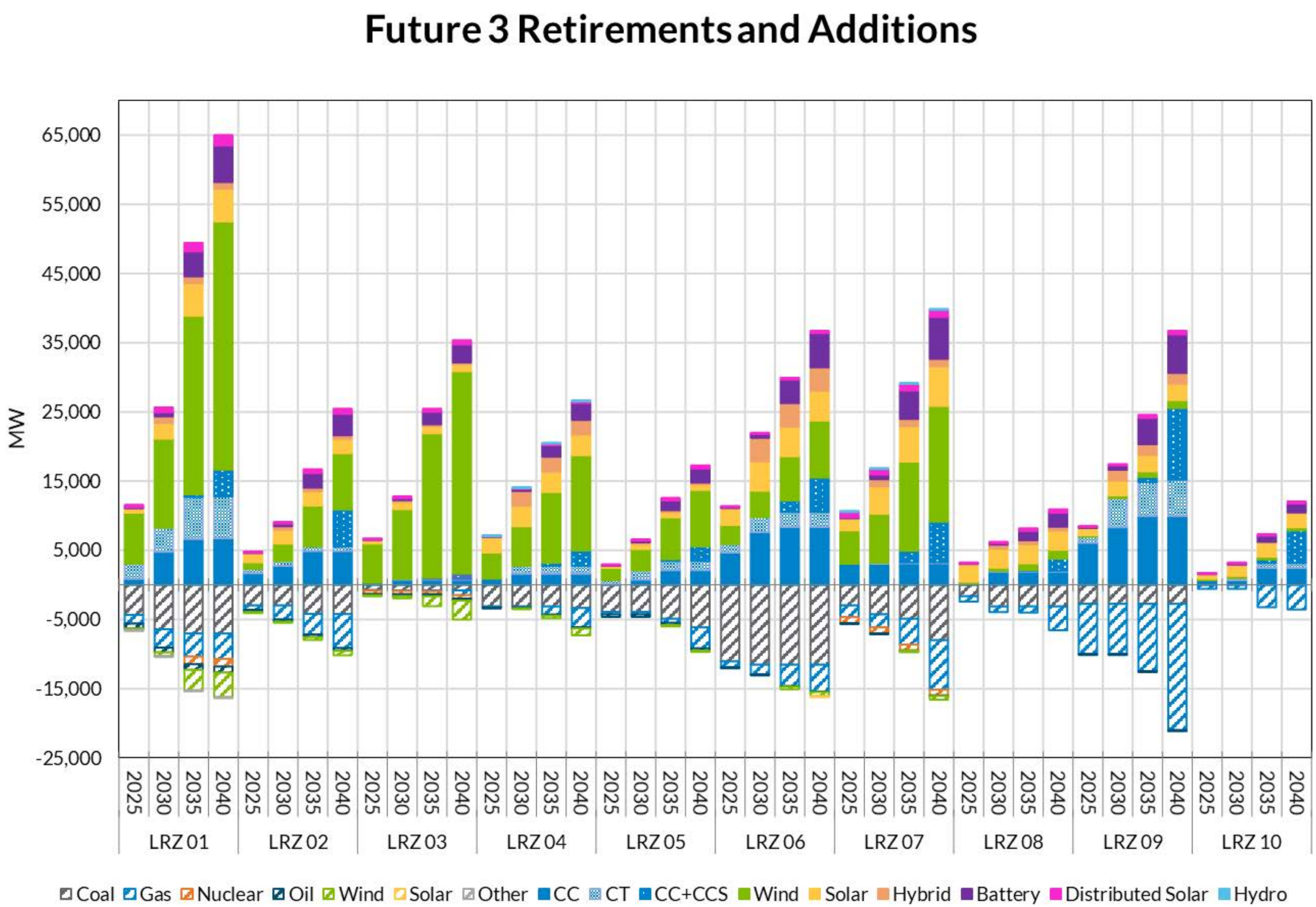


Figure 65: MISO Future 3 Resource Additions per Milestone Year (Cumulative)

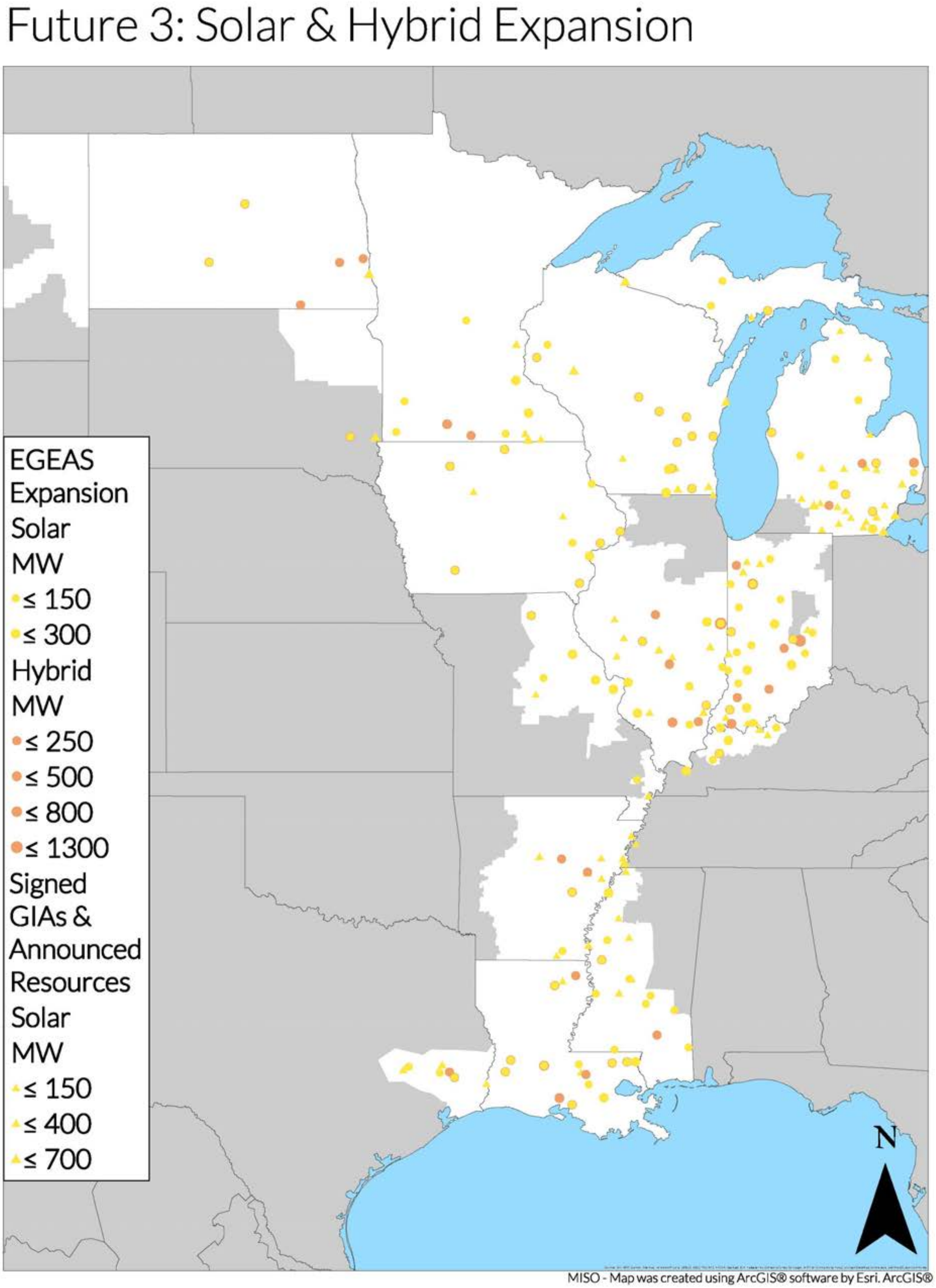


Figure 66: MISO Future 3 Solar and Hybrid Siting

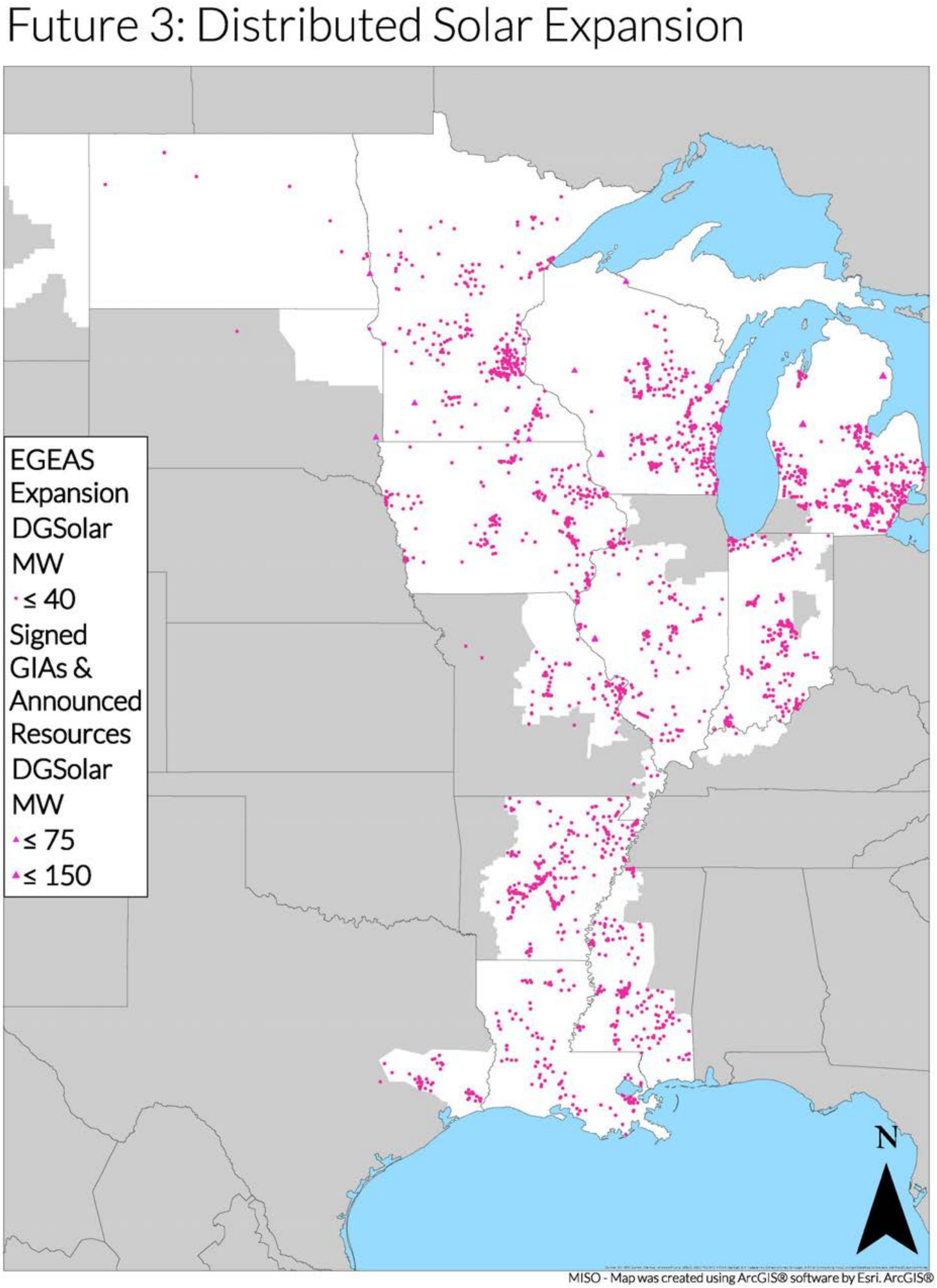


Figure 67: MISO Future 3 Distributed Solar Siting

Future 3: Wind Expansion

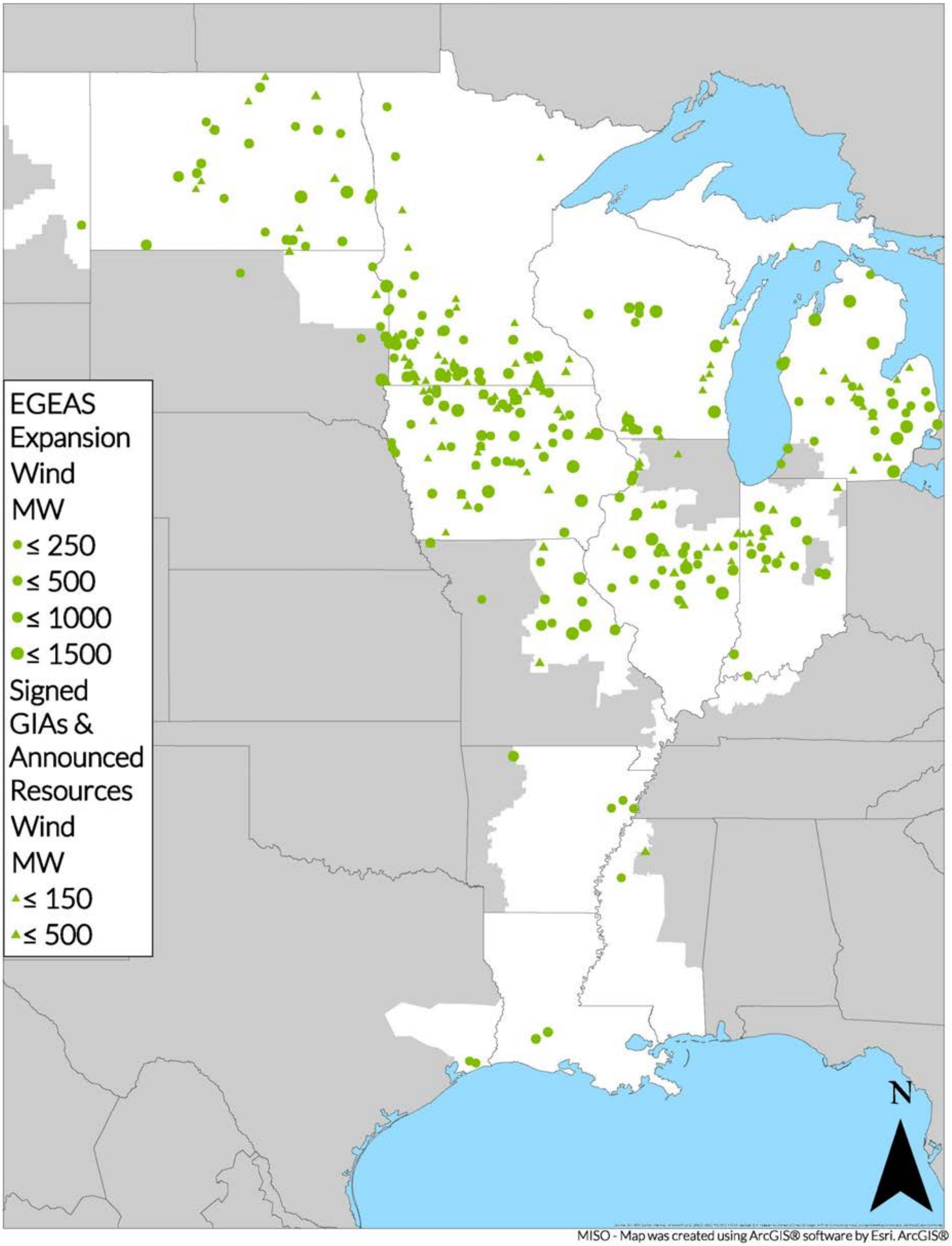


Figure 68: MISO Future 3 Wind Siting

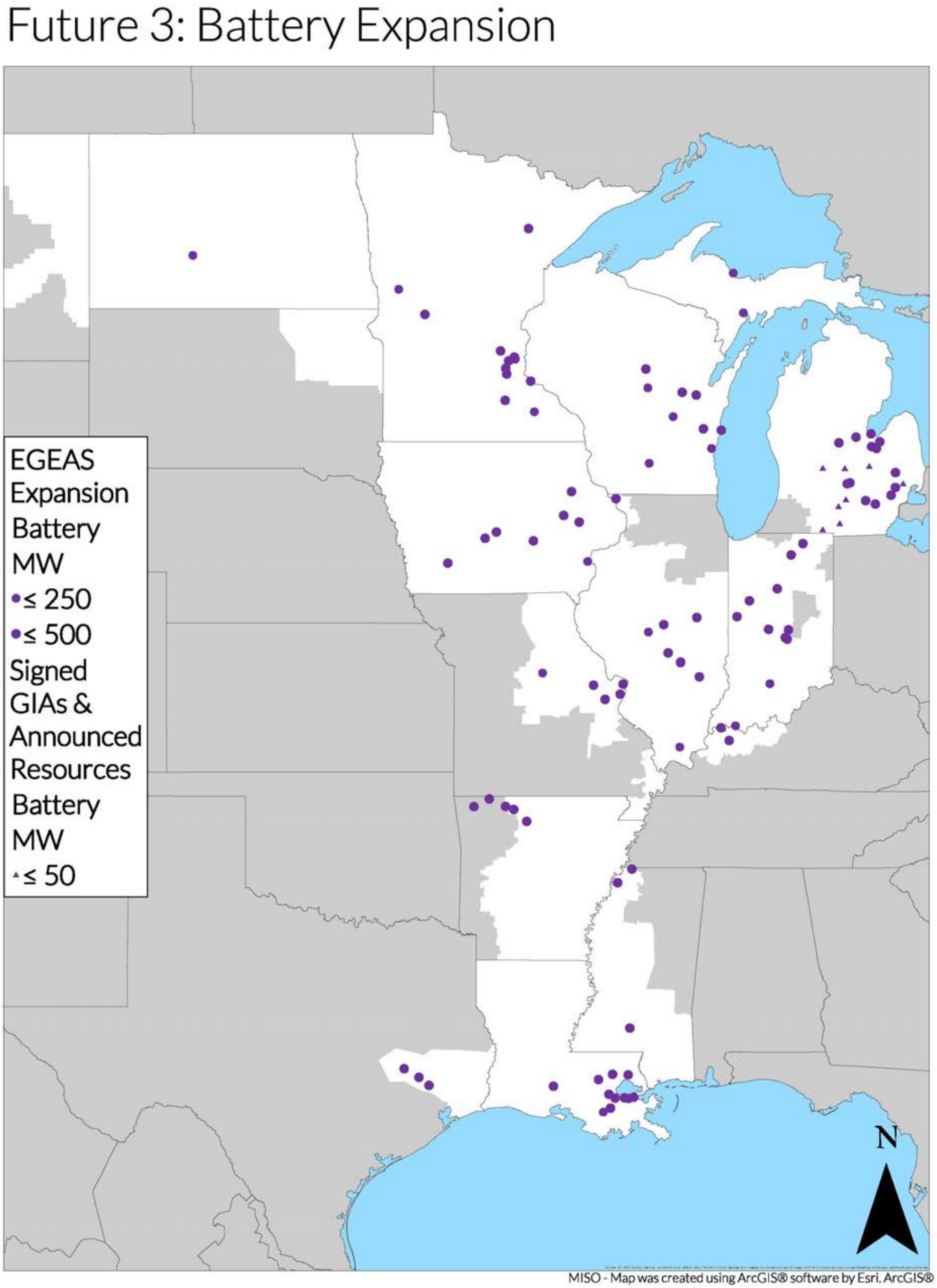


Figure 69: MISO Future 3 Battery Siting

Future 3: Thermal Expansion

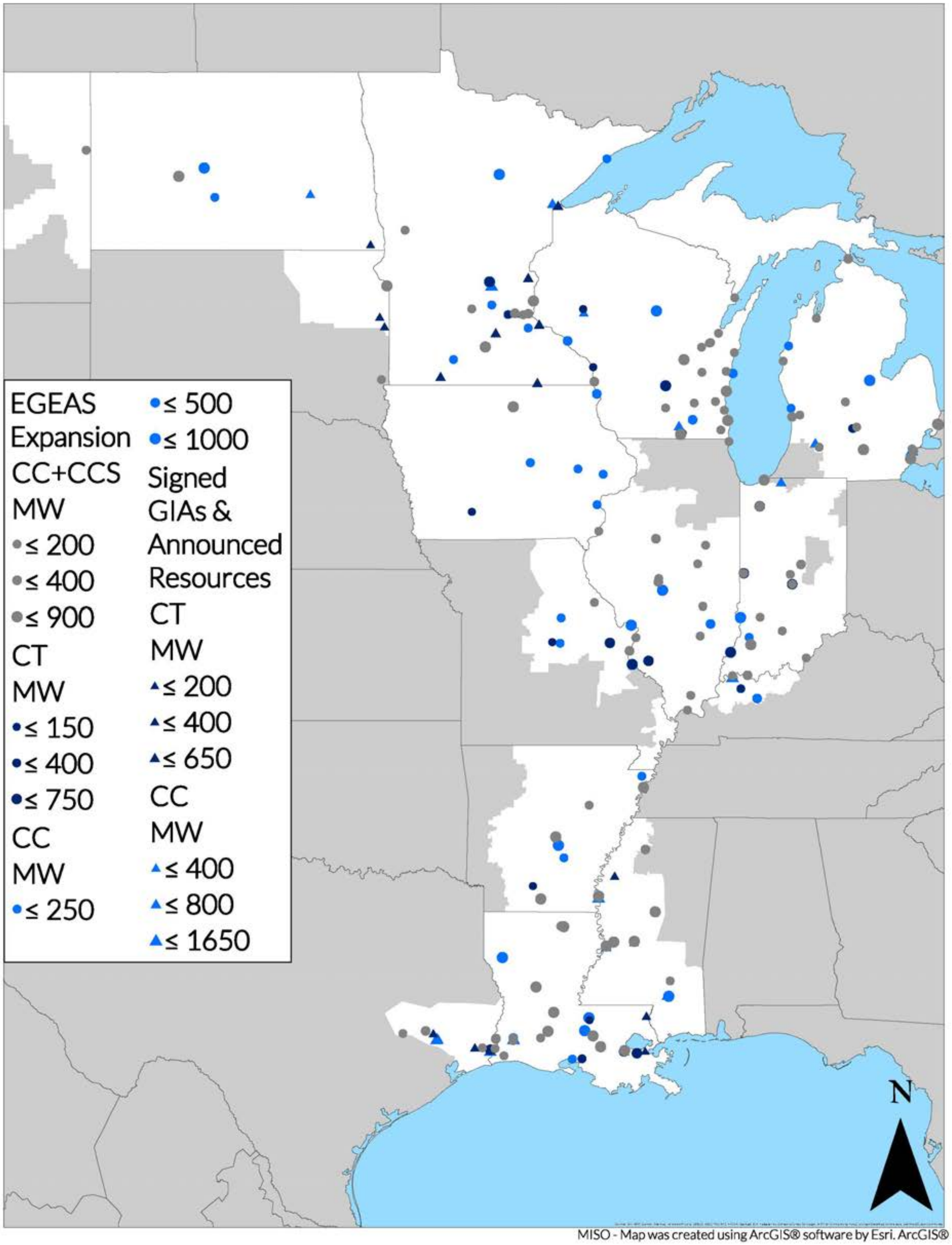


Figure 70: MISO Future 3 Thermal Siting

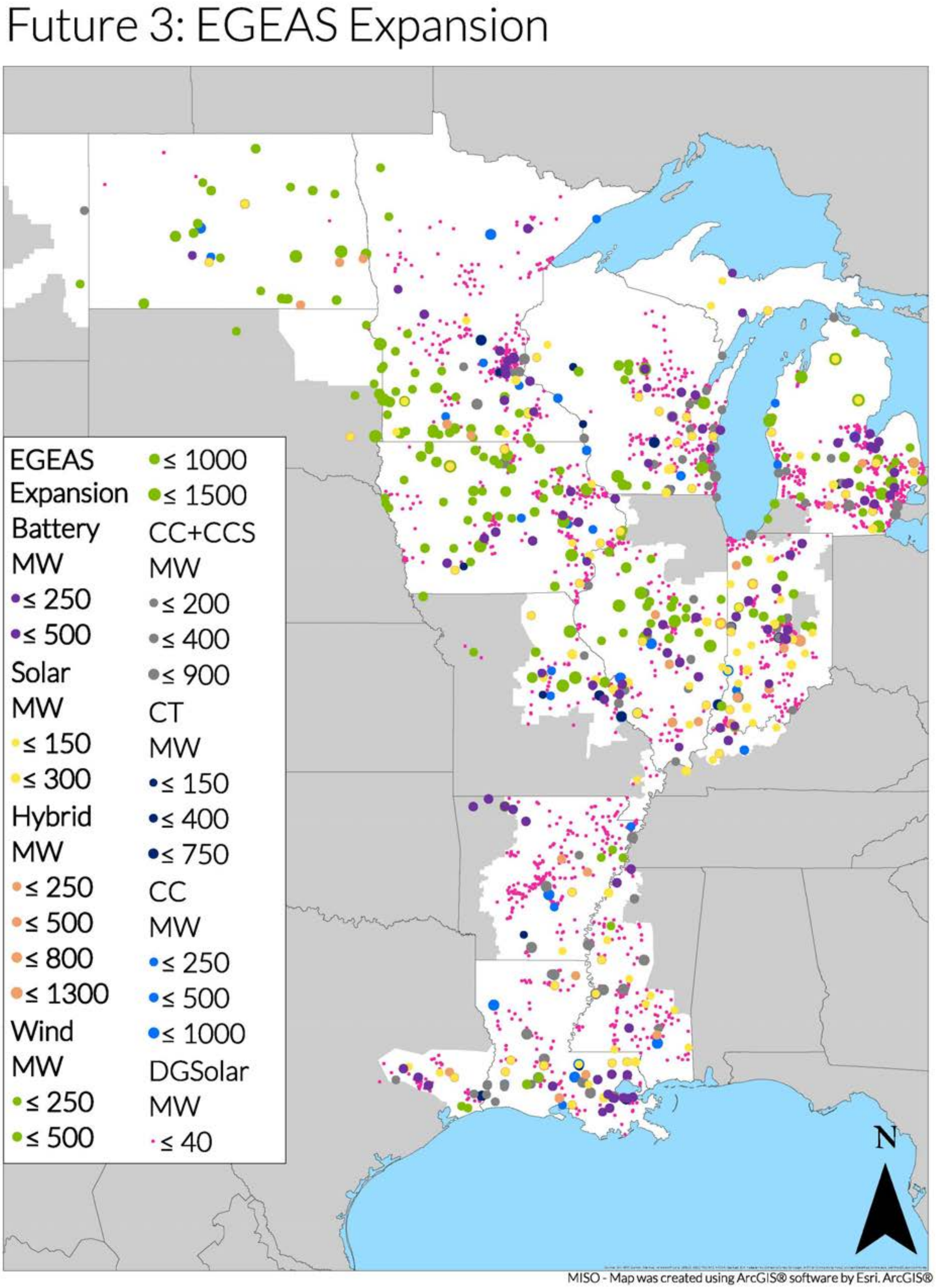


Figure 71: MISO Future 3 Complete EGEAS Expansion Siting

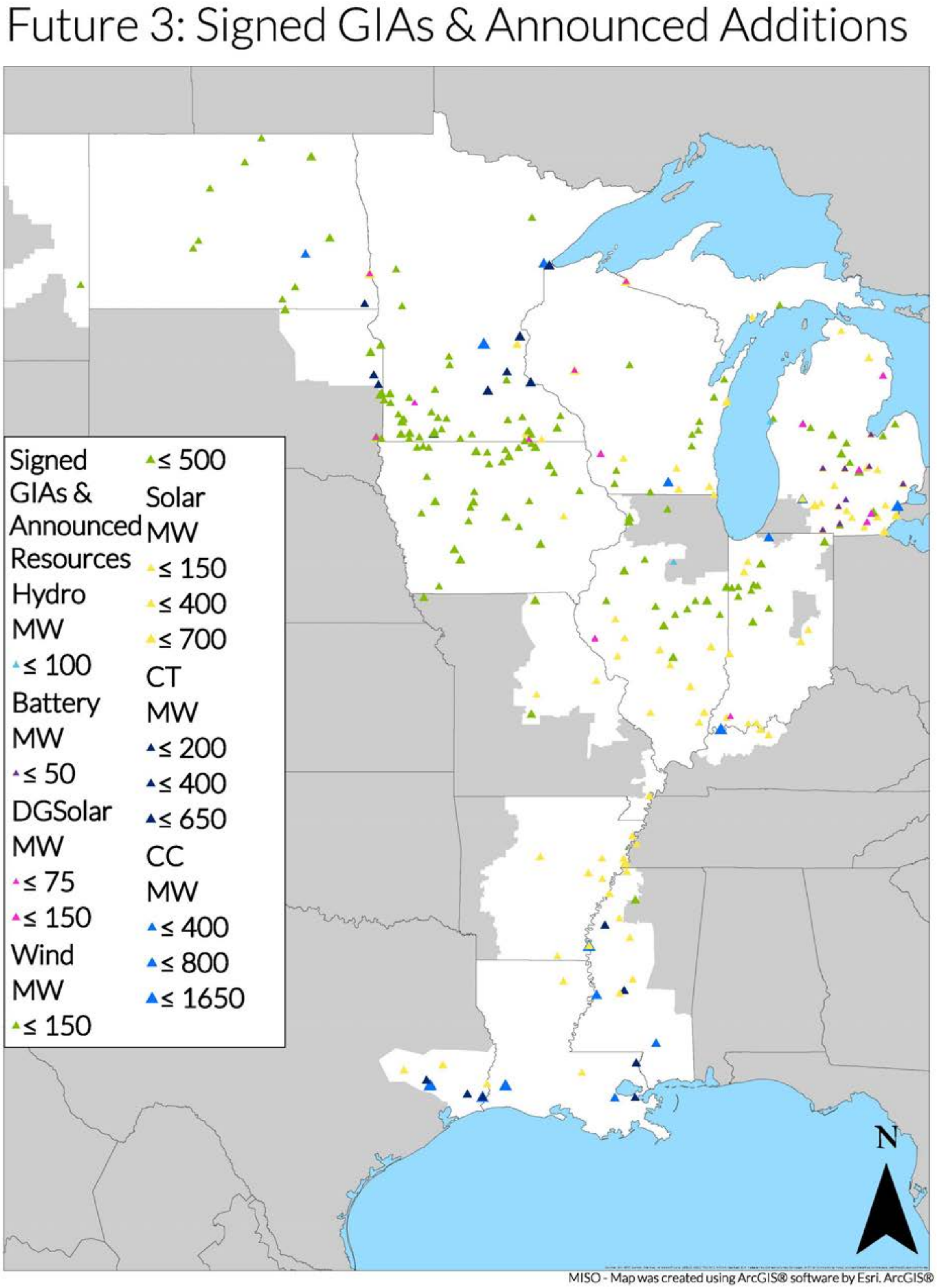
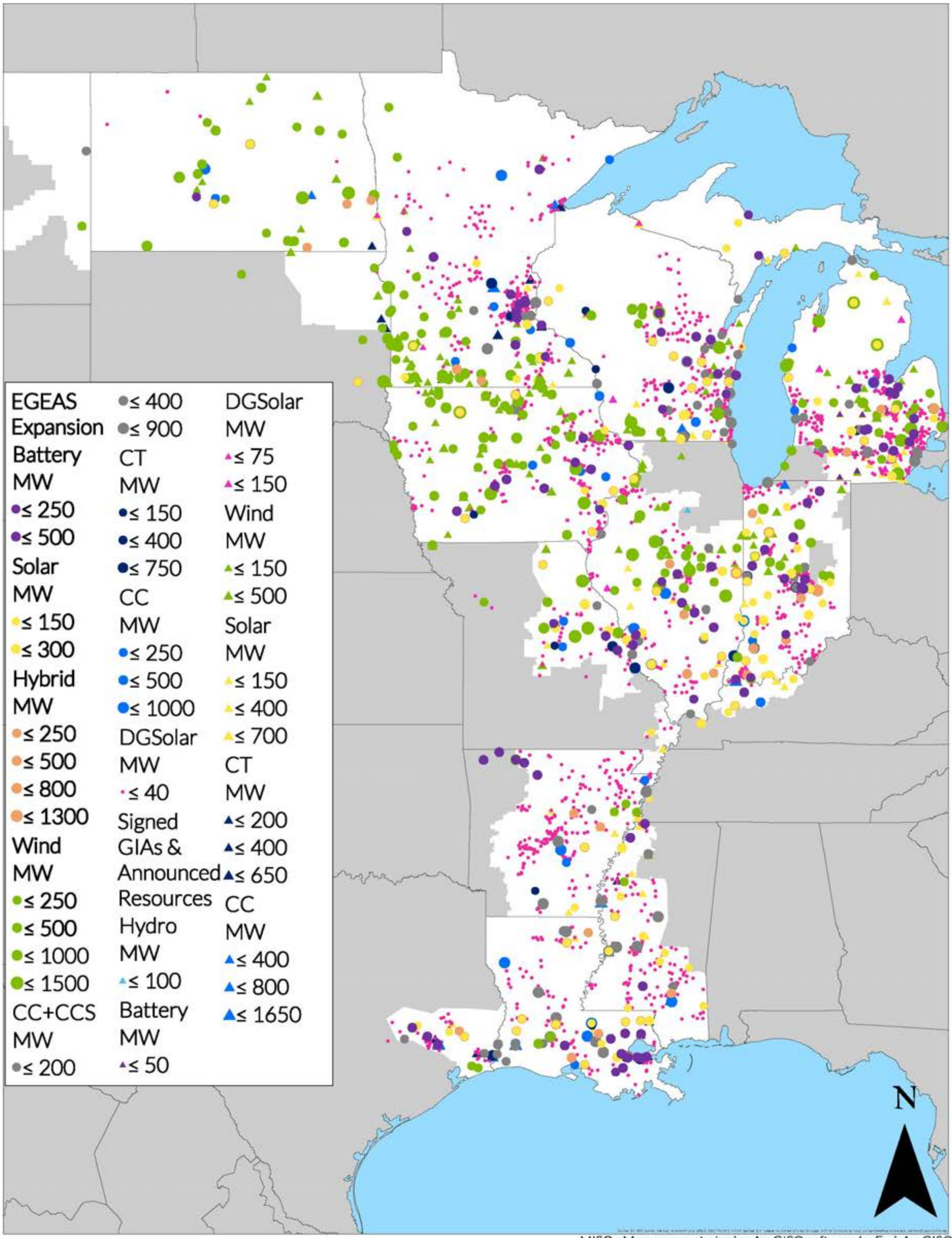


Figure 72: MISO Future 3 Non-EGEAS Expansion Siting

Future 3: Total Expansion



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 73: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

Future 3 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	2,179	0	7,398	640	0	149	350	0	11,565
	2030	4,766	3,486	0	12,897	2,228	969	606	712	0	25,664
	2035	6,641	6,054	409	25,786	4,728	969	3,635	1,202	0	49,425
	2039	6,731	6,054	3,881	35,848	4,728	969	5,302	1,486	0	64,998
LRZ 2	**2025**	1,686	620	0	949	1,332	0	91	86	0	4,764
	2030	2,762	673	0	2,532	1,991	516	356	275	0	9,105
	2035	4,880	673	0	5,898	2,066	516	2,133	556	0	16,722
	2039	4,880	673	5,363	8,132	2,066	516	3,111	703	0	25,443
LRZ 3	**2025**	311	0	0	5,669	513	0	74	74	0	6,640
	2030	769	92	0	10,102	1,019	264	298	235	0	12,779
	2035	769	92	200	20,874	1,019	264	1,786	475	0	25,479
	2039	769	92	766	29,249	1,019	264	2,605	600	0	35,364
LRZ 4	**2025**	900	0	0	3,768	2,240	0	72	68	10	7,059
	2030	1,612	1,134	0	5,745	2,957	2,122	278	130	10	13,988
	2035	1,612	1,134	459	10,219	2,957	2,122	1,668	221	10	20,403
	2039	1,612	1,134	2,203	13,808	2,957	2,122	2,432	269	10	26,548
LRZ 5	**2025**	64	609	0	1,793	283	0	62	57	0	2,868
	2030	748	1,344	0	3,091	728	251	234	181	0	6,577
	2035	2,114	1,344	266	6,029	791	251	1,402	366	0	12,565
	2039	2,114	1,344	2,117	8,143	805	251	2,045	463	0	17,282
LRZ 6	**2025**	4,659	1,223	0	2,765	2,467	0	142	89	0	11,345
	2030	7,629	2,158	0	3,805	4,259	3,401	566	164	0	21,982
	2035	8,375	2,158	1,661	6,410	4,259	3,401	3,398	277	0	29,940
	2039	8,375	2,158	4,988	8,251	4,259	3,401	4,955	336	0	36,723
LRZ 7	**2025**	3,051	0	0	4,837	1,722	0	159	767	72	10,609
	2030	3,051	153	0	7,079	3,936	1,054	648	841	72	16,832
	2035	3,120	153	1,642	12,888	5,136	1,054	4,087	949	72	29,100
	2039	3,120	153	5,870	16,730	5,736	1,054	6,068	1,006	72	39,808
LRZ 8	**2025**	250	0	0	227	2,544	0	57	59	0	3,137
	2030	1,897	134	0	454	2,753	571	229	188	0	6,226
	2035	1,897	134	122	954	2,753	571	1,377	379	0	8,187
	2039	1,897	134	1745	1,317	2,753	571	2,008	479	0	10,904
LRZ 9	**2025**	6,061	915	0	201	1,031	0	160	64	0	8,432
	2030	8,321	4,215	0	401	2,156	1,529	639	205	0	17,466
	2035	9,953	4,907	726	842	2,356	1,529	3,836	415	0	24,564
	2039	9,953	5,253	10,361	1,163	2,356	1,529	5,594	524	0	36,734
LRZ 10	**2025**	672	0	0	245	627	0	34	37	0	1,616
	2030	672	350	0	291	1,517	123	146	119	0	3,217
	2035	2,472	700	515	390	2,017	123	877	240	0	7,334
	2039	2,472	700	4,707	463	2,017	123	1,280	303	0	12,064
MISO Total	**2025**	18,503	5,546	0	27,853	13,400	0	1,000	1,650	82	68,034
	2030	32,228	13,739	0	46,396	23,544	10,800	4,000	3,049	82	133,837
	2035	41,833	17,349	6,000	90,291	28,082	10,800	24,200	5,081	82	223,719
	2039	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	305,869

Table 11: MISO Future 3 Resource Additions by LRZ and Footprint

Future 3 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,272	0	698	240	0	36	6,569
	2030	6,420	2,635	0	698	519	0	36	10,307
	2035	7,040	3,337	1,092	824	2,946	0	36	15,275
	2039	7,040	3,651	1,092	885	3,572	0	36	16,276
LRZ 2	**2025**	2,981	604	0	351	11	0	0	3,947
	2030	2,981	2,017	0	351	41	0	0	5,390
	2035	4,173	3,010	0	351	427	0	0	7,961
	2039	4,232	4,906	0	409	617	0	0	10,163
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	776	107	448	275	348	0	0	1,954
	2035	776	135	448	275	1,434	0	0	3,068
	2039	808	702	448	328	2,707	0	0	4,992
LRZ 4	**2025**	3,118	134	0	117	0	0	0	3,369
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	1,199	0	117	379	0	0	4,813
	2039	3,326	2,794	0	176	1,013	0	0	7,309
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	582	0	345	169	0	0	5,994
	2039	6,132	3,047	0	345	169	0	0	9,692
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	1,398	0	71	0	0	0	13,005
	2035	11,537	3,102	0	71	377	0	0	15,086
	2039	11,537	3,889	0	71	582	21	0	16,100
LRZ 7	**2025**	2,991	1,697	819	59	0	0	0	5,565
	2030	4,258	1,906	819	59	0	0	0	7,041
	2035	4,878	3,760	819	59	230	0	0	9,745
	2039	8,013	7,134	819	74	565	0	0	16,604
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	882	0	0	0	0	0	4,012
	2039	3,130	3,436	0	0	0	0	0	6,566
LRZ 9	**2025**	2,746	7,243	0	7	0	0	0	9,996
	2030	2,746	7,243	0	7	0	0	0	9,996
	2035	2,746	9,711	0	7	0	0	0	12,464
	2039	2,746	18,259	0	7	0	0	0	21,012
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	3,248	0	0	0	0	0	3,248
	2039	0	3,549	0	0	0	0	0	3,549
MISO Total	**2025**	33,525	13,640	1,267	1,822	373	0	36	50,663
	2030	38,858	17,185	1,267	1,922	928	0	36	60,196
	2035	42,297	28,965	2,359	2,049	5,960	0	36	81,665
	2039	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 12: MISO Future 3 Resource Retirements by LRZ and Footprint

Appendix

EGEAS Modeling

Description

The Electric Generation Expansion Analysis System (EGEAS) is a program developed by EPRI which MISO uses to conduct its expansion analysis studies. The primary function of EGEAS is the creation of a generation expansion plan that meets system requirements specified by several inputs, assumptions, and constraints.

Modeling Procedure

The modeling process can be broken down into three main stages: definition of the model through inputs, computational analysis and solution processing, and consolidation of the results in the output file.

Inputs

Listed below are some of the key input parameters that EGEAS uses when selecting the optimal expansion solution. EGEAS allows users to input a variety of variables however, the inputs below include some of the more important parameters when setting up an economic expansion model.

- Hourly load shape files for the system and NDTs
- Projected peak yearly values of demand and energy
- Planning Reserve Margin (PRM) percentage requirement
- Renewable Portfolio Standard (RPS) percentage trajectories
- Decarbonization trajectories, may be input in short tons or $/short ton
- Existing unit data including planned additions and retirements
- Cost of unserved energy
- Available expansion resources and respective cost and emission data

Computational Analysis

To find the optimal resource expansion plan, EGEAS solves two objective functions:

1. Present value of the revenue requirements
2. The levelized average system rates ($/MWh)

The bulk of the work done by EGEAS is in solving these functions. It is an iterative process that progresses through the study year by year. Retaining only the feasible solutions each year, a single expansion plan that satisfies all input constraints and limitations over the study period is selected after the final year of study.

Output

The final report file is a text output file containing a report on the generic units EGEAS built to meet the system constraints in every year of the study. Metrics such as PRM, RPS, systemwide CO_2 emissions, resource generation, and cost data are also included in the report file.

From this information, MISO staff acquires its resource expansion and sites these resources throughout the footprint based on generator availability and other criteria discussed in the New Resource Addition Siting Process section of this report.

An important metric used in the Futures process is the RPS which EGEAS calculates as the ratio of Renewable Energy Generation (from wind, solar, and solar hybrid resources) to Net System Energy. In this calculation, net system energy is the sum of forecasted and storage charging energy minus energy from demand side management programs. While this may be how EGEAS calculated required contribution from renewable resources when defining an economic expansion, MISO displays these results differently so that energy generation from all resources may be seen. The calculation used by MISO is (Renewable Energy GWh / Total Generation GWh).

Shown below is an example of the EGEAS and MISO calculation to meet the RPS in Future 3 year 2039. MISO values appear less than EGEAS calculated values because total generation includes energy from DSM programs and curtailed renewable energy from low demand periods.

EGEAS Calculation

Forecasted System Energy (GWh)	Storage Charging (GWh)	DSM Energy (GWh)	Net System Energy (GWh)	Renewable Energy Generation (GWh)	RPS %
1,063,465	176,423	56,665	1,183,223	622,241	53%

$$\left(\frac{Renewable}{Forecasted + Storage - DSM}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}063{,}465 + 176{,}423 - 56{,}665}\right) \times 100 = 52.59$$

MISO Calculation

Total Energy Generation (GWh)	Renewable Energy Generation (GWh)	RPS %
1,352,519	622,241	46%

$$\left(\frac{Renewable}{Total\ Generation}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}352{,}519}\right) \times 100 = 46.01$$

Additional MISO Assumptions

Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

Variables	Future 1	Future 2	Future 3
Gross Load[29] Total Growth	Low-Base EV Growth 94,275 GWh	30% Total Energy Growth by 2040 196,996 GWh	50% Total Energy Growth by 2040 334,692 GWh
Energy (CAGR) Input/*Result*	0.63% / *0.48%*	1.22% / *1.09%*	1.91% / *1.71%*
Demand (CAGR) Input/*Result*	0.75% / *0.60%*	1.11% / *0.97%*	1.60% / *1.41%*
Electrification Growth & Technologies Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs DR	0.94 GW	0.94 GW	0.94 GW
EE	7.82 GW	8.05 GW	11.72 GW
DG	3.47 GW	3.47 GW	6.17 GW
Carbon Reduction *(2005 baseline)* MISO Footprint currently at 29%	40% *63% realized in results*	60% *65% realized in results*	80% *81% realized in results*
Wind & Solar Generation Percentage[82]	Resulted in 26% with No Minimum Enforced	Resulted in 35% with No Minimum Enforced	46%
Utility Announced Plans	85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

[29] Total Growth is based on 2039 values due to the study period ending on 12/31/2039.

Variables		Future 1	Future 2	Future 3
Retirement Age-Based Criteria	Coal	46 years[30]	36 years	30 years
	Natural Gas-CC	50 years	45 years	35 years
	Natural Gas-Other	46 years	36 years	30 years
	Oil	45 years	40 years	35 years
	Nuclear	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
	Wind & Solar - Utility Scale	25 years	25 years	25 years
Retirements	Coal	44.8 GW	45.1 GW	47 GW
	Gas	18.6 GW	21.6 GW	51.4 GW
	Oil	2 GW	2.03 GW	2.3 GW
	Nuclear	2.4W	2.4GW	2.4GW
	Wind	9.2 GW	9.2 GW	9.2 GW
	Solar	0.02 GW	0.02 GW	0.02 GW
	Other	0.04 GW	0.04 GW	0.04 GW
	Total	77.1 GW	80.4 GW	112.3 GW
Additions	CC	37.1 GW	58.7 GW	41.9 GW
	CT	14.1 GW	10.5 GW	17.7 GW
	CC+CCS	0 GW	1.2 GW	42 GW
	Wind[31]	18.7 GW	63.1 GW	123.1 GW
	Solar	34.7 GW	28.7 GW	28.7 GW
	Hybrid	12 GW	1.2 GW	10.8 GW
	Battery	0.6 GW	3.4 GW	35.4 GW
	Hydro	0.1 GW	0.1 GW	0.1 GW
	Total (Including DERs)	129.5 GW	179.4 GW	318.5 GW

Table 14: MISO Futures Assumptions and Expansion Results

[30] EIA Source for Coal Retirement Age, Future 1: https://www.eia.gov/todayinenergy/detail.php?id=40212

[31] All Futures include 9.2 GW of repowered wind and 9.5 GW of wind from signed GIAs.

Capital Costs

MISO used the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[32] to calculate the capital costs for all resources except for oil,[33] storage compressed air energy storage (CAES),[34] and internal combustion (IC) renewable[35] costs. MISO utilized moderate cost values within the 2020 ATB, which are in 2018 dollars. These values were converted to 2020 dollars and projected into the 20-year study period to create cost trajectories. For Hybrid unit costs, 2020 ATB Solar PV + Battery costs are included.

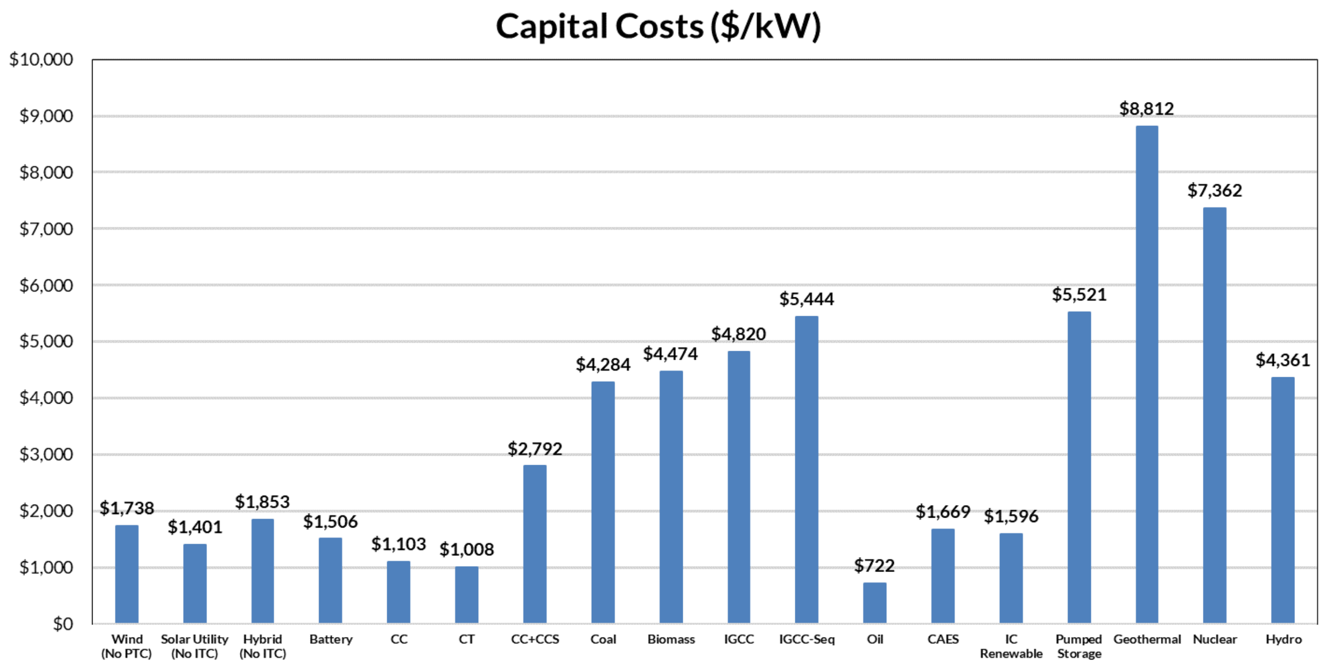


Figure 74: Annual Capital Cost Assumptions by Fuel Type

[32] NREL 2020 ATB: https://atb.nrel.gov/electricity/2020/data.php
[33] EIA costs were used and adjusted for 2020 dollars: https://www.eia.gov/electricity/generatorcosts/
[34] Costs from the DOE Energy Storage Technology and Cost Characterization Report of July 2019: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf
[35] Costs from EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

Production Tax Credit (PTC) and Investment Tax Credit (ITC) effects on wind, utility-scale solar PV, and hybrid units are displayed below. Since the battery in the hybrid unit modeled is charged from solar resources 100% of the time, it may qualify for 100% of ITC benefits.[36,37]

Actual and Modeled Schedule of Wind and Solar Tax Credits

Consolidated Appropriations Act of 2016 PTC with 2020 Extensions	2016	2017	2018	2019	2020	2021	2022	2023 & onward
Utility Wind PTC	Full	80%	60%	40%	60%	0%	0%	0%
Utility Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%
Model Representation	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 & onward**
Utility Wind PTC	Full	Full	Full	Full	Full	Full	Full	0%
Utility Solar ITC	30%	30%	30%	30%	30%	26%	22%	10%
Hybrid ITC (Battery charged by solar 100% of the time)	30%	30%	30%	30%	30%	26%	22%	10%

Table 15: PTC and ITC Schedule

Accreditations of PTC and ITC benefits are seen for wind, solar, and hybrid units since extensions and changes were issued in the spring of 2020. The model representation differs due to the assumed construction time of each of these units, in order to ensure their safe harbor provisions. MISO used the values in the model representation section to build cost trajectories for these resources in EGEAS.

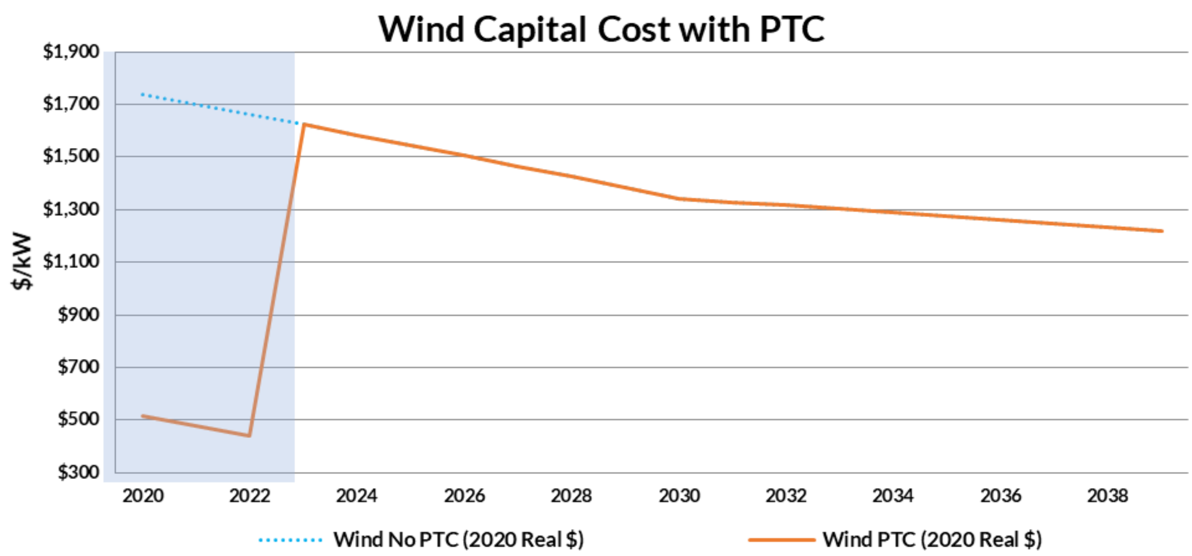


Figure 75: Wind with PTC

[36] Source for PTC and ITC for Wind & Solar PV: https://fas.org/sgp/crs/misc/R43453.pdf

[37] NREL - ITC accreditation for Hybrids: https://www.nrel.gov/docs/fy18osti/70384.pdf

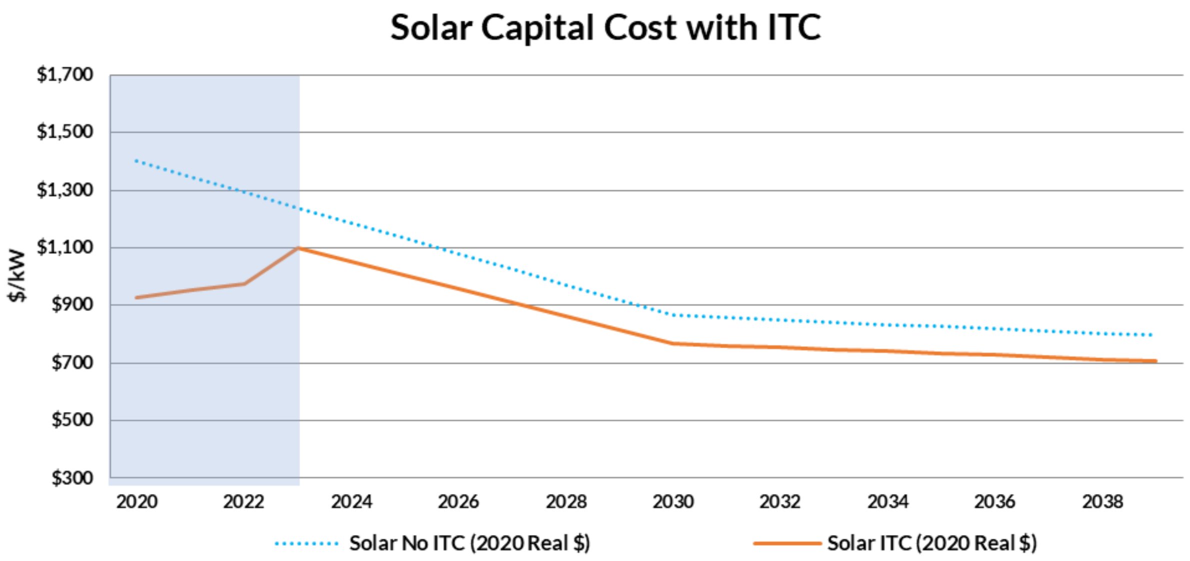


Figure 76: Solar PV with ITC

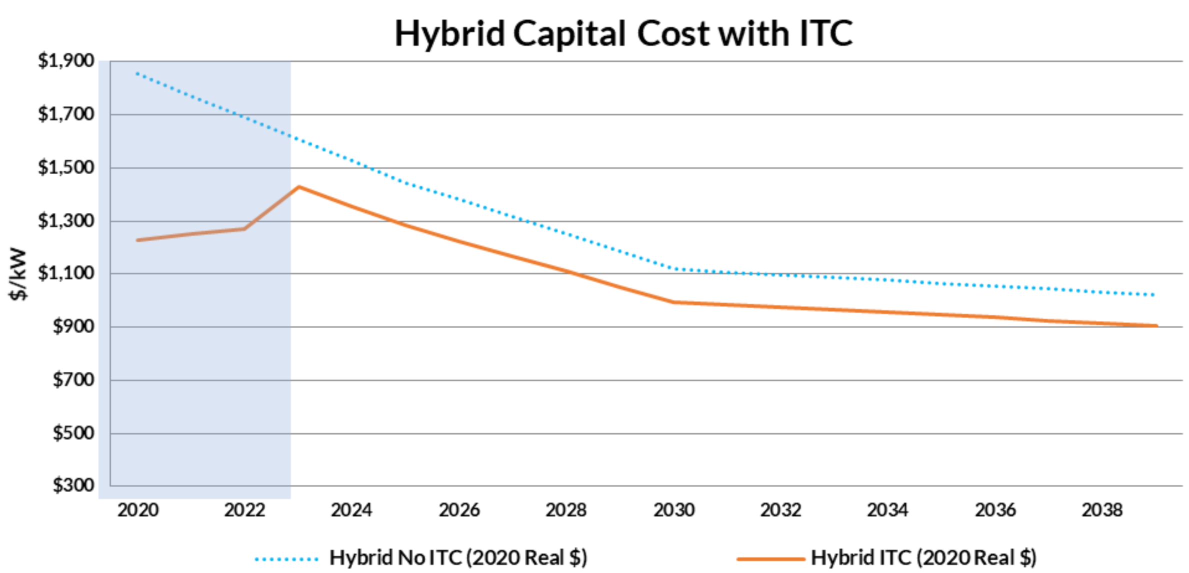


Figure 77: Hybrid with ITC

Electrification and Energy Growth Values

Although the energy growth in Futures 2 and 3 reaches 30% and 50% by 2040 respectively, not all growth is from electrification. Table 16 details the amounts of growth resulting from the reference forecast (SUFG) and electrification (AEG). By the end of the study period (12/31/2039), energy in Futures 1, 2, and 3 increases by 13%, 27%, and 46% respectively. On the following page, Table 17 presents the granular energy values for each technology that was electrified. These numbers represent the total energy growth from electrification in each Future scenario by LRZ.

Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	705,604	716,734	728,773
2039 Reference Growth	80,128	87,895	103,179
Electrification Growth	14,147	109,101	231,513
2039 Energy Forecast	799,879	913,730	1,063,465
Total Energy Increase, 2020-2039	**13%**	**27%**	**46%**
Energy Increase from Reference Forecast	11%	12%	14%
Energy Increase from Electrification	2%	15%	32%
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 16: Future-Specific Growth Assumptions (GWh)

Energy Growth by Technology Type from Electrification (GWh)								
F1	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	0	0	0	0	0	0	2,636	2,636
LRZ 2	0	0	0	0	0	0	2,016	2,016
LRZ 3	0	0	0	0	0	0	719	719
LRZ 4	0	0	0	0	0	0	1,237	1,237
LRZ 5	0	0	0	0	0	0	747	747
LRZ 6	0	0	0	0	0	0	1,264	1,264
LRZ 7	0	0	0	0	0	0	4,352	4,352
LRZ 8	0	0	0	0	0	0	238	238
LRZ 9	0	0	0	0	0	0	851	851
LRZ 10	0	0	0	0	0	0	87	87
Total	0	0	0	0	0	0	14,147	14,147
F2	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	3,108	2,556	1,266	4,711	307	0	6,542	18,489
LRZ 2	1,973	1,685	1,262	3,113	200	0	5,004	13,238
LRZ 3	2,076	945	451	2,425	137	0	1,784	7,818
LRZ 4	874	805	428	4,172	319	0	3,071	9,669
LRZ 5	2,307	654	332	1,686	129	0	1,855	6,962
LRZ 6	4,264	1,920	944	4,602	374	0	3,136	15,239
LRZ 7	3,265	2,574	2,085	5,710	316	0	10,802	24,751
LRZ 8	506	528	470	791	73	0	591	2,960
LRZ 9	1,330	1,540	1,114	2,276	387	0	2,112	8,760
LRZ 10	345	172	231	217	35	0	215	1,215
Total	20,048	13,378	8,584	29,702	2,277	0	35,112	109,101
F3	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	6,005	5,289	1,723	6,411	594	2,573	17,078	39,673
LRZ 2	3,812	3,498	1,718	4,237	387	1,834	13,062	28,548
LRZ 3	4,012	1,967	614	3,300	264	1,662	4,657	16,476
LRZ 4	1,690	1,611	583	5,678	616	1,056	8,017	19,250
LRZ 5	4,457	1,334	452	2,295	249	1,303	4,842	14,931
LRZ 6	8,242	3,806	1,284	6,263	722	1,932	8,186	30,437
LRZ 7	6,308	5,301	2,838	7,771	611	2,878	28,198	53,905
LRZ 8	978	1,050	640	1,076	142	1,116	1,543	6,545
LRZ 9	2,570	3,043	1,516	3,098	749	2,340	5,513	18,829
LRZ 10	666	341	315	295	68	674	562	2,921
Total	38,741	27,240	11,683	40,423	4,400	17,368	91,658	231,513

Table 17: Quantification of Electrified Technologies (2020-2039)

Natural Gas Price Forecasting

MISO used the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures, instead of the Henry Hub price (HH) as in past cycles. GPCM outputs the gas price at a level of monthly granularity and produces unit-specific gas prices. The gas forecast per unit remained the same for all Futures modeled in EGEAS.

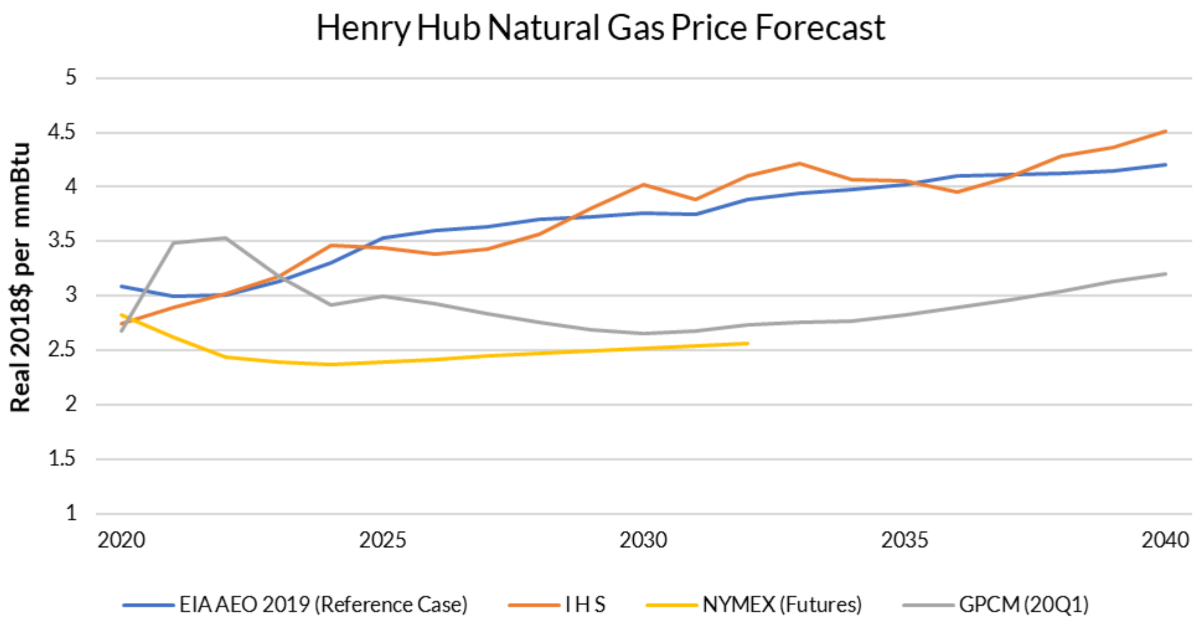


Figure 78: Henry Hub Natural Gas Price Forecast

General Assumptions

Study Period

The study period of the EGEAS resource expansion analysis is 20 years, beginning on 1/1/2020 and ending on 12/31/2039. An extension period of 40 years is added to the end of the simulation, with no new units forecasted during this time. This extension ensures that the generation selected in the last few years of the forecasting period (i.e., Years 15-20) is based on cost of generation spread out over the total tax/book life of the new resources (i.e., beyond Year 20) and does not bias to the cheapest generation in those final years.

Discount Rate

The discount rate of 7.22% is based upon the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

MISO Footprint Study Area

The study area for the updated MISO Futures continued to be the entire MISO footprint. However, the Local Clearing Requirement (LCR) for each zone was evaluated during the siting process to ensure each LRZ met their respective LCR as defined in the 2020/2021 Planning Resource Auction (PRA).

External Assumptions and Modeling

General Assumptions

External Footprint Study Area

From an external-to-MISO (External areas) perspective, MISO increased the EGEAS analysis granularity for External areas/pools represented in the MCPS[38] by increasing the number of representative models.

MISO-Created External Regional Model and Future Assumptions			
EGEAS Models	**Future 1**	**Future 2**	**Future 3**
PJM	Yes	Yes	Yes
SPP	No – Use SPP ITP Future 2 and Results[39]	Yes	Yes
TVA-Other *(includes Southeast, TVA, TVA-Other)*	Yes	Yes	Yes
Manitoba Hydro	No	No	No

Table 18: EGEAS External Model Representation

MISO realizes system flows depend on External areas' representations and the above improvements are intended to help align MISO Future assumptions to MISO's neighbors, as well as provide a Future (Future 1) that utilizes SPP Future assumptions. This Future will be used to help bookmark projected External system flows as decided by External Future assumptions.

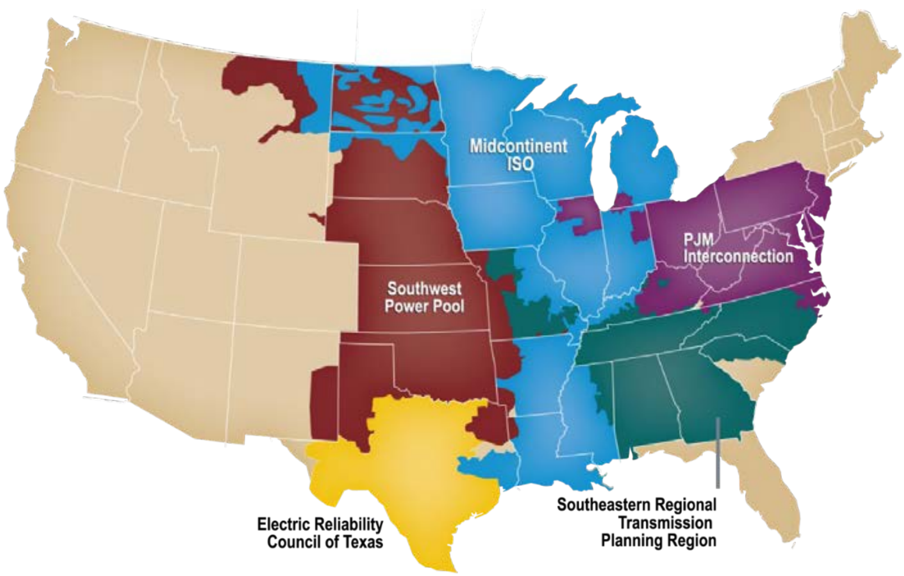


Figure 79: MISO Footprint & Neighboring Systems

[38] MISO Market Congestion Planning Studies (MCPS): https://www.misoenergy.org/stakeholder-engagement/committees/subregional-planning-meeting/market-congestion-planning-studies---south/

[39] https://www.spp.org/documents/61365/2021%20itp%20scope%20mopc%20and%20board%20approved.pdf

External Areas Forecasts Development

The 2019 Merged Load Forecast for Energy Planning forecast did not include External (non-MISO) companies' forecasts, so when available, External areas utilized respective regional model forecasts and when no regional forecast was available, the latest Multiregional Modeling Working Group (MMWG) model was used to create associated forecasts. External forecasts are defined in Table 19 and Future-specific adjustments will follow a similar process as shown in Table 18. Additionally, External areas utilized ABB's Velocity Suite 2018 load shapes.

Peak Load (MW) and Annual Energy (GWh)			
External Area (MCPS-Defined)	**Future 1**	**Future 2**	**Future 3**
PJM	PJM 2020 Long-Term Load Forecast (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
SPP	2021 ITP Future 2 Forecast (40% annual EV growth rate applied to energy only)	2021 ITP Future 1 Forecast + Future-Specific Adjustments	2021 ITP Future 1 Forecast + Future-Specific Adjustments
TVA-Other *(includes Southeast, TVA, TVA-Other)*	2019 MMWG Powerflow Model (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
Manitoba Hydro	MTEP20 CFC Forecast[40]	MTEP20 CFC Forecast	MTEP20 CFC Forecast

Table 19: External Area Demand & Energy Forecast Source

[40] 2020 MISO Transmission Expansion Planning (MTEP20): https://www.misoenergy.org/planning/planning/mtep20/

Electrification Assumptions

In addition to the electrification assumptions that were developed for the MISO footprint, a set of similar assumptions were made for External areas with the collaboration of AEG. The load growth in External areas came from electrification assumptions and reference load growth. Each area's growth is detailed in Table 20, electrification growth in Future 1 for SPP and PJM is reflected as zero due to this growth being incorporated in their reference load forecasts. Additionally, Figure 80 through Figure 87 detail the electrification of each technology within each External area.

PJM			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	939,546	946,602	949,301
2039 Reference Growth	111,347	111,347	111,347
Electrification Growth	0	172,086	353,105
2039 Energy Forecast	1,050,893	1,230,036	1,413,753
SPP			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	297,320	299,152	299,964
2039 Reference Growth	69,616	53,481	53,481
Electrification Growth	0	41,795	84,889
2039 Energy Forecast	366,936	394,428	438,334
TVA-Other (Southeast, TVA, TVA-Other)			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	698,962	702,206	703,821
2039 Reference Growth	78,303	75,059	73,444
Electrification Growth	7,553	76,817	163,373
2039 Energy Forecast	784,817	854,082	940,638
Electrification Technologies	PEVs (Included in reference forecast for PJM & SPP)	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 20: External Area Forecast Growth (GWh)

PJM Electrification

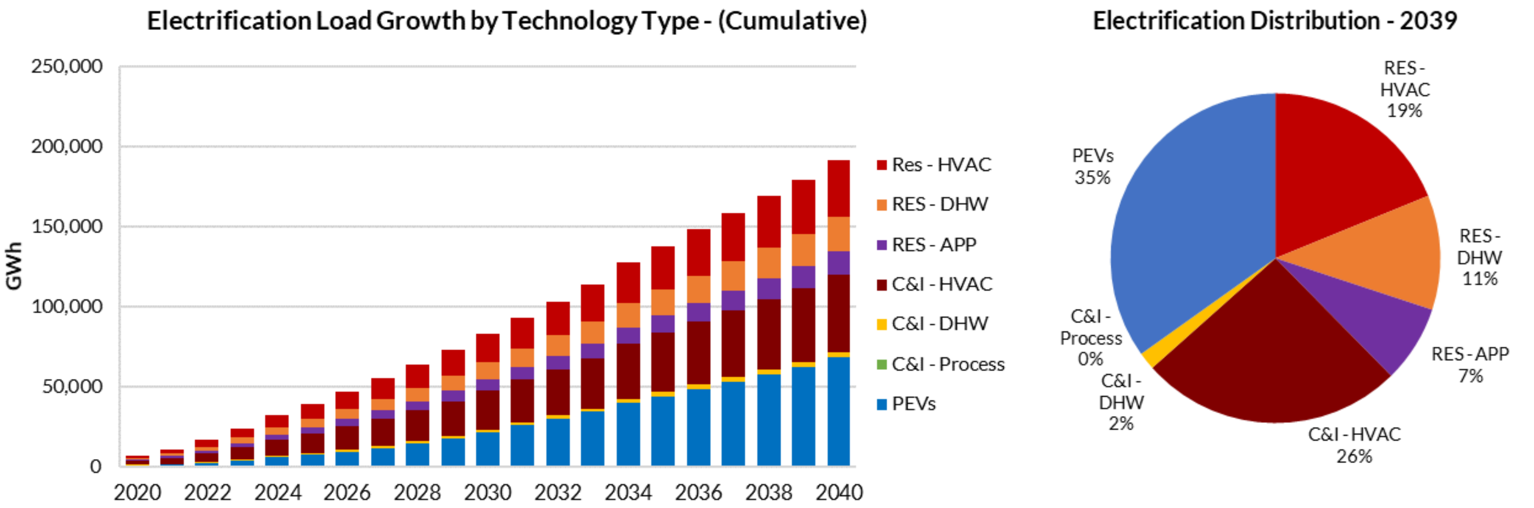


Figure 80: PJM Future 2 Electrification by End-Use

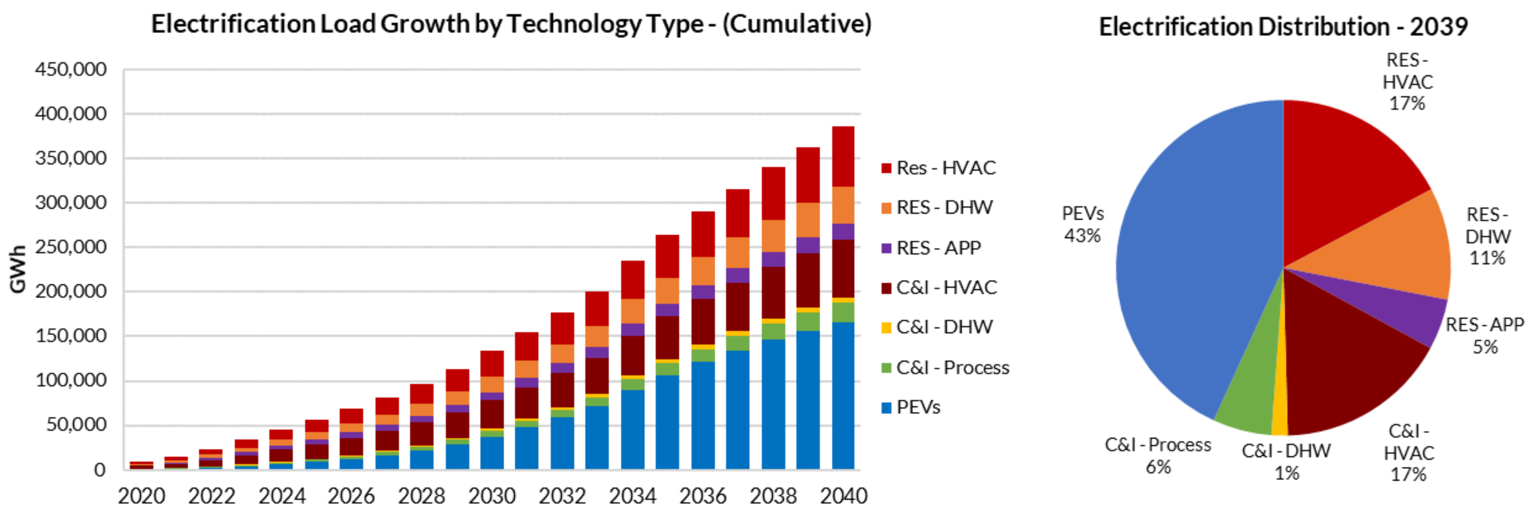


Figure 81: PJM Future 3 Electrification by End-Use

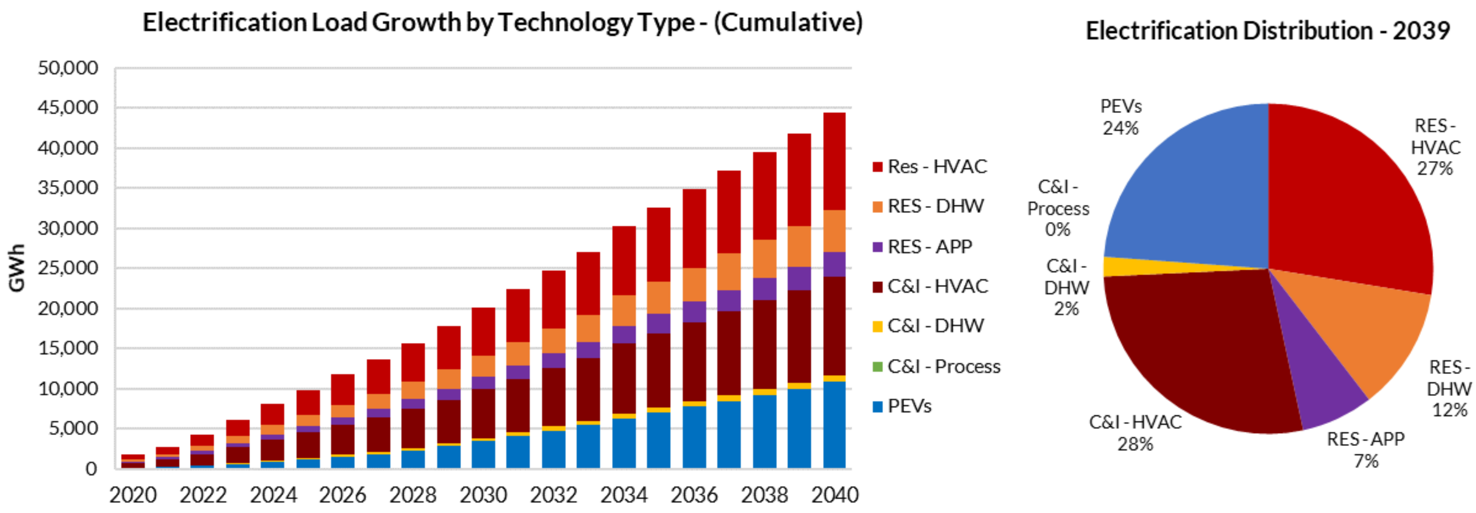


Figure 82: SPP Future 2 Electrification Broken Down by End-Use

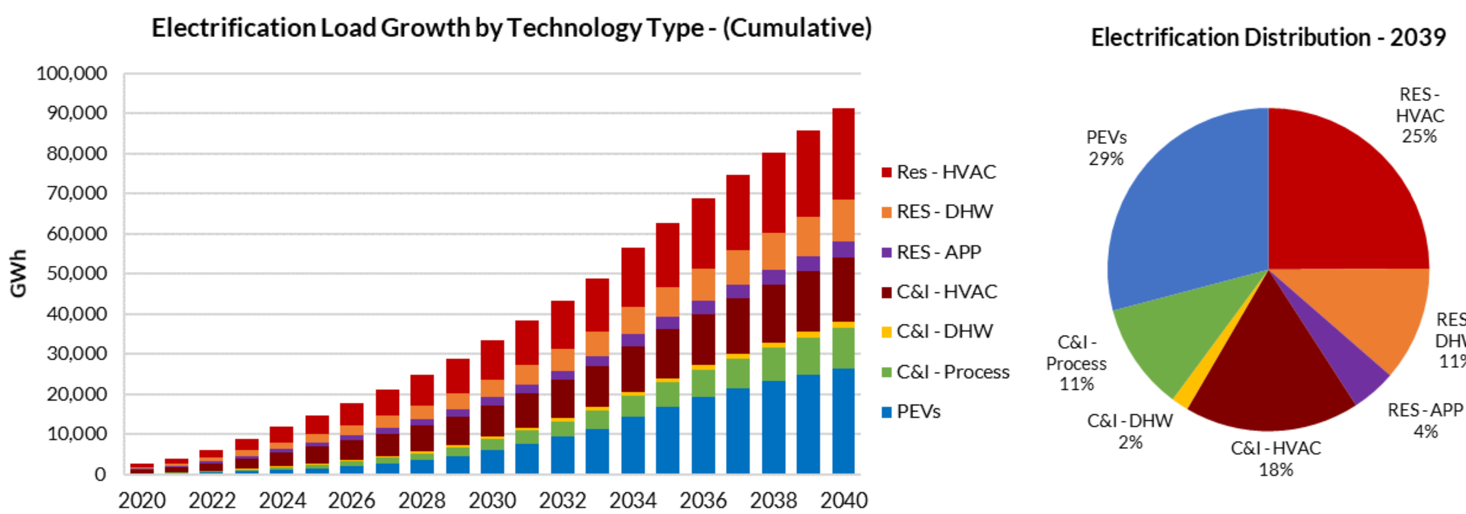


Figure 83: SPP Future 3 Electrification Broken Down by End-Use

TVA-Other Electrification

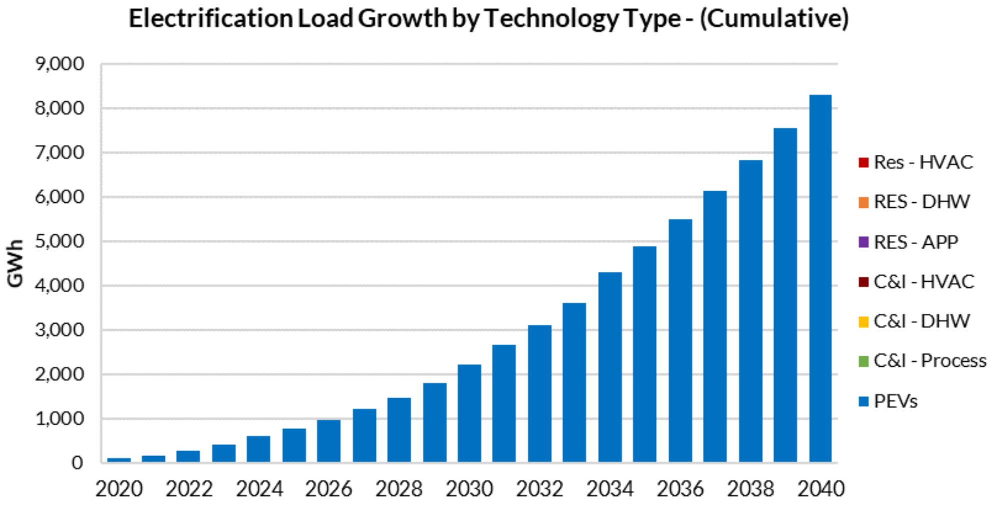
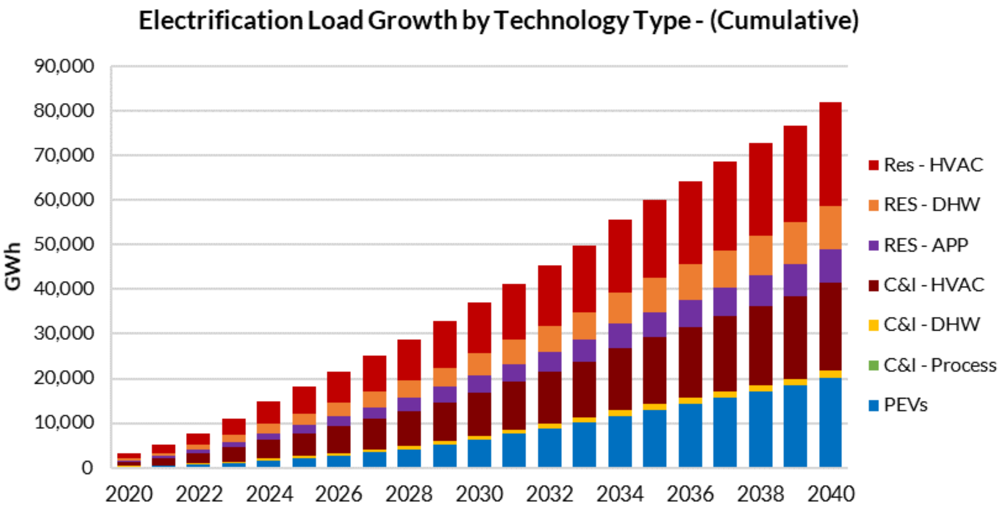


Figure 84: TVA-Other Future 1 Electrification Broken Down by End-Use



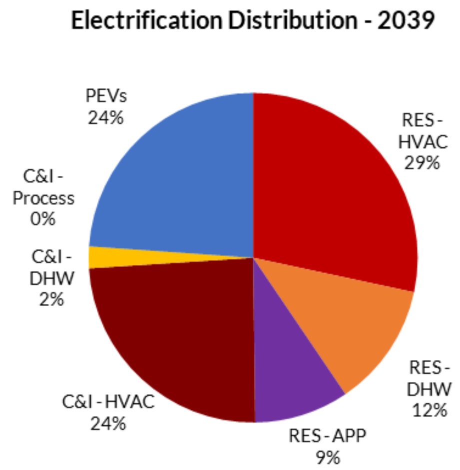


Figure 85: TVA-Other Future 2 Electrification Broken Down by End-Use

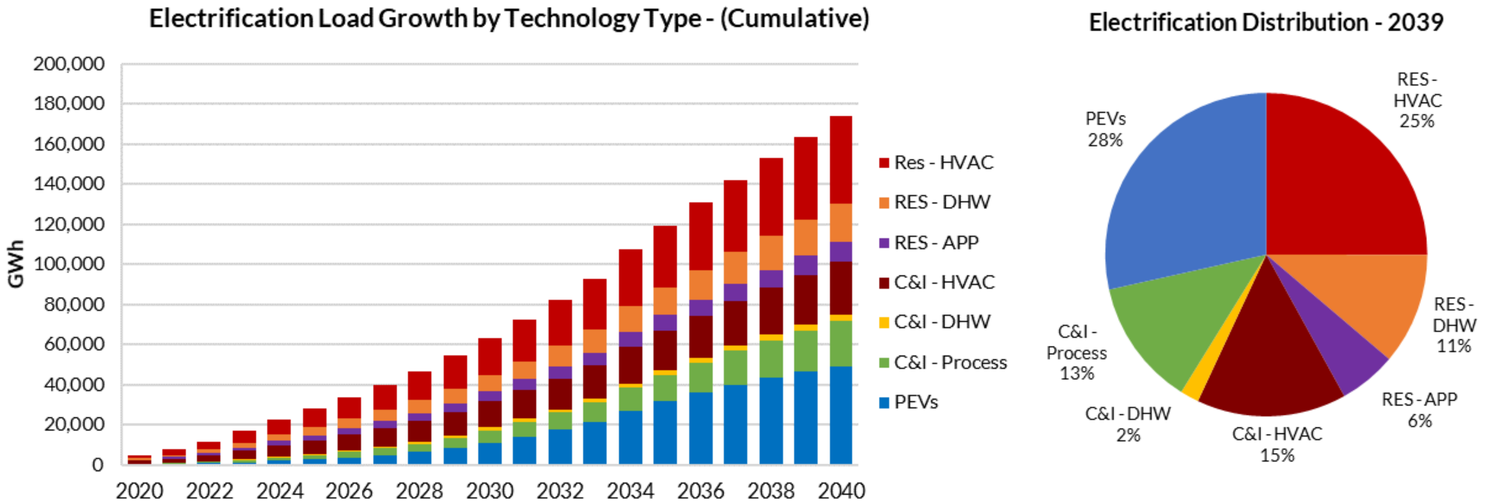


Figure 86: TVA-Other Future 3 Electrification Broken Down by End-Use

External Region Electrification Summary

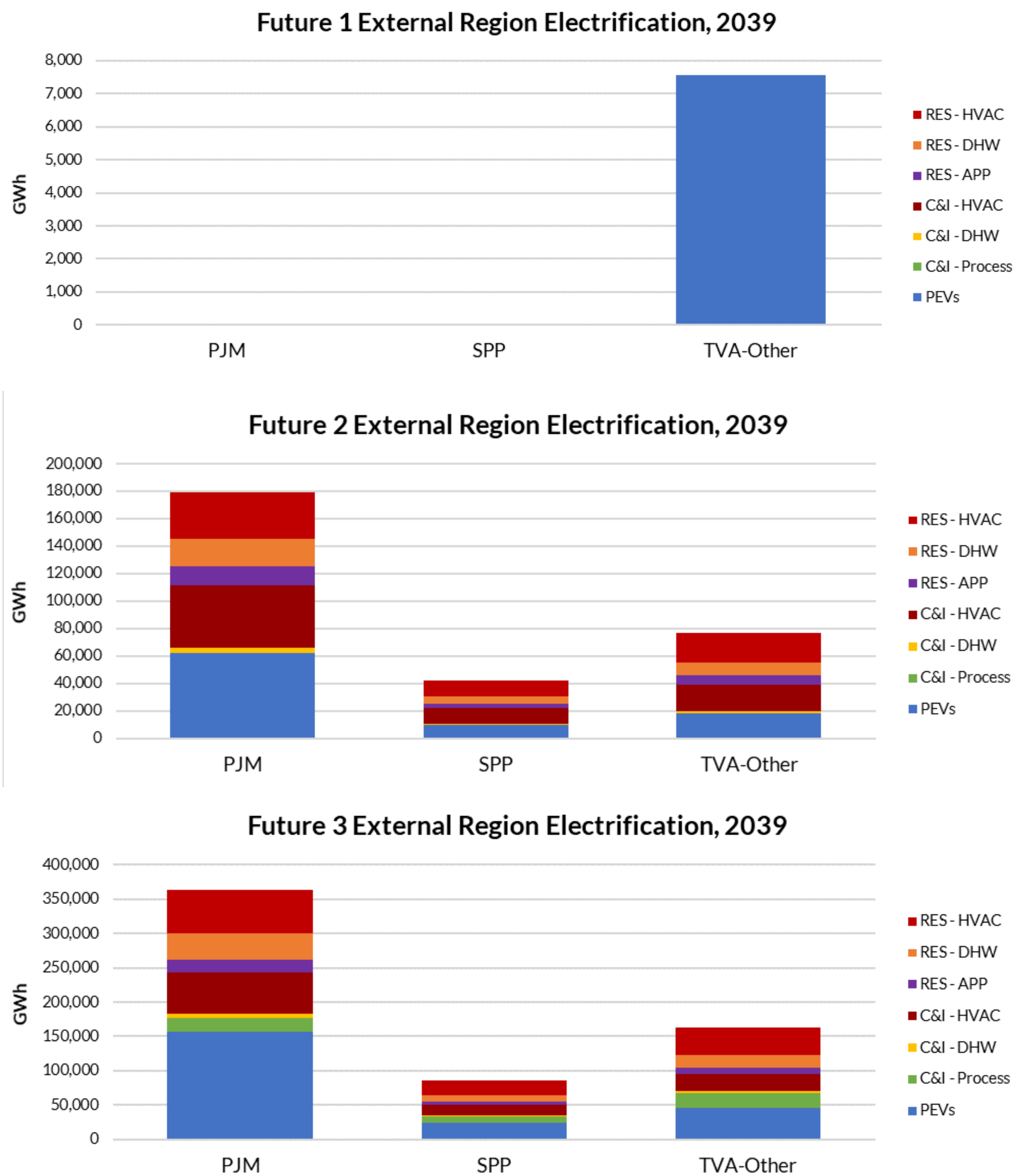


Figure 87: External Region Future Scenario Electrification[41]

[41] The only electrification in Future 1 happens in the external region TVA-Other due to SPP and PJM's Future 1 forecasts already including EVs.

External Expansion Results

While comparing the expansion results of the External regions across each Future scenario, there are several key findings of note:

- All scenarios have very different expansions; this is due to large contrasts among the regions with respect to geography, resource retirements, and current resource mixes.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load and 80% carbon reduction.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across scenarios, with the exception of SPP Future 1. In this future, MISO incorporated retirement assumptions in SPP's Future 2. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- In Future 3, the CC+CCS resource proxy units are needed in the later years of the study to serve base load with low CO_2 emissions, while maintaining a high capacity factor.
- Distributed solar (DGPV) and energy efficiency (EE) programs selected by EGEAS for TVA-Other (TVAO) remained the same across all scenarios. SPP Future 2 selected an additional EE program compared with Futures 1 and 3. Lastly, PJM's first two Futures both selected two DGPV and EE programs, while Future 3 selected one of each. A list of EGEAS-offered and selected programs for External regions is found below in Table 22.

Over the course of the following pages (Table 21 through Table 24) the detailed expansion results of each External Future scenario are displayed. Following the figures in each section are resource-specific additions and retirement (R&A) tables, each table details R&A capacities applicable for each region and milestone year.

Future Resource Additions (MW)											
Area	Future	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	EE	Total
PJM	Future 1	14,400	21,600	0	6,641	3,600	10,800	0	2,954	35,919	95,915
	Future 2	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	38,110	172,106
	Future 3	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	17,291	357,427
SPP	Future 1	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	1,197	58,797
	Future 2	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	3,253	73,009
	Future 3	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	1,332	98,588
TVA-Other	Future 1	16,800	1,200	0	14,405	0	26,400	0	118	346	59,269
	Future 2	16,800	7,200	0	60,005	13,200	25,200	300	118	370	123,193
	Future 3	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	382	274,905

Future Resource Retirements (MW)									
Area	Future	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Total
PJM	Future 1	53,068	9,312	0	7,002	6,641	251	0	76,275
	Future 2	54,680	15,348	0	7,136	6,641	251	0	84,055
	Future 3	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP	Future 1	18,361	5,631	0	1,260	0	0	0	25,252
	Future 2	19,842	13,205	0	1,361	9,856	50	0	44,314
	Future 3	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other	Future 1	42,295	7,350	0	1,910	1,205	165	276	53,201
	Future 2	43,840	9,117	0	1,910	1,205	165	276	56,513
	Future 3	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 21: External Resource Additions and Retirements Summary

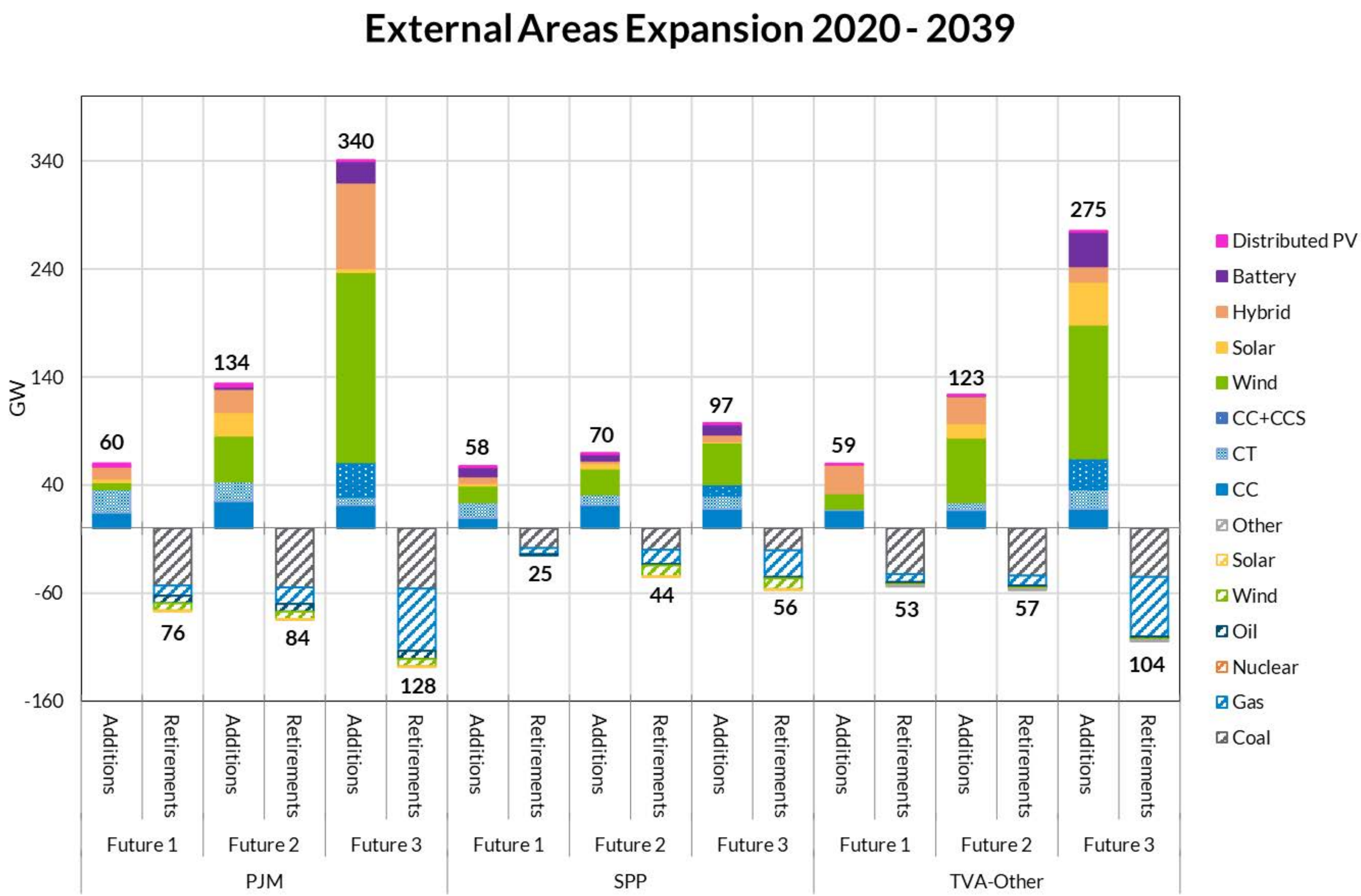


Figure 88: External Region Expansion Summary

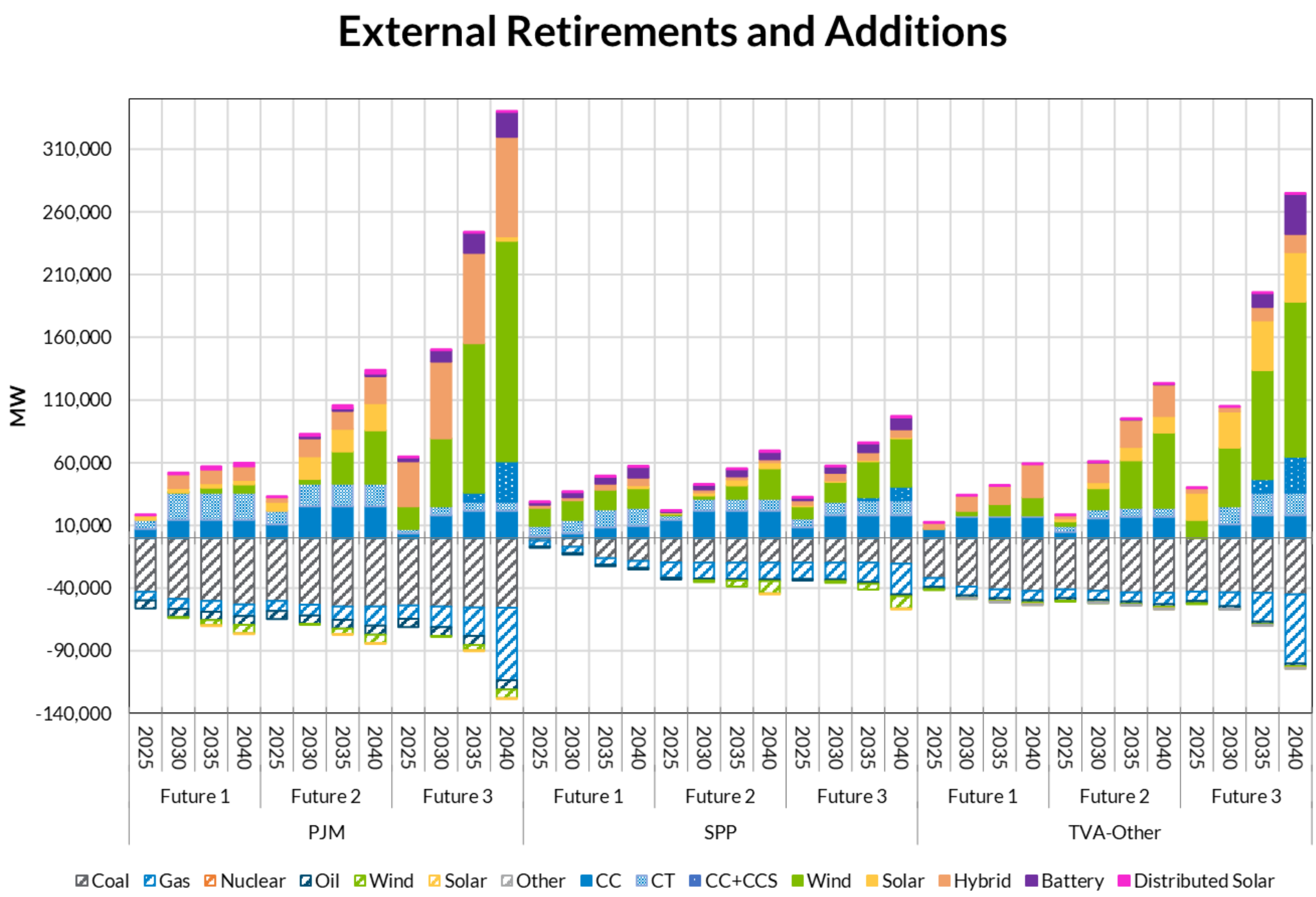


Figure 89: External Resource Additions and Retirements per Milestone Year (Cumulative)

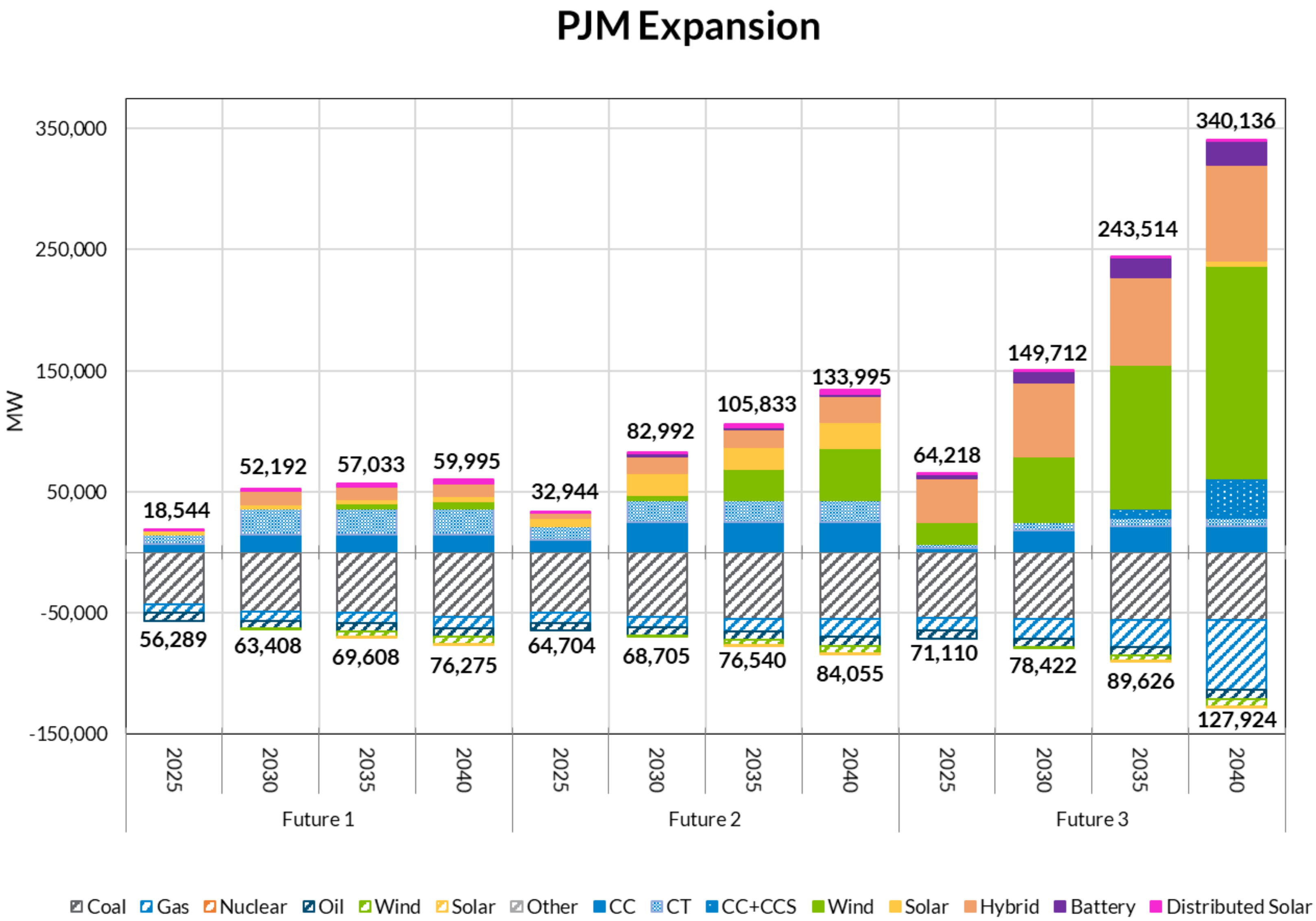


Figure 90: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

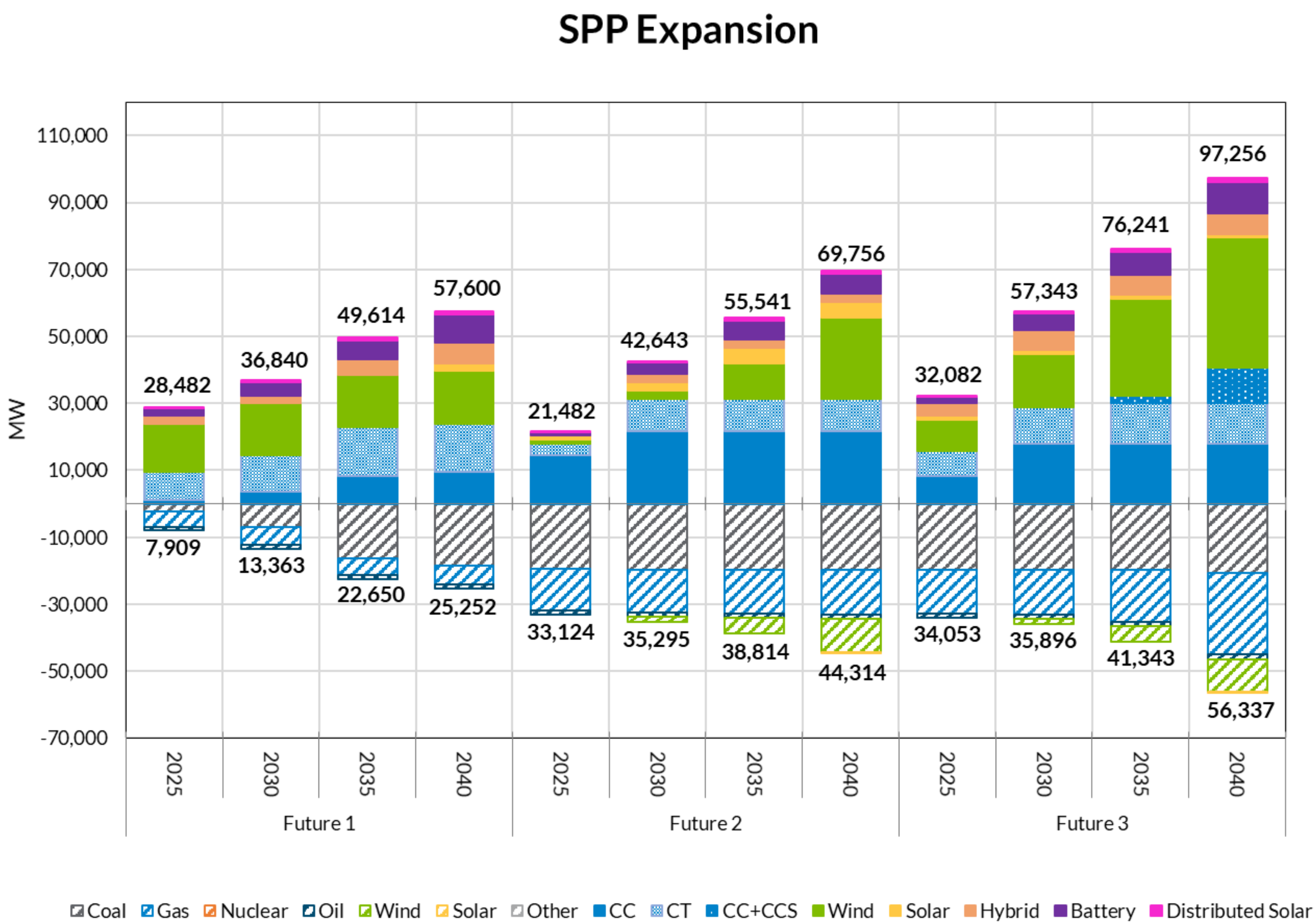


Figure 91: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

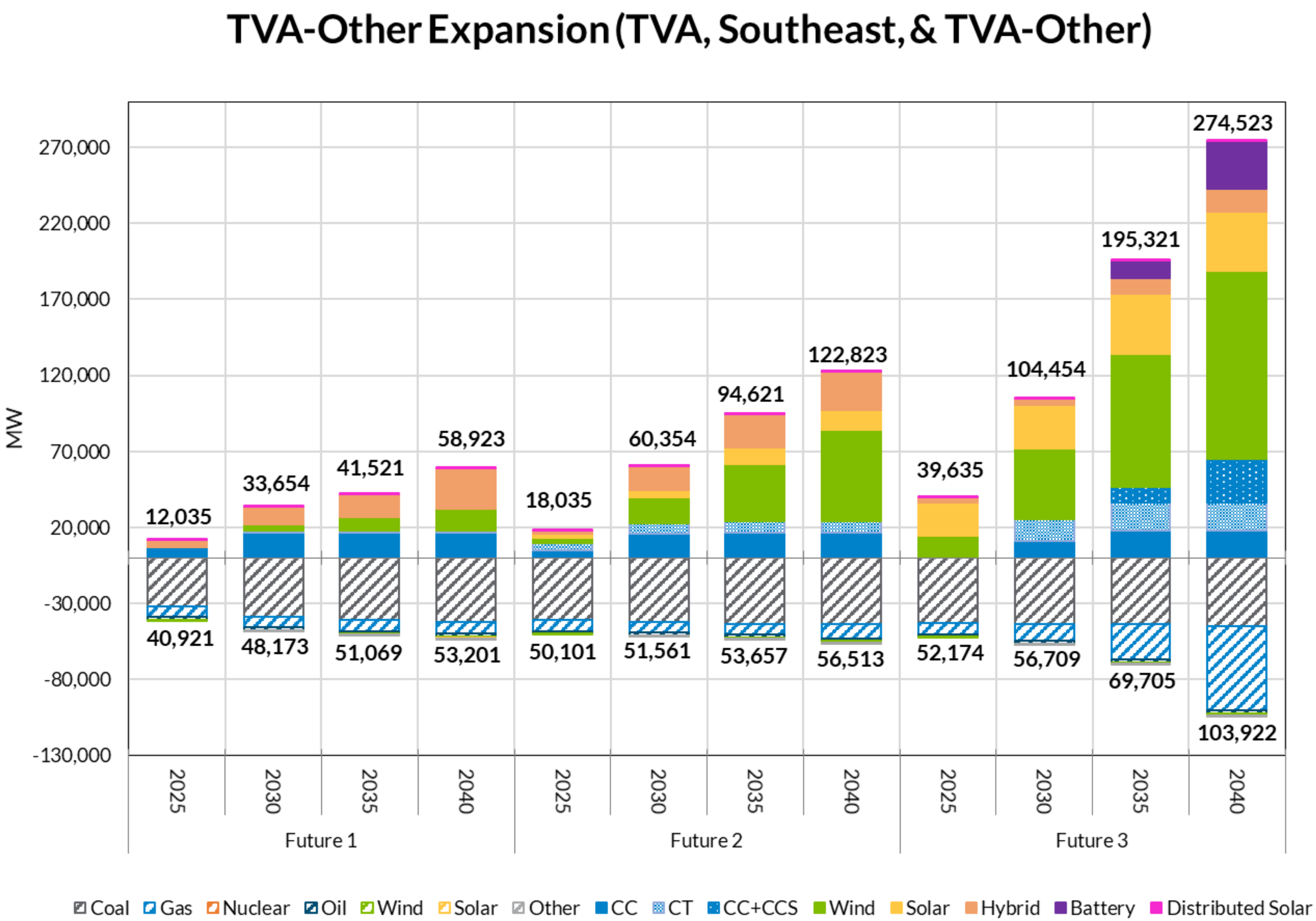


Figure 92: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

External DER Programs: Respective Offerings and Selections

DER Type	EGEAS Program Block	DER Program(s) Included	PJM	SPP	TVAO
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable	*Offered*	*Offered*	*Offered*
DR	C&I Price Response	C&I Price Response	*Offered*	*Offered*	*Offered*
DR	Res. Direct Load Control	Res. Direct Load Control	*Offered*	*Offered*	-
DR	Res. Price Response	Res. Price Response	*Offered*	*Offered*	-
EE	C&I EE	Custom Incentive, Lighting, New Construction, Prescriptive Rebate, Retro commissioning	F1, F2, F3	F2	F1, F2, F3
EE	Res. EE	Appliance Incentives, Appliance Recycling, Behavioral Programs, Lighting, Low Income, Multifamily, New Construction, School Kits, Whole Home Audit	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Customer Solar PV	C&I Customer Solar PV	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV	F1, F2, F3	F1, F2, F3	-
DG	Res. Customer Solar PV	Res. Customer Solar PV	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Solar PV	Res. Utility Incentive Solar PV	*Offered*	*Offered*	-

Table 22: External DER Program Mapping, with Respective Offerings and Selection by Future in EGEAS

External Area Resource Additions per Future (MW) - *Cumulative*										
Future/Area	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Total**
PJM Future 1	**2025**	7,200	7,200	0	0	3,600	0	0	544	18,544
	2030	14,400	21,600	0	245	3,600	10,800	0	1,547	52,192
	2035	14,400	21,600	0	4,129	3,600	10,800	0	2,504	57,033
	2040	14,400	21,600	0	6,641	3,600	10,800	0	2,954	59,995
PJM Future 2	**2025**	10,800	10,800	0	0	7,200	3,600	0	544	32,944
	2030	25,200	18,000	0	3,845	18,000	14,400	2,000	1,547	82,992
	2035	25,200	18,000	0	25,729	18,000	14,400	2,000	2,504	105,833
	2040	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	133,995
PJM Future 3	**2025**	3,600	3,600	0	18,000	0	36,000	3,000	18	64,218
	2030	18,000	7,200	0	54,245	0	61,200	9,000	68	149,712
	2035	21,600	7,200	7,200	119,329	0	72,000	16,000	185	243,514
	2040	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	340,136
SPP Future 1	**2025**	1,200	8,400	0	14,400	0	2,400	2,000	82	28,482
	2030	3,600	10,800	0	15,600	0	2,400	4,000	440	36,840
	2035	8,400	14,400	0	15,600	0	4,800	5,500	914	49,614
	2040	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	57,600
SPP Future 2	**2025**	14,400	3,600	0	1,200	1,200	0	1,000	82	21,482
	2030	21,600	9,600	0	2,703	2,400	2,400	3,500	440	42,643
	2035	21,600	9,600	0	10,727	4,800	2,400	5,500	914	55,541
	2040	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	69,756
SPP Future 3	**2025**	8,400	7,200	0	9,600	1,200	3,600	2,000	82	32,082
	2030	18,000	10,800	0	15,903	1,200	6,000	5,000	440	57,343
	2035	18,000	12,000	2,400	28,727	1,200	6,000	7,000	914	76,241
	2040	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	97,256
TVA-Other Future 1	**2025**	7,200	0	0	29	0	4,800	0	7	12,035
	2030	16,800	1,200	0	3,629	0	12,000	0	25	33,654
	2035	16,800	1,200	0	9,055	0	14,400	0	66	41,521
	2040	16,800	1,200	0	14,405	0	26,400	0	118	58,923
TVA-Other Future 2	**2025**	4,800	4,800	0	3,629	2,400	2,400	0	7	18,035
	2030	15,600	7,200	0	16,829	4,800	15,600	300	25	60,354
	2035	16,800	7,200	0	37,855	10,800	21,600	300	66	94,621
	2040	16,800	7,200	0	60,005	13,200	25,200	300	118	122,823
TVA-Other Future 3	**2025**	0	0	0	14,429	21,600	3,600	0	7	39,635
	2030	10,800	14,400	0	46,829	28,800	3,600	0	25	104,454
	2035	18,000	18,000	10,800	87,055	39,600	10,800	11,000	66	195,321
	2040	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	274,523

Table 23: External Resource Additions by Milestone Year

External Area Resource Retirements per Future (MW) - *Cumulative*									
Future/Area	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Total**
PJM Future 1	**2025**	43,061	6,829	0	6,400	0	0	0	56,289
	2030	48,723	7,981	0	6,460	245	0	0	63,408
	2035	50,263	8,569	0	6,604	4,129	43	0	69,608
	2040	53,068	9,312	0	7,002	6,641	251	0	76,275
PJM Future 2	**2025**	50,263	7,981	0	6,460	0	0	0	64,704
	2030	53,287	8,569	0	6,604	245	0	0	68,705
	2035	54,680	10,687	0	7,002	4,129	43	0	76,540
	2040	54,680	15,348	0	7,136	6,641	251	0	84,055
PJM Future 3	**2025**	53,819	10,687	0	6,604	0	0	0	71,110
	2030	54,680	16,495	0	7,002	245	0	0	78,422
	2035	55,469	22,703	0	7,283	4,129	43	0	89,626
	2040	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP Future 1	**2025**	2,318	4,588	0	1,003	0	0	0	7,909
	2030	7,089	5,062	0	1,213	0	0	0	13,363
	2035	16,238	5,200	0	1,213	0	0	0	22,650
	2040	18,361	5,631	0	1,260	0	0	0	25,252
SPP Future 2	**2025**	19,563	12,329	0	1,232	0	0	0	33,124
	2030	19,842	12,649	0	1,301	1,503	0	0	35,295
	2035	19,842	12,938	0	1,307	4,727	0	0	38,814
	2040	19,842	13,205	0	1,361	9,856	50	0	44,314
SPP Future 3	**2025**	19,842	12,938	0	1,273	0	0	0	34,053
	2030	19,842	13,245	0	1,307	1,503	0	0	35,896
	2035	19,842	15,413	0	1,361	4,727	0	0	41,343
	2040	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other Future 1	**2025**	31,981	7,001	0	1,910	29	0	0	40,921
	2030	38,907	7,051	0	1,910	29	0	276	48,173
	2035	41,111	7,051	0	1,910	655	66	276	51,069
	2040	42,295	7,350	0	1,910	1,205	165	276	53,201
TVA-Other Future 2	**2025**	41,111	7,051	0	1,910	29	0	0	50,101
	2030	42,295	7,051	0	1,910	29	0	276	51,561
	2035	43,400	7,350	0	1,910	655	66	276	53,657
	2040	43,840	9,117	0	1,910	1,205	165	276	56,513
TVA-Other Future 3	**2025**	42,885	7,350	0	1,910	29	0	0	52,174
	2030	43,400	11,094	0	1,910	29	0	276	56,709
	2035	43,840	22,878	0	1,990	655	66	276	69,705
	2040	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 24: External Resource Retirements by Milestone Year

Presentation Materials

Futures Workshops & MISO Stakeholder Presentations:

August 15, 2019: MTEP Futures Workshop – Purpose of MISO Futures

September 26, 2019: MTEP Futures Workshop – Drafting of Futures Assumptions

October 17, 2019: MTEP Futures Workshop – Walkthrough of Initial Strawman

December 5, 2019: MTEP Futures Workshop – Detailing Various Assumptions

February 13, 2020: MTEP Futures Workshop – Updated Assumptions

April 27, 2020: MTEP Futures Workshop – Final Assumptions

July 13, 2020: MTEP Futures Workshop – Siting Review

August 12, 2020: PAC Presentation – Draft Expansion and Siting Results

November 11, 2020: PAC Presentation – Final Expansion and Siting Results

September 22, 2021: PAC Presentation – Correction to Futures Resource Expansion

October 13, 2021: PAC Presentation – Revised Future 2 and 3 Expansion Results for MISO

November 10, 2021: PAC Presentation – Revised Futures Siting and External Expansion Results

Full Futures Evolution Material Available at: MISOEnergy.org

misoenergy.org

SCHEDULE 4:
ASSUMPTIONS USED FOR ADJUSTED MISO FUTURE 1

This schedule provides assumptions used in the economic analysis of Adjusted Production Cost (APC) savings for the Big Stone South – Alexandria – Big Oaks transmissip project (LRTP2 or the Project). Specifically, this schedule provides the assumptions used for those analyses performed using a modified version of MISO's Future 1.

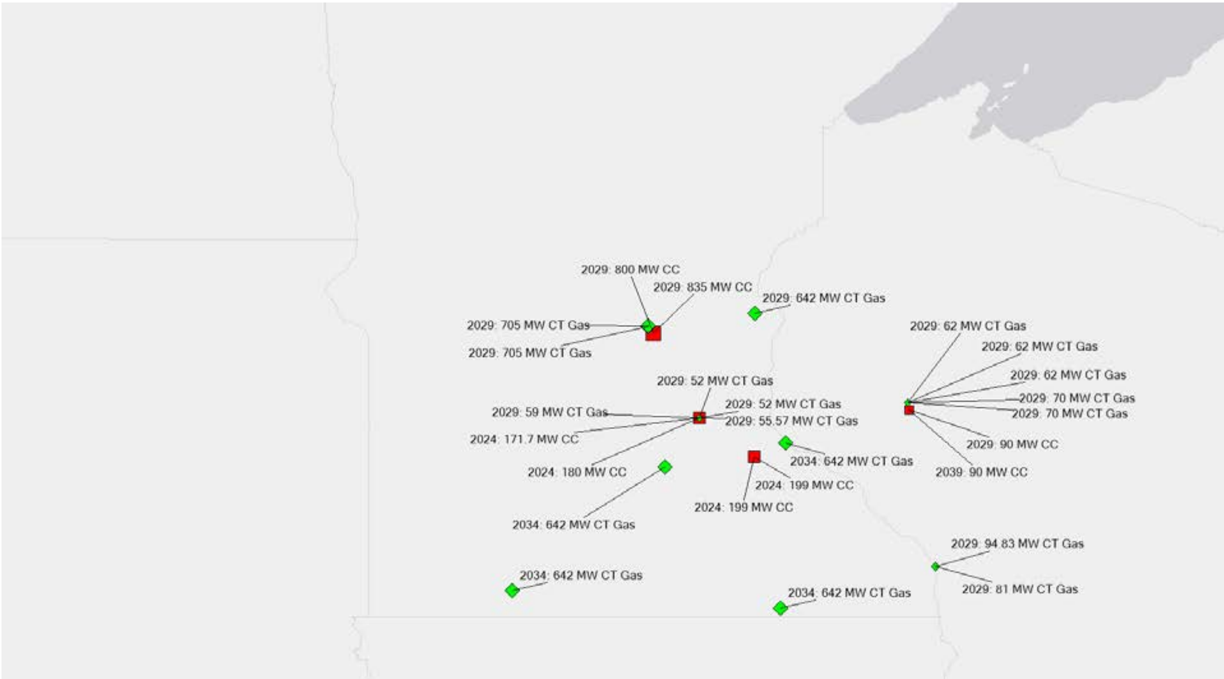
I. BACKGROUND

PROduction MODeling (PROMOD) was used to calculate the Project's APC savings. The economic benefits of the Project were evaluated with PROMOD using the MTEP21 Future 1 and Future 2 assumptions. Future 1 used announced state and utility goals, and other input assumptions through September 2020.

The Company completed its most recent resource planning process after the Future 1 assumptions were established.[1] Future 1 does not fully align with the Company's resource assumptions. Future 1 assumes that, by 2040, an additional 2,565 megawatts (MW) of combined cycle gas-powered generation (CC) and an additional 4,293 MW of combustion-turbine (CT) generation will be added to NSP and Northern States Power Company, a Wisconsin corporation's (NSP-W) system (NSP System). These additional CC and CT resources are depicted in **Figure 1, JS-1 (Sch. 4)**.

[1] Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021); Supplement to 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (June 28, 2020).

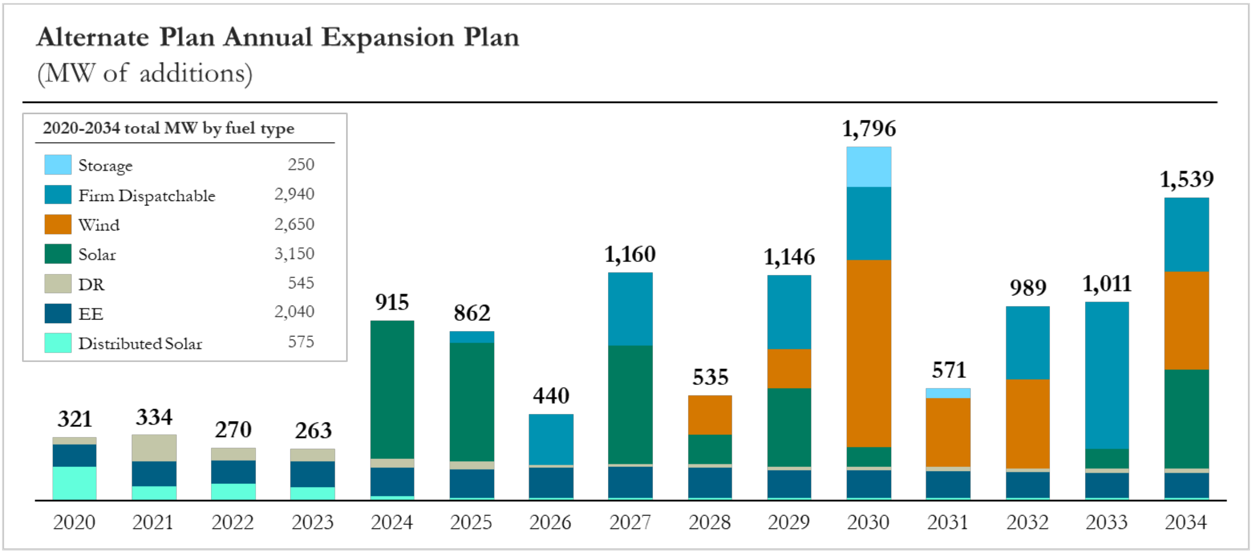
Figure 1, JS-1 (Sch. 4): Future 1 CC and CT Resources



The Company's current resource assumptions anticipate 3,311 MW of new gas generation by 2040. The Company performed a second analysis using the PROMOD tool with assumptions that the Company believes more accurately reflect NSP's future generation mix.[2] These updated resource assumptions are shown, by fuel type, in **Figure 2, JS-1 (Sch. 4).**

[2] Filed as NDPSC Case No. PU-19-220; 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (July 1, 2019); Supplement to 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (June 28, 2020); Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021).

Figure 2, JS-1 (Sch. 4): Upper Midwest Resource Plan, by Fuel Type[3]



The Company's planning period for new generation extends from 2020 to 2034. Generation beyond the planning period is also modeled to capture the "end effects" of the resource assumptions. End effects refer to the impacts outside the planning period of generation added within the planning period. The additional modeled years allowed the economic analysis for the Project to include anticipated generation through 2040. **Table 1, JS-1 (Sch. 4)**, reflects the new generation added in each year of the economic analysis by fuel type.

[3] Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021).

Table 1, JS-1 (Sch. 4): Resource Plan, by Fuel Type

Plan Namplate (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Standalone Storage	-	-	-	-	-	-	-	-	-	-	200	50	-	-	-	-	-	-	100	100	650	1,100
Hybrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	200	200	950	350	450	-	500	600	200	400	-	300	750	4,900
Solar	-	-	-	-	700	600	-	600	150	400	100	-	-	100	500	-	200	550	100	450	-	4,450
Firm Peaking	-	-	-	-	-	60	259	374	-	374	374	-	374	748	374	-	-	-	-	374	-	3,311
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SherCo CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Resources	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	25	27	28	30	32	34	720
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	(23)	(72)	(128)	(122)	(125)	(138)	1,433
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	662
Total	**33**	**132**	**67**	**62**	**747**	**701**	**271**	**988**	**365**	**991**	**1,643**	**420**	**845**	**870**	**1,398**	**625**	**427**	**978**	**230**	**1,256**	**1,434**	**19,881**

The economic analysis also updated Future 1 to include assumptions based on the results of NSP's recent resource procurement process. This process resulted in the planned procurements of 250 MW of new generation in the vicinity of the Company's Sherburne County generation facility site and a power purchase agreement for 100 MW of new generation in Polk County, Wisconsin.

The planned capacity additions are grouped into five-year increments in the economic analysis. **Table 2, JS-1 (Sch. 4)**, shows the total installed new capacity used in the analysis in each five-year period.

Table 2, JS-1 (Sch. 4): Resource Plan and Procurements

Nameplate (MW)	2025	2030	2035	2040
Standalone Storage	-	200	250	1,100
Hybrid	-	-	-	-
Wind	-	1,350	3,250	4,900
Solar	1,300	2,550	3,150	4,450
Firm Peaking	60	1,441	2,937	3,311
CC	-	-	-	-
SherCo CC	-	-	-	-
Distribute Resources	382	459	570	720
Energy Efficiency	781	1,524	2,017	1,433
Distributed Solar	440	515	589	662

PROMOD is typically used in MISO planning to provide forecasts over a 20-year period. The book life of the Project is approximately 63 years. The economic analysis was also updated to derive the present value of 63 years of APC savings. The updated assumptions are detailed below.

II. RESOURCE PLANNING ASSUMPTIONS

Updates were made to Future 1 in the economic analysis to align with NSP's future generation plans. Only NSP's generation resources were updated from the Future 1 assumptions. Generation owned by others remained in the analysis but was not modified from the Future 1 assumptions.

Both the capacity and location of NSP's generation resources were modified to reflect NSP's future generation plans. Reasonable assumptions were made regarding the siting of new resources. The Company attempted to spread changes to generation resources evenly across the NSP System. *With the exception of known resource procurements, the siting of the resources does not represent the location of NSP-planned resource additions*; they were simply reasonable assumptions necessary for conducting the analysis.

A. Battery Storage

Battery storage capacity consistent with the Company's current resource assumptions of 1,100 MW was added and all other battery storage capacity was removed to appropriately reflect the topology of the NSP System. **Table 3, JS-1 (Sch. 4)**, reflects the batteries added to PROMOD and their points of interconnection (POI). Each battery includes five or six POIs. The batteries were given multiple POIs to simulate a greater number of batteries than were actually added to the analysis. Each individual battery is simulated to charge and discharge at the same time and rate across the POIs. Separate batteries can charge and discharge at different times and rates in the analysis.

Table 3, JS-1 (Sch. 4): Battery Storage POIs

Resource	IRP BAT V1	IRP BAT V2	IRP BAT V3	IRP BAT V4
POIs	Inver Hills (MN)	Winona (MN)	Odel (MN)	Wilson (MN)
	North Rochester (MN)	Buffalo Ridge I (MN)	Roseau (MN)	Black Dog (MN)
	Stone Lake (WI)	Red Rock (MN)	Sherco (MN)	Lyon Co. (MN)
	Chisago (MN)	Gingles (WI)	Colvill (MN)	Hurley (WI)
	Crandall (MN)	Blue Lake (MN)	Franklin (MN)	Hazel Creek (MN)
	N/A	N/A	La Crosse (MN)	Minnesota Valley (MN)

Table 4, JS-1 (Sch. 4), provides the cumulative additional battery storage capacity added to the assumptions in five-year increments from a 2020 baseline.

Table 4, JS-1 (Sch. 4): Cumulative Newly Installed Battery Storage Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP BAT V1	0	50	62.5	275
IRP BAT V2	0	50	62.5	275
IRP BAT V3	0	50	62.5	275
IRP BAT V4	0	50	62.5	275

B. Wind Generators

The analysis assumptions were updated to reflect the 4,900 MW of wind generation included in the resource assumptions and all additional wind generation from Future 1 was removed from the NSP System. Three simulated wind plants were created to represent wind sited in North Dakota, South Dakota, and southern Minnesota.

Table 5, JS-1 (Sch. 4), provides the POIs of those three wind resources. Each wind plant has multiple POIs to simulate wind plants sited at multiple locations. The energy output of each individual wind plant is evenly distributed between the POIs.

Table 5, JS-1 (Sch. 4): Wind Generation POIs

Resource	IRP Wind Dakota	IRP Wind SE Minnesota	IRP Wind SW Minnesota
POIs	Generator 302 and 503 (ND)	Crandall (MN)	Deuel (MN-SD Border)
	Prairie Rose (MN-SD Border)	Huntley (MN-IA Border)	Blazing Star (MN)
	Big Stone South (SD)	Adams (MN)	Stone Ray (MN)
	Generator 488 (SD)	Byron (MN)	Buffalo Ridge (MN)

Table 6, JS-1 (Sch. 4), provides the cumulative additional wind generation capacity in five-year increments from a 2020 baseline.

Table 6, JS-1 (Sch. 4): Wind Generation Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP Wind Dakota	300	450	1083	1633
IRP Wind SE Minnesota	20	450	1083	1633
IRP Wind SW Minnesota	107	450	1083	1633

C. Utility-Scale Solar

The capacity of existing solar resources in the analysis was updated to reflect the 4,450 MW of new solar resources in NSP's resource assumptions. Two new solar resources were also added to represent the planned acquisition of 710 MW solar capacity to be interconnected at Sherco (Sherco 1, 2, and 3) and 100 MW to be interconnected at the Apple River Substation in Polk County, Wisconsin (Apple River Solar). No changes were made to the POIs of the existing utility-scale solar resources in Future 1. **Table 7, JS-1 (Sch. 4)**, reflects the added solar resources and updated capacity of the new utility-scale sources.

Table 7, JS-1 (Sch. 4): Utility Scale Solar Generation Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP Solar Apple River	100	100	100	100
IRP Solar Sherco	230	710	710	710
RRF MISO PV: Minnesota - 1	37	57	57	57
RRF MISO PV: Minnesota - 6	37	57	57	57
RRF MISO PV: Minnesota - 7	37	57	57	57
RRF MISO PV: Minnesota - 8	147	165	165	165
RRF MISO PV: Minnesota - 9	37	57	57	57
RRF MISO PV: Minnesota - 10	37	57	57	57
RRF MISO PV: Minnesota - 15	37	57	57	57
RRF MISO PV: Minnesota - 16	70	78	78	78
RRF MISO PV: South Dakota - 1	113	126	126	126
RRF MISO PV: Tier 2 - 11	103	116	116	116
RRF MISO PV: Wisconsin - 8	57	64	64	64

D. Distributed Solar

The capacity of distributed solar resources was updated so that when combined with other distributed solar resources in Future 1, the total distributed solar in the analysis equaled 662 MW, the amount of distributed solar in the Company's resource assumptions. PROMOD does not model the distribution system. The distributed solar's profile and capacity in the analysis reflects the characteristics of rooftop and community solar. The in-service date of all the distributed solar resources the Company modified was accelerated to 2024 to align with the distributed solar capacity in the early years of the Company's resource assumptions. The updated capacity of the distributed solar resources are listed in **Table 8, JS-1 (Sch. 4)**.

Table 8, JS-1 (Sch. 4): Distributed Solar

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
DG Solar_IRP_2031_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_5	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_5	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_5	3.3	8.4	13.3	18.1

III. Gas Resources

Twenty-one CTs and CCs included in Future 1 were removed from the analysis. All CCs in Future 1 were removed because NSP's resource assumptions include no CCs. The capacity of six CTs from Future 1 were adjusted. These removals and adjustments were made so the firm peaking capacity on the NSP System equaled 3,790 MW. The capacity of CTs in the analysis exceeds the resource assumptions by around 500 MW. This additional firm peaking capacity was included as a reasonably conservative assumption in light of the new Midcontinent Independent System Operator, Inc., seasonal capacity construct and uncertainty around accredited capacity.

With the exception of the Lyon County CT, all the CTs and CCs in Minnesota were removed to recognize recent legislation requiring that electric utilities meet all Minnesota retail customers' electricity needs from "carbon-free energy technologies" by 2040.[4] The CT in Lyon County, Minnesota, was retained as a voltage support and potential capacity resource.

[4] *See* 2023 Minn. Laws ch. 7.

The CT and CC gas plants that the Company removed from the analysis are found in **Table 9, JS-1 (Sch. 4)**.

Table 9, JS-1 (Sch. 4): New NSP Generators Removed

Generator's PROMOD Name	Generator's PROMOD Name
CC_IRP_2026_2	RRF MISO CC: 012
CC_IRP_2027_1	RRF MISO CC: 013
CC_IRP_2030_1	RRF MISO CT Gas: 047
CC_IRP_2037_1	RRF MISO CT Gas: 057
CT_IRP_2029_1	RRF MISO CT Gas: 071
CT_IRP_2031_1	RRF MISO CT Gas: 072
CT_IRP_2033_1	RRF MISO CT Gas: 073
CT_IRP_2034_1	Wheaton: 1
CT_IRP_2035_2	Wheaton: 2
RRF MISO CC: 010	Wheaton: 3
RRF MISO CC: 011	Wheaton: 4[5]

Table 10, JS-1 (Sch. 4), provides the CTs whose capacities were adjusted and the POI[6] of those CTs.

Table 10, JS-1 (Sch. 4): CT Resources

Resource	POI	Capacity by Year (MW)			
		2025	2030	2035	2040
RRF MISO CT Gas: 058	Lyon County (MN)	374	374	374	374
RRF MISO CT Gas: 059	French Island (WI)	90	301	675	768
RRF MISO CT Gas: 062	Big Stone South (SD)	90	301	675	768
RRF MISO CT Gas: 066	Angus Anson (SD)	90	301	675	768
RRF MISO CT Gas: 067	Bison (ND)	374	374	748	842
Wheaton 2025[7]	Wheaton (WI)	270	270	270	270

IV. GAS ASSUMPTIONS

The natural gas-price forecasts were updated to match NSP's current resource assumptions. The gas-price forecasts in Future 1 were established in September 2020. The Company's resource assumptions rely on more updated gas-price forecasts

[5] Wheaton 1-4 represent the existing Wheaton CT units anticipated to be retired in 2025.
[6] The Company confirmed there were nearby gas transmission lines that could serve the CTs near these POIs.
[7] "Wheaton 2025" represents the Wheaton Repowering Project in Chippewa County, Wisconsin. NSP-W filed for a Certificate of Public Convenience and Necessity in Wisconsin for the Wheaton Repowering Project on May 12, 2023.[7] The shoulder season (spring and fall) nameplate capacity for Wheaton 2025 was used since that reflects the maximum output capacity.

developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term forecasts from Wood Mackenzie, Cambridge Energy Research Associates, and Petroleum Industry Research Associates.[8] The gas forecast reflects projected prices at the Ventura hub in northern Iowa. The forecasted monthly gas prices used in the Company's economic analysis for the Project are provided in **Table 11, JS-1 (Sch. 4)**.

[8] Reply Comments at 12, Case No. PU-19-220 (June 28, 2021).

Table 11, JS-1 (Sch. 4): Ventura Hub Resource Assumptions Gas Forecast

	January	February	March	April	May	June	July	August	September	October	November	December
2025	3.03	3	2.84	2.62	2.6	2.62	2.68	2.7	2.67	2.71	2.89	3.14
2026	3.27	3.25	3.06	2.81	2.72	2.74	2.77	2.78	2.85	2.98	3.15	3.36
2027	3.5	3.46	3.21	2.93	2.85	2.86	2.88	2.9	2.94	3.11	3.29	3.49
2028	3.58	3.55	3.4	3.09	3.02	3.03	2.96	2.98	3.08	3.3	3.51	3.68
2029	3.84	3.82	3.59	3.29	3.2	3.21	3.03	3.05	3.22	3.5	3.7	3.9
2030	4.05	4.04	3.83	3.48	3.4	3.43	3.44	3.47	3.54	3.69	3.89	4.09
2031	4.26	4.24	3.96	3.64	3.56	3.58	3.63	3.65	3.7	3.87	4.08	4.29
2032	4.4	4.32	4.13	3.79	3.72	3.75	3.79	3.82	3.88	4.01	4.26	4.42
2033	4.48	4.45	4.17	3.84	3.79	3.81	3.85	3.87	3.95	4.07	4.33	4.55
2034	4.68	4.6	4.29	3.95	3.87	3.89	3.94	3.97	4.02	4.12	4.43	4.66
2035	4.82	4.79	4.44	4.07	4	4.04	4.08	4.11	4.19	4.26	4.58	4.8
2036	4.94	4.84	4.55	4.17	4.13	4.16	4.22	4.25	4.31	4.4	4.7	4.95
2037	5.1	5.06	4.72	4.36	4.31	4.34	4.39	4.43	4.5	4.59	4.89	5.13
2038	5.3	5.27	4.94	4.56	4.53	4.56	4.61	4.66	4.69	4.78	5.1	5.34
2039	5.52	5.49	5.14	4.69	4.65	4.68	4.7	4.86	4.92	5	5.31	5.54
2040	5.78	5.59	5.31	4.92	4.9	4.93	4.99	5.03	5.08	5.17	5.4	5.58

SCHEDULE 5:
REVENUE REQUIREMENTS

Total Project Summary

		LRTP2 - Years 1 thru 20		
Line No.	Amounts in dollars	**Line (A)**	**Subs (B)**	**Total**
1	**LRTP2 - Revenue Requirement**	**90,755,344**	**145,146,185**	**235,901,530**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - ND Jurisdiction	6.3%	6.3%	6.3%
6				
7	**Net cost to ND Jurisdiction**	**4,795,509**	**7,669,519**	**12,465,028**

NOTE: Tax assumptions include 21% corp Fed tax rate

Project Summary - Year 1

Amounts in dollars

Line No.		LRTP2 - Year 1 Revenue Requirement		
		Line (A)	Subs (B)	Total
1	**LRTP2 - Revenue Requirement**	**5,921,759**	**9,376,996**	**15,298,755**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - ND Jurisdiction	6.3%	6.3%	6.3%
6				
7	**Net cost to ND Jurisdiction**	**312,906**	**495,480**	**808,386**

NOTE: Tax assumptions include 21% corp Fed tax rate

LRTP2 - Total

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
1	**Project Spend**													
2	Line	47,254,900												
3	Sub	76,300,000												
4	**Total**	123,554,900												
5														
6	Revenue Requirement													
7	Line		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949
8	Sub		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333
9														
10	**Total Revenue Requirements - NSP**		15,298,755	14,903,010	14,451,105	14,027,675	13,629,873	13,255,327	12,897,074	12,544,043	12,190,853	11,837,663	11,484,473	11,131,283
11														
12	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - ND Jurisdiction		6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%
14														
15	**Total Revenue Requirements - ND Jurisdiction**		808,386	787,474	763,596	741,222	720,202	700,411	681,481	662,827	644,164	625,502	606,839	588,177
16														
17														
18	**Discount Rate =**	0.06349334												
19														
20	**Present Value of Revenue Requirements - NSP**	168,003,209	14,385,379	13,176,633	12,014,252	10,965,959	10,018,852	9,161,821	8,382,002	7,665,832	7,005,209	6,396,144	5,834,834	5,317,750
21														
22														
23														
24			12.38%	12.06%	11.70%	11.35%	11.03%	10.73%	10.44%	10.15%	9.87%	9.58%	9.30%	9.01%

LRTP2 - Total

Line No.	Rate Analysis	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	**Project Spend**								
2	Line								
3	Sub								
4	**Total**								
5									
6	Revenue Requirement								
7	Line	4,137,239	3,997,529	3,857,819	3,735,958	3,649,855	3,581,600	3,513,346	3,445,091
8	Sub	6,640,853	6,427,373	6,213,893	6,029,233	5,902,309	5,804,204	5,706,100	5,607,995
9									
10	**Total Revenue Requirements - NSP**	10,778,092	10,424,902	10,071,712	9,765,191	9,552,163	9,385,804	9,219,445	9,053,086
11									
12	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - ND Jurisdiction	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%
14									
15	**Total Revenue Requirements - ND Jurisdiction**	569,514	550,851	532,189	515,992	504,736	495,946	487,155	478,365
16									
17									
18	**Discount Rate =**								
19									
20	**Present Value of Revenue Requirements - NSP**	4,841,610	4,403,370	4,000,200	3,646,904	3,354,367	3,099,171	2,862,491	2,643,024
21									
22									
23									
24		8.72%	8.44%	8.15%	7.90%	7.73%	7.60%	7.46%	7.33%

Rev. Req. 2nd Circuit Subs

LRTP2 - Subs
Based on 56 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
1	Plant Investment		76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve		(1,545,115)	(3,090,231)	(4,635,346)	(6,180,462)	(7,725,577)	(9,270,693)	(10,815,808)	(12,360,924)	(13,906,039)	(15,451,154)	(16,996,270)	(18,541,385)
3	Removal Expense		-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(652,365)	(2,291,518)	(3,722,348)	(4,966,786)	(6,042,373)	(6,964,460)	(7,814,182)	(8,663,905)	(9,515,820)	(10,365,542)	(11,217,458)	(12,067,180)
5			74,102,520	70,918,252	67,942,305	65,152,752	62,532,050	60,064,847	57,670,010	55,275,172	52,878,141	50,483,303	48,086,272	45,691,435
6														
7	Average Rate Base		75,201,260	72,510,386	69,430,278	66,547,529	63,842,401	61,298,449	58,867,428	56,472,591	54,076,656	51,680,722	49,284,788	46,888,854
8														
9	Debt Return		1,571,706	1,515,467	1,451,093	1,390,843	1,334,306	1,281,138	1,230,329	1,180,277	1,130,202	1,080,127	1,030,052	979,977
10	Equity Return		3,654,781	3,524,005	3,374,312	3,234,210	3,102,741	2,979,105	2,860,957	2,744,568	2,628,125	2,511,683	2,395,241	2,278,798
11	Current Income Tax Requirement		821,652	(217,880)	(69,931)	59,958	175,785	279,421	304,135	257,194	208,039	163,269	114,114	69,344
12														
13	Book Depreciation		1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax		652,365	1,639,153	1,430,831	1,244,438	1,075,587	922,087	849,722	849,722	851,915	849,722	851,915	849,722
15	ITC Flow Thru		-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		3,815,000	7,248,500	6,523,650	5,875,100	5,287,590	4,753,490	4,501,700	4,501,700	4,509,330	4,501,700	4,509,330	4,501,700
17	Tax Depreciation on Easements		-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22														
23	Total Revenue Requirements - NSP		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333
24														
25	Discount Rate =	0.06349334												
26														
27	Present Value of Revenue Requirements	103,570,268	8,817,165	8,078,771	7,368,285	6,727,585	6,148,758	5,624,993	5,148,390	4,710,617	4,306,709	3,934,239	3,590,894	3,274,522
28														
29	**Level Annual Revenue Requirement**	**6,792,227**												
30														
31	**57 Year Life LARR %**	**8.90%**												

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(20,086,501)	(21,631,616)	(23,176,732)	(24,721,847)	(26,266,962)	(27,812,078)	(29,357,193)	(30,902,309)	(32,447,424)	(33,992,540)	(35,537,655)	(37,082,771)	(38,627,886)	(40,173,001)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(12,919,095)	(13,768,818)	(14,620,733)	(14,823,561)	(14,379,495)	(13,935,429)	(13,491,363)	(13,047,296)	(12,603,230)	(12,159,164)	(11,715,098)	(11,271,032)	(10,826,966)	(10,382,899)
5		43,294,404	40,899,566	38,502,535	36,754,592	35,653,543	34,552,493	33,451,444	32,350,395	31,249,346	30,148,296	29,047,247	27,946,198	26,845,148	25,744,099
6															
7	Average Rate Base	44,492,919	42,096,985	39,701,051	37,628,564	36,204,067	35,103,018	34,001,969	32,900,919	31,799,870	30,698,821	29,597,772	28,496,722	27,395,673	26,294,624
8															
9	Debt Return	929,902	879,827	829,752	786,437	756,665	733,653	710,641	687,629	664,617	641,605	618,593	595,581	572,570	549,558
10	Equity Return	2,162,356	2,045,913	1,929,471	1,828,748	1,759,518	1,706,007	1,652,496	1,598,985	1,545,474	1,491,963	1,438,452	1,384,941	1,331,430	1,277,919
11	Current Income Tax Requirement	20,188	(24,581)	(73,737)	534,728	1,153,700	1,132,119	1,110,537	1,088,956	1,067,374	1,045,792	1,024,211	1,002,629	981,048	959,466
12															
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	851,915	849,722	851,915	202,828	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	4,509,330	4,501,700	4,509,330	2,250,850	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22															
23	Total Revenue Requirements - NSP	6,640,853	6,427,373	6,213,893	6,029,233	5,902,309	5,804,204	5,706,100	5,607,995	5,509,891	5,411,786	5,313,682	5,215,577	5,117,472	5,019,368
24															
25	Discount Rate =														
26															
27	Present Value of Revenue Requirements	2,983,128	2,714,855	2,467,983	2,251,675	2,072,673	1,916,535	1,771,653	1,637,239	1,512,560	1,396,933	1,289,721	1,190,331	1,098,212	1,012,849
28															
29	**Level Annual Revenue Requirement**														
30															
31	**57 Year Life LARR %**														

Rev. Req. 2nd Circuit Subs

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(41,718,117)	(43,263,232)	(44,808,348)	(46,353,463)	(47,898,579)	(49,443,694)	(50,988,809)	(52,533,925)	(54,079,040)	(55,624,156)	(57,169,271)	(58,714,387)	(60,259,502)	(61,804,618)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(9,938,833)	(9,494,767)	(9,050,701)	(8,606,635)	(8,162,569)	(7,718,502)	(7,274,436)	(6,830,370)	(6,386,304)	(5,942,238)	(5,498,171)	(5,054,105)	(4,610,039)	(4,165,973)
5		24,643,050	23,542,001	22,440,951	21,339,902	20,238,853	19,137,804	18,036,754	16,935,705	15,834,656	14,733,607	13,632,557	12,531,508	11,430,459	10,329,410
6															
7	Average Rate Base	25,193,575	24,092,525	22,991,476	21,890,427	20,789,378	19,688,328	18,587,279	17,486,230	16,385,180	15,284,131	14,183,082	13,082,033	11,980,983	10,879,934
8															
9	Debt Return	526,546	503,534	480,522	457,510	434,498	411,486	388,474	365,462	342,450	319,438	296,426	273,414	250,403	227,391
10	Equity Return	1,224,408	1,170,897	1,117,386	1,063,875	1,010,364	956,853	903,342	849,831	796,320	742,809	689,298	635,787	582,276	528,765
11	Current Income Tax Requirement	937,884	916,303	894,721	873,139	851,558	829,976	808,395	786,813	765,231	743,650	722,068	700,487	678,905	657,323
12															
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22															
23	Total Revenue Requirements - NSP	4,921,263	4,823,159	4,725,054	4,626,950	4,528,845	4,430,741	4,332,636	4,234,532	4,136,427	4,038,322	3,940,218	3,842,113	3,744,009	3,645,904
24															
25	Discount Rate =														
26															
27	Present Value of Revenue Requirements	933,765	860,514	792,681	729,880	671,753	617,965	568,204	522,183	479,632	440,300	403,956	370,381	339,376	310,752
28															
29	**Level Annual Revenue Requirement**														
30															
31	**57 Year Life LARR %**														

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(63,349,733)	(64,894,848)	(66,439,964)	(67,985,079)	(69,530,195)	(71,075,310)	(72,620,426)	(74,165,541)	(75,710,657)	(77,255,772)	(78,800,887)	(80,346,003)	(81,891,118)	(83,436,234)	(84,981,349)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(3,721,907)	(3,277,841)	(2,833,774)	(2,389,708)	(1,945,642)	(1,501,576)	(1,057,510)	(613,443)	(169,377)	274,689	718,755	1,162,821	1,606,887	2,050,954	2,495,020
5		9,228,360	8,127,311	7,026,262	5,925,212	4,824,163	3,723,114	2,622,065	1,521,015	419,966	(681,083)	(1,782,132)	(2,883,182)	(3,984,231)	(5,085,280)	(6,186,329)
6																
7	Average Rate Base	9,778,885	8,677,836	7,576,786	6,475,737	5,374,688	4,273,639	3,172,589	2,071,540	970,491	(130,558)	(1,231,608)	(2,332,657)	(3,433,706)	(4,534,756)	(5,635,805)
8																
9	Debt Return	204,379	181,367	158,355	135,343	112,331	89,319	66,307	43,295	20,283	(2,729)	(25,741)	(48,753)	(71,764)	(94,776)	(117,788)
10	Equity Return	475,254	421,743	368,232	314,721	261,210	207,699	154,188	100,677	47,166	(6,345)	(59,856)	(113,367)	(166,878)	(220,389)	(273,900)
11	Current Income Tax Requirement	635,742	614,160	592,578	570,997	549,415	527,834	506,252	484,670	463,089	441,507	419,925	398,344	376,762	355,181	333,599
12																
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)	(444,066)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22																
23	Total Revenue Requirements - NSP	3,547,800	3,449,695	3,351,591	3,253,486	3,155,382	3,057,277	2,959,173	2,861,068	2,762,964	2,664,859	2,566,754	2,468,650	2,370,545	2,272,441	2,174,336
24																
25	Discount Rate =															
26																
27	Present Value of Revenue Requirements	284,337	259,968	237,496	216,780	197,691	180,109	163,921	149,025	135,323	122,726	111,150	100,520	90,762	81,812	73,606
28																
29	**Level Annual Revenue Requirement**															
30																
31	**57 Year Life LARR %**															

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 56
1	Plant Investment	76,300,000
2	Depreciation Reserve	(86,526,465)
3	Removal Expense	10,226,465
4	Accumulated Deferred Taxes	0
5		0
6		
7	Average Rate Base	(3,093,165)
8		
9	Debt Return	(64,647)
10	Equity Return	(150,328)
11	Current Income Tax Requirement	(2,555,649)
12		
13	Book Depreciation	1,545,115
14	Annual Deferred Tax	2,495,020
15	ITC Flow Thru	-
16	Tax Depreciation & Removal Expense	10,226,465
17	Tax Depreciation on Easements	-
18	AFUDC Expenditure	-
19	Book Depreciation Cleared to Operating	-
20	Avoided Tax Interest	-
21	Property Tax @ 1.4828%	1,131,376
22		
23	Total Revenue Requirements - NSP	2,400,888
24		
25	Discount Rate =	
26		
27	Present Value of Revenue Requirements	76,423
28		
29	**Level Annual Revenue Requirement**	
30		
31	**57 Year Life LARR %**	

LRTP2 - Line
Based on 63 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
1	Plant Investment		47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve		(1,074,986)	(2,149,972)	(3,224,958)	(4,299,945)	(5,374,931)	(6,449,917)	(7,524,903)	(8,599,889)	(9,674,875)	(10,749,861)	(11,824,847)	(12,899,834)
3	Removal Expense		-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(370,102)	(1,351,351)	(2,203,581)	(2,940,371)	(3,572,588)	(4,109,737)	(4,602,068)	(5,094,399)	(5,588,089)	(6,080,420)	(6,574,110)	(7,066,441)
5			45,809,812	43,753,576	41,826,361	40,014,584	38,307,382	36,695,247	35,127,929	33,560,612	31,991,936	30,424,618	28,855,943	27,288,625
6														
7	Average Rate Base		46,532,356	44,781,694	42,789,969	40,920,472	39,160,983	37,501,314	35,911,588	34,344,270	32,776,274	31,208,277	29,640,281	28,072,284
8														
9	Debt Return		972,526	935,937	894,310	855,238	818,465	783,777	750,552	717,795	685,024	652,253	619,482	586,711
10	Equity Return		2,261,473	2,176,390	2,079,592	1,988,735	1,903,224	1,822,564	1,745,303	1,669,132	1,592,927	1,516,722	1,440,518	1,364,313
11	Current Income Tax Requirement		541,977	(103,486)	(13,505)	65,290	135,376	197,913	211,570	180,849	148,757	119,381	87,288	57,912
12														
13	Book Depreciation		1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax		370,102	981,250	852,229	736,790	632,216	537,149	492,331	492,331	493,690	492,331	493,690	492,331
15	ITC Flow Thru		-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		2,362,745	4,489,216	4,040,294	3,638,627	3,274,765	2,943,980	2,788,039	2,788,039	2,792,765	2,788,039	2,792,765	2,788,039
17	Tax Depreciation on Easements		-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22														
23	Total Revenue Requirements - NSP		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949
24														
25	Discount Rate =	0.06349334												
26														
27	Present Value of Revenue Requirements	64,432,942	5,568,215	5,097,861	4,645,967	4,238,373	3,870,093	3,536,828	3,233,612	2,955,215	2,698,500	2,461,904	2,243,941	2,043,228
28														
29	**Level Annual Revenue Requirement**	**4,177,485**												
30														
31	**63 Year Life LARR %**	**8.84%**												

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(13,974,820)	(15,049,806)	(16,124,792)	(17,199,778)	(18,274,764)	(19,349,750)	(20,424,736)	(21,499,723)	(22,574,709)	(23,649,695)	(24,724,681)	(25,799,667)	(26,874,653)	(27,949,639)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(7,560,131)	(8,052,462)	(8,546,152)	(8,637,842)	(8,328,891)	(8,019,940)	(7,710,989)	(7,402,038)	(7,093,087)	(6,784,136)	(6,475,185)	(6,166,234)	(5,857,283)	(5,548,332)
5		25,719,949	24,152,632	22,583,956	21,417,280	20,651,245	19,885,210	19,119,175	18,353,139	17,587,104	16,821,069	16,055,034	15,288,999	14,522,964	13,756,929
6															
7	Average Rate Base	26,504,287	24,936,291	23,368,294	22,000,618	21,034,262	20,268,227	19,502,192	18,736,157	17,970,122	17,204,087	16,438,052	15,672,017	14,905,981	14,139,946
8															
9	Debt Return	553,940	521,168	488,397	459,813	439,616	423,606	407,596	391,586	375,576	359,565	343,555	327,545	311,535	295,525
10	Equity Return	1,288,108	1,211,904	1,135,699	1,069,230	1,022,265	985,036	947,807	910,577	873,348	836,119	798,889	761,660	724,431	687,201
11	Current Income Tax Requirement	25,820	(3,556)	(35,649)	339,543	721,243	706,228	691,213	676,198	661,183	646,168	631,153	616,138	601,122	586,107
12															
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	493,690	492,331	493,690	91,690	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	2,792,765	2,788,039	2,792,765	1,394,020	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22															
23	Total Revenue Requirements - NSP	4,137,239	3,997,529	3,857,819	3,735,958	3,649,855	3,581,600	3,513,346	3,445,091	3,376,837	3,308,582	3,240,328	3,172,073	3,103,819	3,035,564
24															
25	Discount Rate =														
26															
27	Present Value of Revenue Requirements	1,858,483	1,688,514	1,532,217	1,395,229	1,281,694	1,182,636	1,090,838	1,005,785	927,000	854,037	786,483	723,950	666,081	612,541
28															
29	**Level Annual Revenue Requirement**														
30															
31	**63 Year Life LARR %**														

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(29,024,625)	(30,099,612)	(31,174,598)	(32,249,584)	(33,324,570)	(34,399,556)	(35,474,542)	(36,549,528)	(37,624,514)	(38,699,501)	(39,774,487)	(40,849,473)	(41,924,459)	(42,999,445)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(5,239,381)	(4,930,430)	(4,621,479)	(4,312,528)	(4,003,577)	(3,694,626)	(3,385,675)	(3,076,724)	(2,767,773)	(2,458,822)	(2,149,871)	(1,840,920)	(1,531,969)	(1,223,018)
5		12,990,894	12,224,859	11,458,823	10,692,788	9,926,753	9,160,718	8,394,683	7,628,648	6,862,613	6,096,578	5,330,543	4,564,507	3,798,472	3,032,437
6															
7	Average Rate Base	13,373,911	12,607,876	11,841,841	11,075,806	10,309,771	9,543,736	8,777,701	8,011,665	7,245,630	6,479,595	5,713,560	4,947,525	4,181,490	3,415,455
8															
9	Debt Return	279,515	263,505	247,494	231,484	215,474	199,464	183,454	167,444	151,434	135,424	119,413	103,403	87,393	71,383
10	Equity Return	649,972	612,743	575,513	538,284	501,055	463,826	426,596	389,367	352,138	314,908	277,679	240,450	203,220	165,991
11	Current Income Tax Requirement	571,092	556,077	541,062	526,047	511,032	496,017	481,002	465,987	450,972	435,957	420,942	405,927	390,912	375,897
12															
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22															
23	Total Revenue Requirements - NSP	2,967,310	2,899,056	2,830,801	2,762,547	2,694,292	2,626,038	2,557,783	2,489,529	2,421,274	2,353,020	2,284,765	2,216,511	2,148,257	2,080,002
24															
25	Discount Rate =														
26															
27	Present Value of Revenue Requirements	563,020	517,229	474,899	435,779	399,638	366,259	335,441	306,997	280,755	256,551	234,237	213,672	194,729	177,285
28															
29	**Level Annual Revenue Requirement**														
30															
31	**63 Year Life LARR %**														

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(44,074,431)	(45,149,417)	(46,224,403)	(47,299,390)	(48,374,376)	(49,449,362)	(50,524,348)	(51,599,334)	(52,674,320)	(53,749,306)	(54,824,292)	(55,899,279)	(56,974,265)	(58,049,251)	(59,124,237)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(914,067)	(605,116)	(296,165)	12,786	321,737	630,688	939,639	1,248,590	1,557,541	1,866,492	2,175,443	2,484,394	2,793,345	3,102,296	3,411,247
5		2,266,402	1,500,367	734,332	(31,703)	(797,738)	(1,563,773)	(2,329,809)	(3,095,844)	(3,861,879)	(4,627,914)	(5,393,949)	(6,159,984)	(6,926,019)	(7,692,054)	(8,458,089)
6																
7	Average Rate Base	2,649,420	1,883,385	1,117,349	351,314	(414,721)	(1,180,756)	(1,946,791)	(2,712,826)	(3,478,861)	(4,244,896)	(5,010,931)	(5,776,967)	(6,543,002)	(7,309,037)	(8,075,072)
8																
9	Debt Return	55,373	39,363	23,353	7,342	(8,668)	(24,678)	(40,688)	(56,698)	(72,708)	(88,718)	(104,728)	(120,739)	(136,749)	(152,759)	(168,769)
10	Equity Return	128,762	91,533	54,303	17,074	(20,155)	(57,385)	(94,614)	(131,843)	(169,073)	(206,302)	(243,531)	(280,761)	(317,990)	(355,219)	(392,448)
11	Current Income Tax Requirement	360,882	345,867	330,852	315,837	300,822	285,807	270,792	255,777	240,762	225,747	210,732	195,717	180,702	165,687	150,672
12																
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22																
23	Total Revenue Requirements - NSP	2,011,748	1,943,493	1,875,239	1,806,984	1,738,730	1,670,475	1,602,221	1,533,966	1,465,712	1,397,457	1,329,203	1,260,949	1,192,694	1,124,440	1,056,185
24																
25	Discount Rate =															
26																
27	Present Value of Revenue Requirements	161,231	146,461	132,880	120,399	108,935	98,410	88,754	79,900	71,787	64,358	57,560	51,344	45,665	40,482	35,754
28																
29	**Level Annual Revenue Requirement**															
30																
31	**63 Year Life LARR %**															

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 56	Year 57	Year 58	Year 59	Year 60	Year 61	Year 62	Year 63
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(60,199,223)	(61,274,209)	(62,349,195)	(63,424,181)	(64,499,168)	(65,574,154)	(66,649,140)	(67,724,126)
3	Removal Expense	-	-	-	-	-	-	-	20,469,226
4	Accumulated Deferred Taxes	3,720,198	4,029,149	4,338,100	4,647,051	4,956,002	5,264,954	5,573,905	-
5		(9,224,125)	(9,990,160)	(10,756,195)	(11,522,230)	(12,288,265)	(13,054,300)	(13,820,335)	-
6									
7	Average Rate Base	(8,841,107)	(9,607,142)	(10,373,177)	(11,139,212)	(11,905,248)	(12,671,283)	(13,437,318)	(6,910,168)
8									
9	Debt Return	(184,779)	(200,789)	(216,799)	(232,810)	(248,820)	(264,830)	(280,840)	(144,423)
10	Equity Return	(429,678)	(466,907)	(504,136)	(541,366)	(578,595)	(615,824)	(653,054)	(335,834)
11	Current Income Tax Requirement	135,657	120,642	105,627	90,612	75,597	60,582	45,567	(5,709,350)
12									
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	(308,951)	5,573,905
15	ITC Flow Thru	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	20,469,226
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22									
23	Total Revenue Requirements - NSP	987,931	919,676	851,422	783,167	714,913	646,658	578,404	1,159,979
24									
25	Discount Rate =								
26									
27	Present Value of Revenue Requirements	31,447	27,527	23,962	20,725	17,790	15,131	12,726	23,997
28									
29	**Level Annual Revenue Requirement**								
30									
31	**63 Year Life LARR %**								

Key Inputs

Line No	Capital Structure			
1			2024	
2	Capital Structure	Cost	Ratio	WACC
3	Long Term Debt	4.4000%	47.0800%	2.07%
4	Short Term Debt	4.1700%	0.4200%	0.02%
5	Preferred Stock	0.0000%	0.0000%	0.00%
6	Common Equity	9.2500%	52.5000%	4.86%
7	**Required Rate of Return**			6.95%
8	(Rates and Ratios from Settlement in Docket E002/GR-21-630)			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.4828%
12	(percentage based on last TCR filing in Docket No. E002M-21-814)			
13				
14	**Income Tax Rates**			
15	Federal Tax Rate			21.00%
16	StateTax Rate			9.80%
17	State Composite Income Tax Rate			28.7420%
18				
19	**Allocators (2024 Estimate)**			
20	ND 12-month CP demand (Electric Demand)			6.3005%
21	NSPM 36-month CP demand (Interchange Electric)			83.8663%
22	Jurisdictional Allocator			5.2840%
23				
24	**Book Depreciation Lives**			
25	Land			0.00
26	Line			63.28
27	Sub			56.43
28				
29	**Net Salvage %**			
30	Land			0.00%
31	Line			-43.95%
32	Sub			-14.26%
33				
34	**Book Depreciation Rates**			
35	Land			0.00%
36	Line			2.2749%
37	Sub			2.0251%

Assumptions & Validations

Assumptions

AFUDC in included in the cost data provided to Revenue Requirements

O&M is not included

Property tax is included

In service is assumed in year 1

ND filing should match MN for capital structure, tax rates and depreciation per Zev.

Validations

BCH 10/10/2023	Rate base goes to zero at the end of life
BCH 10/10/2023	Data flows from individual tabs to total tab
BCH 10/10/2023	Data flows from total tabs to summary tabs

AFFIDAVIT OF GRANT D. STEVENSON

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the Big Stone South – Alexandria – Big Oaks 345 Kilovolt Transmission Line Project

Case No. PU-23-____

Exhibit 1 (GDS-1)

STATE OF MINNESOTA)
IN THE)
COUNTY OF WASHINGTON)

I, Grant D. Stevenson, under oath, state:

I. Introduction

1. My name is Grant D. Stevenson, and I am a Project Director for Xcel Energy Services, Inc. (XES). XES is a wholly owned subsidiary of Xcel Energy Inc. (Xcel Energy) and provides an array of support services to Northern States Power Company (NSP or the Company) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis. Xcel Energy does business in North Dakota, South Dakota, and Minnesota through NSP.

2. My business address is 414 Nicollet Mall, Minneapolis, Minnesota, 55401.

3. I hold a Bachelor's Degree in Mechanical Engineering from the University of Minnesota, and have completed post-graduate coursework in economics, business law, marketing, and manufacturing at the University of St. Thomas. My statement of qualifications is attached as Schedule 1.

4. As a Project Director, my responsibilities include: leading multi-disciplinary teams working on complex projects; supervising teams of engineering and construction contractors and consultants in implementing projects; developing contractor bid documents and leading contractor selection and oversight; interfacing with regulatory authorities; and shepherding numerous multi-million-dollar projects to completion.

5. Prior to my current position I held various sales, account management, and engineering positions. In those positions, I led teams of employees working on account management and client services, hired, trained, and managed employees working in numerous capacities, worked with industrial customers to provide technical support; interfaced with clients; managed contractors, directed plan operations, and problem spotted mechanical and electrical issues in industrial settings.

6. I am providing this affidavit in support of the Application for an Advanced Determination of Prudence (ADP) filed by Xcel Energy for portions of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (the Project or LRTP2) in which the Company will have an ownership interest.

7. In my affidavit, I provide a description of the Project, the Project schedule, and estimated Project costs.

II. Project Description

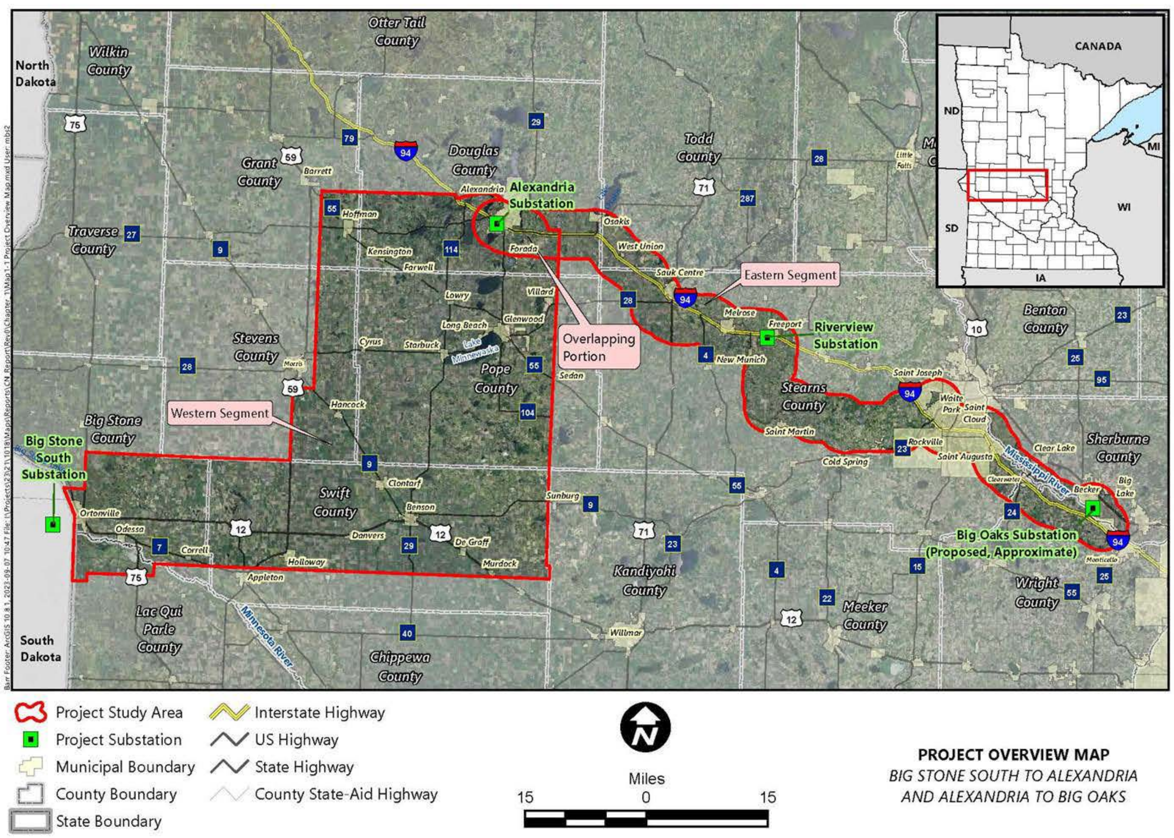
8. The overall Project consists of new 345 kV transmission facilities from the Big Stone South Substation near Big Stone City in Grant County, South Dakota, to a new Big Oaks Substation near the City of Becker, in Sherburne County, Minnesota. The Project consists of an Eastern Segment, a Western Segment, the new Big Oaks Substation, and upgrades to the existing Big Stone South Substation, Alexandria Substation, Quarry Substation, and Riverview Substation.

9. The Eastern Segment will be owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Western Minnesota

Municipal Power Agency (Western Minnesota). Otter Tail and Western Minnesota will co-own the Western Segment. As I stated above, Xcel Energy will own the new Big Oaks Substation, and it also owns the existing Quarry Substation. The Big Stone South Substation is owned by Otter Tail, Western Minnesota owns the Alexandria Substation, and Great River Energy is the owner of the Riverview Substation.

10. The Project's location is depicted in Figure 1 below.

Figure GDS-1: Project Location

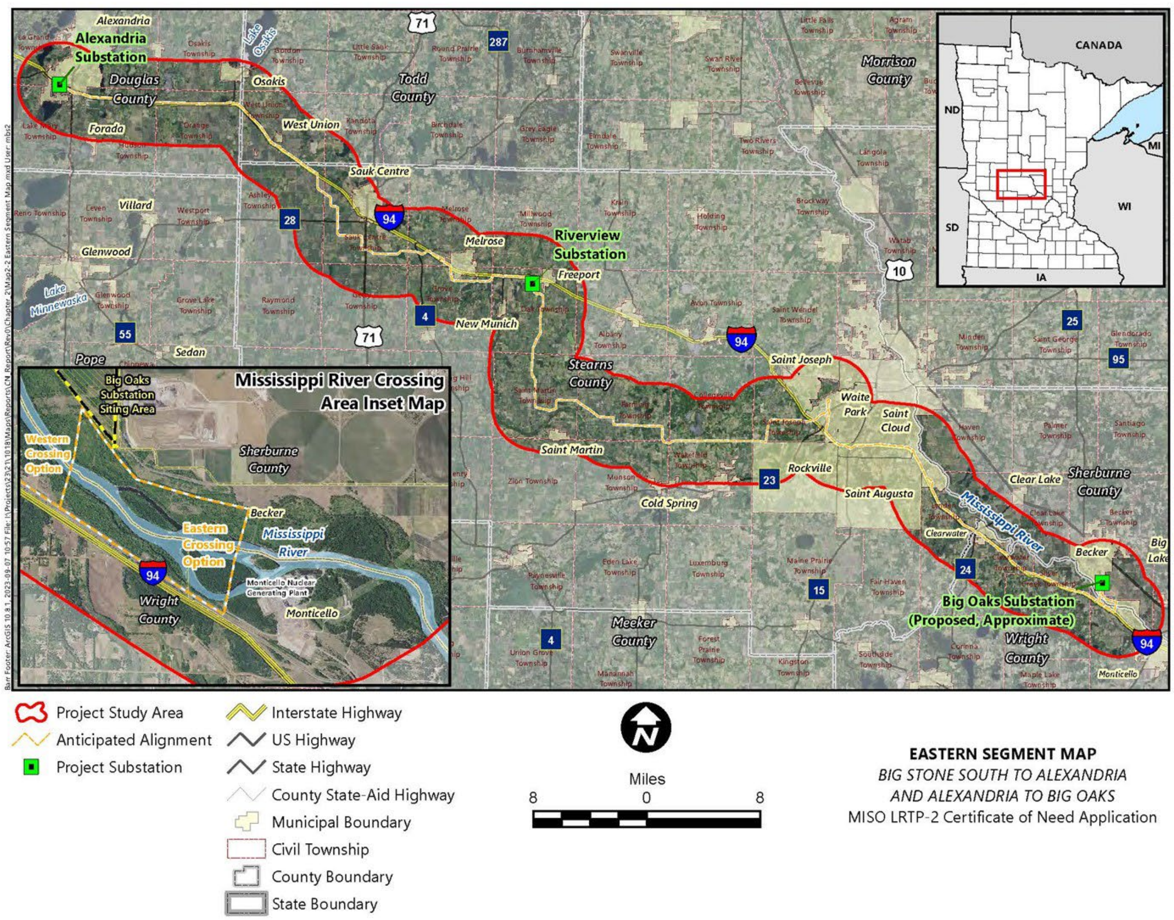


A. Eastern Segment

11. The Eastern Segment of the Project will have a western terminus at the existing Alexandria Substation, which is located near Alexandria, Minnesota and an eastern terminus at the new Big Oaks Substation in Sherburne County, Minnesota.

12. The Eastern Segment is depicted in Figure 2 below.

Figure GDS-2: Eastern Segment



13. Most of the Eastern Segment will be strung on existing double-circuit transmission structures within an existing 150-foot right-of-way. When the existing structures were originally installed, space was left for this future second circuit to allow

electrical capacity to be increased at a limited expense. The double-circuiting of existing structures will keep down the costs of this segment of the Project. There will, however, be some locations where new structures will be installed for the Eastern Segment.

14. The proposed Eastern Segment will deviate from the existing right-of-way at four locations. First, the Eastern Segment will require a new right-of-way to permit the new line's interconnection into the Alexandria Substation. Second, the Project will require reconfiguring the existing circuit from the Alexandria Substation to the Quarry Substation in order to bypass the Riverview Substation near the City of Freeport, Minnesota. Third, the Eastern Segment will require a new circuit from the Riverview Substation to the Big Oaks Substation to bypass the Quarry substation near the City of Waite Park. The cumulative length of these first three deviations is less than one mile. Fourth (and last), the Project will require acquiring new right-of-way for a new crossing to connect the transmission line near Monticello to the new Big Oaks Substation located northwest of the Monticello Nuclear Generating Plant in Becker, Minnesota. This fourth deviation will deploy one of two options: (1) a western option with a crossing directly south of the new Big Oaks Substation or (2) an eastern option with a crossing just west of the Monticello Nuclear Generating Plant. The fourth new segment will be between one and four miles long depending on the exact route chosen.

15. The four new segments will likely be built along new 150-foot wide right-of-way.

16. New structures will be installed to accommodate angles, highway crossings, and the four previously mentioned deviations from the existing right-of-way.

17. All told, the project contemplates approximately 67 to 78 new structures; the exact number depends on the location of the Mississippi River Crossing.

18. The angles along the existing route were originally designed as two-pole structures, typical for double circuit 345 kV lines; one full circuit and a shield wire attached to each pole. When the first circuit was installed, there was no need for the second monopole; also, without wires attached, the second monopole would have been susceptible to damage from vibration. As part of this Project, the second monopole will now be installed at those angles. Where a second monopole structure is required next to an existing structure, it will be placed within the existing right-of-way, 40 to 60 feet from the existing structure. H-frame structures may also be used at the Mississippi River crossing or if needed to accommodate longer spans.

19. The existing and proposed new structures typically range in height from approximately 90 feet to 160 feet tall. The typical span between structures will be about 1,000 feet. All structures are anticipated to be installed on concrete foundations.

20. The Project's owners are currently evaluating several distinct conductor types.

21. The proposed transmission line will be designed and built to meet or surpass Xcel Energy's standards (and that of other project owners) and relevant local and state codes, including the National Electrical Safety Code (NESC). Applicable

standards will be met for construction and installation, and applicable safety procedures will be followed during design, construction, and after installation.

B. Western Segment

22. The Western Segment of the Project will run from the existing Big Stone South Substation to the existing Alexandria Substation.

23. The Western Segment will consist of new single-circuit 345kV line that will be placed on structures that are double-circuit capable so as to facilitate a potential, future expansion.

24. The Western Segment will be installed along a new right of way. The route for the Western Segment is not yet know and will be determined based on site route proceedings in Minnesota and South Dakota.

25. Xcel Energy will not have any ownership interest in the Western Segment.

C. Substation Construction and Upgrades

26. Xcel Energy's new Big Oaks Substation is the eastern endpoint of the planned Project. It will be constructed southwest of the City of Becker, in Sherburne County, Minnesota. It will be a 345 kV switching station that will include eighteen 345 kV circuit breakers configured to accommodate connection of up to twelve 345 kV transmission lines.

27. The Big Oaks Substation will be located on a graded and fenced area of approximately 10 acres.

28. The Big Oaks Substation will be used to connect with the following transmission lines:

- Four existing 345 kV transmission lines originating at the Sherburne County Substation;
- The Eastern Segment of the Project, (the 345 kV transmission line from Alexandria Substation to the Riverview Substation to the Big Oaks Substation) and
- Two 345 kV transmission lines proposed as part of LRTP3 in the MISO LRTP Tranche 1 Portfolio (Benton County – Big Oaks 1, Benton County – Big Oaks 2).

29. The Project will also include improvements to the Big Stone South Substation, the western endpoint of the Project, the Alexandria Substation, the midpoint between the Western Segment and Eastern Segment of the Project, the Riverview Substation, and Xcel Energy's existing Quarry Substation.

30. The existing Big Stone South Substation is located in South Dakota and is the western endpoint for the Western Segment of the Project. The existing ring bus configuration will be modified to a breaker and half configuration by adding one additional row to the 345 kV portion of the substation. The new row will allow for a new breaker position to be added for the 345 kV line to the Alexandria Substation. The Applicants seek all appropriate permits in South Dakota for the Big Stone South

Substation and the portion of the Western Segment that will be located in South Dakota.

31. New substation equipment necessary to accommodate the proposed 345 kV transmission line will be installed at the Alexandria Substation. The substation is currently a ring bus configuration and will be reconfigured to a breaker and a half configuration to accommodate the new 345 kV lines from the Big Oaks and the Big Stone South substations. Equipment will include new termination structures, circuit breakers, relays, and associated control equipment. Expansion of approximately 2 to 4 acres from the current fenced area will be required to accommodate the new substation equipment, and will require the purchase of additional land.

32. The existing Riverview Substation will provide a mid-point termination on the Eastern Segment of the Project between the Alexandria and Big Oaks substations. This substation is located in Stearns County, Minnesota. The existing 345 kV circuit from the Alexandria Substation (to the Quarry Substation) will be reconfigured to bypass the Riverview Substation and the new 345 kV circuit from the Alexandria Substation to the Big Oaks Substation will connect to the Riverview Substation. New substation equipment necessary to provide reactive power support will be installed at the Riverview Substation. The current fenced area of the Riverview Substation will be expanded by approximately 0.5 acres on Great River Energy owned property to accommodate this new substation equipment.

33. The existing Quarry Substation, owned by Xcel Energy, is located in Stearns County, Minnesota. New substation equipment necessary to provide reactive power support will be installed at the Quarry Substation. The current fenced area of the Quarry Substation will be expanded on Xcel Energy owned property to accommodate this new substation equipment.

III. Project Schedule

34. **Table GDS-1** provides the permitting and construction schedule currently anticipated for the Eastern Segment of the Project. This schedule is based on information known as of the date of filing. Estimated dates may change as further information develops or if there are delays in obtaining the necessary federal, state, or local approvals required prior to construction.

Table GDS-1: Eastern Segment – Anticipated Project Schedule

Activity	Estimated Dates
Minnesota Certificate of Need and Route Permit for Eastern Segment Issued	Second/Third Quarter 2024
Land Acquisition Begins	Third Quarter 2024
Survey and Transmission Line Design Begins	Second Quarter 2024
Other Federal, State, and Local Permits Issued	First Quarter 2025
Start Right-of-Way Clearing	Second Quarter 2025
Start Project Construction	Second Quarter 2025
Project In-Service	Fourth Quarter 2027

35. Otter Tail, which is managing the Western Segment, has indicated it is making best efforts to bring that portion of the Project on line by the end of 2030. Because the Western Segment is a greenfield transmission line with a route that is not

yet determined, there is somewhat greater uncertainty and it is possible that the in-service date could be delayed until 2031.

IV. Project Costs

36. Xcel Energy and the Project's other owners have prepared high and low estimates for the overall cost. These estimates include the costs of: transmission line material and construction, substation modification material and construction, right-of-way, land acquisition, permitting, design, and may include risk reserve and Allowance for Funds Used During Construction (AFUDC) or Construction Work in Progress (CWIP).[1]

37. The difference between the high and low estimates largely reflect uncertainty with regard to the route of the Western Segment, with the higher figure representing a longer route and the lower figure a shorter route; and some uncertainty with regard to the equipment that will need to be installed at substations, particularly for voltage control. Studies for the voltage control scope is ongoing.

38. Of course, as with any estimate, particularly those made early in the development process, costs are subject to change, especially given the current inflationary environment.

39. MISO previously developed cost estimates for each of the 18 transmission projects in the LRTP Tranche 1 Portfolio. MISO's estimate for this Project was $574

[1] Individual project owners took different approaches in budgeting for specific portions of the Project.

million in 2022 dollars. The high and low estimates prepared by the Project owners are higher than MISO's estimate for several reasons. The MISO estimate did not include the costs associated with the 67 to 78 new foundations and structures that will be required along the Eastern Segment for the reasons discussed in paragraphs 13 to 16 above. The MISO estimate also did not include the costs associated with adding reactive equipment, expanding the existing Riverview and Quarry substations, and upgrading remote end relays at Sherburne County Substation, Monticello Substation, Coon Creek Substation and Elm Creek Substation, which are discussed in paragraphs 28 to 33 above. Finally, material and labor costs have also increased since MISO developed its cost estimate.

40. **Table GDS-2** below provides a breakdown of the Project costs for each segment and by substation.

Table GDS-2: Construction Cost Estimates

Project Components	Low Capital Expenditures (2022$) ($Millions)	High Capital Expenditures (2022$) ($Millions)
Big Stone South – Alexandria 345 kV Transmission Line (Western Segment)	$385.0	$441.2
Big Oaks – Alexandria 345 kV Transmission Line (Eastern Segment)	$123.1	$130.9
Big Stone South Substation Modifications	$12.0	$20.0
Alexandria Substation Modifications	$20.0	$28.0
Riverview Substation Modifications	$3.0	$3.0
Quarry Substation Modifications	$3.0	$4.0
New Big Oaks Substation	$60.4	$72.3
Total Project Costs*	**$606.5**	**$699.4**
**The sum of the individual component amounts and Total Project Costs may differ due to rounding*		

41. These costs should be considered in the context of (1) the benefits the Project is projected to provide, reliability benefits and also economic benefits, which are discussed in the Affidavit of Jason Standing and the Company's Application and (2) the MISO cost-sharing applicable to the Project, which is also discussed in Mr. Standing's affidavit and the Application.

V. Project Construction

42. Construction for the Western and Eastern Segment will occur at different times, but construction of each segment will last approximately 18 to 20 months from start to finish and will employ approximately 100 to 150 construction workers.

43. Construction will begin after necessary federal, state, and local approvals are obtained and property and rights-of-way are acquired for each respective segment. Construction in areas where new easements are not needed or have already been obtained may proceed while right-of-way acquisition for other areas are still in process. The precise timing of construction will consider various requirements of permit conditions, environmental restrictions, availability of outages for existing transmission lines (if required), available workforce, and materials.

44. Construction typically progresses as follows:

- survey marking of the right-of-way
- right-of-way clearing and access preparation;
- grading or filling if necessary;
- installation of culverts or concrete foundations;
- installation of poles, insulators, and hardware;
- conductor stringing; and
- installation of any aerial markers required by state or federal permits.

VI. Conclusion

45. The Company and the other owners of the proposed Project have developed schedules and high and low-end cost estimates that the Commission can use in evaluating the prudence of the Project. The costs should be compared to the Project's reliability and economic benefits described in Jason Standing's affidavit and the Addendum to the MISO 2021 MTEP Report, which is attached as Schedule 2 to Mr. Standing's Affidavit.

[SIGNATURE PAGE FOLLOWS]

Further, Affiant sayeth not.

Grant D. Stevenson

Subscribed and sworn to before me
This 12 day of October, 2023

Notary Public

DEANNA PEARCE
Notary Public
Minnesota
My Commission Expires January 31, 2027

SCHEDULE 1:
STATEMENT OF QUALIFICATIONS
MR. GRANT D. STEVENSON

Grant David Stevenson

Xcel Energy
414 Nicollet Mall, 414-05
Minneapolis, MN 55401

612-330-6330
grant.stevenson@xcelenergy.com

Experience

Project Director, Principal Project Manager, Senior Project Manager **2000 to present**
Transmission Business Unit, Xcel Energy, Minneapolis, MN

- Provide strategic leadership to multi-disciplinary teams on complex, high-profile and often multi-owner transmission and substation projects.
- Lead teams including engineering, permitting, construction, consultants and contractors to define scope of work, produce project estimates, gain capital spending authorization, establish project schedules, track and reconcile expenditures, gain permits, design, acquire rights-of-way, bid and construct capital projects that meet budgets and in-service dates.
- Lead development of construction contractor bid documents, contractor selection and contractor oversight.
- Work extensively with the public and state regulatory officials to permit and locate new transmission lines in areas that balance issues of land use, cost, impact to people and impact to the natural environment.
- Project portfolio has included the following significant projects, among others:
  - Huntley-Wilmarth 345 kV Project: Project manager leading $115 million 52-mile 345 kV transmission line project in Minnesota. Project is jointly owned with ITC Midwest. Project required state and federal permits, acquisition of new right-of-way. Managed team of employees and contractors for cradle-to-grave oversight including oversight of construction contractors. Testified in state permit proceedings. Project completed on schedule and under budget.
  - CapX2020 345 kV Project: Led dedicated team for a complex, multi-owner $475 million transmission project in Minnesota and Wisconsin. Testified in state permit proceedings. Project came in $25 million under budget. Included triple-circuit crossing of Mississippi River, portions which were accessible only by barge. https://youtu.be/PILUFRe_jjM
  - Badger-Coulee 345 kV Project: Represented interests of Xcel Energy and other minority owners in the $550 million jointly-owned portion of the Badger – Coulee 345 kV transmission project.
  - Fifth Street Substation underground transformer replacement: Project required coordination with City of Minneapolis and Metropolitan Transit to shut down light rail transit in downtown Minneapolis. https://youtu.be/v32338cAJBE
  - Southwest Minnesota 825 MW Project: This $250 million project involved construction of 200 miles of new transmission lines, the reconstruction of 300 miles of existing lines, and impacted 29 substations. The project also required agreements with 11 electric utilities.

Sales and Customer Service Manager **1999 to 2000**
Electric Sales and Customer Service, Northern States Power Company, Minneapolis, MN

- Successfully led team of 10 account representatives to meet goals in sales, customer service, demand side management and customer satisfaction.
- Managed projects to improve customer satisfaction and team effectiveness.
- Hired, trained and coached employees on energy management, conservation, distribution reliability.

Energy Management Engineer, Account Executive **1990 to 1999**
Electric Sales and Customer Service, Northern States Power Company, Minneapolis, MN

- Provided effective technical support to key industrial customers and NSP sales representatives regarding energy conservation programs and initiatives.
- Managed NSP's relationship with several demanding, strategic, high-tech manufacturing customers.
- Led multidisciplinary teams to solve customer-specific electric reliability, power quality, capacity, and distribution construction problems.

Plant Project Engineer **1986 to 1990**

Sherburne County Generating Plant, Northern States Power Company, Becker, MN

- Managed contractors, directed work of plant operations, maintenance and technical personnel.
- Managed projects to improve productivity, efficiency and safety at NSP's largest generating plant.
- Identified electrical and mechanical problems and recommended corrective repairs.

Professional Certification

Certified Project Management Professional (PMP) by Project Management Institute

Education and Certificates

OSHA 10 Safety Certification

Project Management Institute Project Management Professional Training and Certification

Minnesota Management Institute, University of Minnesota Carlson School of Management
Intensive, condensed mini-MBA business management curriculum.

Minnesota Management Academy, University of Minnesota Carlson School of Management
Management principles and skills for front-line managers.

Post-graduate coursework at University of St. Thomas and University of Minnesota in economics, business law, marketing, manufacturing.

Bachelor of Mechanical Engineering, University of Minnesota