Exhibit No.:
Issue(s): *Certificates of Convenience, Feasibility Analysis*
Witness: *Shawn E. Lange, P.E.*
Sponsoring Party: *MoPSC Staff*
Type of Exhibit: *Rebuttal Testimony*
Case No.: *EA-2022-0245*
Date Testimony Prepared: *December 21, 2022*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

ENGINEERING ANALYSIS DEPARTMENT

REBUTTAL TESTIMONY

OF

SHAWN E. LANGE, P.E.

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. EA-2022-0245

Jefferson City, Missouri
December 2022

******* Denotes Highly Confidential Information *******
****** Denotes Confidential Information ******

TABLE OF CONTENTS OF

REBUTTAL TESTIMONY OF

SHAWN E. LANGE, P.E.

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. EA-2022-0245

REBUTTAL TESTIMONY

OF

SHAWN E. LANGE, P.E.

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. EA-2022-0245

Q. Please state your name and business address.

A. My name is Shawn E. Lange, and my business address is Missouri Public Service Commission, P.O. Box 360, Jefferson City, Missouri, 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission ("Commission") as a Senior Professional Engineer in the Engineering Analysis Department of the Industrial Analysis Division.

Q. Please describe your educational and work background.

A. Please see Schedule SEL-r1.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to provide support for Staff's determination that the proposed project is not needed as an Ameren Missouri resource and other topics for the Commission's consideration.

Q. Do you support any of Staff's recommended conditions if the Commission were to grant a CCN for the project?

A. Yes. If the Commission were to grant Ameren Missouri a CCN for the project Staff recommends the following conditions:

- Ameren Missouri shall notify the Commission and provide an updated economic analysis if the upgrade cost exceeds those outlined in the GIA more than 15%.
- Ameren Missouri shall accept that the in-service criteria contained in confidential attachment SEL-3 and confidential attachment SEL-4 are appropriate for use in a future case to determine whether the Boom Town solar project is in-service.
- Ameren Missouri shall use sound engineering judgement and commercially reasonable efforts to meet the IEEE standard P2800 for the Boomtown project and future transmission interconnected solar projects.

PROJECT

Q. What is the project?

A. The Project is a 150 MW-AC solar generation facility in White County, Illinois. Upon completion, the Project will interconnect to the transmission system under the functional control of the Midcontinent Independent System Operator, Inc. (MISO). The granting of the requested CCN would allow Ameren Missouri to acquire the project under the Build Transfer Agreement ("BTA").[1] *** [redacted] ***

Q. What is the purpose of the project?

A. The purpose of the project, as proposed by Ameren Missouri, is twofold:

1) To be a generation resource for Ameren Missouri.
2) To be a generation resource for the Renewable Solutions Program.

[1] Ameren Missouri Application EA-2022-0245 Section II.A.6

Staff witnesses Michael L. Stahlman and Cedric E. Cunigan, P.E. discuss the Renewable Solutions Program.

<u>TARTAN CRITERIA</u>

Q. What are the Tartan Criteria?

A. When making a determination of whether an applicant or project is convenient or necessary, the Commission has traditionally applied five criteria, commonly known as the Tartan factors, which are as follows:

a) There must be a need for the service;

b) The applicant must be qualified to provide the proposed service;

c) The applicant must have the financial ability to provide the service;

d) The applicant's proposal must be economically feasible; and

e) The service must promote the public interest.[2]

Q. What aspects of the tartan criteria will you be addressing?

A. This testimony will focus on the project from the perspective as an Ameren Missouri resource. Staff witnesses Michael L. Stahlman and Cedric E. Cunigan, P.E. discuss the Renewable Solutions Program. Staff witness J Luebbert presents policy considerations, and Staff witness Brad J. Fortson discusses resource planning.

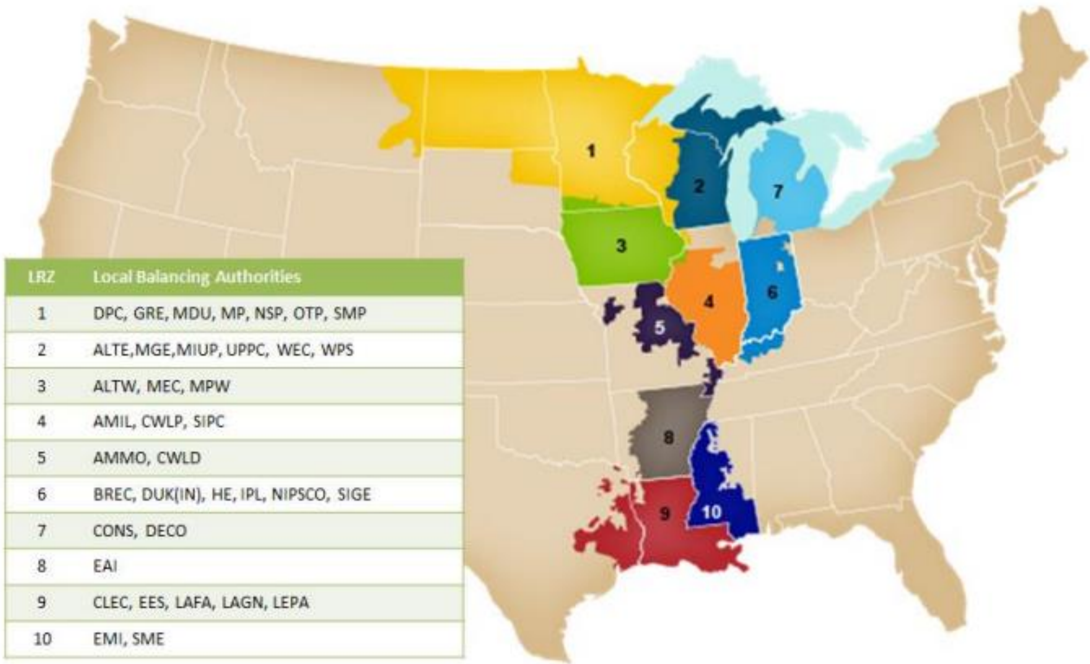
<u>NEED</u>

Resource Adequacy

Q. How does MISO look at resource adequacy?

[2] In re Tartan Energy, Report and Order, 3 Mo.P.S.C. 3d 173, Case No. GA-94-127, 1994 WL 762882 (September 16, 1994).

A. MISO requires load serving entities within each zone[3] to have sufficient resources to meet load and required reserves[4]. A map[5] showing the different zones is shown below.

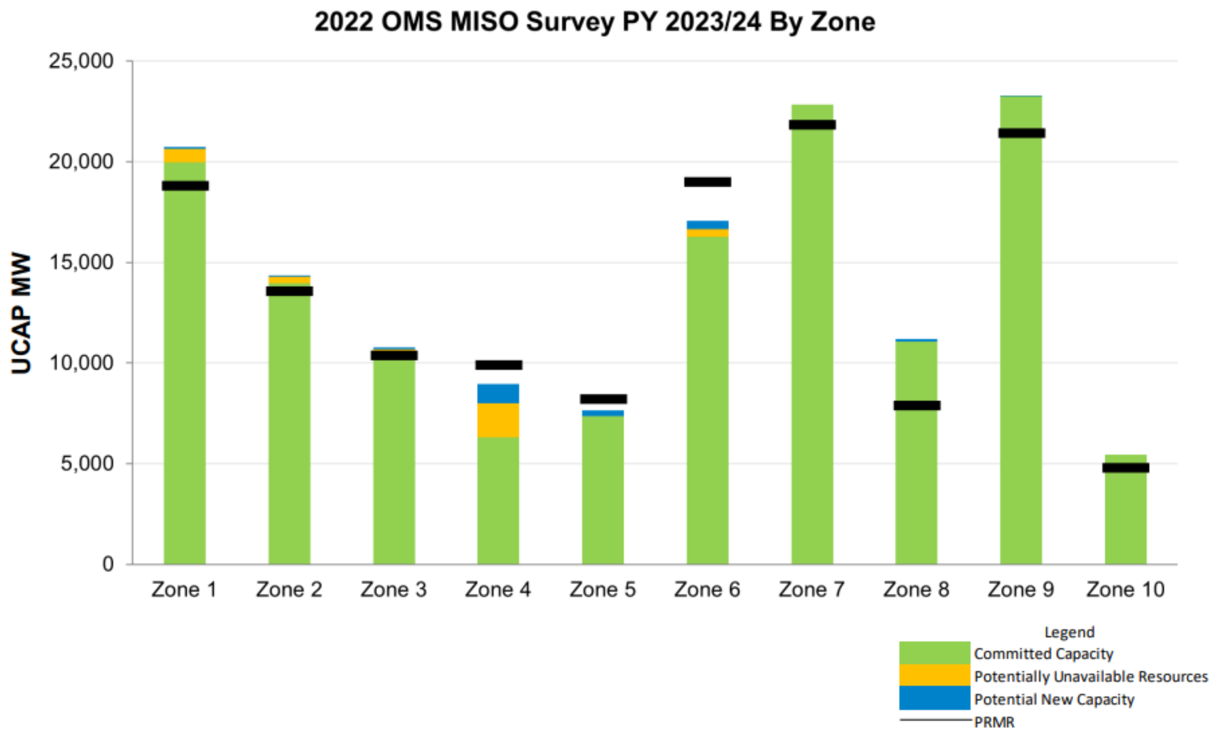


LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE,MGE,MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMI, SME

Below is the results of the MISO OMS survey for 2023/2024 by zone.

continued on next page

[3] Ameren Missouri is in zone 5. Ameren Missouri has ownership in generation in zone 4.
[4] Surplus resources may be shared among load serving entities with resource deficits to meet reserve requirements.
[5] https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf



This chart shows for zone five (5) the planning reserve margin requirement (PRMR) as being higher than the sum of the committed capacity and the potential capacity.

Q. What is the PRMR?

A. The PRMR is essentially the amount of load plus reserve margin to be served by the Load Serving Entity (LSE) (i.e. Ameren Missouri). MISO uses credits called Zonal Resource Credits (ZRCs) as a currency to ensure LSE's have enough planning resources to reliability serve load.[6]

[6] "The Planning Reserve Margin Requirement (PRMR) is the number of Zonal Resource Credits (ZRCs) required to meet a Load Serving Entity's (LSE) Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load. LSEs that have a PRMR will be obligated to procure capacity equal to their PRMR pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone (LRZ) where they have PRMR unless, and to the extent that, the LSE meets its PRMR via a Fixed Resource Adequacy Plan (FRAP)." https://help.misoenergy.org/knowledgebase/article/KA-01099/en-us

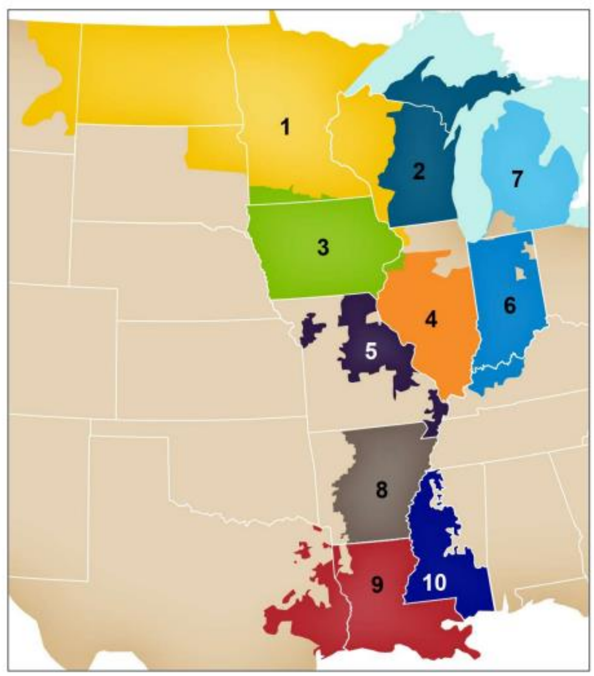
Q. For zone five (5) when the PRMR is higher than the aggregate of the committed capacity and potential capacity, does that mean Ameren Missouri is short on capacity for 2023-2024?

A. No. The chart shows the PRMR is higher than the committed capacity and potential capacity for zone five (5). Ameren Missouri generation resources in zone four (4) would be shown as a committed capacity resource for zone four (4).[7]

Q. What was the MISO Capacity Auction results?

A. The MISO capacity auction for 2022-2023 resulted in a capacity auction price of $236.66 MW-Day, as shown below[8].

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$236.66
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$236.66
3	ALTW, MEC, MPW	$236.66
4	AMIL, CWLP, SIPC, GLH	$236.66
5	AMMO, CWLD	$236.66
6	BREC, CIN, HE, IPL, NIPS, SIGE	$236.66
7	CONS, DECO	$236.66
8	EAI	$2.88
9	CLEC, EES, LAFA, LAGN, LEPA	$2.88
10	EMBA, SME	$2.88
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$133.70-236.66



[7] The Ameren Missouri facilities physically located in Illinois and capacities are the Venice Energy Center (489 MW), the Raccoon Creek Energy Center (308 MW), Pinckneyville Energy Center (316 MW), Goose Creek Energy Center (444 MW), and the Kinmudy Energy Center (210 MW).

[8] https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf Pg. 4

Q. What does a capacity auction price of $236.66 indicate?

A. If the auction does not have enough installed capacity, the auction uses a price for the Cost of New Entry (CONE)[9]. The CONE for 2022-2023 Capacity auction was priced at $236.66. The local resource zones for MISO north priced at $236.66 shows that as a whole, MISO north is short on capacity.

Q. Has Ameren Missouri performed analysis or studies on the impacts of the proposed project on this issue?

A. Staff has asked for studies from Ameren Missouri with Staff DR 0002 and in response Ameren Missouri has stated:

> No such analysis has been performed[10].

Q. Does Ameren Missouri's testimony seem to indicate that Ameren Missouri has performed some level of Ameren Missouri capacity analysis?

A. Yes. In Matt Michels' Direct testimony[11] he states:

> Based on our analysis of winter capacity position consistent with MISO's proposed seasonal capacity construct, we do have a need for winter capacity in 2026 that can be met with new solar resources, which are assumed to provide reliable capacity of about 11% of rated output during the winter season.
>
> Based on this statement Ameren Missouri has a need for capacity in the winter of 2026[12]. However, as Ameren Missouri itself points out the solar resource contributes just 11% of the rated output during the winter season (i.e. approximately 16.5 MWac). This resource in isolation does not fulfill Ameren Missouri's need for capacity in 2026 and thereafter.

---

[9] Cost of New Entry is an industry-wide term, used to indicate the current, annualized, capital cost of constructing a power plant.
https://cdn.misoenergy.org/20190911%20RASC%20Item%2004a%20CONE%202020-2021380208.pdf slide 4

[10] Ameren Missouri Response to Staff Data Request 2

[11] Matt Michels Direct Pg. 14 lines 9-12

[12] The capacity balance sheets provided are a snapshot in time and capacity needs are changing due to the seasonal construct and the early required retirement of Rush Island.

Q. Did Staff review Ameren Missouri's winter capacity need for 2026 as represented in the capacity balance sheets provided in response to Staff DR 0079?

A. Yes, Staff reviewed the capacity balance sheets for errors. No errors were found, although Staff is unable to independently verify the assumptions used or the managerial preferences input by Ameren Missouri. ** [redacted] **

Q. Does Staff agree there is a need for winter capacity in 2026?

A. Yes. ** [redacted] **

Q. Will this project alleviate the entire need shown for winter of 2026?

A. No. While this resource may help address a small portion of Ameren's capacity needs in the short term, things are changing like the seasonal construct[13]; and Ameren's proposed solution does not fulfill its need.

Q. Is Ameren Missouri looking at internal projects to help address the winter resource availability issue?

A. Yes, however, these potential new projects were not considered at the time of the 2020 IRP or in its recent notice of preferred resource plan change. In Ameren Missouri's

[13] MISO conducts seasonal resource assessments to evaluate potential resource adequacy risks for the upcoming season. These assessments evaluate projected near-term available capacity under probable and extreme peak load forecasts and historical generator outage conditions for each season. The assessments highlight potential issues in the upcoming seasons to help system operators and stakeholders prepare for potential strained system conditions and develop preventative actions.

presentation to the Commission in Case EO-2022-0215 on August 17, 2022, concerning the investigation into the retirement of Rush Island, Andrew Meyer stated[14]:

We're studying restarting the existing idled equipment for dual fuel capability at our Peno Creek Combustion Turbine Energy Center. There's four units there. What that means is they normally run on natural gas, but this would allow for them to run on fuel oil as well. So if you can't get the gas on a cold day, you're running on fuel oil. We can typically keep one of those four units available on gas during the severely cold weather. So this would allow us to regain the use of the other three units on fuel oil during those days to help meet that load.

The other option that we're analyzing right now is installing dual fuel capability at Audrain Energy Center. So Audrain Energy Center is eight units all simple cycle combustion turbines roughly, you know, 80 megawatts. In the winter they could probably maybe reach closer to 90 megawatts with the ambient temperatures being down. So that would add another 700 megawatts of oil-fired capability to meet the load on these critically cold days. But that option will require a review of the current operating permit, and I believe the operating permit only allows them to operate on natural gas.

Q. What was Ameren Missouri's decision on restarting the dual fuel equipment at Audrain and Peno Creek?

A. Staff is unaware of the status of that study or whether a decision has been made. However, changes in the availability of these resources will improve Ameren Missouri's winter capacity balance.

Q. In 2022, has MISO investigated the level of renewable penetration15 that can be accommodated by the regional grid?

[14] Ameren Missouri's presentation to the Missouri Public Service Commission on August 17, 2022 transcript Pg. 17 line 21 through Pg. 18 line 18

[15] Penetration generally refers to the percentage of electricity generated by a particular resource.

A. Yes. In the attached MISO Regional Resource Adequacy Report, Attachment SEL-2, discussion is provided concerning the complexities that are associated with increased renewable penetration, and the necessity to ensure coordination among utilities, States, and MISO to achieve higher levels of renewable penetration. In particular, "Key Insight 3," is that:

Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system. A major driver for increasing penetration of renewables is company and state decarbonization goals. According to this year's analysis, MISO-wide emissions are projected to decrease from 2005 levels by 65% in 2030 and achieve a nearly 80% reduction by 2041. MISO's system could approach 30% of annual energy from wind and solar generation within five years, and renewable penetration levels my increase by approximately 10% every five years after. This level of renewable penetration is significant because of a key finding of another MISO study called the Renewable Integration Impact Assessment (RIIA), which assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. The RIIA identified an inflection point between renewable penetrations of 30% and 40%, where planning and operating the grid will become significantly more complex and challenging. The RRA indicates that the MISO region's renewable penetration could reach that inflection point later this decade (Figure 3). **The RIIA found that renewable penetrations of 50% or higher could be reliably achieved if MISO, members, and states coordinate closely on advanced actions that will be needed. [Emphasis added.]**

Q. Has Ameren Missouri provided evidence in this docket of close coordination with MISO, other MISO generation owners and load serving entities, and Missouri or other states?

A. No. The recent MISO materials emphasize that closer coordination of resource planning enables more renewable resource integration. Staff is concerned that Ameren Missouri's approach lacks the level of coordination referenced by MISO, and thus limits the level of renewable penetration that can be integrated into the regional grid without negative impacts to reliability.

Climate and Equitable Jobs Act (CEJA)

Q. What is CEJA?

A. CEJA in Illinois has timelines for retirements of fossil generation types starting in 2030 and extending to 2045. CEJA also has a requirement that:

As of the effective date of the Act, no unit may emit, in any 12-month period, CO2e or copollutants in excess of that unit's existing emissions for those pollutants.

The current existing emissions is equal to their unit specific average from 2018-2020. One thing to keep in mind is that 2020 was impacted significantly because of Covid-19.

Q. How is Ameren Missouri impacted by CEJA?

A. All of Ameren Missouri's generation assets in Illinois[16] will have limitations on emissions and depending on certain factors in the legislation, may be required to retire more quickly than expected prior to the legislation passage. Both of these impact Ameren Missouri with the potential speeding up of retirements as well as limiting the output of the natural gas generation in Illinois.

Q. Has Ameren Missouri performed analysis or studies on the impacts of the proposed project on this issue?

[16] The Ameren Missouri facilities physically located in Illinois and capacities are the Venice Energy Center (489 MW), the Raccoon Creek Energy Center (308 MW), Pinckneyville Energy Center (316 MW), Goose Creek Energy Center (444 MW), and the Kinmudy Energy Center (210 MW).

A. Staff has asked for studies of Ameren Missouri with Staff DR 3 and in response Ameren Missouri has stated:

No such analysis has been performed[17].

In its supplemental response to Staff DR 0003, Ameren Missouri points to its resource planning. Staff Witness Brad Fortson further discusses integrated resource planning.

Rush Island

Q. How does Rush Island impact this project or the decision to do this project?

A. As Staff stated in its motion to open an investigation in EO-2022-0215:

On August 20, 2021, the United States Court of Appeals for the Eighth Circuit issued its decision in Sierra Club v. Ameren Missouri, Case No. 19-3220, affirmed the finding of Ameren Missouri's liability for violations of the Clean Air Act ("Clean Air Act") at Rush Island made by the United States District Court for the Eastern District of Missouri; specifically, the district court "enter[ed] a finding of liability against Ameren," concluding that "the Rush Island Unit 1 and 2 projects . . . were major modifications under the CAA, Ameren violated the PSD[18] program's requirements 'by failing to obtain a preconstruction permit and install best available pollution control technology,' and Ameren violated Title V of the CAA." The 8th Circuit stated, "In summary, the district court found Ameren in violation of the CAA for 'mak[ing] major modifications to expand Rush Island's capacity' without 'apply[ing] for a PSD permit and meet[ing] reduced emissions requirements.'"[19]

[17] Ameren Missouri Response to Staff Data Request 0003

[18] In 1977, Congress amended the CAA "to add the 'Prevention of Significant Deterioration' ("PSD") program, which seeks to ensure that the 'air quality floor' established by the National Ambient Air Quality Standards ("NAAQS") does not 'in effect become a ceiling.'" Id. (quoting Sierra Club v. Thomas, 828 F.2d 783, 785 (D.C. Cir. 1987)).

[19] Staff Motion to Open an Investigation in EO-2022-0215, Paragraph 9.

As suggested by the Y-2 study and reaffirmed by the Attachment Y study, MISO determined that continued plant operations are required beyond September of 2022 until the Company can complete certain specified transmission system upgrades[20].

Project	Estimated Completion Date
Installation of a Capacitor Bank at the Overton Substation to address voltage issues	Spring/Fall 2023
Replacement of a Transformer at the Wildwood Substation in St. Louis County to address overload concerns	Spring 2024
Upgrading of a bus bar tie position at a substation adjacent to Rush Island to address voltage issues	Spring/Fall 2023
Installation of four (4) STATCOMs in the St. Louis Metropolitan area to provide reactive power support; installations to occur as equipment becomes available 2024-2025	Final STATCOM Fall 2025, perhaps earlier

New resources could impact the need for these upgrades and/or the current timeline for said upgrades. Staff requested all analysis performed showing what, if any, impact the proposed project will have on all issues outlined in the Rush Island attachment Y study results as well as attachment Y2 study results.

Q. Has Ameren Missouri performed analysis on the impacts of the proposed project on this issue?

A. Staff has asked for analysis of Ameren Missouri with Staff DR 0001, and in response Ameren Missouri has stated:

> No such analysis has been performed[21].

In its supplemental response to Staff DR 0001, Ameren Missouri states, in part, "[the] Boomtown project does not address the largely Metro St. Louis area voltage and other

[20] ER-2022-0337 Mark Birk Direct Testimony, Page 7, Lines 4-6.
[21] Ameren Missouri Response to Staff Data Request 1

transmission system issues identified in the Y2 study." Ameren Missouri conceptually addresses its resource plan and its generation transition in supplemental DR 1. Staff witness J Luebbert and Brad J. Fortson further discuss these issues.

Renewable Energy Standard

Q. What is the Renewable Energy Standard?

A. The Renewable Energy Standard (RES) is a statute (Section 393.1030 RSMo) requiring electric utilities obtain a portion of its energy portfolio from renewable resources. By 2021 and thereafter, electric utilities are required to generate or purchase no less than 15% of their energy from renewable resources. At least 2% of the electric utility's renewable portfolio must be from solar resources. The Commission rules implementing the RES are contained in 20 CSR 4240-20.100.

Q. What is used to determine if a portion of the energy is from renewable resources?

A. A Renewable Energy Credit (REC), means a tradable certificate, that is either certified by an entity approved as an acceptable authority by the commission or as validated through the commission's approved REC tracking system or a generator's attestation. RECs can be generated from non-solar resources or solar resources. RECs generated from solar resources are called S-RECs. Each REC represents that one (1) megawatt-hour of electricity has been generated from renewable energy resources. Electric utilities must generate or purchase RECs and S-RECs associated with electricity from renewable energy resources in sufficient quantity to meet the RES portfolio requirements for that reporting year. The RES portfolio requirements are based on total retail electric sales of the utility.

Q. Does Ameren Missouri need additional solar RECs for compliance with the renewable energy standard?

A. No. If the Huck Finn project is granted a Certificate of Convenience and Necessity and that project would address Ameren Missouri's RES compliance position after the expiration of the Pioneer Prairie wind PPA, it is difficult to conclude this project is needed for Missouri RES compliance. In EA-2022-0244, Staff stated

In conclusion, this Project is a reasonable solution to address Ameren Missouri's RES compliance position after the expiration of the Pioneer Prairie wind PPA[22].

This conclusion is made even clearer since Ameren Missouri's application in this case includes a Renewable Solutions tariff that, as designed, would retire RECs on the tariff customer's behalf, thus making those recs unavailable for use by Ameren Missouri for RES Compliance purposes through the first fifteen years of the project and tariff.

RECOMMENDATIONS

This section will discuss other considerations and Staff recommendations not covered by the other Tartan Criteria, including interconnection costs, in-service testing, and applicable standards.

INTERCONNECTION COSTS

Q. What type of interconnection service will this project have?

A. *** [redacted][23].

[22] EA-2022-0244 Staff Report Pg. 20
[23] Ameren Missouri response to Staff Data request no. 0006 Generator Interconnection agreement Original Sheet No. 84.

[redacted] ***

Q. What are ERIS and NRIS?

A. FERC's pro forma Large Generator Interconnection Agreement (LGIA) defines ERIS and NRIS as follows[24]:

[ERIS] shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. [ERIS] in and of itself does not convey transmission service.

[NRIS] shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System: (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. [NRIS] in and of itself does not convey transmission service.

Q. What are the current interconnection costs?

A. The table below shows the interconnection costs[25] for the project.

continued on next page

[24] https://www.ferc.gov/sites/default/files/2020-10/10-2020-E-12.pdf Pg. 4
[25] Ameren Missouri response to Staff Data request no. 26 Appendix A to the Generator Interconnection Agreement Original Sheet 95.

***

[redacted]

***

Q. Does Staff have concerns related to the project's projected interconnection costs?

A. Yes, the GIA provided for the Boom Town project states:

*** [redacted][26] ***

Based on this, Staff is concerned that actual costs may be higher than presented in Ameren Missouri's application and supporting testimony.

Therefore, Staff recommends if the Commission grants a CCN, include in its order, a condition related to transmission upgrade costs. Specifically, Ameren Missouri shall notify the Commission and provide an updated economic analysis if the upgrade cost exceeds those outlined in the GIA more than 15%.

IN-SERVICE CRITERIA

Q. What are in-service criteria?

[26] Ameren Missouri response to Staff Data request no. 6 Generator Interconnection agreement Original Sheet No. 100.

A. In-service criteria are a set of operational tests or operational requirements developed by the Staff to determine whether a new unit is "fully operational and used for service."

Q. Where does the phrase "fully operational and used for service" come from?

A. The phrase comes from Section 393.135, RSMo. 2000, a statute that was adopted by Initiative, Proposition No. 1, on November 2, 1976. Section 393.135, RSMo. 2000, provides as follows:

Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is <u>fully operational and used for service</u>, is unjust and unreasonable, and is prohibited. (Emphasis added)

Q. Should the Commission grant a CCN, does the Staff have a recommendation for the Commission with regard to in-service criteria?

A. Yes. For any CCN granted in this case, Staff recommends that the Commission note the in-service criteria contained in confidential attachment SEL-3 and confidential attachment SEL-4 are appropriate for use in a future case to determine whether the Boom Town solar project is in-service. Staff prefers to have in-service criteria that the parties can agree to prior to the case(s) in which the plant is put into rate base. In this case, Ameren Missouri provided Staff with the in-service criteria they are proposing to use for the proposed Boom Town project in the confidential response to Staff Data Request No. 7. Staff is in agreement that the in-service criteria is appropriate and should be used in a future case to determine whether the project be considered fully operational and used for service. These criteria are listed in confidential attachment SEL-3. Staff is also including the capacity test procedure as confidential attachment SEL-4.

INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS ("IEEE") STANDARDS

Q. Does this project interconnect into the transmission system or the distribution system?

A. The Boom Town is intended to interconnect with the transmission system.

Q. What Institute of Electrical and Electronics Engineer ("IEEE") standard is applicable to interconnection at the transmission voltage level?

A. IEEE Standards Association ("IEEE SA") recently published a new standard related to projects such as Boom Town. Specifically, on April 22, 2022, IEEE published IEEE Standard 2800™. IEEE Standard 2800™ is the Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems. IEEE SA explained the need to establish a new standard: "Recent events in North America such as the Blue Cut Fire Disturbance as well as institutional challenges in North America that suggest the inappropriate use of IEEE Standard 1547™ for large-scale solar plants underscores this need."[27] IEEE Standard 1547™ is the IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The IEEE 1547 ™ is appropriate for distributed energy resources, such as net-metered customers.

[27]https://sagroups.ieee.org/2800/#:~:text=Given%20that%20IEEE%20standards%20are%20voluntary%20industry%20standards%2C,resources%20interconnecting%20with%20associated%20transmission%20electric%20power%20systems.

NERC also highlighted the need for developing a standard that is pertinent to inverters used for generation that will be connected to the transmission system in its *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*.

Staff is aware that IEEE Standard 2800™ will require its adoption by the regional authority governing interconnection requirements (AGIR)[28]. At this time Ameren Missouri represents the AGIR does not require compliance with IEEE Standard 2800™.[29]

Q. What is Staff's Concern?

A. Staff is concerned that NERC investigated the need for a standard for inverters interconnecting into the transmission system and IEEE SA developed IEEE Standard 2800 ™. However, Boomtown will adhere to IEEE Standard 1547™.[30]

Q. What is Staff's Recommendation?

A. Staff recommends the Commission include the following condition in its order granting any CCN:

> Ameren Missouri shall use sound engineering judgement and commercially reasonable efforts to meet the IEEE standard P2800 for the Boomtown project and future transmission interconnected solar projects.

<u>CONCLUSION</u>

Q. What is Staff's Conclusion regarding the Tartan criteria need element?

A. Ameren Missouri has not demonstrated the need element of the Tartan criteria.

[28] AGIR is an entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of inverter-based resources interconnecting with associated transmission electric power systems.
[29] Ameren Missouri Response to Staff Data Request 14.
[30] For IEEE Standard 1547™, the AGIR is defined as: A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the area Electric Power System (EPS). This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc.

Q. Do you support any of Staff's recommended conditions if the Commission were to grant a CCN for the project?

A. Yes, if the Commission were to grant Ameren Missouri a CCN for the project Staff recommends the following recommendations:

- Ameren Missouri shall notify the Commission and provide an updated economic analysis if the upgrade cost exceeds those outlined in the GIA more than 15%.
- Staff recommends that the Commission note the in-service criteria contained in confidential attachment SEL-3 and confidential attachment SEL-4 are appropriate for use in a future case to determine whether the Boom Town solar project is in-service.
- Ameren Missouri shall use sound engineering judgement and commercially reasonable efforts to meet the IEEE standard P2800 for the Boomtown project and future transmission interconnected solar projects.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CREDENTIALS AND CASE PARTICIPATION OF SHAWN E. LANGE, PE

PRESENT POSITION:

I am a Senior Professional Engineer in the Engineering Analysis Department, Industry Analysis Division, of the Missouri Public Service Commission.

EDUCATIONAL BACKGROUND AND WORK EXPERIENCE:

In December 2002, I received a Bachelor of Science Degree in Mechanical Engineering from the University of Missouri, at Rolla now known as the Missouri University of Science and Technology. I joined the Commission Staff in January 2005. I am a registered Professional Engineer in the State of Missouri and my license number is 2018000230.

TESTIMONY FILED:

Case Number	Utility	Testimony	Issue
ER-2005-0436	Aquila Inc.	Direct	Weather Normalization
		Rebuttal	Weather Normalization
		Surrebuttal	Weather Normalization
ER-2006-0314	Kansas City Power & Light Company	Direct	Weather Normalization
		Rebuttal	Weather Normalization
ER-2006-0315	Empire District Electric Company	Direct	Weather Normalization
		Surrebuttal	Weather Normalization
ER-2007-0002	Union Electric Company, d/b/a AmerenUE	Direct	Weather Normalization
ER-2007-0004	Aquila Inc.	Direct	Weather Normalization
ER-2007-0291	Kansas City Power & Light Company	Staff Report	Weather Normalization
		Rebuttal	Weather Normalization
ER-2008-0093	Empire District Electric Company	Staff Report	Weather Normalization
ER-2008-0318	Union Electric Company, d/b/a AmerenUE	Staff Report	Weather Normalization

Case Number	Utility	Testimony	Issue
ER-2009-0089	Kansas City Power & Light Company	Staff Report	Net System Input
ER-2009-0090	KCP&L Greater Missouri Operations Company	Staff Report	Net System Input
ER-2010-0036	Union Electric Company, d/b/a AmerenUE	Staff Report	Net System Input
ER-2010-0130	Empire District Electric Company	Staff Report	Variable Fuel Costs
		Surrebuttal	Variable Fuel Costs
ER-2010-0355	Kansas City Power & Light Company	Staff Report	Variable Fuel Costs
ER-2010-0356	KCP&L Greater Missouri Operations Company	Staff Report	Engineering Review-Sibley 3 SCR
ER-2011-0004	Empire District Electric Company	Staff Report	Variable Fuel Costs
ER-2011-0028	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Net System Input
ER-2012-0166	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Weather Normalization
		Surrebuttal	Weather Normalization Maryland Heights In-Service
ER-2012-0174	Kansas City Power & Light Company	Staff Report	Weather Normalization Net System Input Variable Fuel Costs
		Surrebuttal	Weather Normalization
ER-2012-0175	KCP&L Greater Missouri Operations Company	Staff Report	Weather Normalization Net System Input
		Surrebuttal	Weather Normalization
ER-2012-0345	Empire District Electric Company	Rebuttal	Interim Rates
		Staff Report	Weather Normalization
EC-2014-0223	Noranda Aluminum v. Ameren Missouri	Rebuttal	Weather Normalization
EA-2014-0207	Grain Belt Express CCN	Rebuttal	Certificates of Convenience/Feasibility Analysis
		Surrebuttal	

Case Number	Utility	Testimony	Issue
ER-2014-0258	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Net System Input Variable Fuel Costs
ER-2014-0351	Empire District Electric Company	Staff Report	Net System Input Variable Fuel Costs
ER-2014-0370	Kansas City Power & Light Company	Staff Report	Net System Input Variable Fuel Costs
		True-up Direct	Variable Fuel Costs La Cygne In-service
EA-2015-0146	ATXI CCN	Rebuttal	Certificates of Convenience/Feasibility Analysis
		Surrebuttal	
ER-2016-0023	Empire District Electric Company	Staff Report	Net System Input Variable Fuel Costs
		Surrebuttal	Variable Fuel Costs
ER-2016-0179	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Variable Fuel Costs
EA-2016-0385	Grain Belt Express CCN	Rebuttal	Certificates of Convenience/Feasibility Analysis
		Surrebuttal	
ER-2018-0145	Kansas City Power & Light Company	Staff Report	Variable Fuel Costs Market Prices
		Rebuttal	Variable Fuel Costs Market Prices
		True-up Direct	Variable Fuel Costs Market Prices
EA-2018-0327	ATXI CCN	Rebuttal	Certificates of Convenience/Feasibility Analysis
EA-2019-0021	Ameren CCN	Staff Report	Certificates of Convenience/Feasibility Analysis
EA-2019-0010	Empire District Electric Company CCN	Staff Report	Certificates of Convenience/Feasibility Analysis
EC-2020-0408	MLA v. Grain Belt Complaint	Staff Recommendation	Formal Complaint
EA-2021-0167	ATXI CCN	Staff Recommendation	Certificates of Convenience/Feasibility Analysis

Case Number	Utility	Testimony	Issue
EA-2021-0087	ATXI CCN	Staff Report	Certificates of Convenience/Feasibility Analysis
ER-2021-0240	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Variable Fuel Costs Atchison wind farm Construction Audit and in-service review
		Rebuttal	Atchison in-service and Variable Fuel Costs
		True-up Direct	Variable Fuel Costs
ER-2021-0312	Empire District Electric Company	Staff Report	Transmission and Distribution Investment
EA-2022-0043	Evergy Metro and Evergy West Hawthorn Solar CCN	Staff Report	Certificates of Convenience/Feasibility Analysis
EA-2022-0099	ATXI CCN	Staff Direct Testimony	Certificates of Convenience/Feasibility Analysis
EA-2022-0244	Union Electric Company, d/b/a Ameren Missouri	Staff Report	Certificates of Convenience/Feasibility Analysis

2022 Regional Resource Assessment

A RELIABILITY IMPERATIVE REPORT

NOVEMBER 2022

Highlights

- MISO's Regional Resource Assessment (RRA) provides a collective view of how members' resource plans are evolving, revealing insights and implications that can inform the work that members, states, and MISO are doing to balance reliability, affordability, and sustainability priorities.

- RRA modeling indicates a continued near-term capacity risk, highlighting the immediate importance of coordinated resource planning and additional investment.

- Reliably achieving the decarbonization targets set by many MISO members and states will require a shared understanding of how operational risks emerge and shift over time. The RRA improves that understanding and informs the proactive problem-solving that is needed to meet the region's Reliability Imperative.

Table of Contents

Executive Summary

1. The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.

2. The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.

3. Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system.

4. As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.

5. The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

CONTEXT

Reliably achieving the decarbonization targets set by many MISO members and states will require an accurate and collective view of how resource plans are evolving, and a shared understanding of the ways in which operational risks and needs will emerge and shift over time. MISO's **Regional Resource Assessment (RRA)** offers that collective view and provides insights and technical findings that can inform the work that members, states, and MISO are doing both individually and collaboratively to plan ahead. The 2022 RRA studies capacity and other system attribute needs over a 20-year study period, highlighting the shared responsibility of proactive problem-solving and investment to meet the region's Reliability Imperative.

As in the previous iteration, this report develops a resource outlook that includes model-built resource additions to supplement what MISO members have publicly announced, which then serves as the basis for Flexibility and Resource Adequacy assessments of the out-year resource fleet. This year's work also includes an exploration of emerging technologies and other sensitivities. The 2022 RRA package, including interactive data visualization tools, Local Resource Zone (LRZ)-level results, supplemental charts and data, and a detailed Technical Appendix can be found on the [MISO RRA website.]

INSIGHTS

Key insights from the 2022 RRA are highlighted here and explained in more detail in the body of the report.

KEY INSIGHT 1: The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.

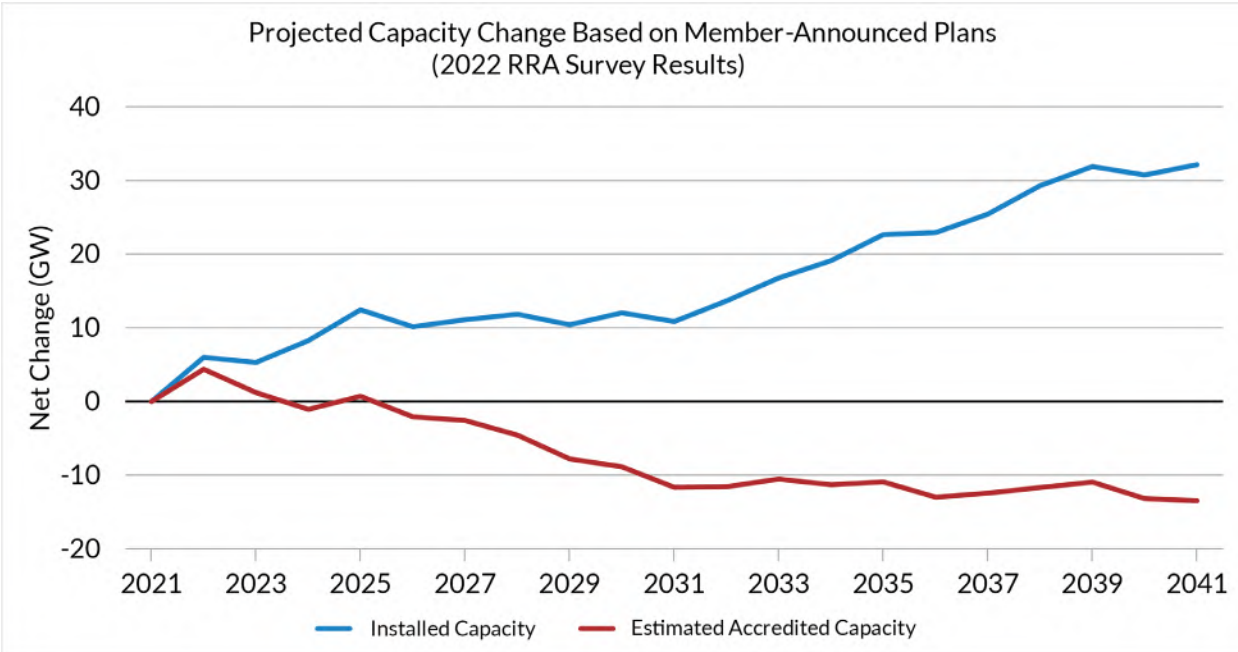


Figure 1: Projected capacity change based on member-announced plans

In the aggregate, MISO members are planning significant investments in new resources, resulting in an increase in installed capacity compared to 2021 levels (Figure 1, the blue line). Installed capacity is the maximum amount of energy that a resource can theoretically produce under ideal conditions. Accredited capacity, by contrast, reflects how much energy a resource is expected to produce to meet tight conditions after accounting for historic performance. Because the new resources that MISO members plan to build — primarily wind and solar — have lower accredited values than the thermal resources that members are planning to retire, the estimated accredited capacity (the red line) is declining below current MISO levels. The accredited capacity value of a resource will vary by season and shift over time as the resource portfolio changes, particularly for weather-dependent resources. Estimation of future accredited values are provided in the Resource Adequacy section of this report.

It is important to understand that the RRA provides a "snapshot in time" view of MISO member and state plans; Figure 1 is based on the publicly available resource plans as of January 2022. Resource plans are continuously being evaluated by MISO members and states, and final generation investment decisions are most often made and publicly announced only as the need for them draws closer. That said, the distinction between installed and accredited capacity is a key consideration for resource adequacy and the RRA survey trend highlights a continued capacity risk for the MISO region.

KEY INSIGHT 2: The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.

The region's combined levels of existing resources (dark blue) and planned resources (light blue) meet the anticipated load-plus-reserve level (black line) on a region-wide basis for the next four years, but the margin of error is small (Figure 2). That said, the risks and the timing of potential capacity shortfalls differ across MISO's 10 Local Resource Zones (LRZs), as shown here. The risk of capacity shortfalls will increase if load growth exceeds the RRA's assumptions or if retirement schedules are accelerated without sufficient replacement. These risks will be further heightened if any planned resources are delayed beyond their currently scheduled in-service dates and other solutions are not promptly implemented.

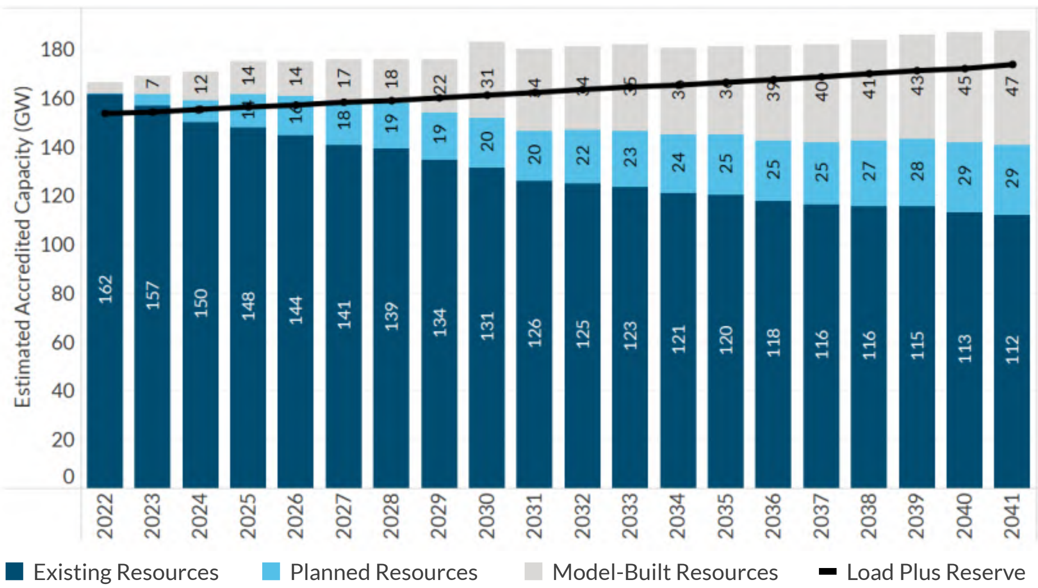


Figure 2: System-wide existing, planned, model-built resources, and load plus reserve

Figure 2 also shows that in 2027, the combined levels of existing resources (dark blue) and planned resources (light blue) fall just short of the forecasted load plus reserve level (black line), potentially putting the region at risk of a capacity shortfall. That apparent gap remains roughly flat in 2028, then steadily increases out to 2041.

The gray "model-built resources" shown in Figure 2 are not included in MISO members' current publicly available resource plans; rather, they are added during an analysis step of the RRA called the Resource Assessment. Because members do not produce detailed resource plans 20 years in advance, the Resource Assessment uses computer modeling to select additional resources — informed by capital cost, emissions profiles, and other assumptions — members may choose to build to achieve their decarbonization goals and reserve margin in a reliable manner.

Note: The RRA presents a favorable, or best-case view of capacity in the near years compared to other MISO studies or joint efforts like the Organization of MISO States (OMS)-MISO Survey. For instance, the RRA adds new resources to the model based on the year provided by the MISO member and/or estimated on the Generator Interconnection Agreement (GIA). In recent years MISO has observed a growing number of project delays and expects that trend, which is not captured by the RRA, to continue. The full report details additional assumption differences.

KEY INSIGHT 3: Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system.

A major driver for increasing penetration of renewables is company and state decarbonization goals. According to this year's analysis, MISO-wide emissions are projected to decrease from 2005 levels by 65% in 2030 and achieve a nearly 80% reduction by 2041.

MISO's system could approach 30% of annual energy from wind and solar generation within five years, and renewable penetration levels my increase by approximately 10% every five years after. This level of renewable penetration is significant because of a key finding of another MISO study called the Renewable Integration Impact Assessment (RIIA), which assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. The RIIA identified an inflection point between renewable penetrations of 30% and 40%, where planning and operating the grid will become significantly more complex and challenging. The RRA indicates that the MISO region's renewable penetration could reach that inflection point later this decade (Figure 3). The RIIA found that renewable penetrations of 50% or higher could be reliably achieved if MISO, members, and states coordinate closely on advanced actions that will be needed.

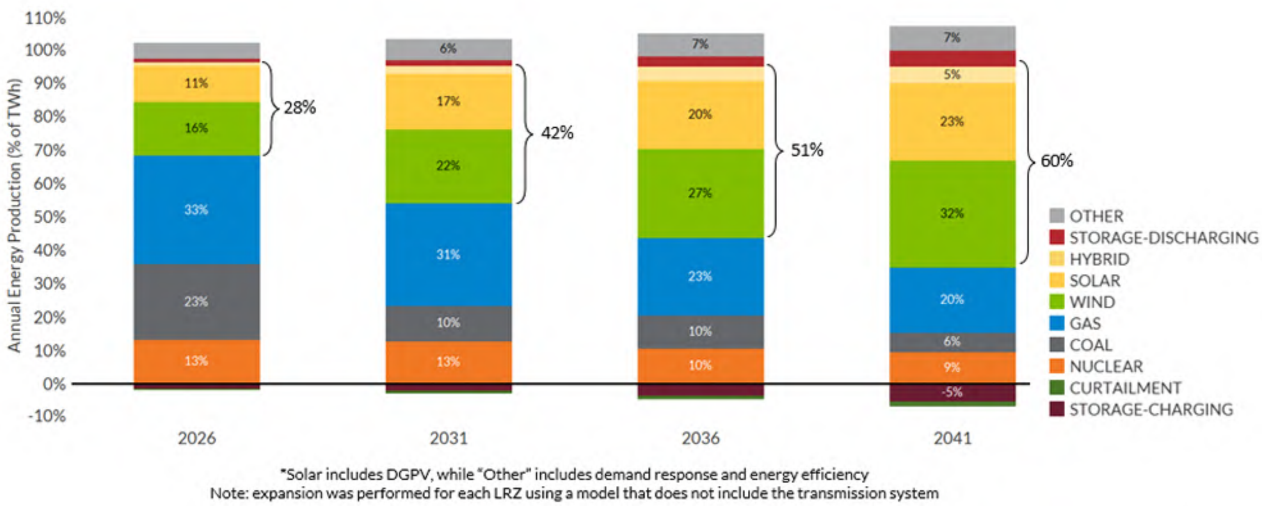


Figure 3: Resource Assessment results

KEY INSIGHT 4: As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.

This year, MISO launched an initiative to identify system reliability attributes that, under current market constructs, could become scarce due to the region's rapidly evolving mix of generation. The work explores the best means of ensuring sufficient reliability attributes, whether through coordination for greater visibility, improvements to existing requirements and products, or the development of something new. The RRA is well-positioned to support the attributes initiative through data collection and analysis, and by providing insight into future system needs and timing considerations.

Take, for example, controllable ramp-up capability. The RRA analysis of future fleet portfolios indicates the maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels. As the solar generation capacity grows, so does the challenge of steeper ramping needs, expected to vary by season and be most prominent in the winter months. Figure 4, as an example, illustrates average net load patterns (load minus renewable generation) of the RRA resource portfolio in January 2041.

To complement the growth of solar, MISO will increasingly need controllable resources that can rapidly turn on and ramp-up or -down quickly, and perhaps cycle multiple times during a day. Additional market simulation insights are provided in the Flexibility section of this report.

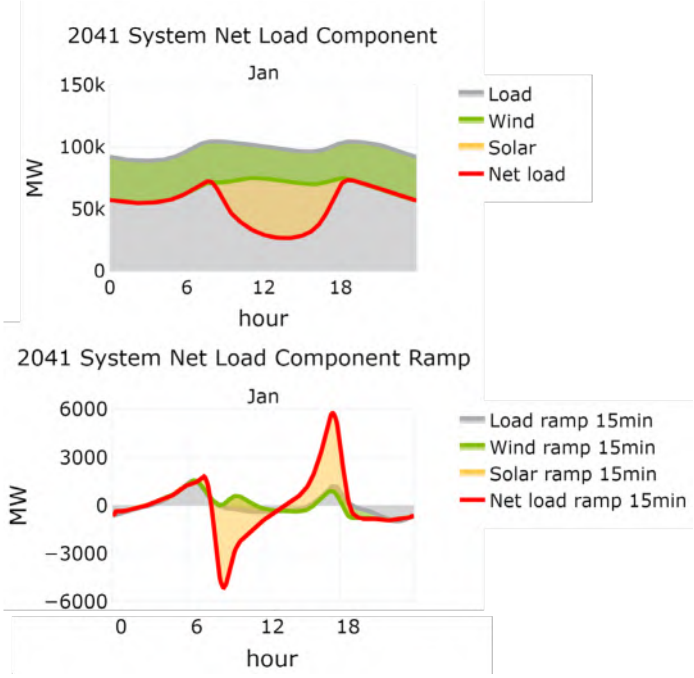
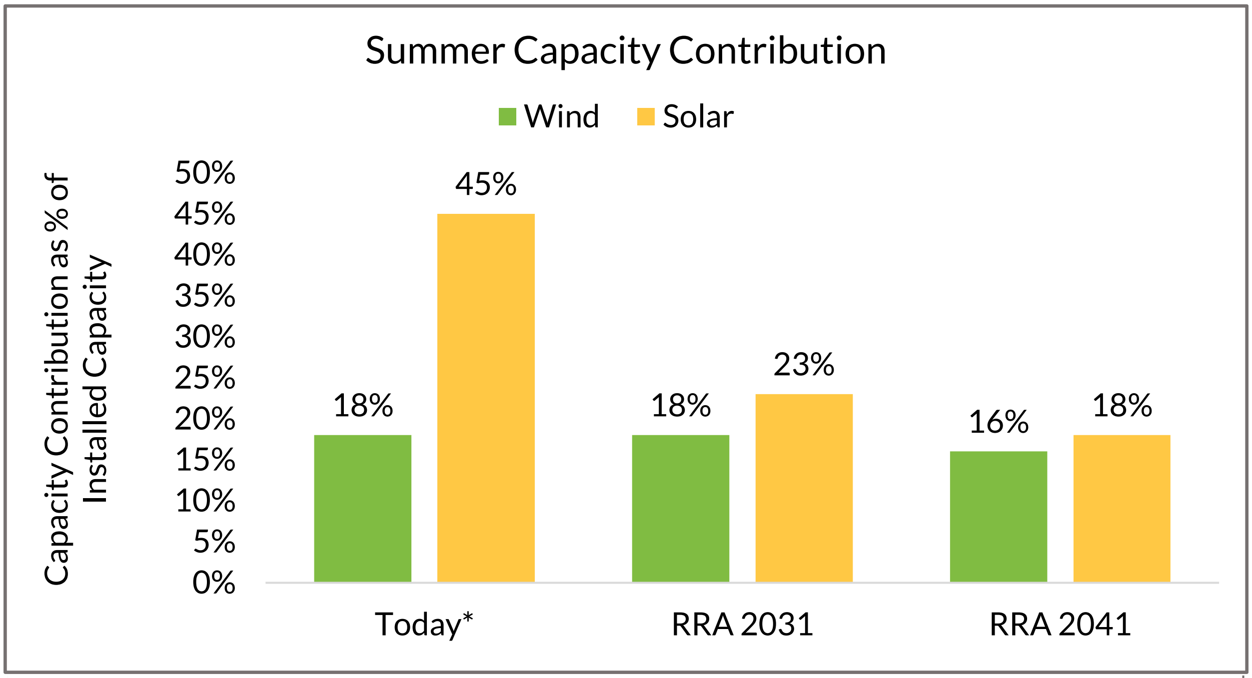


Figure 4: RRA data for January 2041 showing average diurnal net load components (top) and ramps (bottom)

KEY INSIGHT 5: The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

Capacity contribution refers to a resource's ability to meet resource adequacy requirements. In other words, the ability of a resource to be available when most needed. Changes in expected capacity contribution of different resources over time is an important planning consideration. As the fleet changes, the region's portfolio of resources will complement one another in new ways, which will redefine the high-risk hours. The shifting risk will impact a resource's ability to meet that risk, particularly for weather-dependent resources that have varying diurnal and seasonal capability, impacting the resulting capacity contribution of the resource.

Figure 5 illustrates the capacity contribution for the wind and solar classes in the summer months, comparing today's values to the out-years of the RRA analysis. As solar penetration grows, the higher risk hours begin to shift to earlier morning and later afternoon hours, meaning that the solar profile is less and less able to address the new tightest risk hours. In contrast, the wind profile tends to be better matched to the new tightest risk hours, and so further increases in wind penetration minimally impacts the capacity contribution.



(GW)	Today Installed Capacity	Today Accredited Capacity	2031 Installed Capacity	2031 Accredited Capacity	2041 Installed Capacity	2041 Accredited Capacity
Wind	25.6	4.6	56.0	10.1	86.6	13.9
Solar	4.7	2.1	56.3	12.9	86.9	15.6

*Today's values are from the MISO PY23-24 Loss of Load Expectation (LOLE) Study

Figure 5: Summer capacity contributions for the wind and solar classes for today, 2031, and 2041

MISO and stakeholders are continuously working to evolve MISO's Resource Adequacy construct to address the changing planning paradigm, including implementation of a seasonal construct and the redesign of accreditation methodologies for non-thermal resources — both are currently underway. The Resource Adequacy section of the report includes seasonal accreditation estimations for solar, wind, battery, and hybrids in the years 2031 and 2041.

COLLABORATION

MISO is addressing fleet change, extreme weather events, and other challenges through a "lens" that primarily focuses on reliability, in keeping with its role as a federally designated Independent System Operator (ISO) and Regional Transmission Organization (RTO). But MISO also recognizes that sustainability and affordability are top priorities — along with reliability — for many MISO members and the states in the region. MISO is committed to working with its members and states to appropriately balance these priorities while also enabling members and states to achieve their policy goals.

As the MISO region rapidly transitions to a decarbonized fleet, the system will become more interconnected and interdependent and the task of resource planning more complex. The objective of the RRA is to provide insights and data that are useful and actionable for the many MISO stakeholders working to balance reliability, affordability, and sustainability priorities. A shared understanding of future trends and risks is necessary to collaboratively meet the region's Reliability Imperative.

The RRA analysis would not be possible without the information that MISO members willingly provide about their forward-looking resource plans and goals. MISO thanks all the stakeholders who have contributed their time and valuable perspectives to this work.

Introduction

UNDERSTANDING THE RRA

The Regional Resource Assessment (RRA), a periodic study that MISO launched in 2021, models how the portfolio of generating resources in the MISO region might evolve over a 20-year time horizon. In the assessment, MISO analyzes the goals that MISO members and states have publicly announced to reduce the carbon emissions and/or increase the renewable energy levels of their fleets, as well as announced retirements of specific existing resources and the building of new resources. For 2022, MISO used a new survey instrument to collect information directly from MISO members, which improved data quality and stakeholder engagement.

In keeping with industry practices, MISO members and states engage in long-term resource planning, but do not typically make specific, public retirement dates or generation decisions over the full 20 years. In order to complete the 20-year RRA outlook, MISO models additional resources its members may choose to build in order to economically and reliably achieve their decarbonization/renewable energy goals and meet planning reserve margin requirements. That step, called the "Resource Assessment," produces a forecasted future generation portfolio that includes both publicly announced and model-selected resources.

The Resource Assessment portfolio then undergoes two different types of analyses. The "Resource Adequacy Analysis" performs a loss of load expectation (LOLE) assessment to explore potential seasonal risk drivers in future years, and seeks to understand capacity value trends over time, particularly of weather-dependent resources. The "Flexibility Assessment" looks to understand how net load variability and uncertainty changes over time, identifies days/periods of increased risk, and conducts market simulations to evaluate the sufficiency of MISO's current reserve products to meet future needs.

The 2021 RRA published results on a region-wide basis. In 2022, thanks to deeper engagement from MISO members and states, the Resource Assessment modeled each of the region's 10 Local Resource Zones (LRZ), providing a more granular view of the locational results. This year's report additionally includes an exploration of emerging generation and storage technologies. Additional advancements made with this year's RRA are listed as "New in 2022" (Figure 6).

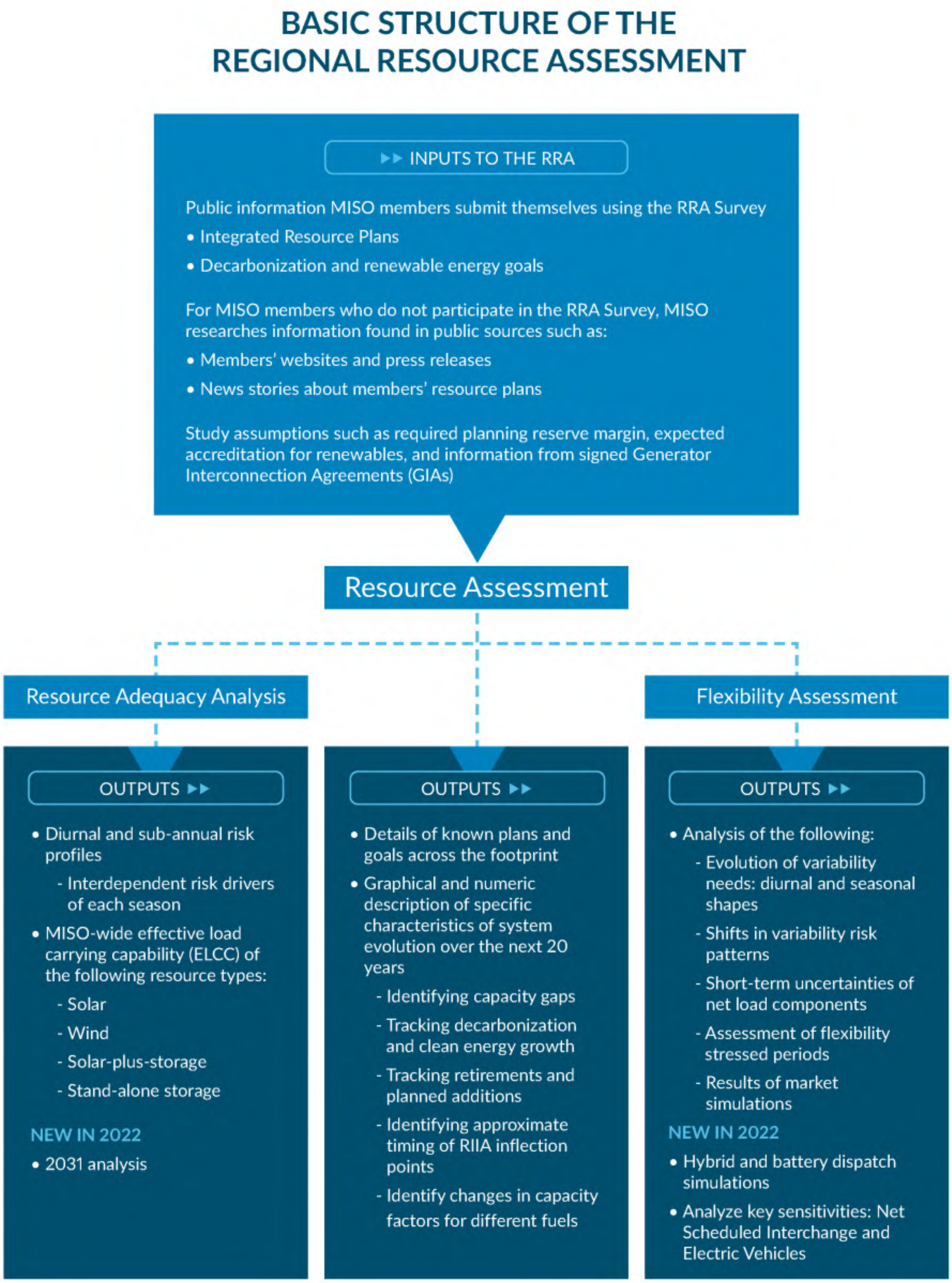


Figure 6: Basic structure of RRA

A CHANGING PLANNING PARADIGM

There was little need for a study like the RRA when there were robust reserve margins and the region's generation mix was comprised of conventional thermal resources with expected availability. Both load (with a predictable summer peak) and generation (with non-correlated outages) were relatively consistent, bolstering system reliability. MISO members and states planned for the future within the confines of their own needs and policy objectives, without a compelling need to know about their neighbors' resource plans.

Today presents a much different situation. The energy industry is evolving in profound ways, with MISO members and states retiring existing resources due to changing economics, environmental regulations, technological advancements, state and federal policies, and consumer preferences for cleaner energy. MISO members and states are primarily replacing retired thermal resources with renewables such as wind and solar, augmented with smaller quantities of battery storage.

These trends create new challenges and complexities in the realm of resource planning. Before, planning was a relatively well-understood task, akin to arranging generally uniform building blocks. Now, planning is far more complicated, like assembling a jigsaw puzzle with many disparate pieces. For example, renewables share a common risk driver — regional weather patterns — and therefore have correlated outage risks. As a result, when renewables are not available or their output is reduced, MISO members may need to rely on the MISO market more than they have historically. Insight into the availability of future resources in the MISO market is needed to make informed planning decisions today. The RRA increases visibility across the region so that members and states, who have resource planning jurisdiction, can make informed decisions.

MISO does not have authority over generation planning or procurement, yet MISO relies on transparent, forward-looking insight into the generation planning activities of its members and states in order to effectively carry out its responsibilities as a federally designated ISO and RTO. The RRA helps guide MISO's effort to ensure prioritization and in-time implementation of Reliability Imperative efforts that support and enable MISO's member plans and goals. Similarly, the RRA aims to help members and states to identify potential resource gaps and associated reliability issues years before they actually materialize, creating a window to develop cost-effective solutions.

A FOCUS ON THE TRANSITION

Many industry discussions focus on the end state of decarbonization with less talk about the path to get there. The potential of emerging technologies like long-duration energy storage and green hydrogen is exciting, but these resources are so nascent it is difficult to confidently predict their timeline to commercial viability, much less the deployment of these solutions at the scale required to meet MISO's challenges. As the transition planning continues, it is imperative to balance three key priorities: reliability, affordability, and sustainability.

MISO's chief concern with the transition is the potential for compromised system reliability. Key capabilities and attributes that are bundled with existing resources may become scarce as the resource fleet changes. For example, to compliment the continued growth of solar, MISO will increasingly need resources that can rapidly ramp-up to meet net load (load minus renewables). Reliably achieving the decarbonization targets set by many MISO members and states will require an accurate and collective view of how resource plans are evolving, and a shared understanding of the ways in which operational risks and needs will emerge and shift over time. MISO's RRA gathers that aggregate view and provides insights and technical findings that can help inform the work that members, states, and MISO are doing both individually and collaboratively to plan ahead.

THE RELIABILITY IMPERATIVE AND RELATED MISO INITIATIVES

The RRA is one of several sources of data that MISO uses to support an umbrella initiative called the Reliability Imperative — the term that MISO uses to describe the shared responsibility that MISO, members, and states have to assess and proactively address the urgent and complex challenges to electrical system reliability in the region. In addition to the RRA, other sources of data that underpin the work that MISO and its stakeholders are doing under the Reliability Imperative include:

OMS-MISO Survey

In partnership with the Organization of MISO States (OMS), this annual survey asks members to provide information on new generation they plan to build and existing generation they plan to retire going forward. The survey focuses on the five-year forward view but does contain 10-year forward data with an understanding that uncertainty will increase in the latter five years. Unlike the RRA, the OMS-MISO Survey does not solicit members' decarbonization and renewable energy plans. Survey responses are confidential and may include plans that are not yet publicly available. More information on the OMS-MISO survey is available here.

MISO Futures

The MISO Futures utilize a range of economic, policy, and technological data and assumptions to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. MISO uses the Futures to inform the development of transmission plans and inform other MISO processes. Both the RRA and Futures incorporate and reflect MISO members' publicly announced plans and goals, and some input data is shared between the project teams. The RRA considers only public information from members and is intended to be refreshed more frequently. The Futures use different modeling assumptions in some key areas, such as decarbonization levels and electrification load growth to create a wide range of possible outcomes for use in robust, least-regrets planning activities. More information on Futures development is available here.

Reliability attributes work

In 2022, MISO launched an initiative to identify which system attributes may become scarce due to the region's rapidly evolving mix of generation. Attributes such as voltage stability have historically been freely supplied with conventional resources, and their increased scarcity in pockets of asynchronous generation pose a potential reliability risk. Continued investigation in this area will quantify the size, timing, and impact of critical reliability attribute gaps such as gaps in availability, ramp-up capability, rapid start-up, long duration energy at high output, and fuel assurance. The work will also explore the best means of ensuring sufficient reliability attributes, whether through greater visibility, new requirements, optimizing existing and/or developing new market products. The RRA is well-positioned to support the attributes initiative by providing insight into future system needs and timing considerations. More information on the attributes framing is available here.

Planning Resource Auction (PRA)

MISO conducts the PRA each year, a voluntary capacity auction that provides a way for MISO members to meet resource adequacy requirements. The auction results in a commitment of capacity to the MISO region for the upcoming planning year, including performance obligations. The RRA presents an optimistic picture of the region's capacity position compared to the PRA. This is due to different base datasets and different assumptions which are explained in more detail in Resource Assessment section of the report, but include key differences such as long-term outage considerations, in-service date assumptions, and the RRA's exclusion of confidential information. More information on the PRA is available here.

MISO is committed to working with its members, state regulatory agencies, and other stakeholders to find ways to streamline these initiatives wherever possible. This is especially true of initiatives such as the RRA and the OMS-MISO Survey, which ask members and states to respond to MISO survey requests for information on their resource plans. Streamlining these initiatives and the survey processes that underpin them will improve the consistency, fidelity, and value of the information to the benefit of members, states, and other stakeholders.

RRA Survey and Stakeholder Engagement

With input from state regulatory agencies and other stakeholders, MISO launched a new survey effort with this year's RRA to allow members to submit their resource plans and goals to MISO directly rather than relying on third-party research. This new process improved the quality of the inputs and led to higher rates of member engagement due to increased confidence in the process and results.

Note: The RRA analysis would not be possible without the information that MISO Members willingly provided about their forward-looking resource plans and goals. MISO thanks all of the stakeholders who contributed their time and valuable perspectives to this work.

Additional details about the survey:

- Platform: The survey was hosted on an interactive website designed in partnership with Meier Engineering Research LLC, using a platform called "Juicebox."
- Cut-off date: The survey requested information on plans and goals that members publicly announced prior to January 31, 2022. Any plans or goals announced after that date will be considered in future iterations of the RRA.
- Types of information requested: The survey asked for information on planned generation additions; planned retirements; load forecasts; historic carbon emissions for the years 2000, 2005, and 2021; plans and/or goals to reduce carbon emissions; plans and/or goals to increase renewable energy.
- Target audience: MISO distributed the survey by sending an email to three groups of Stakeholders: (1) those on the Resource Adequacy Subcommittee email list; (2) those on the Planning Superlist; and (3) those on the OMS-MISO Survey distribution list. The email contained a hyperlink to the online survey, along with instructions on how to complete it. The survey was open to members and non-members alike (although only members provided information).
- Quality control: Once the survey closed, MISO reached out to individual members to review their submittals prior to finalizing the data and beginning the analysis.

SURVEY RESULTS

The 2022 RRA survey had a high participation rate, with engagement from 33 members representing approximately 75% of MISO's load. Respondents provided varying levels of detail, reflecting differences in regulatory processes and availability of planning information (Figure 7).

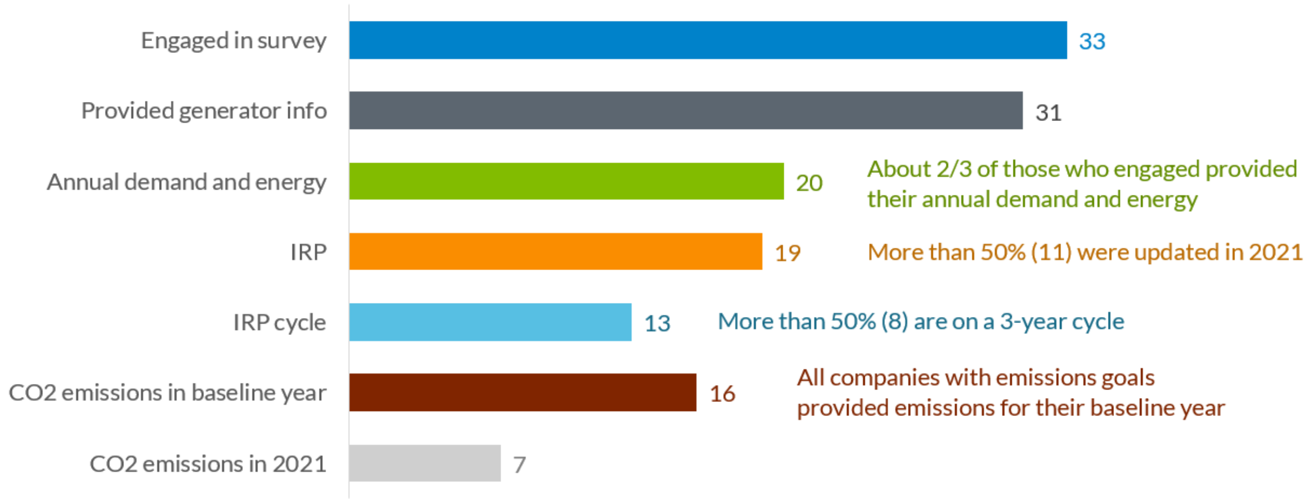


Figure 7: The number of MISO members that participated in different survey aspects

DECARBONIZATION GOALS

The RRA survey indicates that MISO Members use a wide range of approaches to measuring progress toward their decarbonization goals (Figure 8). Examples of differences include:

- Some member goals apply to electricity generated, some apply to load served, and some lack specifics of how they will be applied
- Some member goals apply to market purchases of energy, some do not, and some lack specifics of how the goal will be met
- A small number of members aim to reduce carbon "intensity" of energy production
- A few members are aiming to achieve "net zero" carbon emissions, but they differ in how they define that term
- Notably, 75% of the load in the MISO region is served by members who have publicly stated carbon goals, renewable energy goals, or both

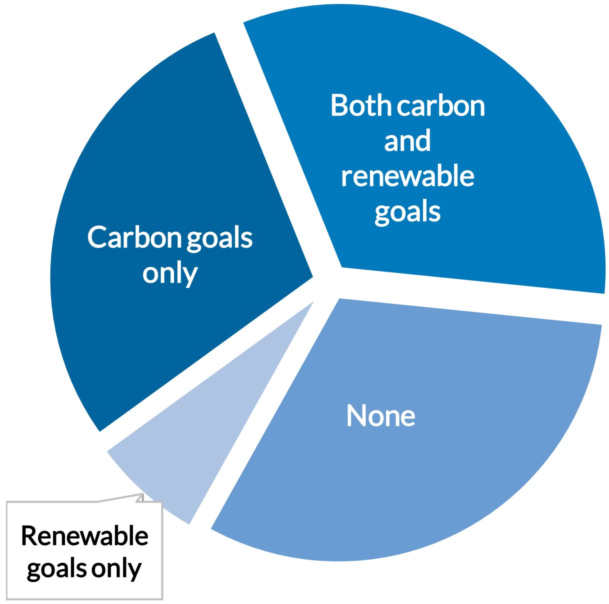


Figure 8: MISO member approaches to measuring decarbonization progress

KEY INSIGHT 1: The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.

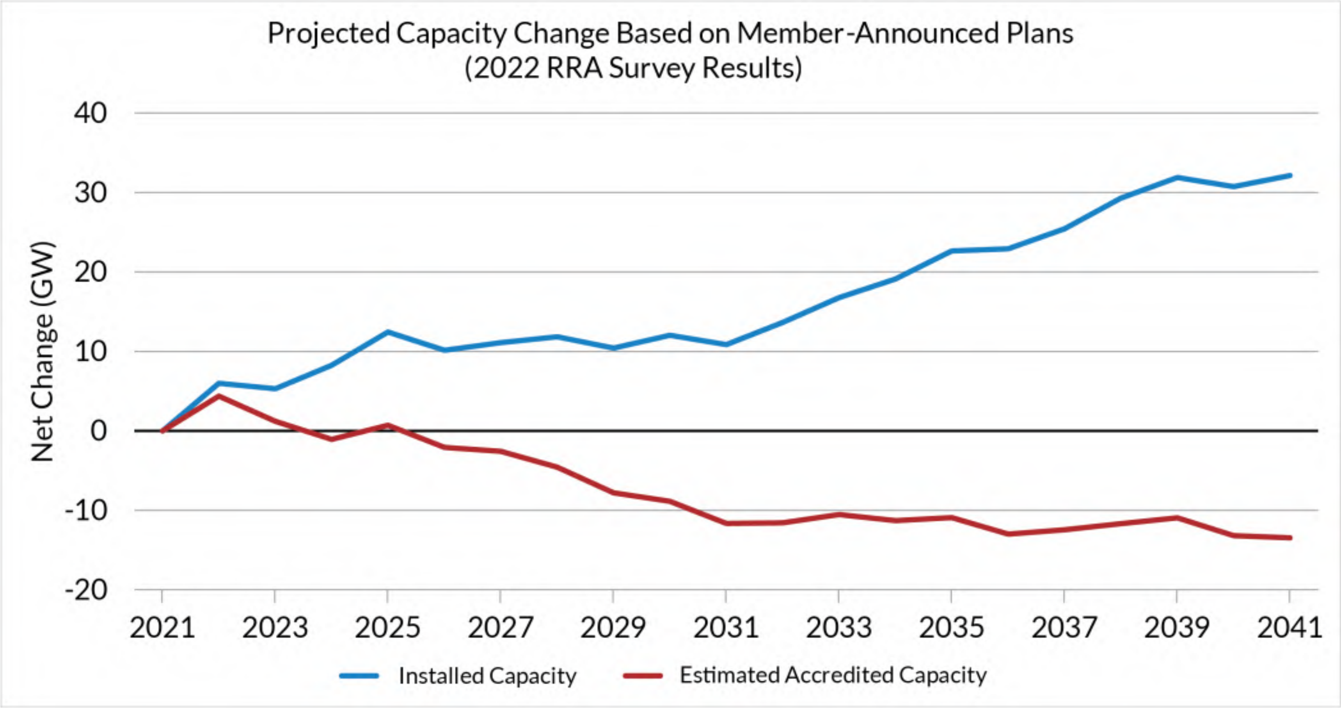


Figure 9: Projected capacity change based on member-announced plans

Installed capacity is the maximum amount of energy that resources can theoretically produce under ideal conditions. Installed capacity (the blue line) is expected to increase going forward (Figure 9). This is due to the numerous new resources — primarily wind and solar — that MISO members plan to build in the coming years.

Accredited capacity, by contrast, reflects how much energy resources are expected to produce to meet tight conditions after accounting for historic performance, which includes limiting factors such as forced outage rates and resource availability due to weather conditions. Without additional resource investment, accredited capacity in the MISO region is expected to decline (red line). This is because the new wind and solar resources that MISO members plan to build going forward have lower accreditation values than the thermal resources that members are retiring.

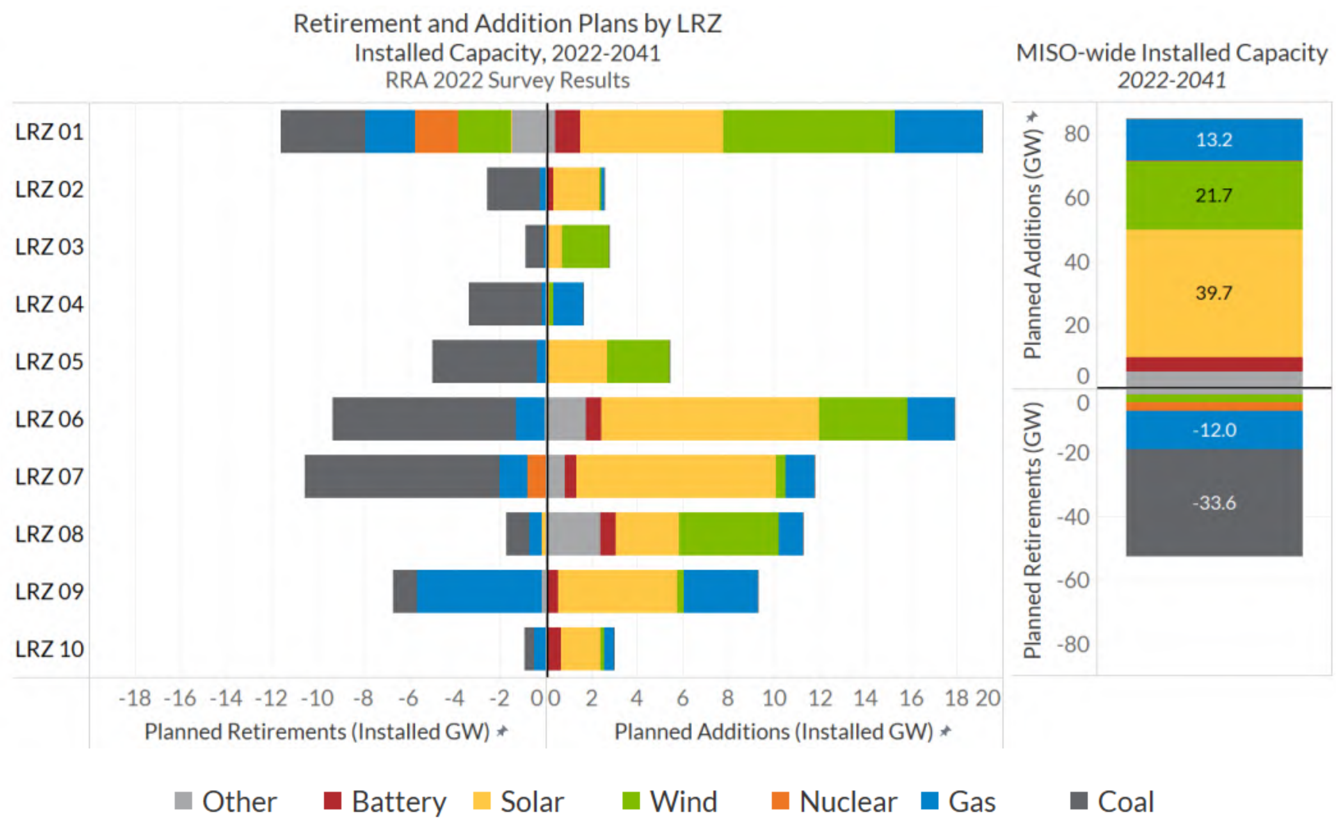


Figure 10: Planned retirements and additions (installed capacity GW) by resource type, according to publicly announced plans

The survey and publicly announced plans show that MISO members are planning to replace retiring coal capacity with investment in, primarily, solar and wind capacity (Figure 10). On a system level, natural gas units remain more or less neutral, in terms of capacity expected to retire versus planned additions. As noted in Figure 9 and discussion on the difference between accredited and installed capacity, 1 GW of coal has a much higher capacity contribution than 1 GW of solar. Therefore, even though the planned additions appear to outnumber the planned retirements on the stacked bar chart in Figure 10, additional investment beyond what is currently being planned by MISO members will be required to reliably achieve decarbonization targets and meet the planning reserve margins.

Resource Assessment and Modeling

INPUTS

The Resource Assessment models the generation needs of the MISO system through 2041. Like all MISO studies, the results of the assessment are sensitive to the input information and the assumptions made. The member survey provided MISO with carbon reduction and renewable target goals, planned additions, and planned retirements, as of January 31, 2022. MISO also researched and included publicly announced plans for any members that did not engage with the survey. All capacity that had signed Generation Interconnection Agreements (GIA) was included, and no retirements beyond what was publicly announced were considered in the model. No generation in the interconnection queue was included unless there was a signed GIA.

Based on stakeholder feedback that the RRA would be most useful at a granular level, this year's RRA Resource Assessment was modeled at the LRZ level as well as regionally aggregated. The MISO-wide numbers shown in this report represent a straight summation of the independent simulation results from all the LRZs. Readers may notice that the load levels are relatively high compared to other MISO analysis, this is because non-coincident peak values were used for each LRZ-level analysis.

Inputs were incorporated into the capacity expansion model, which optimizes a system by selecting the lowest-cost resource mix for a given set of constraints, using Electric Generation Expansion Analysis System (EGEAS) software. Assuming planned additions and retirements, the model solved for carbon reduction and renewable goals, and Future 1 load expectations. In the 2022 RRA, each of MISO's 10 LRZs were modeled separately.

The Planning Reserve Margin targets were based on the 2021-22 PRA, as the 2022-23 PRA information was not available by January 31, 2022. MISO used the 2021 RRA Resource Adequacy analysis for capacity contribution assumptions for future resources, particularly solar, hybrid (solar-plus-storage), and battery.

For new units, the assumed capital costs were updated based on the 2021 National Renewable Energy Lab (NREL) Annual Technology Baseline (ATB) publication, and natural gas price increases were assumed from the December 2021 Gas Pipeline Competition Model (GPCM). While the natural gas prices have significantly increased since December 2021, the prices in the model were higher than industry trends throughout 2021 and are higher than prices assumed in the MISO Futures study. Federal tax credits were modeled as of January 2022 and do not include the extensions and expansions provided by the Inflation Reduction Act.

These inputs, which are explained in greater detail in the Technical Appendix, result in a resource projection for each LRZ that satisfies the assumed planning margin and known renewable and carbon-reduction goals for the next 20 years. An interactive view of the 2022 Resource Assessment modeling results is available on the Generation Resource Portal.

MODEL-BUILT RESOURCE ADDITIONS

INSIGHT: Members may need to build more than 100 GW of new installed capacity within the next 10 years to achieve their publicly announced plans and goals in a reliable manner

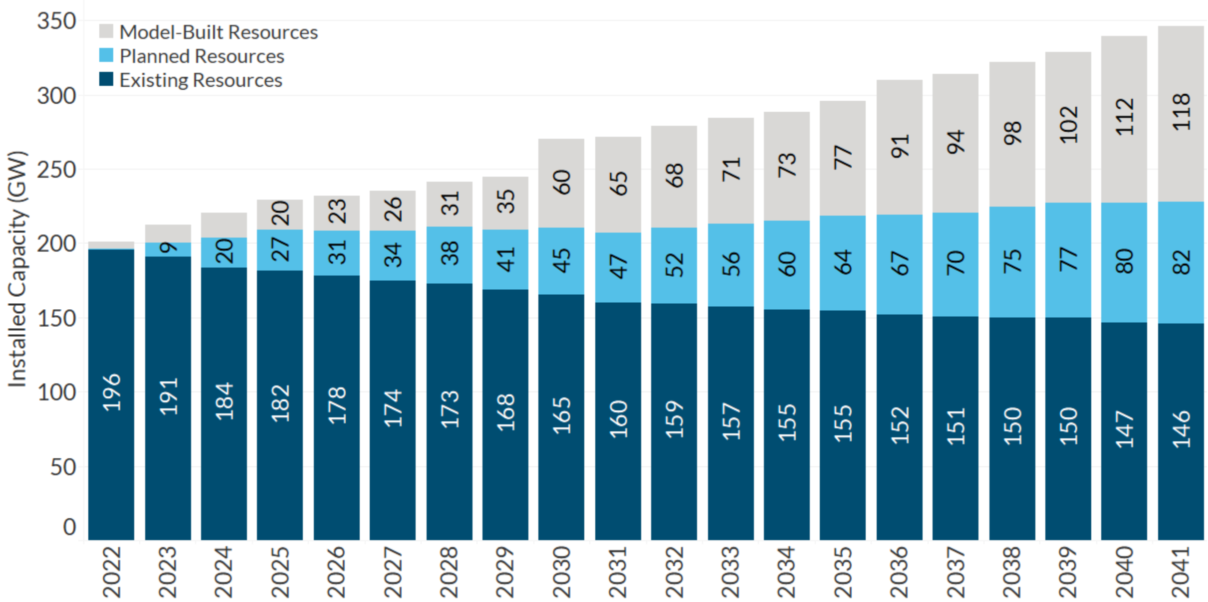


Figure 11: System-wide existing, planned, and model-built resources (installed capacity view)

Figure 11 shows installed capacity levels for three categories of resources: (1) current **existing resources** in the MISO system (net of retirements); (2) **planned resources** as communicated by survey participants and public announcements; and (3) **model-built resources**, RRA model of what MISO members may build to reliably meet their publicly announced plans and goals. Significantly more installed capacity is required to supply reserve requirements and reach decarbonization goals. Members may need to build more than 100 GW of new installed capacity within the next 10 years, an unprecedented volume for the MISO region.

The installed capacity of planned plus existing resources (the dark and light blue bars) remains relatively constant through 2041, but the installed capacity that the model determines to be needed increases significantly throughout the study period. The increase in installed capacity need is the result of high capacity value resources being replaced with lower capacity value resources (Figure 12) and the assumption that much of the additional capacity will also be lower capacity value resources which are chosen based on the carbon constrained requirements.

Note: The RRA presents an optimistic, or 'best case' view of capacity in the near years compared to other MISO studies or joint efforts like the OMS-MISO Survey. Assumption differences are detailed in the Resource Assessment caveats section.

KEY INSIGHT 2: The RRA modeling indicates a continued near-term capacity risk, highlighting the immediate importance of coordinated resource planning and additional investment.

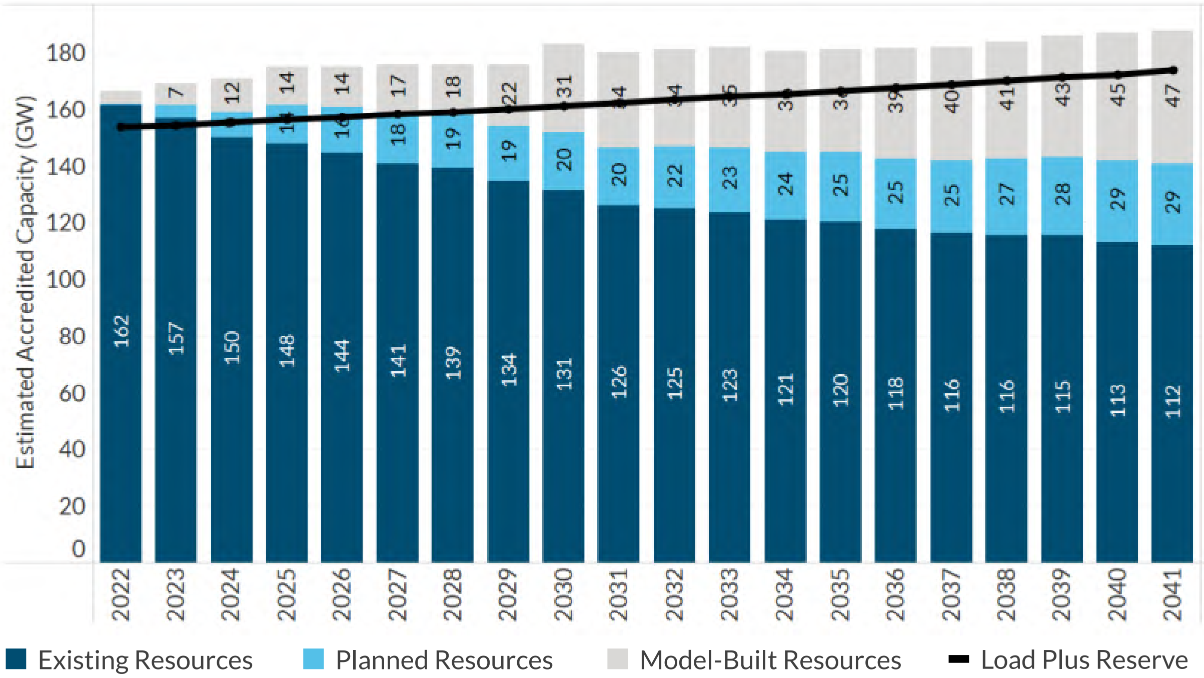
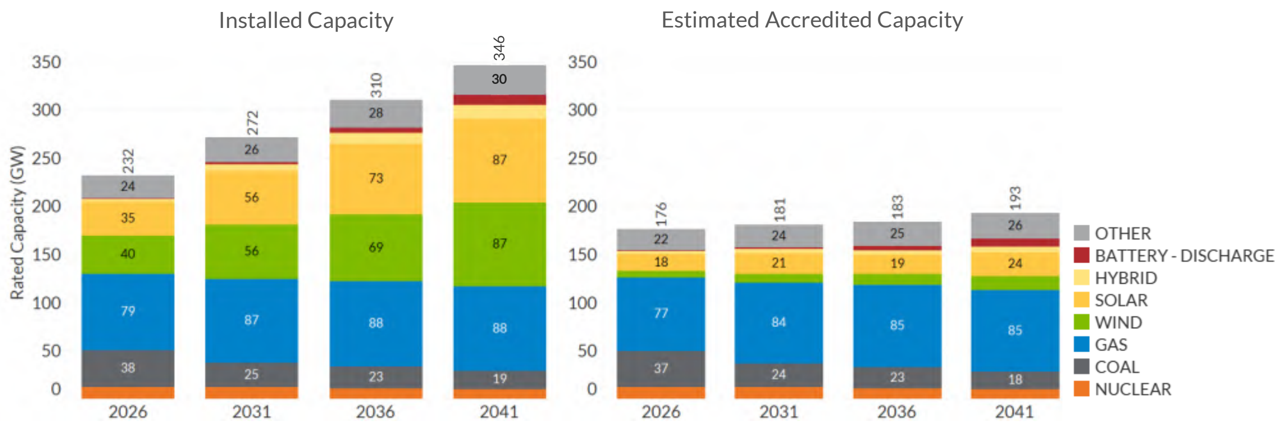


Figure 12: System-wide existing, planned, and model-built resources and load plus reserve (accredited capacity view)

The RRA calculated the estimated accredited capacity from existing, planned, and model-built resources, compared to load plus reserve (Figure 12). For 2022 through 2026, the load plus reserve line remains below the existing or planned resources. For 2027 through 2041, the load plus reserve line is met with model-built resources, suggesting a higher risk of system capacity shortfall without additional investment. Again, note that the 2022 RRA simulated each LRZ separately, considering the non-coincident peak values. For that reason, the load plus reserve number may appear higher than expected. Additionally, timing of capacity shortfall risk occurs in different years at the LRZ-level of granularity — risk is heightened for some areas as early as year 1 of the study and others in year 10 or beyond. LRZ-level results can be found on the MISO RRA Webpage.

Importantly, member plans often do not provide resource information for the full 20-year study period, and not every member participated in the survey. Especially for later years, the model-built "gap" is more likely an information gap than a planning gap. Additionally, the RRA uses the MISO Future 1 load forecast, which may be different than load forecasts used for planning purposes by individual members and states. The RRA assumes declining capacity contributions for solar, hybrid (solar-plus-storage), and battery resources over the study period based on today's methodologies applied to the 2021 RRA results.

Changes to the accreditation methodology applied to non-thermal technologies are currently being considered by MISO's Resource Adequacy Subcommittee (RASC) stakeholders.

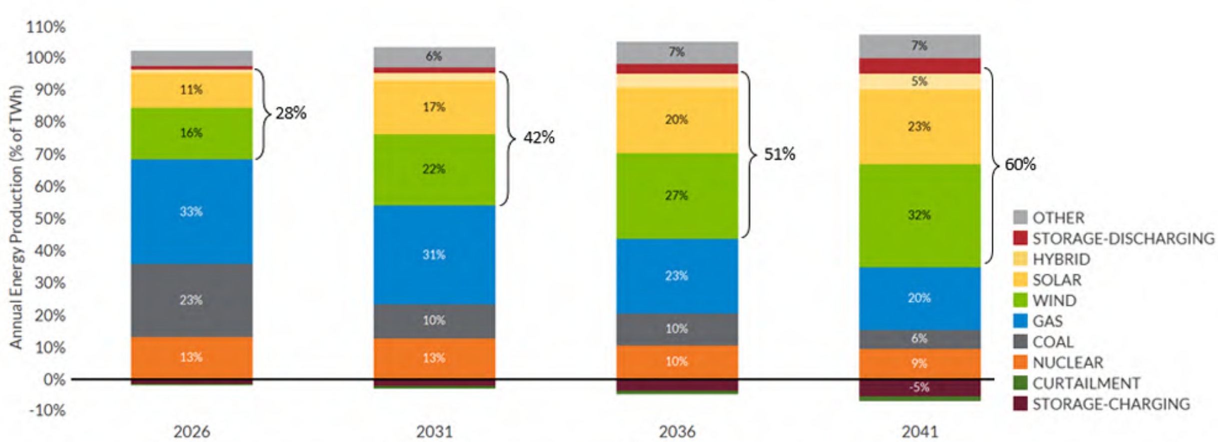


Note: Over the study period, RRA assumes wind accreditation stays at ~16.7%, solar declines from 50% to 20%, hybrid declines from 60% to 30%, and battery declines from 100% to 75%. Thermal units are accredited between 90% and 100%. The assumptions in RRA should not be taken as indicative of the outcomes of the non-thermal accreditation reform effort underway

Figure 13: System-wide installed capacity and estimated accredited capacity of total resources

Figure 13 further illustrates the installed versus accredited capacity comparison. In total, the net installed capacity on the MISO footprint may increase by more than 100 GW over the study period, while the estimated accredited capacity increases by less than 20 GW.

KEY INSIGHT 3: Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system.



*Solar includes DGPV, while "Other" includes demand response and energy efficiency
Note: expansion was performed for each LRZ using a model that does not include the transmission system

Figure 14: Annual energy production by resource class 5, 10, 15, and 20 years into the RRA study

The RRA illustrates that within five years, the MISO's system could approach approximately 30% of its annual energy from renewables, and renewable penetration levels increase by 10% every five years through the remainder of the study period (Figure 14).

The RIIA, published by MISO in February 2021, describes a journey of increasing system integration complexities as the region transitions from today's relatively low levels of renewable energy resources to much higher levels. The assessment describes inflection points in complexity, as quantified by the incremental cost needed to reach each next milestone of 10% increments of annual renewable energy up to 50%. The RIIA demonstrates that larger system penetrations of renewables will lead to increasing complexity in resource adequacy, energy adequacy, and operating reliability. The RRA can provide useful insight into the timing of these RIIA milestones based on member plans and goals.

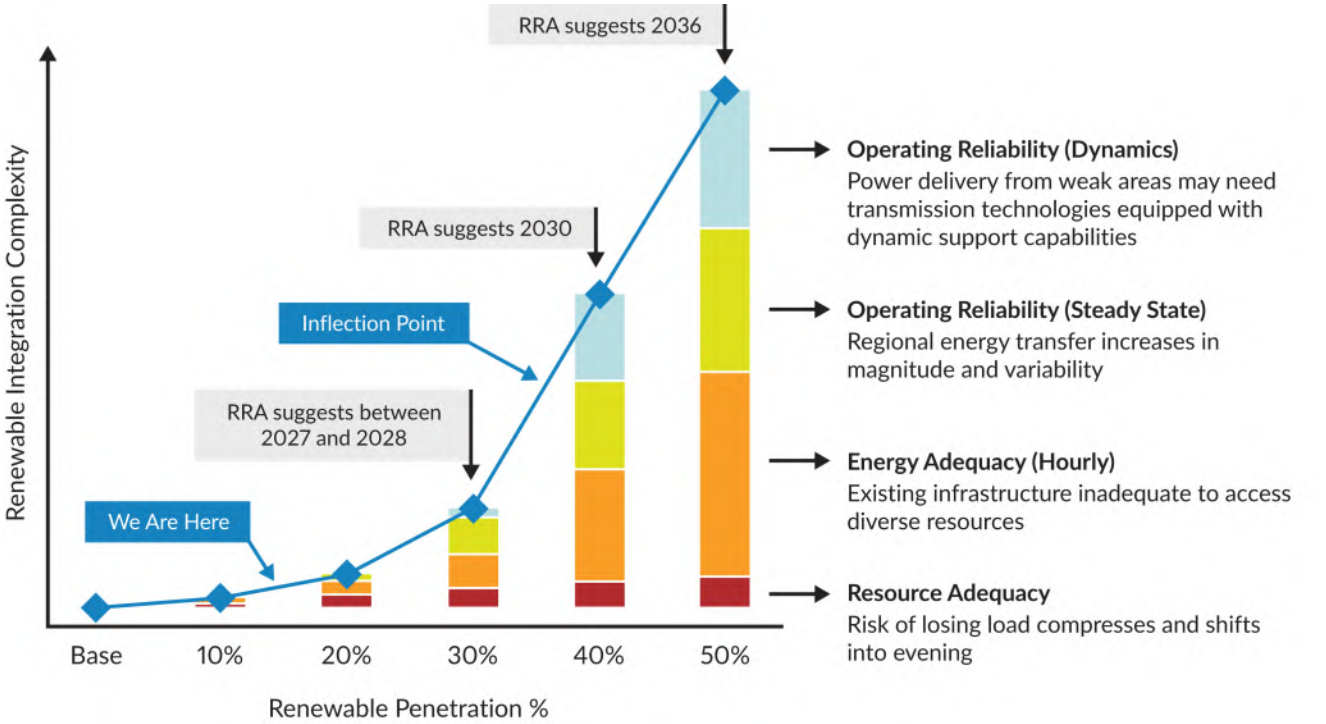


Figure 15: RRA renewable penetration compared with RIIA inflection points

The RIIA considered transmission in both the energy adequacy and operating reliability work, and while the RRA did not include transmission (and thus the study assumes adequate delivery of energy), the overall inflection points identified in the RIIA are relevant for the RRA planning considerations.

The RRA demonstrates that the 30% RIIA milestone could be reached by 2028, and the inflection point in complexity could come by the end of the decade, when 40% of annual energy is generated from renewables. The 50% RIIA milestone is achieved in the RRA study by 2036. The complexities identified within RIIA must be addressed sooner than previously expected to prepare the system for the inflection points leading to increasing complications in prioritizing and executing change initiatives.

EMISSIONS TRENDS

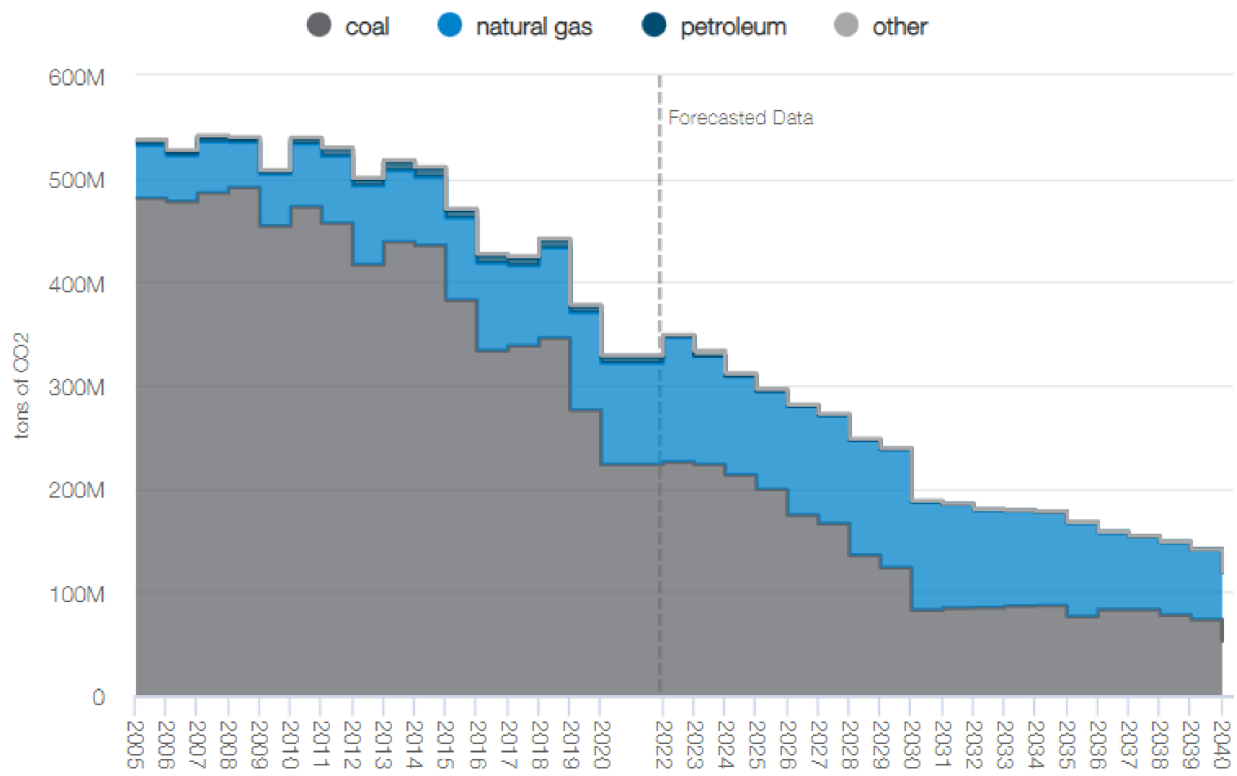


Figure 16: The MISO region's historic emissions data and forecasted emissions trend based on RRA analysis

Since 2005, emissions from the MISO footprint have decreased by more than 30%, according to unit data published by the Environmental Protection Agency (EPA). Based on members' announced plans and the EGEAS modeling that MISO performed, power sector carbon emissions in the MISO region would continue to decline — reaching an 80% reduction by 2041 compared to the 2005 baseline level (Figure 16). At an intermediate milestone of 2030, the expected reduction is approximately 65%. This performance includes model-built units in addition to company planned resources and assumes Future 1 load.

Many companies have anchored carbon reduction milestones to the year 2030, and MISO did not make any phasing assumptions to smooth the goal over multiple years. For example, if a company reported its annual emissions goals at its current level for the next eight years and indicated a steep decrease in 2030, MISO used these annual assumptions directly. This resulted in a large, single-year build-out of 28 GW of new generation installed capacity to meet the sudden emissions constraint between 2029 and 2031 (Figure 17). For context, in 2020 MISO brought online 6.5 GW of new installed capacity which is the most additions in a single year. Given historical experience, it is unlikely that members would collectively install that many new resources in a single year.

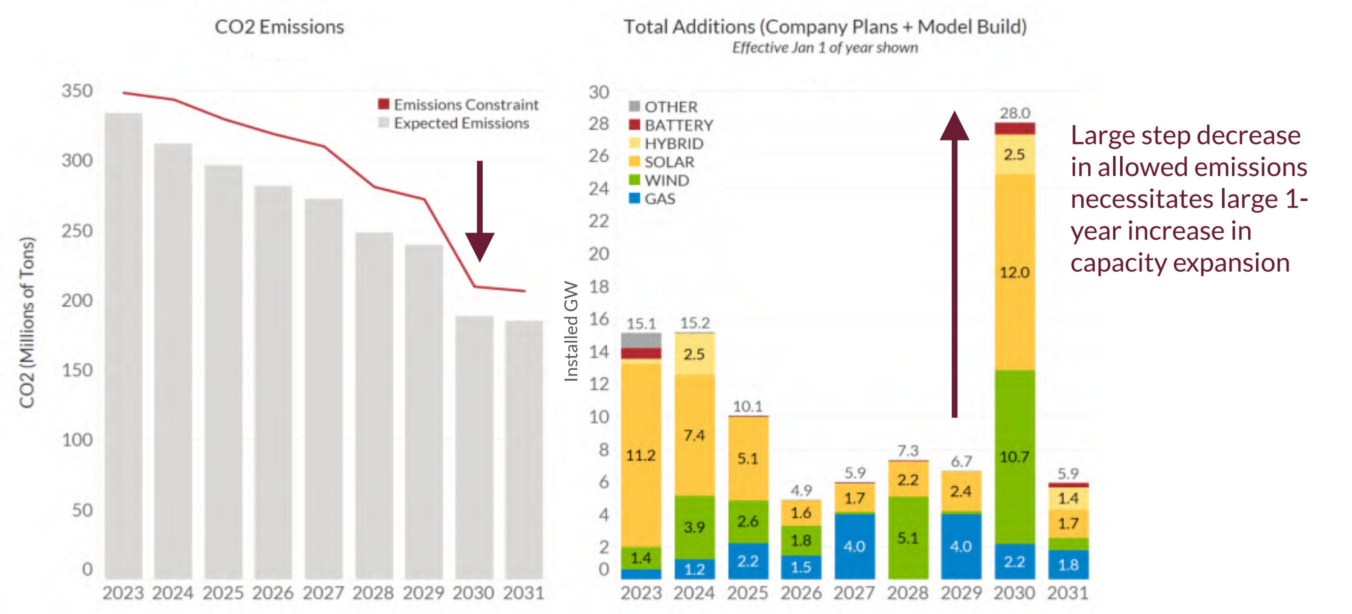


Figure 17: Annual system-wide carbon emission reduction goals and planned plus model-built resources

CAPACITY FACTOR TRENDS

INSIGHT: Over the study period, the average capacity factors of coal and gas units decline

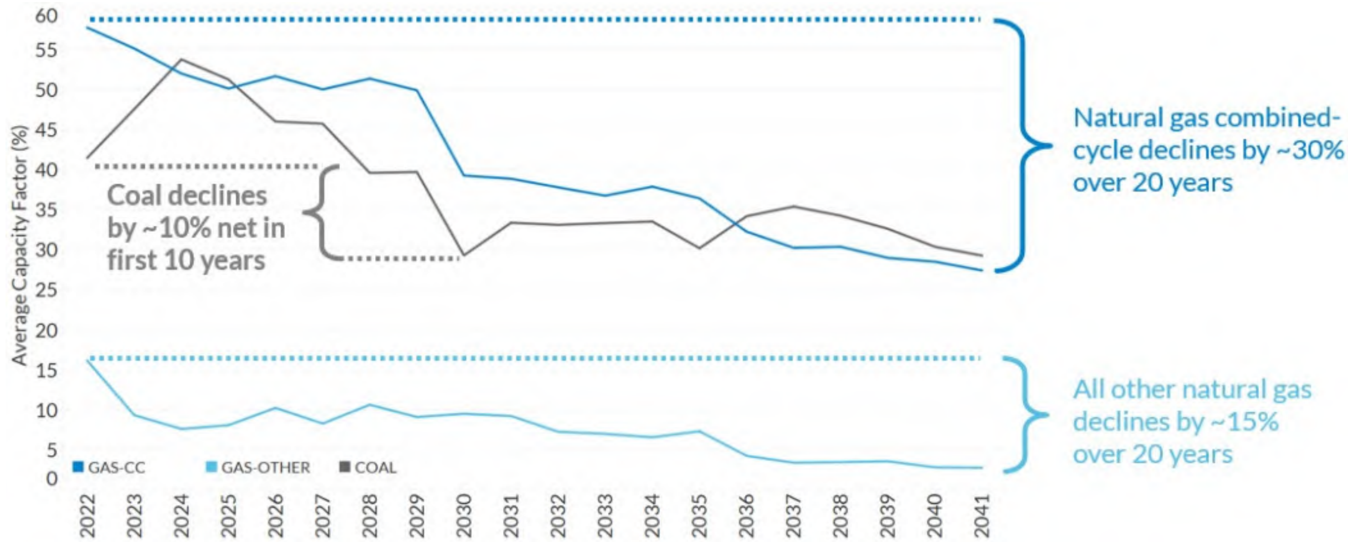


Figure 18: Average capacity factor of in-service fuel class

Capacity factor measures how often a generator is running at maximum power. The RRA provides insight into the value of having flexible resources available to support reliability when needed, even if those units do not run often. Over the course of the study period, the average capacity factor of natural gas combined cycle units decreases by 30%. All other natural gas units decline by approximately 15% (Figure 18). The average capacity factor of coal decreases by 10% in the first 10 years and then remains stable for the rest of the study period. The initial increase in the average capacity factor for coal is due to relatively high natural gas price assumptions coupled with some emissions goals that are not in effect until 2030. During this period, coal is relatively cheaper than gas while emissions are still falling within the goals.

Analysis of how the thermal units are dispatched over the study period highlights potential risk of additional retirements as the financial viability of the lower capacity factor units may be challenging. In contrast to the MISO Futures, which makes age-based assumptions on unit retirements, the RRA only models publicly announced retirements.

CAVEATS OF THE RESOURCE ASSESSMENT

This study, like all MISO studies, is sensitive to the assumptions made and limitations of the data available to shape assumptions. One such limitation is visibility into company plans. The Resource Assessment does not consider any confidential company plans and only includes publicly available data as of January 31, 2022.

The Resource Assessment — and the RRA more generally — provides an optimistic picture of the region's capacity position compared to other MISO studies, due to differences in assumptions. For example, the RRA assumes:

- There are no transmission constraints anywhere in the Local Resource Zone (LRZ), and capacity is deliverable to anywhere it is needed within the LRZ, any time it is needed
- MISO members will meet their decarbonization/renewable energy goals in a reliable manner on the timeframes they have publicly announced, even if they have not yet worked out the details of how they will do so
- All planned but not-yet-built resources with signed GIAs will be in service by the dates that MISO members have publicly announced, with no exceptions for construction delays or other issues
- All capacity — whether committed, potentially unavailable, or potential new capacity — will be available to serve load. The RRA assumes that no existing or planned resources will unexpectedly be forced out of service on long-term outages for unanticipated mechanical problems, supply chain issues, or other factors
- No existing or planned resources are excluded for long-term outages or suspensions, though some units with expiring power purchase agreements (PPAs) were excluded in later years, depending on data MISO members provided
- No retirements were considered that were not publicly announced, regardless of the age of the resources
- Units with installed capacity of less than 50 MW are included in the RRA, even though such units may be withheld from the Planning Resource Auction without penalty in some cases

Flexibility Assessment

The RRA Flexibility Assessment aims to understand how net load (load minus renewables) variability and uncertainty changes over time, identify days/periods of increased risk, and conduct market simulations to evaluate the adequacy of MISO's current reserve products to meet future needs. This work considers the increase of weather-dependent renewable resources as well as the impacts of newer technologies, such as hybrids and storage, on the MISO system. Historically, outages, load, and Net Scheduled Interchange (NSI) were the largest contributors of uncertainty and variability in managing the operating margin for the MISO region. As the region's resource portfolio ages and evolves, the complexity of managing operating margins will significantly increase.

Factors contributing to the increasing operational complexity, either due to greater variability or greater uncertainty include: (1) increased volatility in load forecasts due to changing weather and demand patterns, (2) more volatile generator outages, particularly related to aging of thermal units, extreme weather events, and fuel supply challenges, (3) greater uncertainty for available energy at low margin hours as the fleet becomes more weather-dependent, and (4) increasing frequency and magnitude of system ramps, largely driven by the growth in solar resources.

These sources of increased variability and uncertainty drive the need for greater system flexibility in the future. The RRA provides a way to quantify and improve the understanding of what specific changes might occur. Further, the specific needs across different timescales inform the development and prioritization of solutions for the planning and operating horizons. The Flexibility work seeks to address several broad research questions:

- Needs: What flexibility needs, in terms of variability patterns and uncertainty levels, are arising due to the expected RRA portfolios for years 2031 and 2041?
- Risks: When do the worst cases of variability and uncertainty intersect to create potentially stressed system conditions?
- Market Efficiency: Can MISO's current market products procure sufficient flexibility to meet future real time needs?

FUTURE NET LOAD RAMP NEEDS

KEY INSIGHT 4: As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps could increase by three times by 2031 and four times by 2041 compared to current levels.

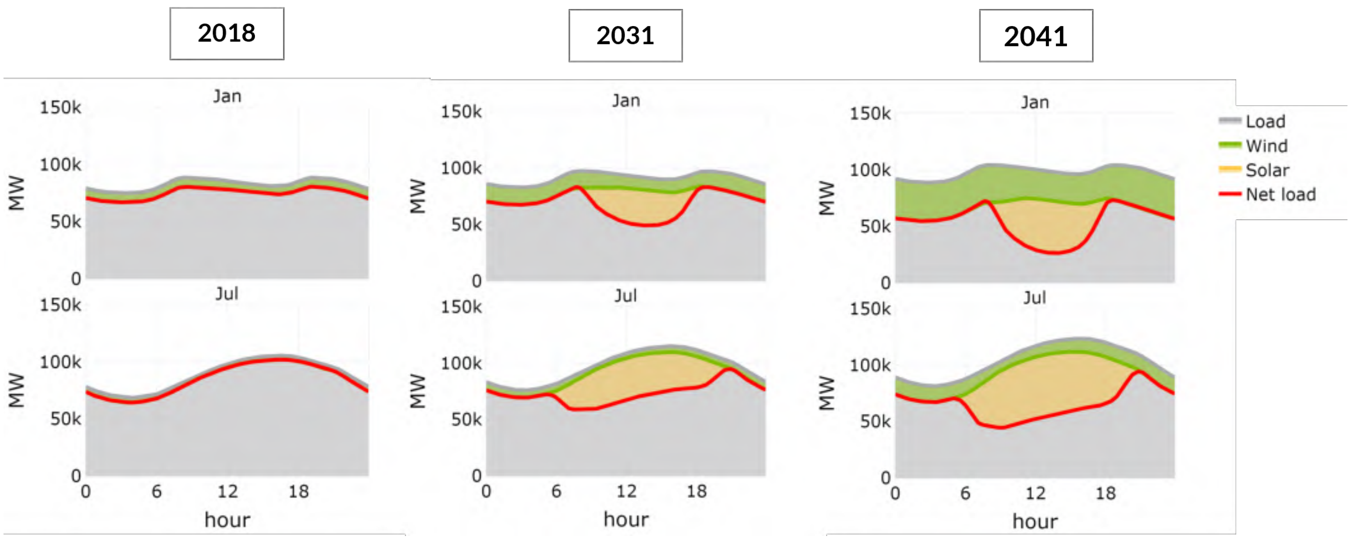


Figure 19: Monthly averages of diurnal net load components for January and July

The RRA fleet results in the emergence of distinct new patterns in the diurnal net load profiles, as illustrated by the snapshots of two months (January and July) compared across the years 2018, 2031 and 2041 as shown in Figure 19.

In winter months, historically, MISO has seen two peaks in the diurnal net load. The first occurs in the morning as people wake up, followed by a mid-day dip in demand, and then the load increases again in the evening. With the changing fleet estimated by the RRA, the "two peak" pattern begins to morph into the familiar "duck curve" shape. The term "duck curve" has become well-known in the industry as system operators in California studied the potential impacts of increasing penetration of variable renewables, predominantly solar, on the net load. The notable feature of this diurnal shape is the drop in the net load around mid-day due to the impact of solar production. Then in the evening as the solar production decreases and electricity consumption increases, there is a significant need for a rapid ramp-up of production from dispatchable generation resources. Generally, the wind production is better than average during the evening peak load hours, whereas solar production is less aligned with the evening peak load (particularly during winter months). The net load analysis becomes important when growth in solar capacity is projected.

In the summer months, the MISO system has historically seen a single daily net load peak in the late afternoon hours. By 2031, due mainly to the solar production, the daily net load peak is shifted to later in the day, into the post-sunset hours (Figure 19). While the summer afternoons experience a slower rate of net load increase relative to today.

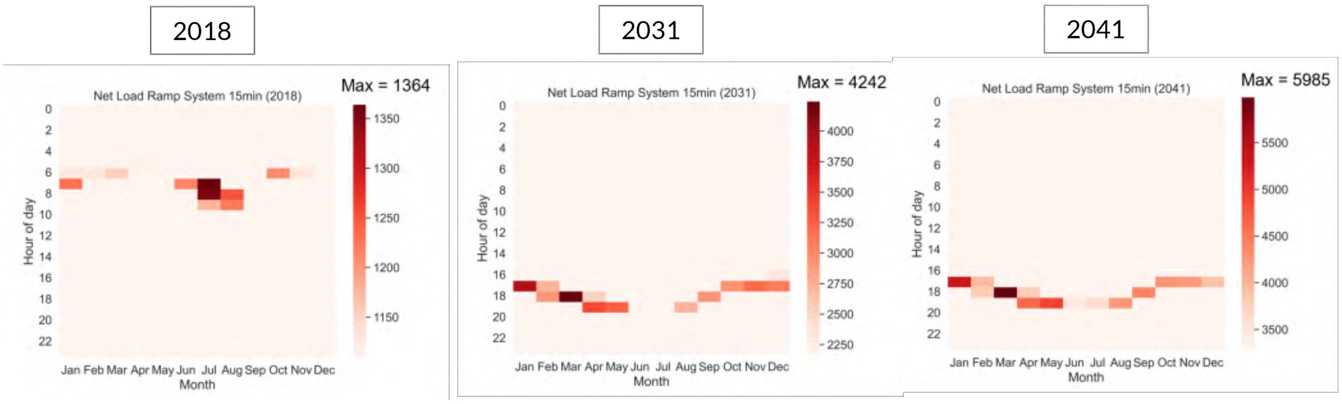


Figure 20: Highest 10 percentile of short duration net load (excluding hybrid and battery) up ramps

Another way to visualize the ramping patterns is to look at the highest 10 percentile of short duration up ramps. Historically, these highest risk hours occurred in the morning and in the summer months (2018 chart, Figure 20). However, with the expected increase in solar penetration, by 2031 these hours are expected to shift into the winter afternoons (Figure 20). From 2031 to 2041 the overall patterns will remain similar, although the magnitude of risk grows significantly.

The quantitative change is significant. The average 15-minute up-ramps will increase by 63% from 2018 to 2031 and by 120% from 2018 to 2041. The maximum 15-minute up-ramps will increase by three times by 2031 and four times by 2041 compared to 2018 levels. Multiple timescales were considered for this study, from 15-minute to four-hour ramps, and needs were observed to significantly increase across all timescales. Charts showing these additional results can be found in the RRA Supplemental Material here.

HYBRID AND BATTERY RESOURCES

INSIGHT: Hybrid and battery units may help to reduce the evening peak net load by shifting energy demand to off-peak hours

Informed by stakeholder discussions, this Flexibility Assessment assumed that hybrid (solar-plus-storage) and battery units will seek profit maximization by charging during low-price hours and discharging during high-price hours (i.e., energy arbitrage). In this analysis, all hybrid units were assumed to be comprised of solar (70% capacity) and battery storage (30% capacity). Using locational marginal prices (LMPs) from the RIIA, hypothetical hourly dispatch profiles at the unit level were simulated using profit maximization models.

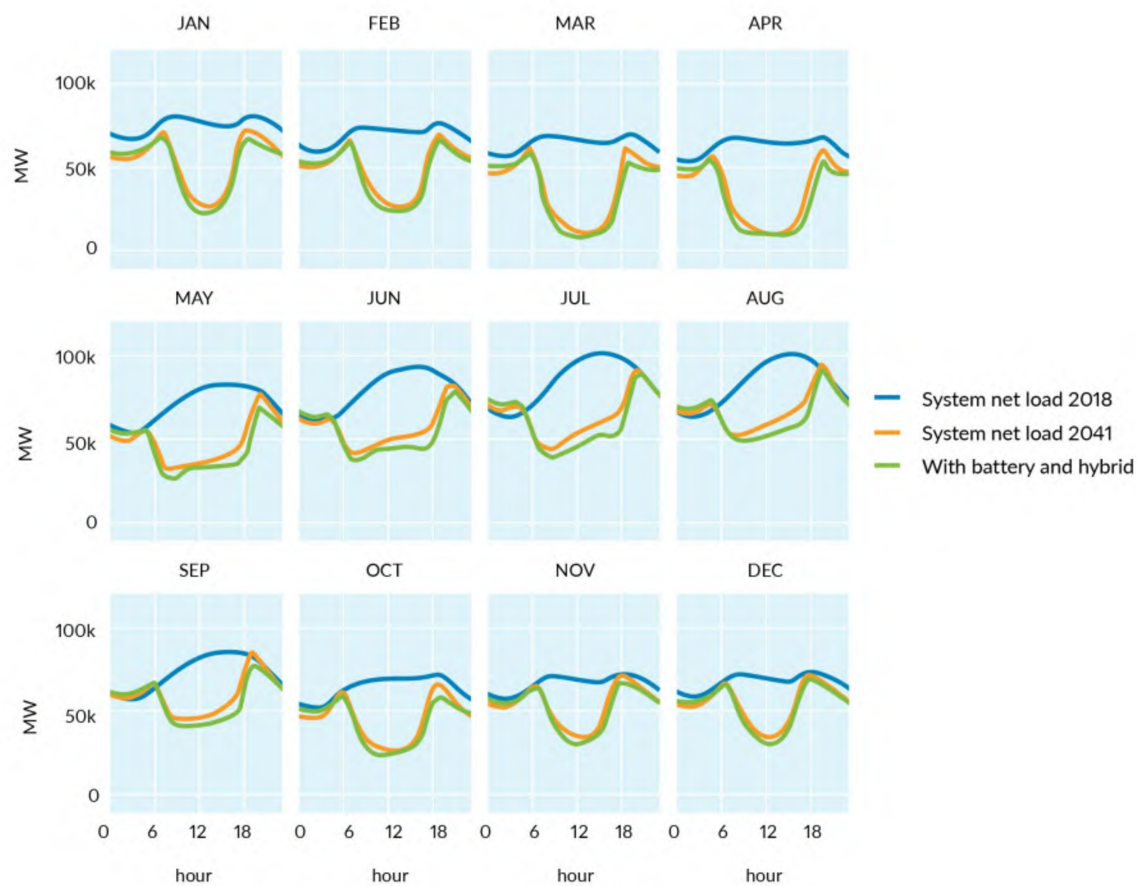


Figure 21: Impacts of both hybrid (solar-plus-storage) and battery resources on net load diurnal shapes in 2041

Figure 21 shows the average diurnal net load without hybrid and battery units (orange line), and with hybrid and battery units (green line), for the year 2041. Through 2041 in the RRA the total installed capacity of hybrid units is 14.8 GW and battery units is 11 GW. The monthly patterns show that the combined impact of solar-plus-storage and battery units results in reducing the evening peak net load. Hybrid and battery storage resources contribute to slightly steeper morning down-ramps, depending on prices. Down-ramps are anticipated to be simpler to manage relative to up-ramps. Increasing the size of the battery resource fleet would likely further increase the system benefits shown by this comparison, but additional batteries were not chosen by the model due to higher relative cost.

INSIGHT: Unmanaged charging of electric vehicles may increase the peak load in some zones, which could be partially mitigated through the adoption of Time of Use rates

MISO's Electrification Insights report published in 2021 considered the impact of increased adoption of electric vehicles (EVs) within the MISO footprint. EV adoption forecasts and assumed uncontrolled charging for light-duty vehicles were incorporated into load shapes. While unmanaged EV charging might exacerbate the daily peak loads, a number of studies have shown the potential of various managed EV charging methods to mitigate this problem.

In this year's Flexibility work, MISO explored the impacts of different EV charging scenarios using LRZ 7 (Lower Michigan) as a case study. Per the Electrification Insights report, LRZ 7 is projected to have the greatest penetration of EVs within the MISO footprint. In general, there are two main methods to implement managed charging for EVs — indirect and direct. Indirect methods use special electricity rates such as Time of Use (TOU) to incentivize particular customer behavior. Some utilities within the MISO footprint have begun to explore EV-specific TOU rates as an option to manage the load on their distribution systems imposed by EV charging. Direct methods, or controlled charging, consist of two broad types — unidirectional (V1G) or bidirectional (V2G). There have been a number of pilots to study these approaches.

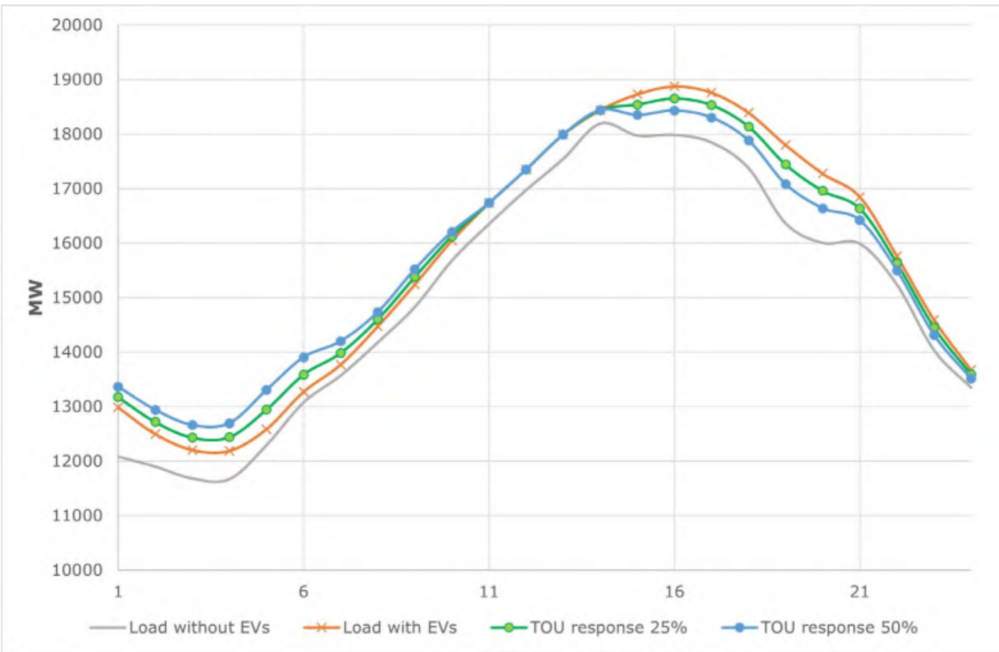


Figure 22: Load profiles with managed EV charging for LRZ 7 in Aug 2041

This simulation uses the LRZ 7 forecast data for 2041 (orange line), which includes the projected demand from the light-duty EVs (Figure 22). To manage the peak load, a two-level TOU rate is assumed with a high-level from 14:00 to midnight and a low-level for the rest of the day. This analysis considers the response to the TOU rate only from the EV demand. Two scenarios of customer response/participation rate are assumed (25% and 50%), where it is assumed that customers shift their EV charging load out of the high-level hours and into the low-level hours. Figure 22 also shows, the average August 2041 LRZ 7 load shape has a peak of 18.9 GW in hour 16. With participation from 25% of customers, the peak load is reduced by 1.2%. With participation from 50% of customers, the peak load is reduced by 2.4%. This example shows that as EV penetration grows, the potential impact of TOU rate design on peak load also grows. Some other considerations for real-world implementation are the price sensitivity of customers and the extent to which interval smart meters and their corresponding communication infrastructure is available.

IMPACT OF RENEWABLES GROWTH IN NEIGHBORING AREAS

INSIGHT: Increased variability of Net Scheduled Interchange (NSI) slightly exacerbates the net load ramps in the future

Net Scheduled Interchange is the net sum of all interchange schedules between MISO and neighboring Balancing Authorities. The NSI for the future system is projected to become more variable due to the increased penetration of renewables across MISO's neighbors. This increased variability in NSI slightly exacerbates the magnitudes of net load ramp needs. To understand this impact, MISO compared the highest risk hours of different resource portfolios with and without NSI.

The RIIA projects the system wide Net Scheduled Interchange (NSI) amounts associated with different penetration levels of renewables in the MISO footprint and neighbors. For this analysis, MISO combined the net interchange estimates for the RIIA 40% and 50% renewable penetration milestones with the net load from the 2031 and 2041 RRA scenarios respectively.

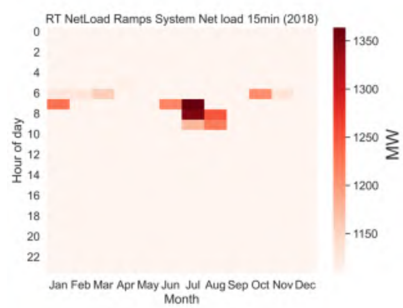
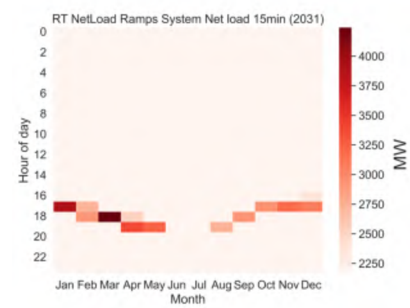
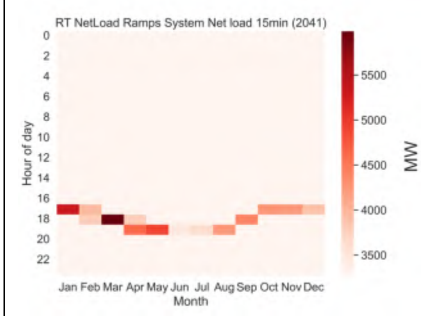
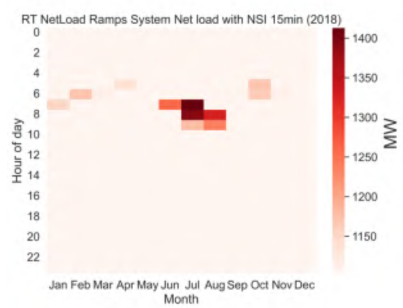
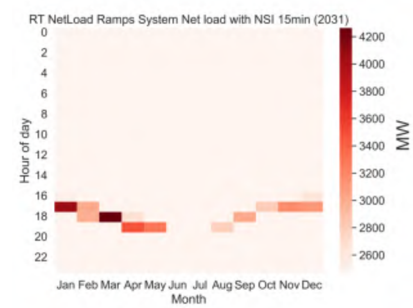
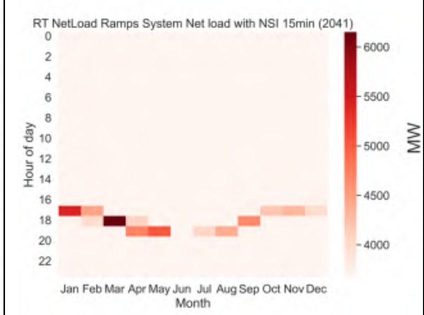
	2018	2031	2041
Net load			
Net load with NSI			

Figure 23: Highest 10 percentile of 15-minute net load up-ramps with and without NSI

Figure 23 shows the top 10 percentile of 15-minute up-ramps both with and without NSI for 2031 and 2041, compared to 2018 levels. NSI increases the 90^{th} percentile of the 15 minute up-ramps by approximately 300 MW in 2031 and approximately 400 MW in 2041 relative to 2018. Due to the sun setting the imports into MISO reduce resulting in higher net load ramp up needs for MISO. This indicates that the already challenging ramping trends expected with MISO's own resource portfolio transition could be made even more challenging when considering exchanges with its neighbors.

SHORT-TERM UNCERTAINTY ANALYSIS

INSIGHT: The increase in short-term uncertainties will contribute to growing flexibility needs in the future

Short-term uncertainties for load, wind, and solar significantly increase over the 20-year study horizon as both load and weather-dependent generation becomes more challenging to forecast. To better understand this trend, MISO studied the magnitude of wind over-forecast trends. For context, the 95th percentile of six hour-ahead wind over-forecast increased from 1.13 GW to around 1.75 GW between 2017 and 2020. The analysis indicates that this same metric grows to around 2.44 GW in 2031 and around 4.77 GW in 2041, even with an assumed improvement in forecasting accuracy (Figure 24). Reliably operating a system with growing system uncertainty requires more system flexibility.

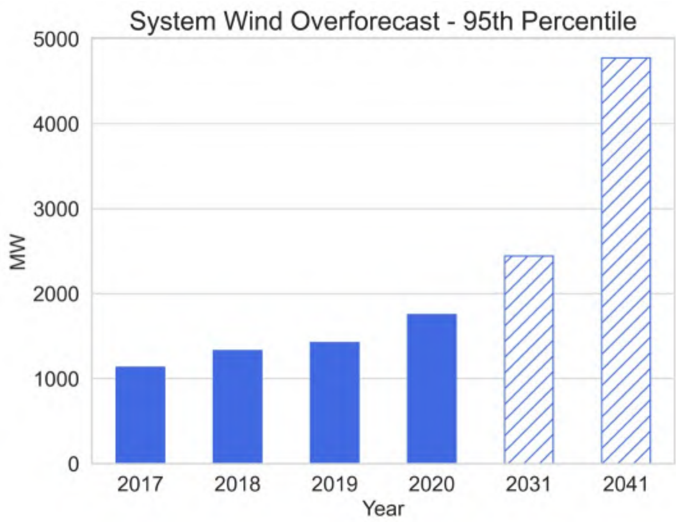


Figure 24: 95th percentile of system six-hour ahead wind over-forecast

To further examine this trend, MISO looked at extreme net load uncertainties and found that extreme net load uncertainties will increase in both magnitude and frequency over the 20-year horizon due to the aggregated impact of load, wind, and solar uncertainties (Figure 25). The net load forecast error exceeds 5 GW for 3.7% of the time in 2031 and 16.9% of the time in 2041. Note that the 2018 comparison for wind-solar was excluded due to insufficient solar data.

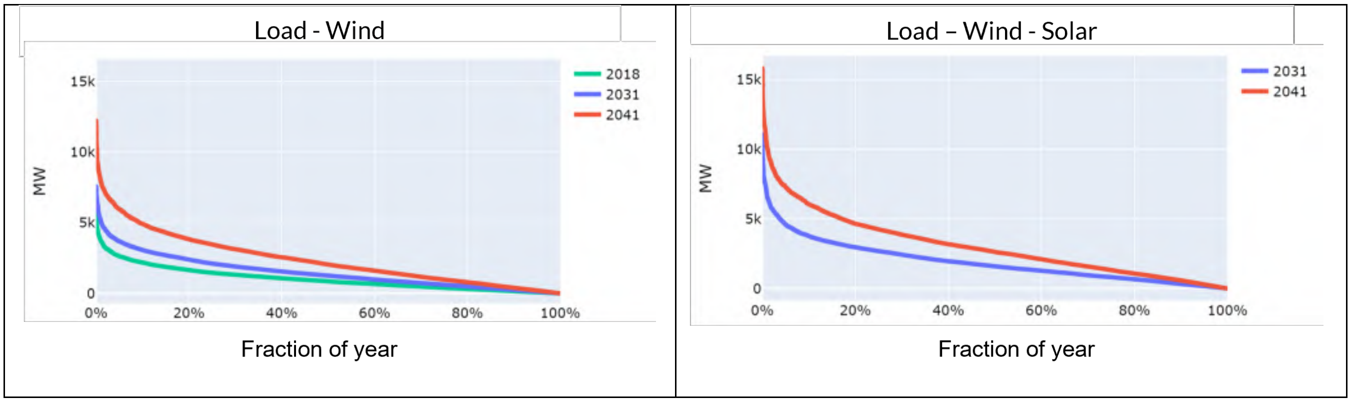


Figure 25: Short-term forecast error duration curves for Net Load: (a) net of load and wind (b) net of load and renewables (wind & solar)

As the penetration of renewables increases, more effort will be needed to improve forecasting models. MISO's operating practices must adapt to deal with the increasing level of net load forecast error. Operators will have to pay closer attention to changing seasonal and diurnal patterns in net load forecast errors as the system evolves. Additional factors that will impact the net load forecast error but are not captured in this analysis include extreme weather events and distributed energy resources.

INSIGHT: Renewable forecast errors in combination with the load forecast error will result in higher net load forecast error in the future

Understanding the distributions of solar and wind forecasting errors and their joint contribution is important to better understand system flexibility needs. The RRA analyzed the short-term uncertainties (6-hour ahead) in load, wind, and solar and the distributions of over-forecast or under-forecast hours over the year.

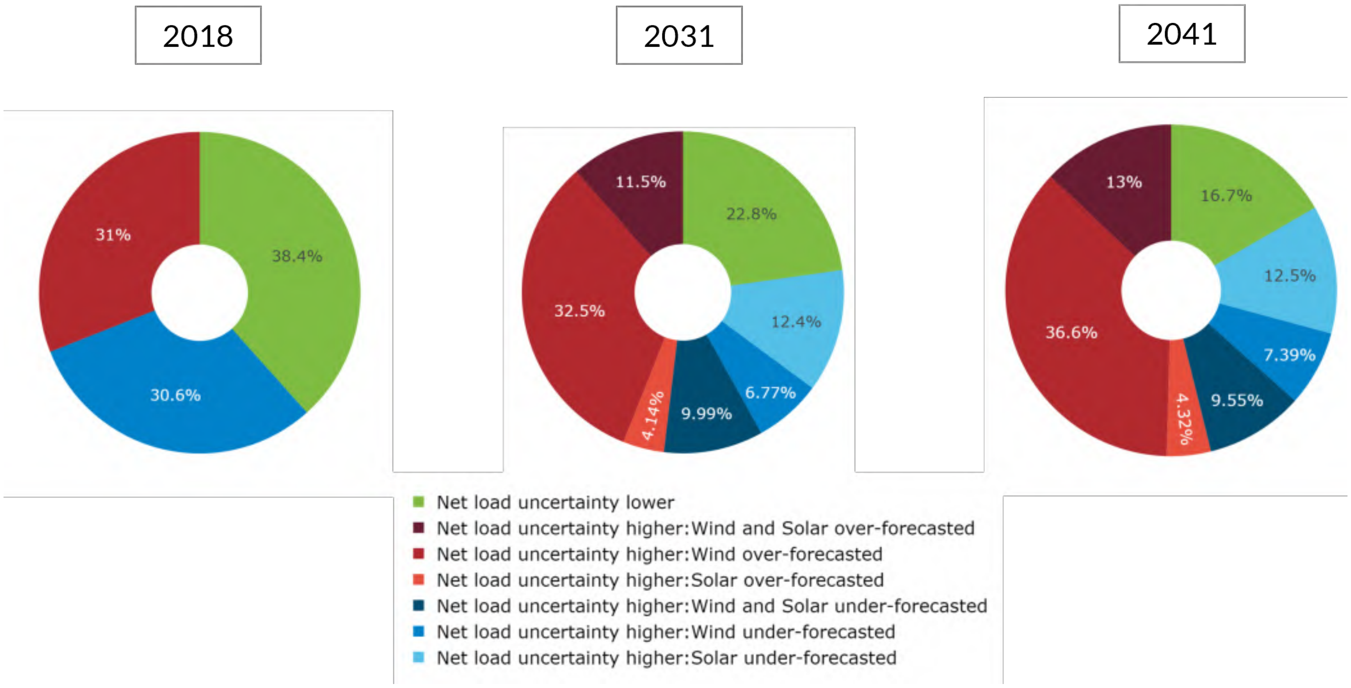


Figure 26: Annual contributions of load and renewable forecast errors

The number of hours of the year in which the net load forecasting error is higher than the forecasting error due to load alone is growing, as illustrated by the multiple "net load uncertainty higher" categories making up a larger percentage of the Figure 26 graphs over time. In 2018, the system net load forecasting error was greater than the load error in 61.6% of hours. By 2031, this is estimated to occur in 77.2% of the hours. By 2041, the forecasting error of net load will be higher than load error in 83.3% of hours. Wind generation over-forecasting becomes the largest contributor to renewable forecast errors. As the penetration of renewables increases, improved forecasting models will have increased benefit.

SYSTEM STRESS TRENDS

INSIGHT: The intersection of high variability and high uncertainty leads to potential system stressed conditions in non-summer hours

Analysis of the combination of variability and uncertainty indicates the potential for stressed conditions to occur not only in summer but also non-summer seasons, while historically such conditions only occurred in summer. Figure 27 shows the potential system stressed hours identified in each season of 2018, 2031 and 2041. The grey dots show each hour's variability and uncertainty, and the green, blue, and red dots signify if the hour is potentially stressed in each season of 2018, 2031 and 2041 respectively. The variability in demand considered here is based on net load (load minus renewables) combined with hybrid and battery dispatch and net scheduled interchange. The uncertainty considered here is the day-ahead vs. real-time difference in the net load. This study considered any hours to be potentially stressed in which the variability (hourly ramps) was above its 98th percentile as well as uncertainty (day-ahead to real-time error) was above its 90th percentile.

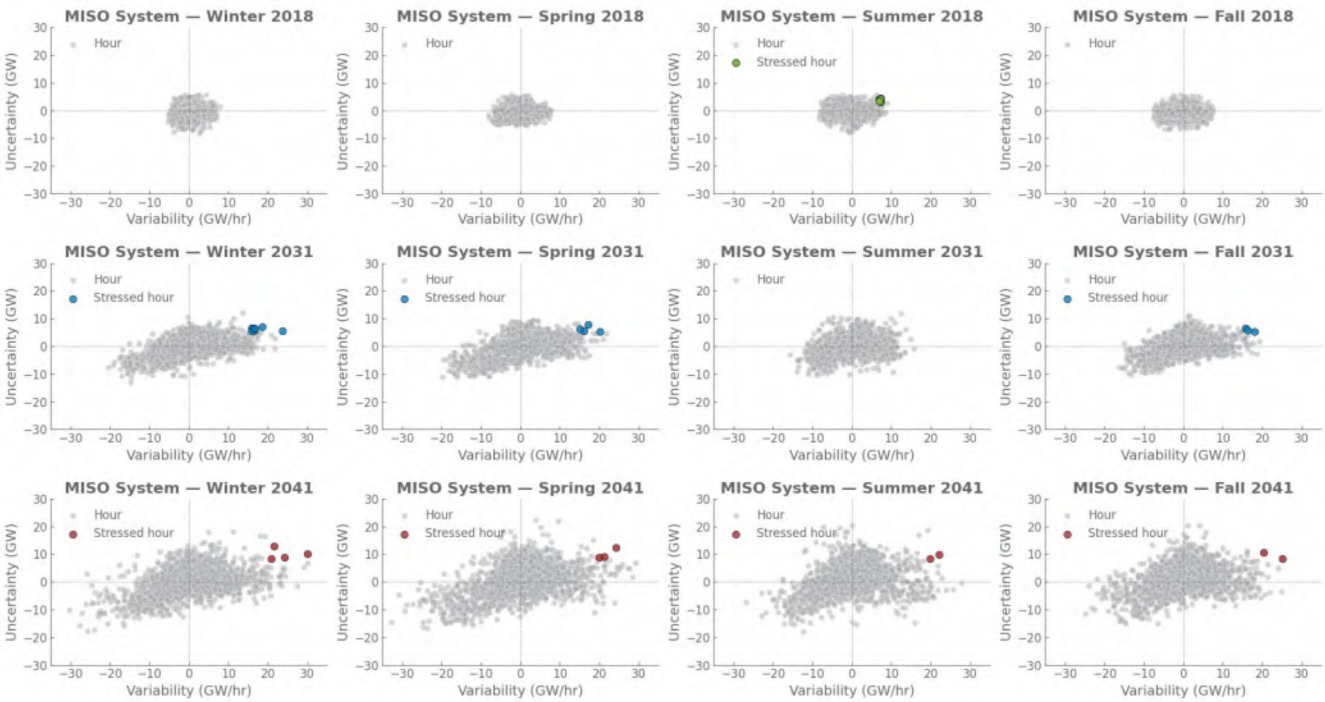


Figure 27: System-wide variability and uncertainty

INSIGHT: Enhancements to MISO's current reserve requirements may be one approach in mitigating future stressed periods

Market simulations were conducted across 2031 and 2041 for 40 potentially stressed days identified by the stressed period analysis, to evaluate the flexibility deficit risks. These risks occur due to a combination of day-ahead uncertainties and sub-hourly flexibility needs. The simulations analyzed the system flexibility under different levels of ramp capability and static short-term reserve (STR) requirements. The analysis indicates that with current levels of reserves and market practices, suboptimal actions such as out-of-market commitments of units might be needed to address the flexibility deficit risks.

The market simulation portion of the RRA Flexibility Assessment was carried out using a MISO-enhanced version of the Electrical Grid Research & Engineering Tool (MISO-EGRET) that has implemented certain MISO products, services, and commitment rules. The original EGRET is a Python-based unit commitment and economic dispatch tool developed by the Sandia National Lab. For the RRA, MISO-EGRET ran a simplified MISO day-ahead market for selected days based on the stressed period analysis for the future years 2031 and 2041. Further, analysis of available offline units for out-of-market commitments was conducted to compare the flexibility of day-ahead commitments versus the real-time needs.

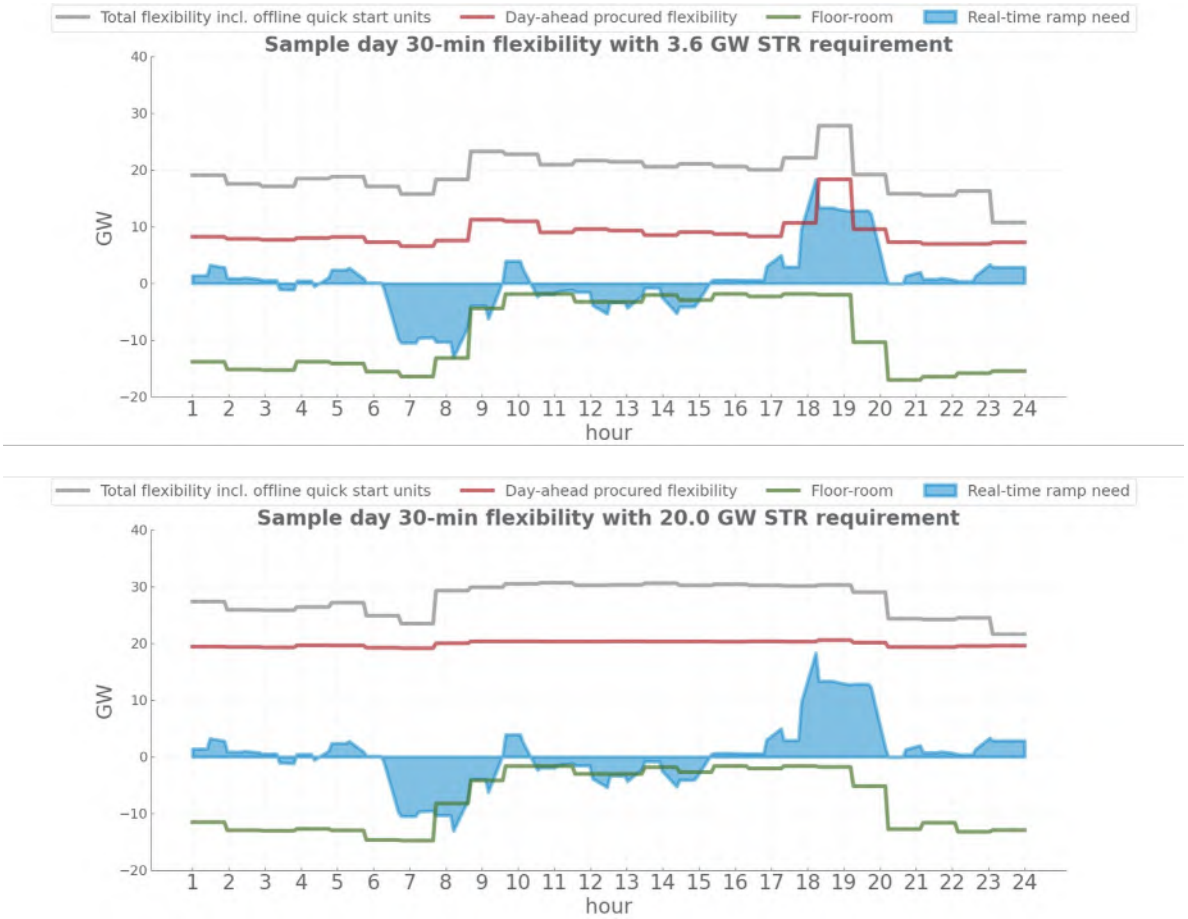


Figure 28: Sample day for 2041 RRA generation portfolio with short-term reserve (STR) requirement

Figure 28 shows the results for a sample day (from April 2041) under two different levels of STR requirements, 3.6 GW and 20 GW. The top graphic illustrates the scenario with 3.6 GW of STR requirement, in which the day-ahead procured flexibility (red line) is not sufficient to meet the real-time flexibility needs (blue area; positive for ramp-up and negative for ramp down), since an evening deficit is observed. In this case, additional capacity through out-of-market commitments of offline quick-start units (total offline capacity = difference between grey and red lines) would be needed. The bottom graphic illustrates the scenario for the same day with the STR requirement increased to 20 GW. In this case, the day-ahead flexibility procured amount meets the real-time need for the entire day.

The market simulations indicated that 15 to 20 GW of reserves can manage the ramp-up flexibility risks of the 40 stressed days, while a lower STR requirement is sufficient for non-stressed days. Dynamic reserve requirements, which vary by season and hour of the day, may offer a valuable mitigation strategy for stressed conditions while also optimizing costs on the non-stressed days.

CAVEATS OF THE FLEXIBILITY ASSESSMENT

Important caveats to the Flexibility Assessment insights:

- The insights are based on data analysis of flexibility needs and do not give a complete picture of the supply side or specific timings of when gaps might emerge.
- Dispatch analysis for hybrids and standalone batteries are based on simplified models, and perfect foresight of the electricity prices is assumed.
- This analysis does not model transmission constraints. The market simulation portion considers only the Regional Dispatch Transfer (RDT) limit.
- The market simulation assumes unit offers for conventional units in future years to be the same as a recent historical day. Further, wind and solar unit offer prices were assumed to be zero.
- For uncertainty, only short-term uncertainty of 6 hours ahead forecast is considered, due to software tool limitations.

Additional details about the methodology and assumptions can be found in the Technical Appendix.

Resource Adequacy Analysis

The RRA Resource Adequacy (RA) analysis focuses on sufficiency of storage and generation resources to meet the system demand across the year. The RA analysis is based on the 2031 and 2041 resource portfolios identified in the Resource Assessment. Probabilistic methods are applied to captures a wide range of system uncertainties, including correlated weather events across multiple weather years, planned maintenance, site-specific renewable variability, and random forced outages. In its current form in the RRA, RA analysis is focused solely on the MISO footprint and does not include any non-firm imports, transmission constraints, or flow-gate constraints. Although load uncertainty is accounted for by including multiple weather years, load forecast uncertainty due to economic factors is not incorporated in this analysis. Find a more detailed description of the study framework adopted in this work in the Technical Appendix.

The main objective of this year's RA analysis is to characterize the seasonal and diurnal risk profiles and to quantify the MISO system capacity contributions from utility-scale wind, solar, batteries, and solar-plus-storage hybrids. The analysis used hourly Sequential Monte Carlo simulation and MISO's currently established metric of a Loss of Load Expectation (LOLE) of 1 day in 10 years.

The 2022 RRA Resource Assessment selected a portfolio with capacity above the PRM target for 2031 or 2041 in the RA analysis. Though the Resource Assessment solved to meet load plus reserves, the resulting capacity expansion included more renewable capacity than was required for peak load plus planning reserves so that carbon reduction and renewable generation goals would be met. Another factor was that each LRZ was solved to a non-coincident peak load, which results in more capacity than needed for a MISO footprint-wide coincident peak.

Following LOLE modeling best practices[1], fixed load was added to the MISO system to achieve the 1 day in 10 years (0.1 days/year) annual target. If a season did not show any LOLE, a 0.01 days/year LOLE target was set. This methodology is consistent with MISO's Wind and Solar Capacity Credit study and for the annual Loss of Load Expectation (LOLE) Study, and is explained in more detail in the Technical Appendix.

Table 1 presents the level of fixed load that was added to the system and the resulting seasonal LOLEs for the 2031 and 2041 models. The level of load needed to meet the target LOLE was as low as 7 GW for fall in 2031, and as much as 19.7 GW for winter in 2031.

[1] G. Stephen *et al.*, "Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric," *2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, 2022, pp. 1-4, doi: 10.1109/PMAPS53380.2022.9810615.

2031

Season	Fixed Load Addition (MW)	LOLE (day/year)
Winter	19,700	0.01
Spring	13,500	0.01
Summer	9,250	0.01
Fall	7,000	0.10

2041

Season	Fixed Load Addition (MW)	LOLE (day/year)
Winter	15,300	0.01
Spring	13,600	0.01
Summer	8,500	0.07
Fall	8,500	0.03

Table 1: Fixed load additions to the Resource Assessment portfolio resulting in 1 day in 10 years LOLE

LOSS OF LOAD RISK ANALYSIS

INSIGHT: Loss of load risk is generally centered around correlated low wind availability, low solar availability, and thermal outages during time of high net load, often outside of expected solar production hours

Figure 29 shows seasonal loss of load (LOL) probability distributions for 2031 along with average wind and solar generation, load, and net load during shortfall events. In the RA workstream, net load is defined as the difference between gross load and expected energy production from renewables, solar-plus-storage, and stand-alone batteries. The loss of load probability (LOLP) for a system with a 0.1 days/year LOLE represents the probability of a shortfall event. The darker green hourly probability indicators represent a higher probability of LOL.

With the exception of spring, where risk events are spread over morning and evening hours, risk is largely centered around just a few evening hours. The probability of a loss of load event during daytime hours is low across all seasons as a large amount of solar generation is added. This is due to risk aligning instead with peak net load which shifts to the late evening hours as renewable penetration increases.

The seasonal pattern for 2041 is similar to 2031 and is presented with the LOLP distributions in Figure 29. One difference in the 2041 model is that winter risk is distributed across more hours, starting earlier in the evening and extending through the last hours of the day. Spring risk is also expanded to include more morning hours.

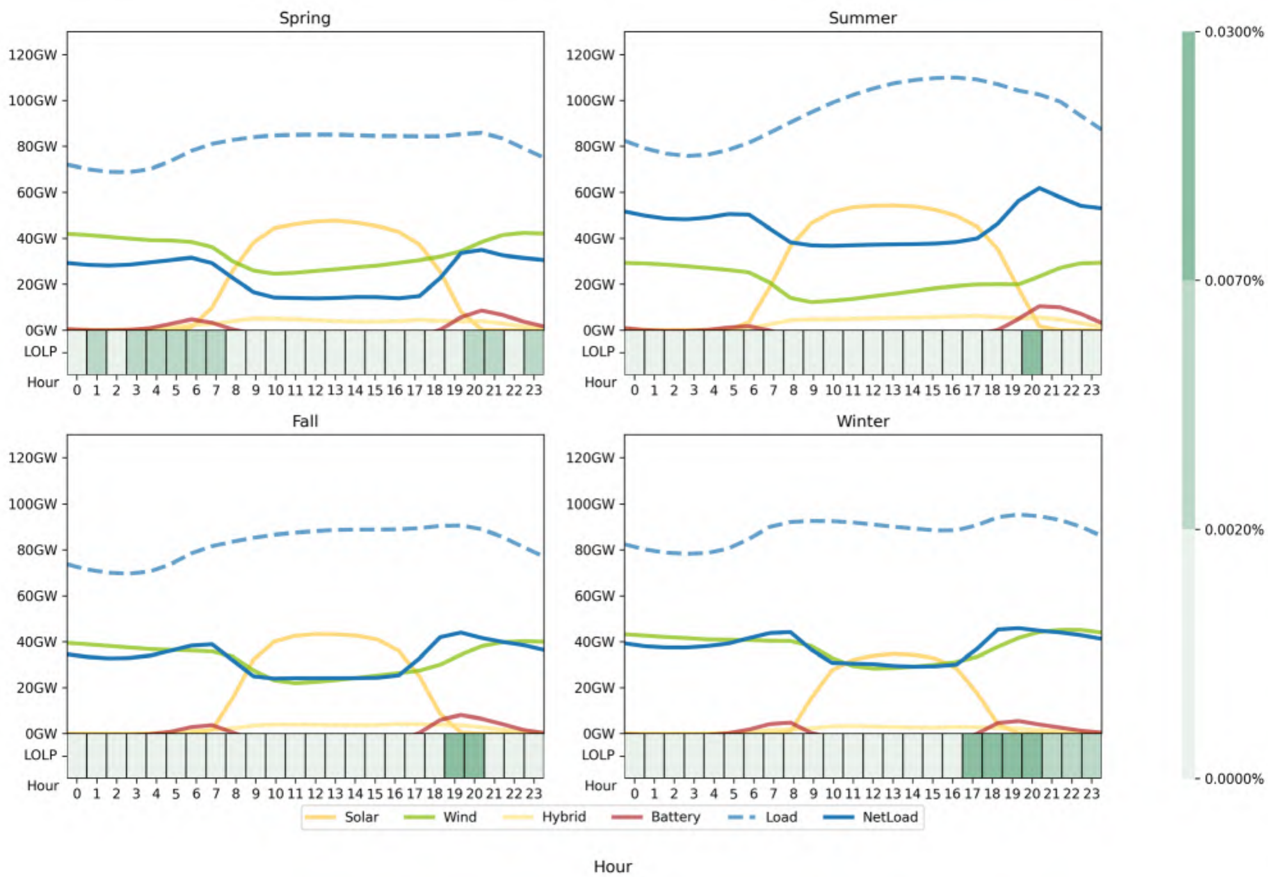
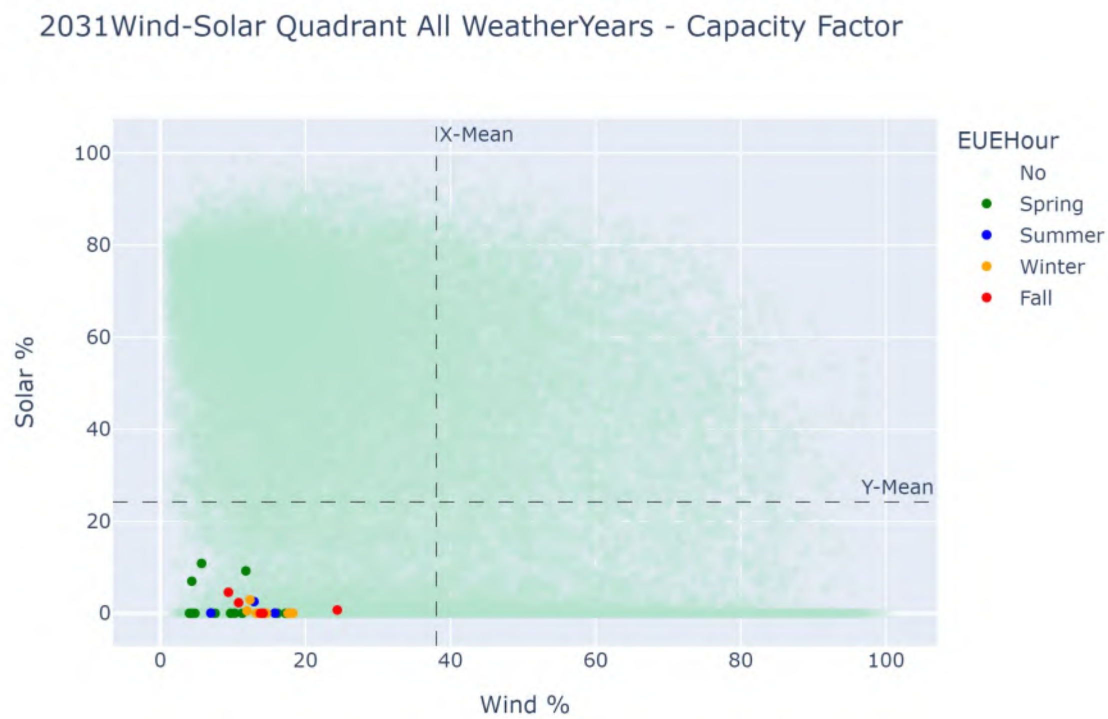


Figure 29: Diurnal renewables, load, net load, and loss of load probability during expected unserved energy days in 2041

Figure 30 shows the levels of wind and solar production for all modeled hours for 2031 and 2041, highlighting wind and solar output conditions during hours of expected unserved energy (EUE). Hours with EUE are shown in bright colored dots denoted by season, while hours with no EUE are represented by the cluster of light green dots. All EUE events for 2031 occur when total MISO solar capacity factor[2] is below 19% and wind capacity factor is below 27%. For 2041, the EUE events occur when solar capacity factor is below 17% and wind capacity factor is below 23%. The outliers on the graph, which are the EUE hours that occurred on the higher range of the wind or solar capacity factor, are often caused by a combination of risk factors which include hours with high load, especially in summer and early fall, and hours with high levels of planned maintenance outages in the spring and fall seasons.

[2] Capacity factor in this context is the average generation during EUE events.



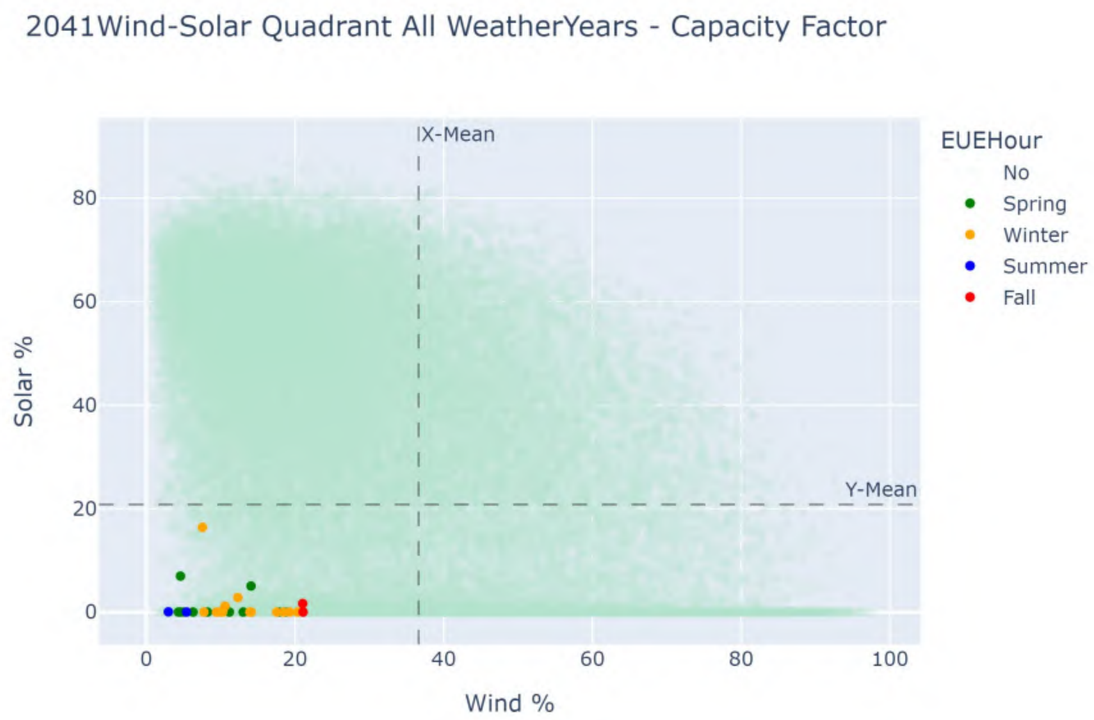
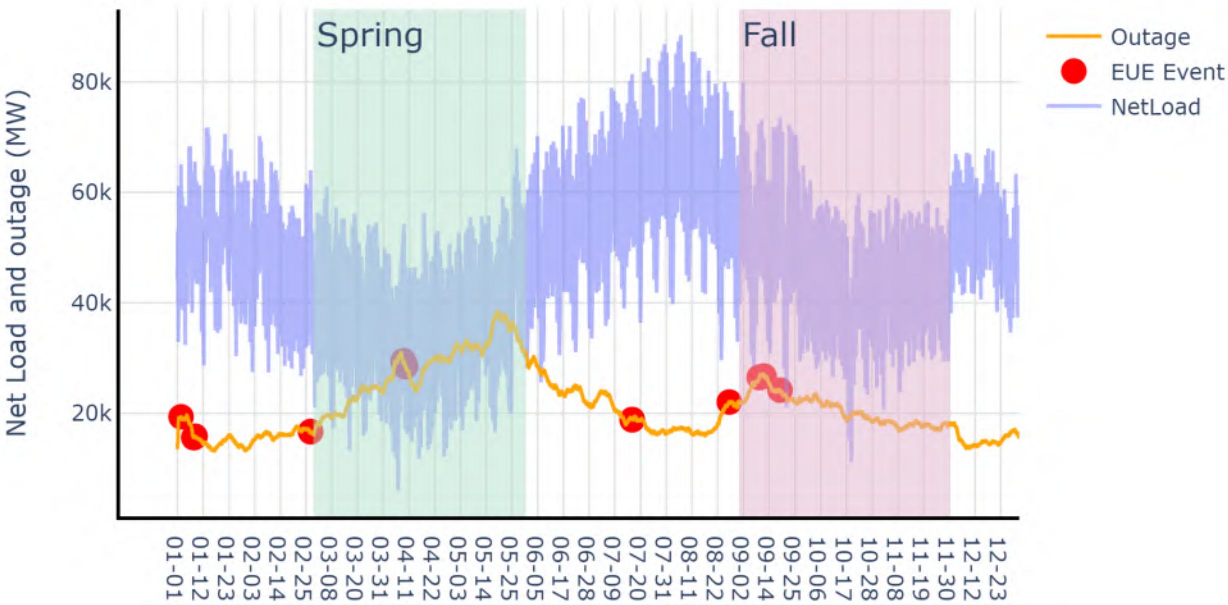


Figure 30: Solar and wind capacity factors with EUE events

Thermal outages also contributed to risk, particularly in shoulder months. Planned maintenance outages were scheduled with a perfect forecast of load and generation for each weather year. Figure 31 shows 2031 and 2041 net load, planned maintenance and EUE events. Exploring the impact of planned maintenance on loss of load events will be considered in future versions of the RRA.

2031



2041

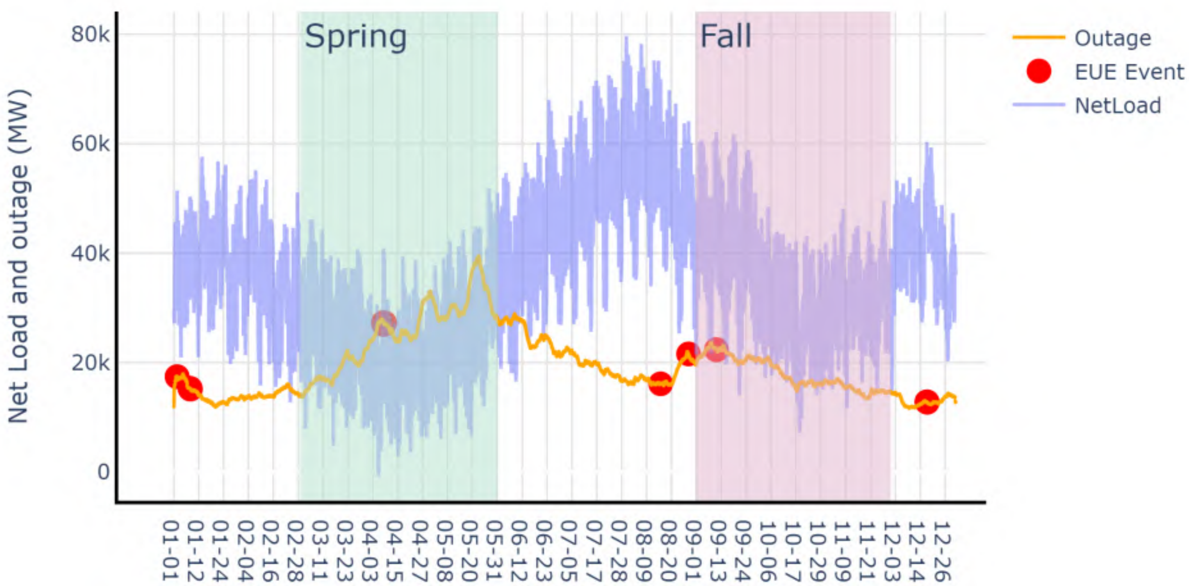


Figure 31: Net load and thermal outage MW with EUE events

AVERAGE EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

MISO currently estimates the capacity contribution of wind resources by measuring the average Effective Load Carrying Capability (ELCC). The average ELCC is used to calculate the accredited capacity for the wind resource class in the Planning Year 2022-2023 Wind and Solar Capacity Credit study for the Planning Resource Auction (PRA) and for the annual Loss of Load Expectation (LOLE) Study, which determines the PRA Planning Reserve Margin Requirement (PRMR) to meet the 1 day in 10 years LOLE standard.

The average ELCC is meant to reflect the amount of incremental load the resource class can dependably and reliably serve, while accounting for the random and probabilistic nature of generation shortfalls and effects of time-varying electricity demand. The analysis considers the variability of load, wind, and solar output along with planned maintenance and outages of generation units.

To measure the ELCC of a resource class, the reliability effects need to be isolated for that resource class from all other resources, so the LOLE is found both with and without the resource class in question. The portfolio *with* the resource class should be more reliable (and have lower LOLE) than the portfolio *without* the resource class. The ELCC is the difference in MW needed to bring the LOLE of these two portfolios to 1 day in 10 years, and it is applied as a percentage of total installed capacity of the resource class. The process and the calculation are described in further detail in the Technical Appendix.

Average ELCC has been the industry standard for estimating an intermittent resource class capacity contribution, but this approach may not be adequate for a system with large amounts of intermittent generation. Changes to the accreditation methodology applied to non-thermal technologies are currently being considered by MISO's Resource Adequacy Subcommittee (RASC) stakeholders.

CAPACITY CONTRIBUTION BY FUEL CLASS

As the resource portfolio becomes increasingly diverse, the ways in which different resource types interact and complement one another are important to understand and consider in resource planning. By analyzing future generation profiles, the RRA Resource Adequacy work provides insights on shifting high-risk periods over time and the expected capacity contribution of utility-scale wind, solar, solar-plus-storage and stand-alone storage during those times of greatest need. New generation takes years to plan and build — anticipation of future portfolio interactions is important for resource planning decisions made today.

The RRA analysis further supports MISO's 2021 RIIA report finding that the capacity contribution of wind and solar are both improved when the portfolio interactions are accounted for. Diversity of resource types leads to higher generation availability across all hours and complementary advantages to mitigate shifting risk over time.

KEY INSIGHT 5: The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

SOLAR CAPACITY CONTRIBUTION

INSIGHT: Increase in solar installed capacity noticeably decreases the solar class capacity contribution in some seasons, but is also highly dependent upon the generation portfolio which shifts the hour of the day in which risk emerges

The average ELCC for the solar resource class is presented in Figure 32. Since solar generation is only available during daylight hours, solar ELCC decreases as more solar is added to the system and the net load peak moves later in the day.

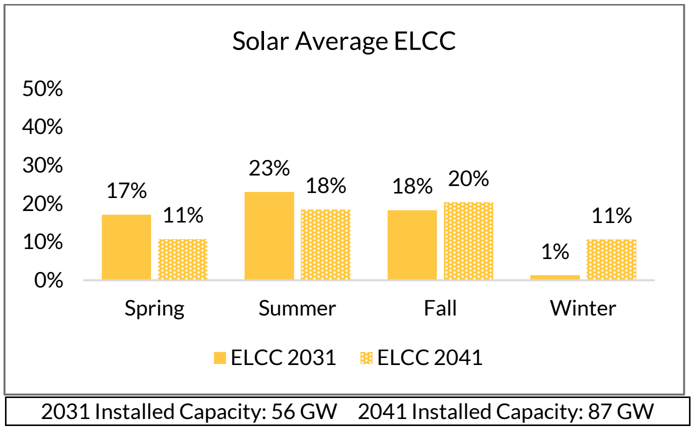
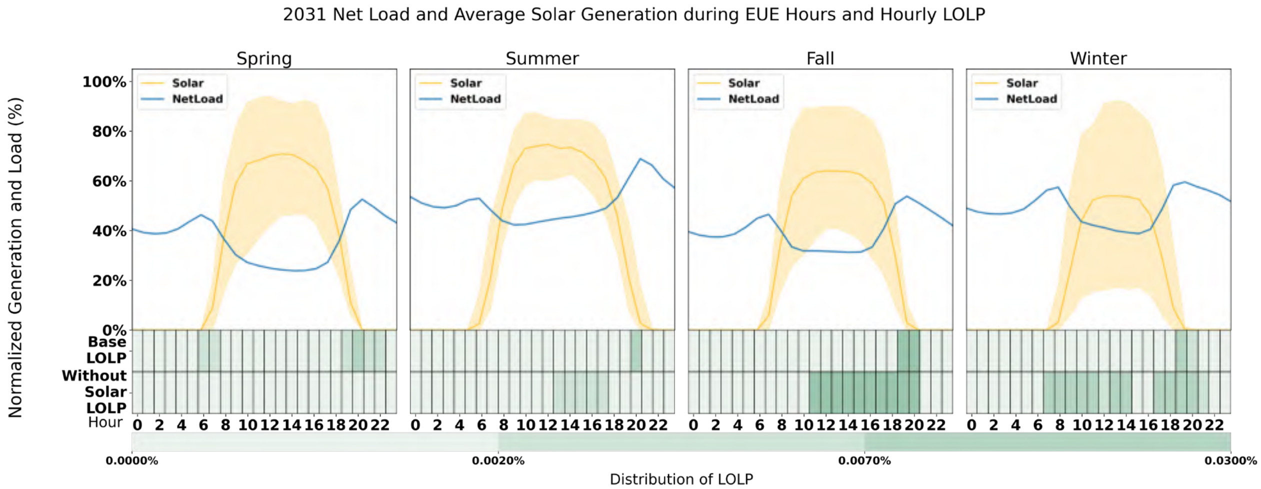


Figure 32: Average seasonal ELCC for the RRA solar class

Contrary to the expected declining trend in ELCC when more of a resource type is added to the system, the solar average ELCC for the winter season increased from 1% for 2031 to 11% for 2041, despite more solar on the system for 2041. This is due to the hour in which risk emerged in winter. The evening risk emerged two hours earlier in 2041 than in 2031, due to low wind output. This otherwise minor shift in risk changed the ELCC outcome by 10%.

Figure 33 presents 2031 and 2041 LOLP distributions on EUE days, with normalized solar and net load plotted, with the range in solar output covered by the area in yellow. The EUE hours in winter for both 2031 and 2041 indicate that the 2041 risk emerged just two hours earlier, while solar was still generating.



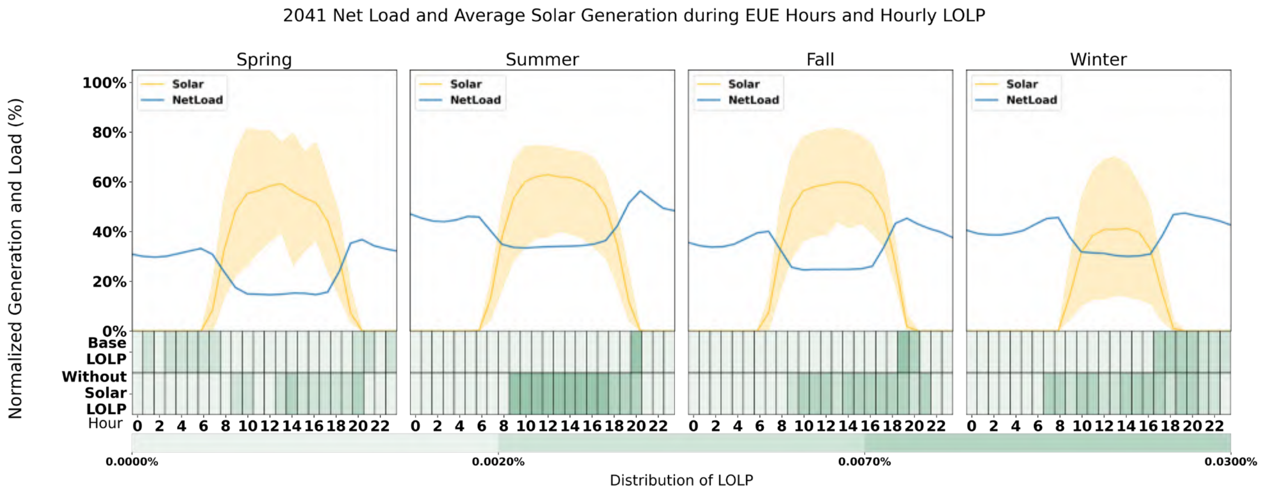


Figure 33: Net load and average solar generation during EUE hours with hourly LOLP

WIND CAPACITY CONTRIBUTION

The capacity contribution of the MISO-wide wind class as assessed by average ELCC is presented in Figure 34. The ELCC in this analysis uses the portfolio of all technologies with and without wind, which means that it captures the synergistic effects of other technologies.

INSIGHT: The wind class capacity contribution remains relatively stable even as wind installed capacity increases significantly between 2031 and 2041

The summer wind ELCC is 18% for 2031 and 16% for 2041, which is comparable to the PY22-23 Wind Accreditation ELCC of 15.5%. While the PY22-23 result was an annual ELCC, it is most directly comparable to the RRA summer results as summer is currently the season with the highest risk in the MISO system.

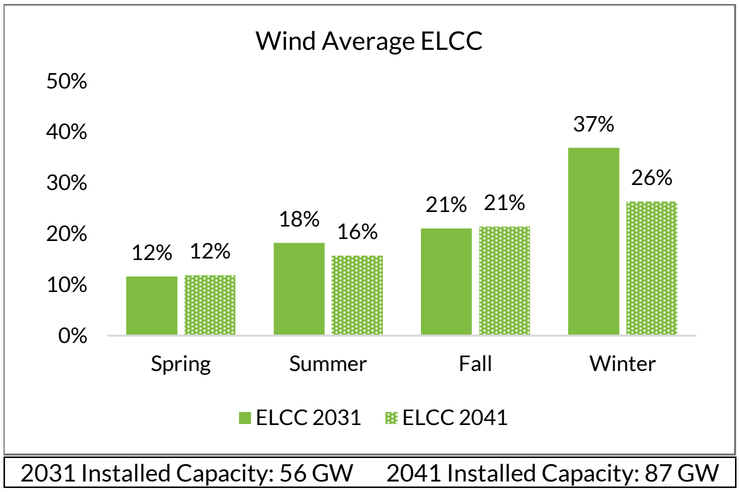


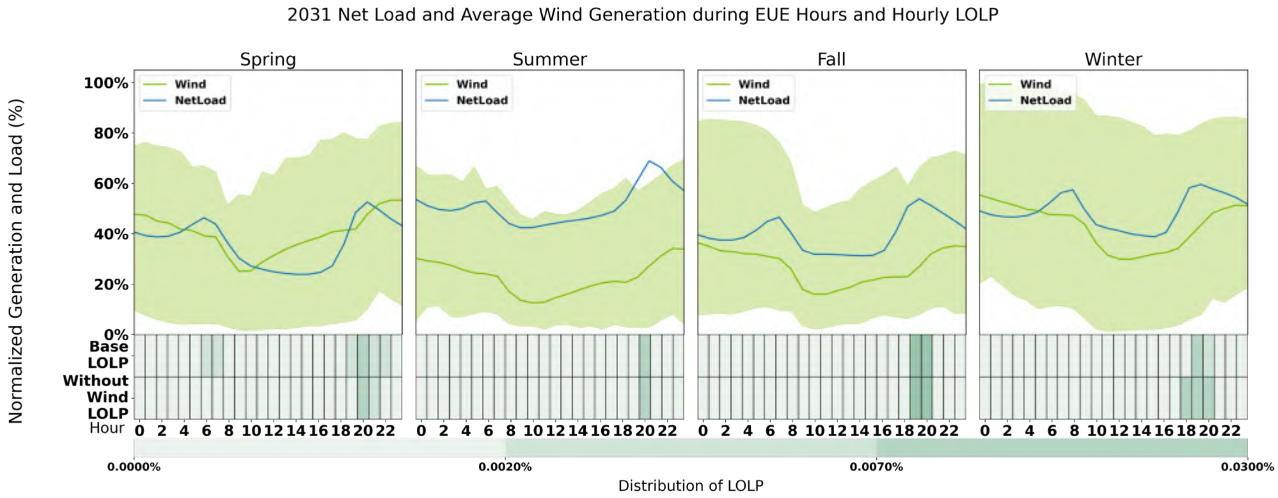
Figure 34: Average seasonal ELCC for the RRA wind class

Figure 35 presents 2031 and 2041 LOLP distributions on EUE days, with normalized average wind[3] and net load[4] plotted. The wide green area indicates the maximum and minimum normalized wind output during EUE days. On average, wind output is relatively high during EUE hours, but the EUE emerged in weather years with very low wind generation. Although on average there is a relatively high generation of wind during high LOLP hours, the ELCC of wind does not fully reflect this outcome. Because wind generation plays a critical role during risk hours, low wind generation is highly correlated with EUE events. The spring season in both 2031 and 2041 show seasonal ELCC values that are close to the minimum generation value of wind during EUE event days.

The winter wind ELCC drops between 2031 and 2041 because LOLP shifts earlier in the evening in 2041, when wind output is lower during its ramp-up from daytime output which is generally low to nighttime output which is generally high. Wind ELCC remains stable for the other three seasons with just a slight decrease in summer due to risk in those seasons remaining in high-wind output hours for 2031 and 2041.

[3] Normalized average wind with respect to installed capacity (ICAP).

[4] Normalized average net load with respect to peak load.



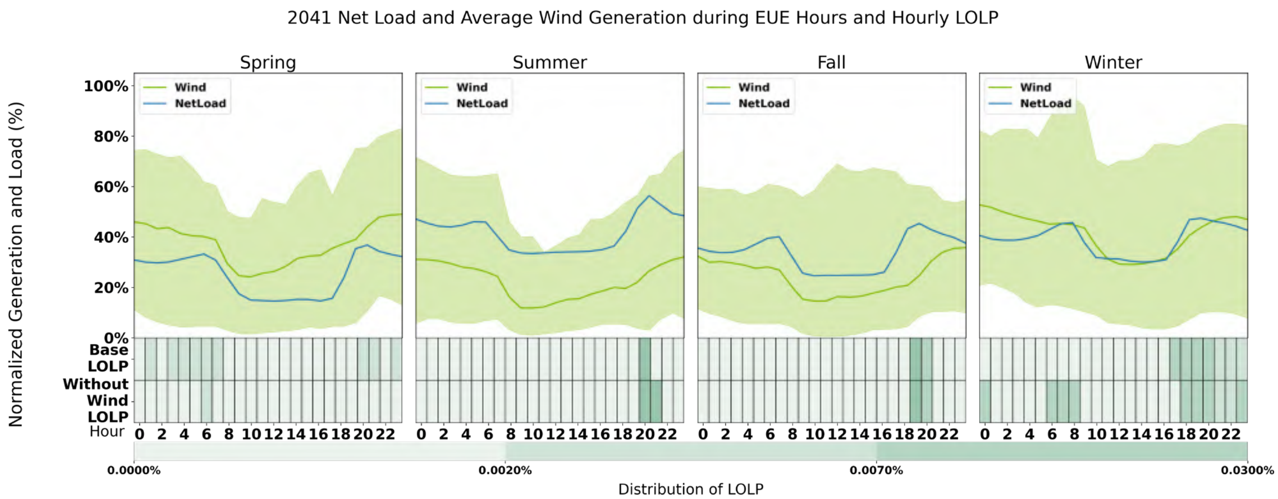


Figure 35: Net load and average wind generaton during EUE hours with hourly LOLP

SOLAR-PLUS-STORAGE CAPACITY CONTRIBUTION

INSIGHT: The addition of batteries to solar generation in the form of hybrid (solar-plus-storage) resources improves the capacity contribution when compared to standalone solar resources, even as the installed capacity of hybrid resources increase

The average seasonal ELCCs for the hybrid (solar-plus-storage) resource class are shown in Figure 36. When compared with stand-alone solar resources, the ELCC of utility-scale hybrid generation is higher, due to the pairing of the four-hour batteries with the solar generation. Energy is stored during daytime hours and used later in the evening, when EUE events are more likely to occur.

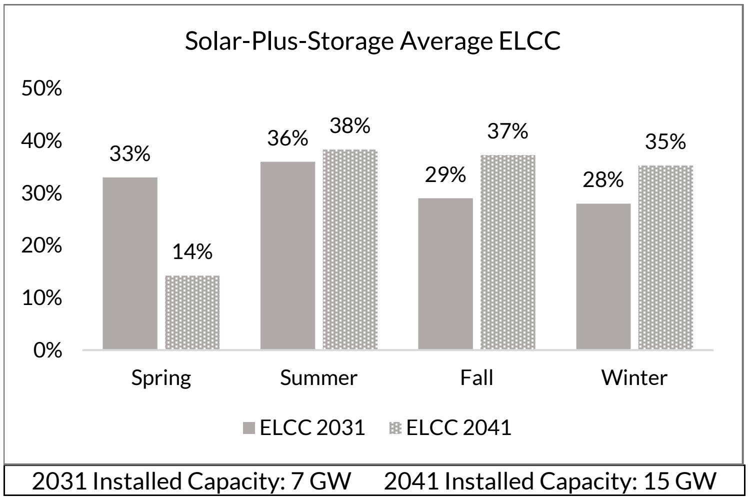


Figure 36: Average seasonal ELCC for MISO solar-plus-storage class

Hybrid resource ELCC increases from 2031 to 2041 in most seasons due to the ability of the battery capacity to mitigate loss of load risk in evening hours. The exception is spring, where hybrid ELCC decreases due to events that last longer than the hybrid's battery duration (Figure 36).

The hourly LOLP distributions with the range of hybrid generation are presented in Figure 37. The additional hours of generation from these resources available after sunset helps mitigate the evening risk and therefore improves the ELCC of these resources in comparison with stand-alone solar generation.

Note: This analysis does not assess the relative value of adding battery capacity at a solar facility (i.e., a hybrid) compared to a stand-alone battery resource. Until recent passage of the Inflation Reduction Act (IRA), there was a tax advantage to pairing batteries with renewable generators. Now that the IRA provides a tax incentive for stand-alone storage, MISO is doing further research into paired vs. stand-alone storage and its relative impact on reliability. Discussion of hybrid accreditation methodology and market participation options will continue in MISO's stakeholder forums in 2023.

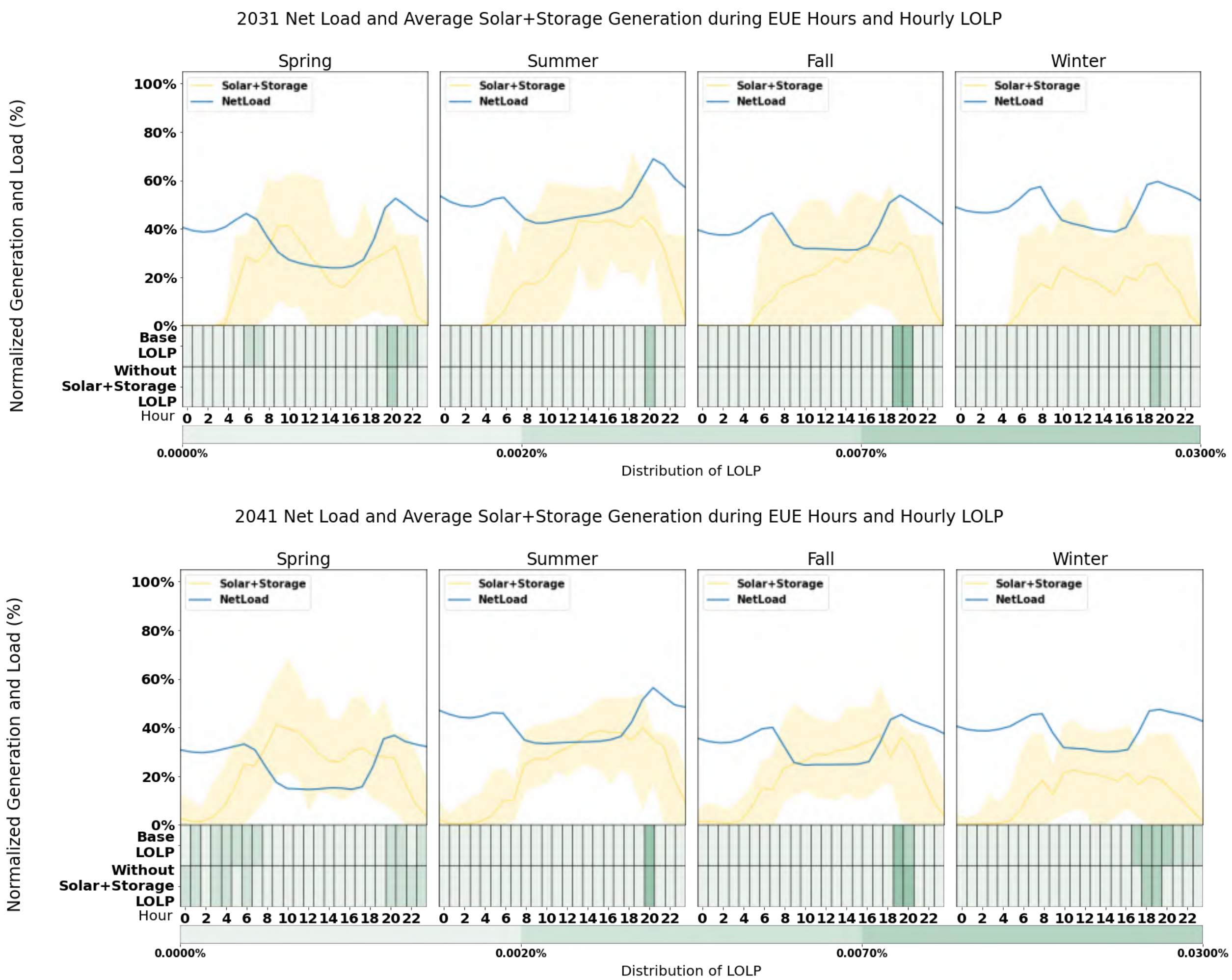


Figure 37: Net Load and average Solar Generation during EUE hours with hourly LOLP

STORAGE CAPACITY CONTRIBUTION

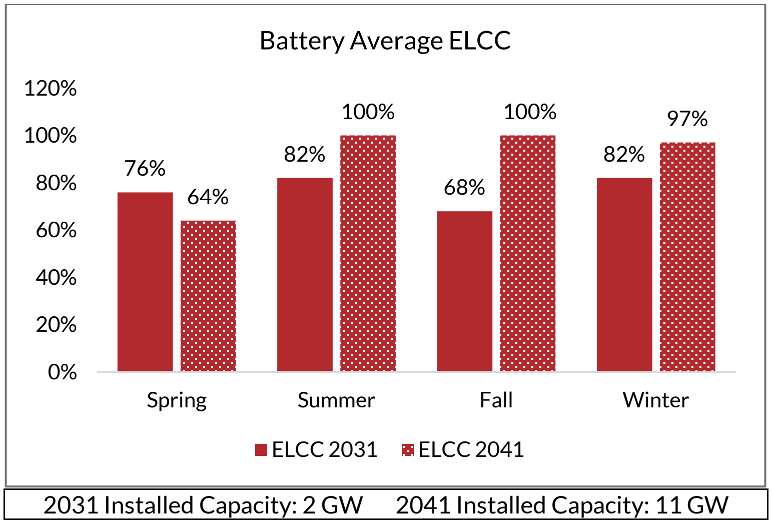


Figure 38: Average seasonal ELCC for the RRA battery class

The average seasonal ELCCs for the battery storage resource class are shown in Figure 38. Average ELCCs for battery storage resources are dependent on their ability to contribute at full capacity for the entire duration of a shortfall event. Batteries are the most effective in seasons with risk concentrated to just a few hours, and less effective in the spring where risk is spread out over more hours, where event duration exceeds the energy storage capability of the modeled 4-hour batteries.

Similar to hybrid resources, battery ELCC decreases from spring 2031 to spring 2041 due to the greater distribution of risk across overnight hours. ELCC increases in the other three seasons despite the increase in modeled battery installed capacity from 1.8 GW in 2031 to over 11 GW in 2041. This is due to the ability of 4-hour storage to mitigate short duration shortfall events.

INSIGHT: The capacity contribution of stand-alone battery storage depends on assumed energy storage duration limitations and the dispatch strategy of the battery storage itself, including the state of charge before the beginning of an event

The risk distribution for winter 2041, as presented in Figure 39, shows LOL risk first appearing in the evening hours and extending into overnight hours. This is due in part to low wind generation which persisted throughout the overnight hours. During these conditions, the 4-hour batteries are depleted by the late evening hours as the low wind generation persist throughout the night.

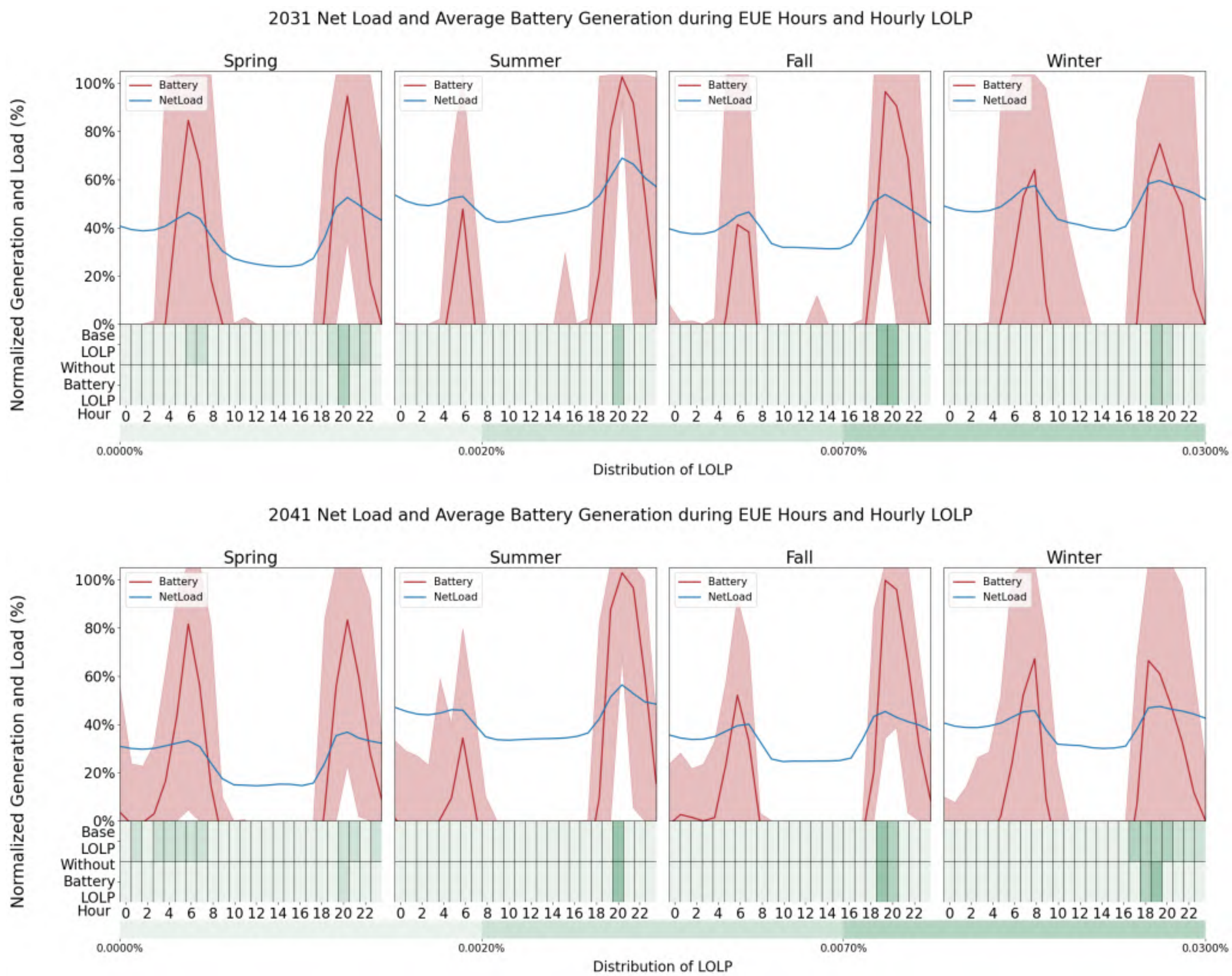


Figure 39: Net load and average battery generation during EUE hours with hourly LOLP

Figure 40 presents storage charging and discharging for each weather year on the day in which EUE emerged for winter in the 2041 model, with LOL hours indicated with red dots on the weather year and hour with LOL. Batteries are typically fully charged when the LOL event begins and start to discharge to offset the event. This is shown by the three red dots that indicated LOL, with discharge peaking. However, some LOL hours occurred when wind generation was low, and batteries were fully discharged and unable mitigate LOL risk, which is indicated by the red dot at the far right side of the chart, where battery discharge is approaching 0 MW.

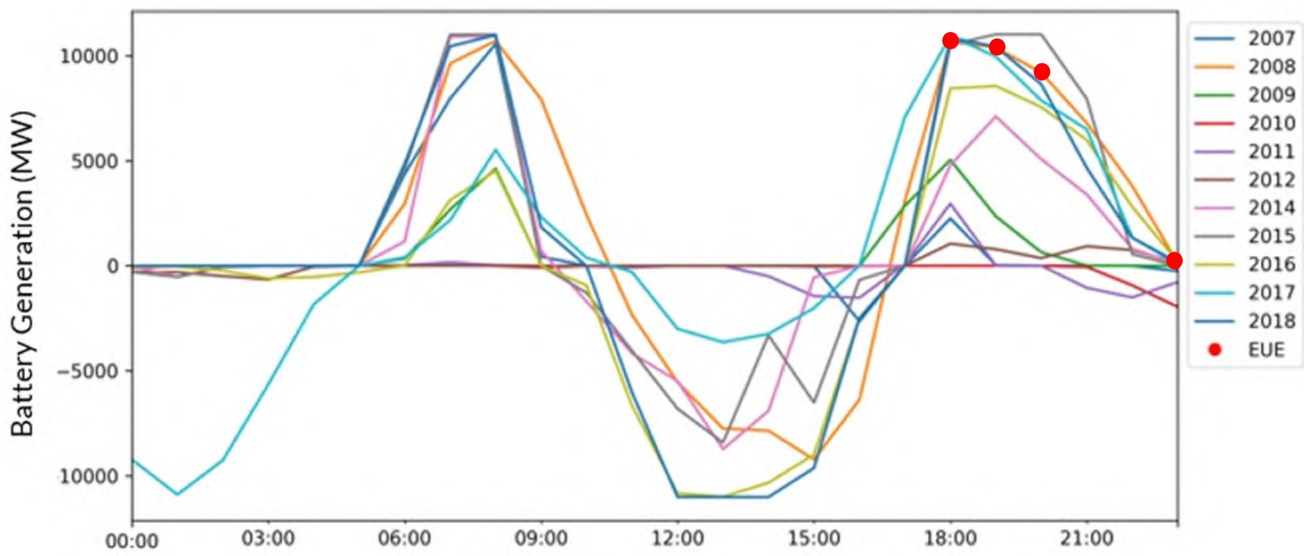


Figure 40: Hourly battery generation per weather year with EUE on winter EUE day for 2041

The duration of EUE events in winter for 2041 supports the finding that four-hour storage duration may not be sufficient to entirely mitigate LOL risk. Figure 41 shows distributions of EUE events by duration in hours. For spring, summer, and fall, EUE events are all four hours in duration or shorter, but EUE events in winter are as long as six hours in duration. The seasonal distributions were similar for 2031, except that all events were four hours or shorter in duration.

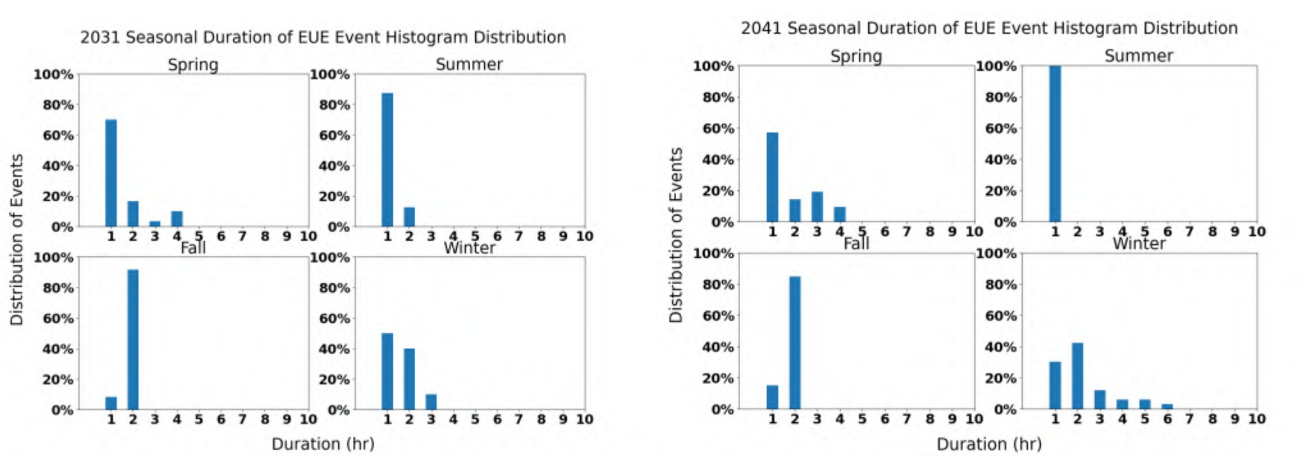


Figure 41: Seasonal duration of EUE events for 2031 and 2041

CAVEATS OF THE RESOURCE ADEQUACY ASSESSMENT

Important caveats to the Resource Adequacy Assessment insights:

- Hourly dataset for 2031 and 2041 models, which includes expected unserved energy (EUE), loss of load (LOL) hours and frequency across outage samples, along with load, net load, and renewable, battery, and hybrid (solar-plus-storage) generation is included in the report's Supplemental Materials.
- The model and analysis capture risks aligned with the planning horizon, but the system also faces operational risks that are not captured.
- The risks included in the model are intermittent resource generation, forced outages, planned maintenance outages, and load uncertainty.
- Operational risks that are not captured in the analysis include fuel supply, common-mode failure, transmission congestion, and forecast errors.
- Planned maintenance outages were scheduled with a perfect forecast of load and generation. Including a more realistic maintenance scheduling will align planned outages better with real time operations.
- Economic information was neglected in the simulations. Including energy pricing will capture arbitrage effects of storage resources and their availability at the beginning of shortfall events.

Additional details about the methodology and assumptions can be found in the Technical Appendix.

Emerging Technologies

Several technologies are emerging as potential new energy generation options within the MISO footprint. While most are still nascent, these technologies may have the potential to play a role within the 20-year study horizon of the RRA. Specific technologies will likely be accelerated by the tax credits and other financial incentives for clean energy in the $370 billion federal Inflation Reduction Act (IRA) signed into law in 2022. Furthermore, the federal Infrastructure Investment and Jobs Act (IIJA), signed into law in 2021, also contains considerable provisions and funding to accelerate the transition to the grid of the future. Still, modeling future adoption of nascent technology is complex due to uncertain pricing assumptions, unclear operational limitations, and unknown timelines for when the technology will become available for broad commercialization.

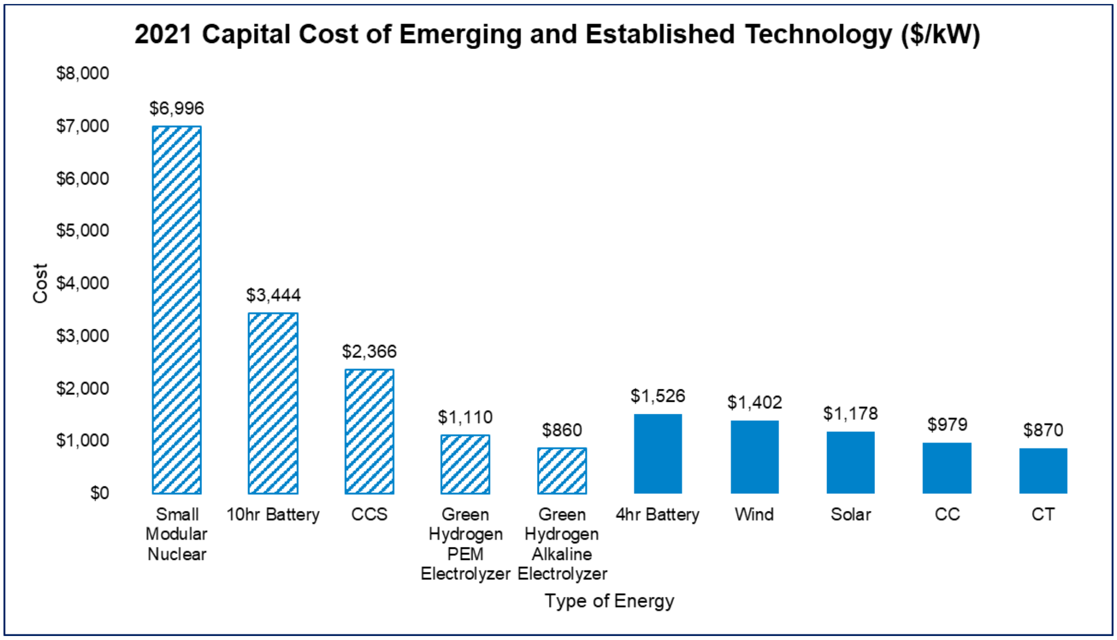
INSIGHT: Future Technology sensitivity analysis indicates that a low-emissions, high-capacity factor future technology, if technically mature, may displace additional wind and solar capacity at certain price points starting as soon as 2030

To gain insight into how emerging technologies will fare in the RRA model, MISO inventoried leading emerging technologies and conducted a break-even analysis for a simulated "future technology" as part of the Resource Assessment workflow. Due to the high uncertainty and a wide variety of possible low-emission, high-capacity factor units, MISO chose to evaluate a Future Tech Proxy Unit that combined characteristics of multiple technologies so as not to favor any one technology type. The proxy unit was included in the system-wide model to identify a breakeven cost point for when an emerging technology unit would be selected.

The results indicate that such a unit is selected in 2030 (pending appropriate technological maturity) at approximately $2,000/kW direct construction cost and a fixed Operation and Maintenance (O&M) cost of $90/kW. Alternatively, the unit is selected in 2030 with a direct construction cost of $2,120/kW and a fixed O&M cost of $80/kW. The fixed O&M cost is tied to an assumed 2.5% inflation rate. The direct construction cost follows a slow-growing trajectory over the 20 years but is less than the inflation rate of 2.5%. When selected, the low-emissions and high-capacity factor unit replaces added wind and solar capacity.

EMERGING TECHNOLOGY WITHIN THE MISO FOOTPRINT

Several emerging technologies are vying to gain a foothold through pilot projects, development partnerships, and government support within the MISO region. Generally, capital costs for emerging technologies are often more expensive than existing technologies (Figure 42); fuel costs might also be more expensive than existing technologies, especially for hydrogen generation. The following section chronicles several emerging technologies that may break into the energy sector during the RRA time horizon.



Costs represent 2021 dollars from NREL's 2022 Annual Technology Baseline, with the exception of hydrogen, reported from Lazard's Levelized Cost of Hydrogen Analysis. Green hydrogen cost represents only electrolyzer costs and not generation, storage, or transportation costs.

Figure 42: 2021 capital cost of emerging and established technology ($/kW)

Nuclear Small Modular Reactors

Nuclear Small Modular Reactors (SMR) are generally defined as small units with up to 300 MW in power capacity, which is about a third of the capacity of a traditional nuclear unit. SMRs function like other nuclear reactors, but perform this task on a smaller scale, with individual units manufactured in a factory, and shipped to the project site as nearly complete units. Traditional, large-scale nuclear plants are one of the most expensive and longest to build generator technologies. Including the difficult and long permitting process, only one large-scale unit has come online in the U.S. in the last two decades. The standardization of SMRs offer a potentially cheaper unit, with shorter construction time, simpler permitting regime, and can be combined for additional output.

SMRs operate on a smaller project footprint compared to conventional nuclear plants, and their module configuration allows project adaptability for a variety of settings. For example, by repurposing existing transmission infrastructure and interconnection rights, retiring coal sites could see a second act by converting to the zero-carbon, SMR resource. When comparing to wind and solar, SMRs can generate far more energy on a smaller tract of land. SMRs could compliment generation from variable resources by providing flexible, load-following energy, as they are being developed to allow more operational flexibility than conventional nuclear facilities.

Globally, there are a handful of SMR pilots underway, but domestically, there is only one company with an approved SMR design with the Nuclear Regulatory Commission. Within the MISO region, there are no concrete plans to build any SMRs. However, several MISO Members are exploring the idea with a host of signed Memorandums of Understanding (MOUs) between load-serving entities, SMR developers, and research institutions. The one U.S. SMR pilot project is building six SMR units at the Idaho National Laboratory and has a completion date of 2029. Other companies are gaining international traction with pilot projects, MOUs, and developing SMR factories to decrease production costs.

Barriers to the widescale adoption of SMRs include substantially higher cost than other zero- or low-carbon energy sources and the relatively lengthy permitting time. SMRs and traditional nuclear facilities both face a public perception problem around safety. A recent Pew Research Center survey conducted prior to the War in Ukraine shows ambivalent views on nuclear where 35% of US adults think the federal government should encourage the production of nuclear power as compared to wind and solar at 72% .

Just like traditional nuclear plants, SMR projects must also safely manage their spent fuel. Because the U.S. does not currently reprocess or dispose of spent fuel in a permanent national repository, the material is often stored at individual plant sites. A recent study, found that certain types of SMRs produce 2 to 30 times more spent fuel by volume than conventional reactors, making SMR projects even more expensive to build when considering the costs for storage sites and over-all negative externalities. That said, the IRA provides $700 million to fund the reestablishment of domestic enrichment capabilities for future nuclear projects coupled with $2.5 billion from the IIJA for nuclear demonstration projects and $58 million for advanced nuclear research and development.

Carbon Capture, Utilization, and Storage

Carbon capture, utilization, and storage (CCUS) is a process intended to capture carbon dioxide at thermal generators or directly from the atmosphere and either use it (most likely for enhanced oil and gas recovery) or store it permanently underground. CCUS offers a potential solution to reduce carbon emissions while maintaining existing energy systems and infrastructure. CCUS technology can be applied to existing thermal power generation and carbon-intensive manufacturing, such as steel, iron, and cement. With a greater desire for low-carbon hydrogen production, CCUS may also support the growth of *blue hydrogen*, which is produced with natural gas (or coal) but leverages CCUS technology to lower the carbon intensity of the process.

Currently, there are three main approaches to generator carbon capture: post-combustion capture, pre-combustion capture, and oxy-fuel combustion capture. Once separated from other emissions, carbon dioxide gas is compressed, transported, and stored in underground geologic formations, such as depleted oil and gas reservoirs, saline reservoirs, or inaccessible coal seams. The gas is then used in enhanced oil recovery methods or sequestered permanently underground.

While CCUS technology has existed for roughly five decades, it has struggled to advance. The technology has not substantially declined in cost and continues to under-perform on promised removal rates. Even with government subsidies and alternative revenue streams, CCUS projects often fail to break even with costs. Another challenge is that generating units equipped with CCUS technology have high "parasitic load," meaning a significant fraction of a unit's electricity output is used to operate the carbon capturing equipment. Parasitic load can comprise 20% to 30% of energy output, drastically reducing revenue.

For more than a decade, the DOE funded CCUS research and pilot projects with few successes. According to a 2021 U.S. Government Accountability Office report, the DOE spent roughly $684 million on six coal CCS projects where only one project (Petra Nova) became operational and spent roughly $438 million on three industrial projects with two becoming operational. The one DOE funded project to become operational was the Petra Nova CCS project in Texas, which was touted as the world's largest carbon capture system combined with a coal-fired power plant but closed in late 2020 due to low oil prices. Currently, there are twelve CCUS projects operating in the U.S., which are primarily at natural gas processing or ethanol production facilities, according to the Global CCS Institute. Other than industrial facilities, no power plants in the U.S. have operational CCUS technology.

A shift occurred in 2021 when a record 51 new U.S. CCUS projects (three projects are at power plants) were announced following the 2021 federal IIJA, which expanded federal tax credits and provided more than $10 billion for carbon capture, direct storage, and industrial emissions reduction. The majority of these funds will be directed toward scaling existing technologies used for direct-air capture, CO_2 utilization, and other carbon management techniques. CCUS projects are further benefited by the passing of the IRA, which substantially increased the tax credit value of captured carbon oxides, included direct air capture as a qualifying project, extended the construction start date until 2032 for the 45Q credit, and reduced the emission eligibility threshold for CCUS qualification.

While the subsidies in the IIJA and the recently enacted IRA have resulted in a boon in CCUS ventures, the technology's success may be limited to specific sectors outside of the power sector. According to an S&P Global report, the levelized cost for CO_2 capture does not pass the break-even point for most CCUS facilities, with the exception of Gas Processing facilities coupled with carbon capture for storage. While there have been more announced projects after the IRA, few are for the power sector.

Ultimately, the high installation and operational costs for CCUS, coupled with the decrease in revenue from parasitic load, present challenges. Furthermore, choosing feasible sites for carbon storage and the potential for leakage and/or contaminating groundwater is another barrier to scaling CCUS technology. With numerous failed pilot projects, the high costs associated with capturing and transporting carbon oxides, and the regulatory uncertainty with sequestration; broad commercialization of CCUS may be limited over the next decade without technological breakthroughs or a price on carbon.

Hydrogen

Globally, hydrogen has gained attention as a low-carbon energy source with similar attributes to existing thermal generation. With the passing of the IRA and the promotion of regional Hydrogen Hubs from the federal government, the U.S. has seen a dramatic uptick in hydrogen interest. Hydrogen discussions are bifurcated into two processes: hydrogen production, which requires substantial power as a key input, and hydrogen power generation.

Hydrogen, usually as H_2, is the most abundant chemical substance in the universe. It is highly combustible and is used primarily as a component or catalyst in ammonia production, oil refining, methanol production, a fuel source in transportation, and other high-tech services. Electrolysis is the process of using electricity to split water into hydrogen and oxygen and the reaction takes place in a unit called an electrolyzer.

On the hydrogen production side, the interest is focused on the type of electricity used in the electrolysis process and the carbon intensity to produce hydrogen. The major contenders are: *green hydrogen*, produced from renewable energy sources; *blue hydrogen*, produced from natural gas or coal with CCUS capabilities; and *pink hydrogen*, produced with nuclear power. Most hydrogen is currently produced as *gray hydrogen*, which uses natural gas or coal without CCUS capabilities and is carbon intensive.

Hydrogen as an energy source can be deployed in two methods: in an electrochemical fuel cell and in a combustion generator. Even though hydrogen fuel cells produce minimal emissions (primarily water), the combustion method is likely the major pathway for MISO members given the relatively minor technological change from current thermal resources. Many view hydrogen power generation as a resource that can reliability support the grid when renewable generation cannot fully meet demand and provide flexible load services during large fluctuation events. However, while hydrogen power generation can be a low-carbon option, so long as the fuel source is low-carbon, it is not emissions free. Hydrogen combustion process may produce more nitrogen oxide (NO_X) than traditional natural gas facilities, especially when blended with natural gas.

Another hurdle for the adoption of hydrogen in the power sector is the lack of infrastructure for transportation and storage. Hydrogen is much lighter and less dense than methane, making it harder to store. While existing gas pipelines, freight shipping, and other infrastructure can be leveraged for hydrogen to some degree, it is not specifically designed to accommodate hydrogen. Existing gas infrastructure will require costly retrofits to limit leakage and accommodate hydrogen embrittlement. Although infrastructure limitations will prevent the rapid adoption of hydrogen as an energy resource in the short term, some MISO members are including hydrogen electrolyzers at future and existing plants, piloting hydrogen infusion into gas pipelines, and blending hydrogen into gas units over the next few years.

In 2021, DOE announced its Hydrogen Shot initiative, which aims to reduce the cost of *clean hydrogen* (hydrogen produced using any power source so long as the lifecycle greenhouse gas emissions are 4 $kgCO_2e/kgH_2$ or less) by 80%, or to $1/kg, in a decade. The IIJA provides $1.5 billion to fund clean hydrogen manufacturing and the IRA also provides tax credit of up to $3/kg for qualifying, low-carbon hydrogen projects. Allocated for $8 billion under the IIJA, the DOE's Regional Clean Hydrogen Hubs competition establishes six to ten regional clean hydrogen hubs. While the proposal date for hub concepts is after the publication of this report, several MISO members, states, and industry groups have made hub announcements including: the Heartland Hydrogen Hub (MN, MT, ND, WI), the Midwest Hydrogen Coalition (IL, IN, KY, MI, MN, OH, WI), HALO Hydrogen Hub (LA, OK, AR), Houston, Greater St. Louis, and Mississippi.

The ultimate cost of generating electricity with hydrogen is influenced by the availability and price of the energy used to produce the hydrogen fuel, including electrolyzers, hydrogen storage, and transportation. Hydrogen may have a promising future for reducing power sector carbon emissions while also providing the same services as existing thermal plants, but substantial infrastructure is needed before this approach is commercially and economically viable. As it stands, when accounting for the costs to produce, transport, store, and generate power; green hydrogen is substantially more expensive that other low-carbon resources.

Long-Duration Energy Storage

Long-duration energy storage (LDES) is advanced by many as a potential solution to challenging grid issues such as: system operations (frequency regulation, flexible ramping, black start services, peaking capacity, congestion relief, etc.), deferring transmission upgrades, and complementing variable generation (reduce curtailment, improve capacity accreditation).

Today, most utility-scale battery resources are capable of continuously discharging at full capacity levels around four hours or less. The DOE defines LDES as a storage resource with continuous discharge cycles of 10-plus hours. One of the main claims of adding LDES resources to the grid is the increased flexibility provided on a near-immediate timeframe. Storage attributes can help mitigate problems such as supply and demand forecast uncertainties, changing transmission flow patterns, and grid stability issues. When coupled with renewable generation, LDES resources have the potential to help MISO members achieve their decarbonization goals and decrease curtailments in oversupply situations.

Currently, Pumped Storage Hydropower is the only LDES technology that is commercially deployed at scale, comprising roughly 95% of the U.S.'s utility-scale storage and roughly 2.5 GW of installed capacity in the MISO region. All other LDES technologies are in pilot phases. A front runner in the general battery storage race are Lithium-ion (li-ion) batteries, which are commercially viable for utility-scale uses today. However, li-ion batteries are expensive to scale past four hours and therefore unlikely to be used for LDES.

Other LDES technologies currently exist only as small pilots, including iron-air batteries, compressed air energy storage (CAES), flow batteries, and hydrogen storage. While each storage type has various attributes and benefits, securing a cheap and steady supply chain of rare-earth metals and other materials is a major hurdle for commercial propagation. For Pumped Storage Hydropower and CAES, suitable locations, lengthy permitting, and shifting weather patterns limit viable locations.

In 2021, the DOE launched the Long Duration Storage Shot initiative, which aims to reduce the costs of 10-hour-plus storage by 90% within 10 years through grants, research, and loans. The IIJA allotted $505 million towards the new Long Duration Energy Storage for Everyone, Everywhere (LD ESEE) Initiative and the IRA allows for standalone storage projects to claim the federal investment tax credit. Despite the federal government's support and general technological advancements, certain LDES technologies are not likely to be cost-competitive with li-ion batteries in the near term as the costs and capabilities of li-ion batteries are improving rapidly. NREL forecasts that shorter-duration li-ion storage projects will continue to outpace longer-duration storage and account for most storage capacity into 2050.

Interactive RRA Tools and Additional Data

GENERATION RESOURCE PORTAL

MISO partnered with the software company JuiceBox on the development of a public, interactive, online portal to facilitate the RRA survey and host the Resource Assessment results.

Prior to the survey launch, the generation resource portal was pre-populated with data on existing generating units as compiled by the U.S. Energy Information Administration (EIA) (Figure 43). Stakeholders were asked to confirm or update the pre-populated data on their units. Members edited 500-plus units using the online portal, plus an additional 700-plus units using templates downloaded from the JuiceBox website.

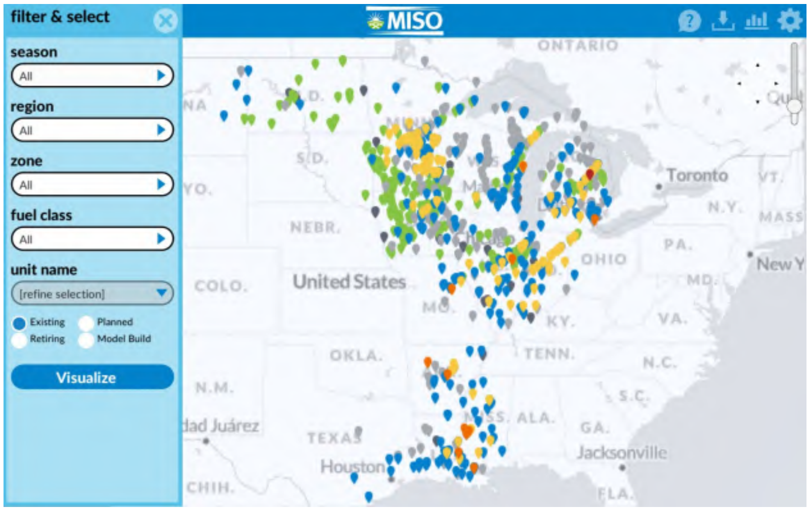


Figure 43: Screenshot of existing units in the Generation Resource Portal (JuiceBox)

Once MISO's expansion model was complete, the tool was updated to include planned and model-built units to provide users with an interactive way to view of the results of the 2022 RRA. Users can filter generators in various ways, such as by fuel type and their status: existing, retiring, planned, and model built. Information can be sorted by season, region, zone, and fuel class. The portal also creates graphic visualizations of what the region's forecasted future resource mix might look like in terms of generation (TWh), installed capacity by fuel type, and estimated production costs over time.

EMISSIONS DASHBOARD

MISO's pilot emissions dashboard displays historical emissions compiled from Energy Information Administration (EIA) and Environmental Protection Agency (EPA) data for the entire U.S. and future estimated emissions for the MISO footprint based on RRA simulations. MISO partnered with Singularity Energy, a data science and visualization company specializing in emission tracking, to create this interactive tool (Figure 44). The goal of the emissions dashboard is to enable MISO stakeholders to explore emissions trends by time period, fuel type, season, and LRZ, both historically and into the future using estimates based on the RRA results. The application will have periodic updates as public data from the EIA and EPA are processed.

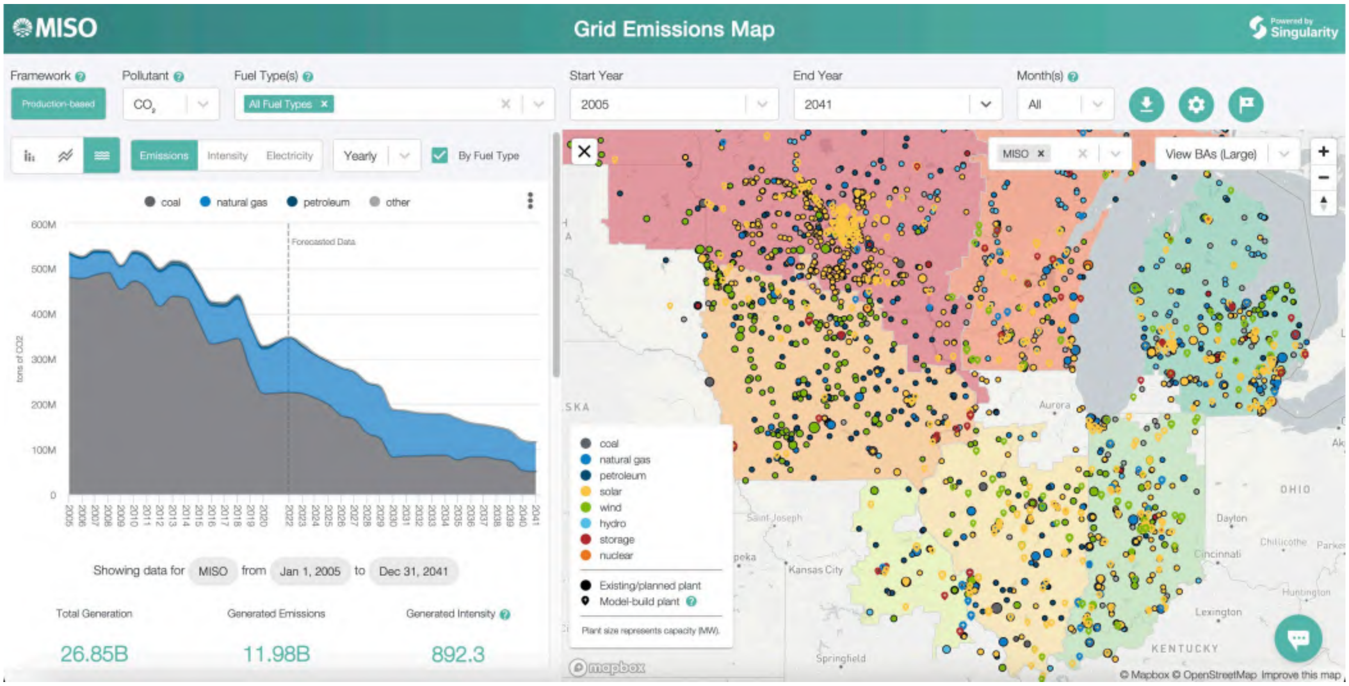


Figure 44: Screenshot of the emissions dashboard displaying RRA results

LRZ-LEVEL RESOURCE ASSESSMENT RESULTS

The 2022 Resource Assessment modeled each of MISO's 10 LRZs separately. MISO also published general assumptions and results for each LRZ, located on the RRA website.

Prepared assumptions include the Planning Reserve Margin for each LRZ, as well as peak load, carbon emission limits, minimum renewable energy goals; and installed capacity of publicly announced resource additions and the expected fleet by resource type for 2025, 2030, 2035, and 2040.

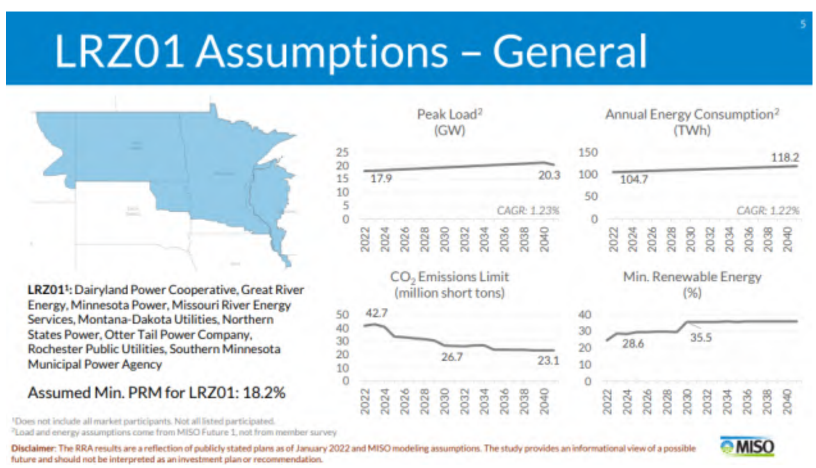


Figure 45: Example LRZ-Level assumptions

LRZ-level results include capacity by resource type, capacity compared to estimated required load plus reserve, energy share by resource type, emissions, and capacity and energy production gaps (Figure 45). As some LRZs are expected to experience a capacity shortfall in years different than the MISO footprint as a whole, the LRZ-level results provide helpful detail of the expected timing of the gaps discussed in this report.

SUPPLEMENTARY FLEXIBILITY ASSESSMENT RESULTS

The Flexibility Assessment considered variability needs for the MISO regions at multiple timescales (sub-hourly to multiple hours). A supplemental deck that includes additional visualizations beyond those shared in this report can be found on the RRA website.

RESOURCE ADEQUACY MODEL DATA AND INTERACTIVE SCATTERPLOTS

The Resource Adequacy analysis used the RRA Resource Assessment model and added fixed load to the system to reach the 1 day in 10 years loss of load expectation (LOLE). MISO prepared hourly dataset for 2031 and 2041 models, which are located on the RRA website. Datasets include expected unserved energy (EUE), loss of load (LOL) hours and frequency across outage samples, along with load, net load, renewable, battery, and hybrid (solar-plus-storage) generation.

Additionally, interactive scatter plots (Figure 46) show the generation of resources at any hour in the model, with LOL hours brightly highlighted for each season. As the user hovers over the dots, the plot indicates the hourly data behind the dot.

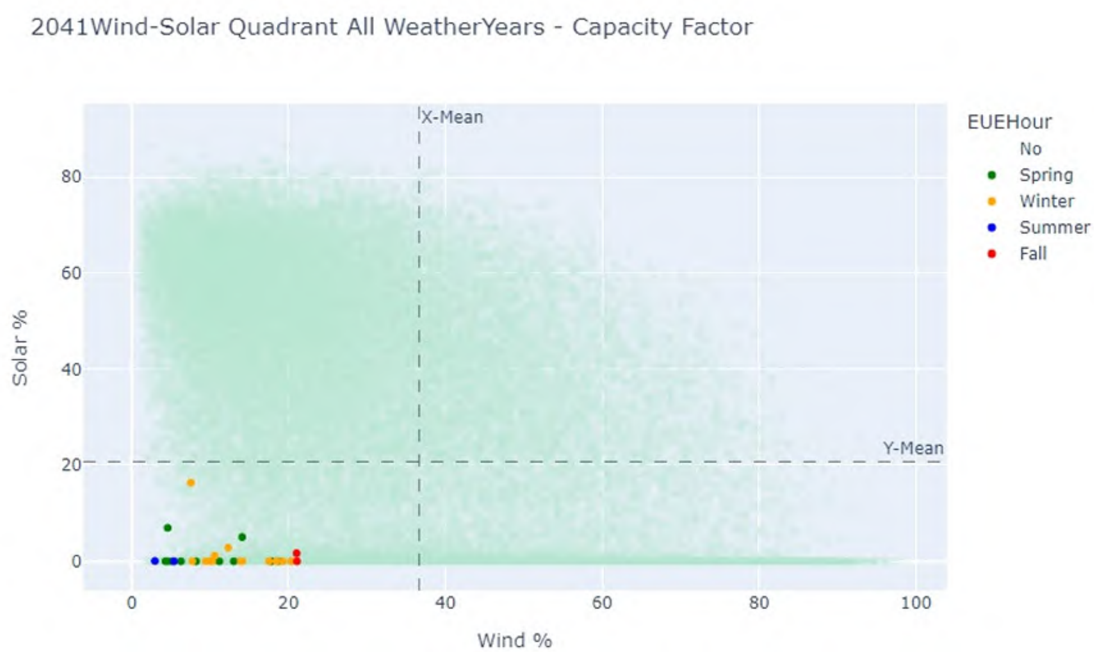


Figure 46: Example interactive scatterplot with hourly wind and solar generation

Next Steps and Future Scope

In preparation for future iterations of the RRA, MISO will once again invite members to share publicly available information about their resource plans and decarbonization/renewable energy goals by participating in the RRA survey tool. MISO anticipates launching the survey in early Q1, 2023.

MISO is weighing a number of options for the scope of the analysis in future iterations of the RRA. MISO welcomes ideas and engagement from members, states, and other stakeholders in this area. MISO encourages stakeholders to share their ideas at meetings of the Resource Adequacy Subcommittee (RASC), which has been the primary forum for discussing the RRA for the last two years. As previously discussed, the RRA is well-positioned to support MISO's new critical attributes initiative through data collection and analysis, and by providing insight into future system needs and timing considerations. Synergies between these two projects will be a priority focus with the next RRA iteration.

MISO would not be able to produce the RRA without the invaluable feedback and cooperation that MISO members and states have generously extended to this initiative. MISO realizes the RRA asks much of members and states, and that the transparency it provides may prompt tough questions that might otherwise go unasked. MISO appreciates members and states for their willingness to lean into the RRA, and hopes this engagement yields valuable insights that benefit everyone in the MISO region.

ATTACHMENT SEL-3

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY

ATTACHMENT SEL-4

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY