Technical Appendix: 2024 Regional Resource Assessment Assumptions and Methodology

MISO's Regional Resource Assessment (RRA) provides a collective view of the evolution of members' resource plans and aims to provide insights and implications that help members, states and MISO prepare for the energy transition. The 2024 Regional Resource Assessment (RRA) consists of several interdependent technical analyses, including a resource expansion assessment, resource adequacy assessment, and flexibility assessment. This Technical Appendix provides a detailed discussion of the RRA's analytical processes, data, and key modeling assumptions.

The RRA starts with a base model of the current MISO system (neglecting transmission), as of February 2024. It combines currently available public information with a Survey from member utilities to assess how the region's resource mix could evolve in the future. Because currently available public information does not account for all the new resources the region will need in future years, the RRA conducts a "Resource expansion" modeling to fill the gaps. This step uses PLEXOS, a computer optimization tool, to assess the fuel types, sizes, timing, and locations (at the local resource zone level) of additional resources utilities could build based on policy goals and reliability requirements.

The combined results of the Base and Resource expansion models are then used to conduct two types of analyses. A Flexibility Assessment is performed to examine the flexibility needs of the region given the increased capacity of weather-dependent renewables, such as wind and solar. This analysis investigates risks given the increased variability and uncertainty in future generation portfolios, as well as the changing diurnal and seasonal net-load patterns. Also, a Resource Adequacy assessment is performed to examine the adequacy of future generation portfolios and their ability to meet the established 1 day in 10 years loss-of-load expectation (LOLE) requirement and associated seasonal adequacy targets. Furthermore, this assessment studies the drivers of loss of load risk and calculates the seasonal capacity contribution of MISO resource classes (except load modifying resources). This year's RRA uses an iterative process with a LOLE calibration loop to incorporate key results from the resource adequacy assessment into a second iteration Resource expansion (See Figure 1) and test the robustness of the final resource portfolio.

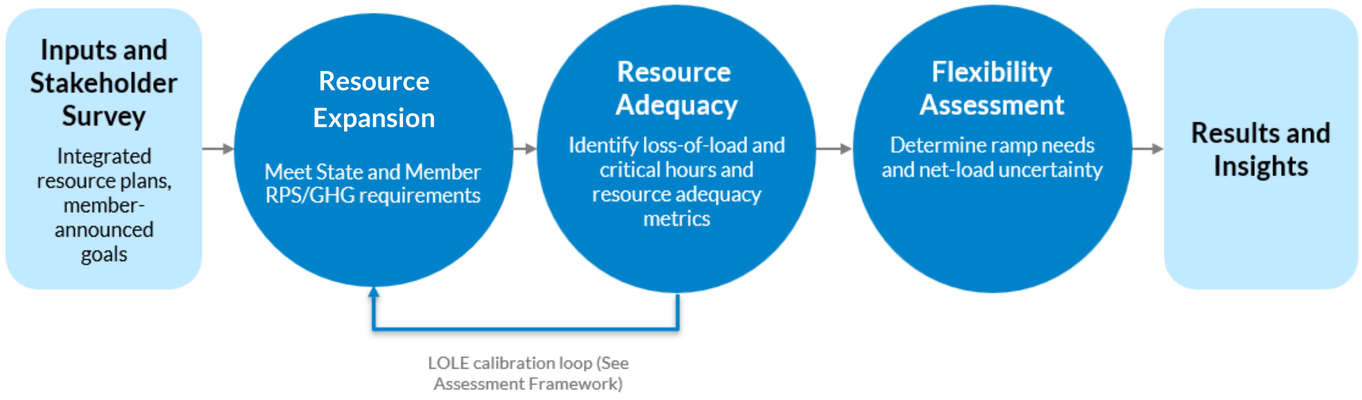

Figure 1: RRA process overview.

1. Assessment framework

Resource adequacy results are highly dependent on the resource portfolio resulting from the Resource expansion; however, the Resource expansion is also dependent on the accreditation estimates resulting from the resource adequacy assessment. The 2024 RRA incorporates a loss-of-load expectation (LOLE) calibration loop to accommodate the interdependency of the Resource expansion and resource adequacy analyses (Figure 2).

In the initial assessment (1), a Resource expansion is conducted using the "base" generation portfolio as a starting point and assuming legacy Planning Reserve Margin (PRMR) and Direct Loss of Load (DLOL) based accreditation values. An initial LOLE assessment is done on the resulting "intermediate" resource expansion, which include member plans and additional model builds. The calculated DLOL-based PRMR and DLOL-based accreditation values resulting from this initial LOLE assessment are fed into a second, and final, Resource expansion during the calibration loop (2)[1]. The final LOLE resource adequacy assessment is completed for study years 2030, 2033, and 2043 using the final Resource expansion; resulting in a final DLOL-based resource class accreditation and PRMR forecast output from the resource adequacy assessment (3). Results corresponding to the Flexibility and Resource Adequacy assessments in the 2024 RRA report are based on the final portfolio (3).

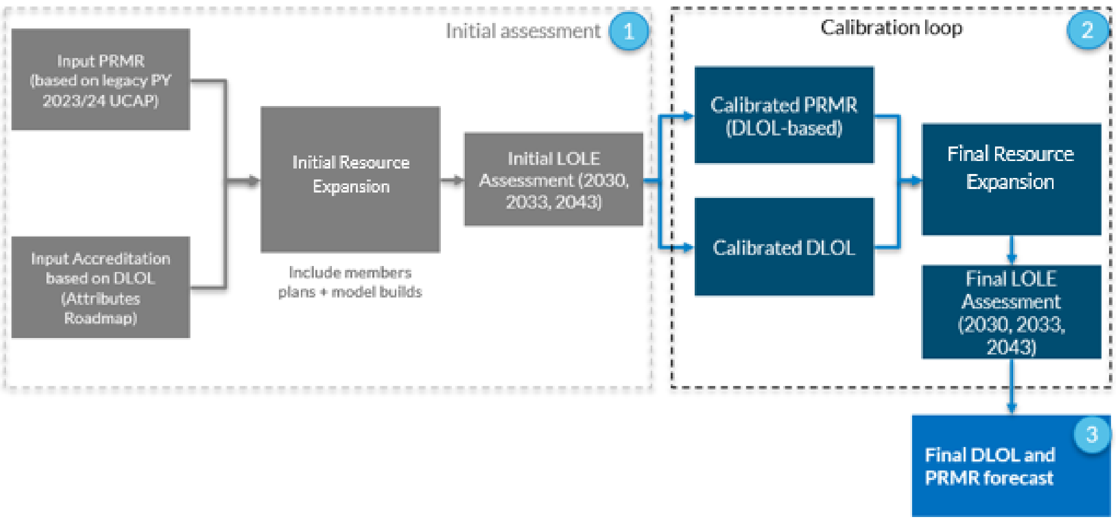

Figure 2. Resource Expansion and Resource Adequacy Calibration Loop

2. Study Period

The final Resource expansion was performed on a 20-year time planning horizon (2024 – 2043). However, given the RRA's focus on the longer-term horizon, reporting is limited to 2029 – 2043. Cumulative reporting for the Resource expansion in both the report and presentations include member planned and policy-driven[2] additions occurring before reporting period. Meanwhile, both the Resource expansion and flexibility assessment were conducted on select study years – 2030, 2033, and 2043. This selection is consistent with previous versions of the RRA (10- and 20- year out portfolios) and incorporates a mid-term perspective (2030) to provide an outlook closer to the DLOL implementation date.

[1] DLOL-based accreditation values as a function of installed capacity are developed and entered as inputs in the PLEXOS expansion model. PRMR is estimated using linear interpolation for the years in between (e.g., 2030-3031, 2033-3043).

[2] Policy-driven resources refer to computer-model simulation resources selected to fulfill anticipated renewable/carbon-free generation and decarbonization need resulting from member and state policy objectives.

3. Base System Model

Each iteration of the RRA starts with a base system model. It is comprised of the existing resources that MISO members have publicly announced they intend to utilize for all or some of the RRA's 20-year study period. The base system model also includes planned but not-yet-built resources that MISO considers to be "committed" or "planned" because they have signed Generator Interconnection Agreements (GIAs) or have been submitted to MISO as a part of the RRA survey.

3.1 RRA Survey

For the 2022 RRA, MISO created an interactive survey tool that members could use to submit information about their forward-looking resource plans, which was then updated for the 2024 RRA (MISO JuiceBox). The survey requested information on members' planned generation additions and retirements; load forecasts; and plans/goals to reduce their carbon emissions and/or to increase their use of renewable energy. Members could use the survey to submit information they had publicly announced prior to January 31, 2024. Any plans and goals that members announced after that date will be considered in future iterations of the RRA. Participation in the 2024 RRA survey was strong, with engagement from 41 MISO members, as shown in Figure 3.

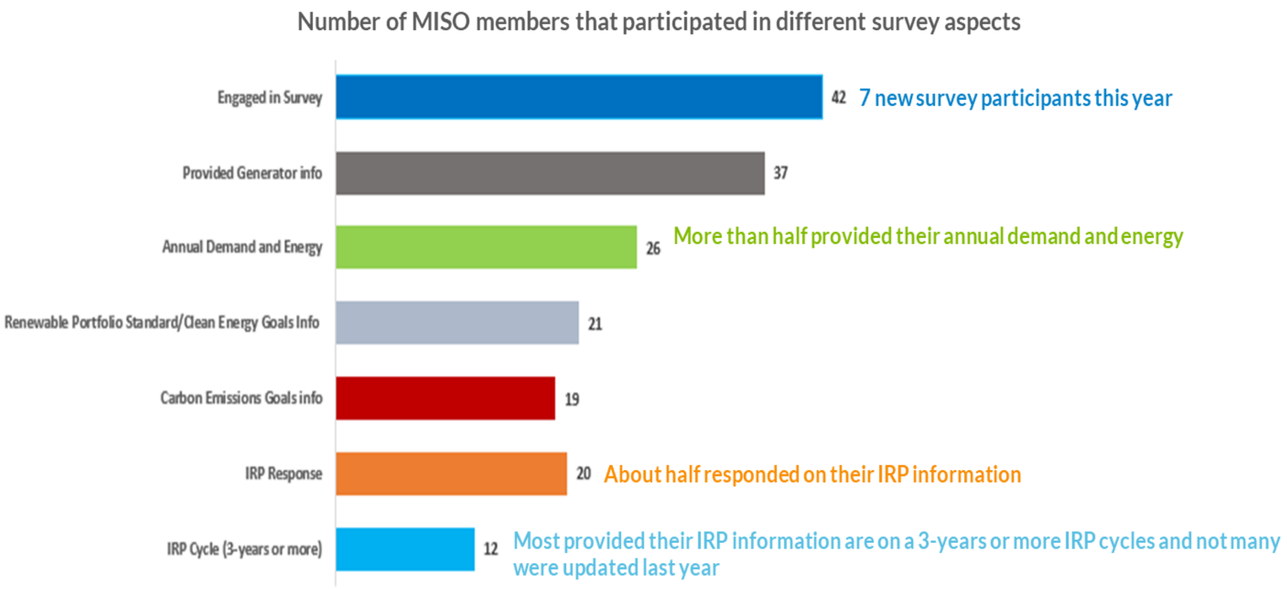

Figure 3: Number of MISO members that participated in different survey aspects.

3.2 Other Publicly Available Information

For the MISO members that did not participate in the survey, MISO used information collected through publicly available company plans, press releases, and other public means. In some cases, this included pulling information from the Integrated Resource Plans (IRPs) that some — though not all — MISO members are required to prepare for state regulatory agencies. An IRP may describe the type, location, and timing of new resources a member intends to build going forward. IRPs may also identify which existing resources a member intends to keep in service, and which resources it intends to retire.

4. Resource Expansion Modeling

Because publicly announced plans do not account for all the resources MISO members will need to build to reliably meet their goals for all 20 years of the RRA study period, MISO conducts a second major step in the RRA process is to utilize a capacity expansion model software, PLEXOS, to model which additional resources members may choose to build. Additional resources for the final 2024 RRA resource expansion were selected to fulfill member and state policy objectives not yet fulfilled by existing and planned resources, rather than for reliability purposes. Thus, they are referred to as "policy-driven" resources[3] throughout the 2024 report and technical appendix.

PLEXOS optimizes the types and sizes of resources that members may elect to build to reliably achieve their goals. PLEXOS modeling is combined with members' publicly available resource plans in the base system model to produce a comprehensive view of how the region's resource mix could evolve on a year-by-year basis over the course of 20 years. To fulfill the Planning Reserve Margin Requirements (PRMR) and any modeled carbon or renewable goals, PLEXOS selects between various unit types, including gas units (both combined-cycle and combustion turbine), utility-scale wind (inland), utility-scale solar (single axis tracking), and 4-hour battery. PLEXOS considers a full range of assumptions[4], constraints, and other factors when selecting resources to achieve the resource adequacy and policy objectives (Figure 4).

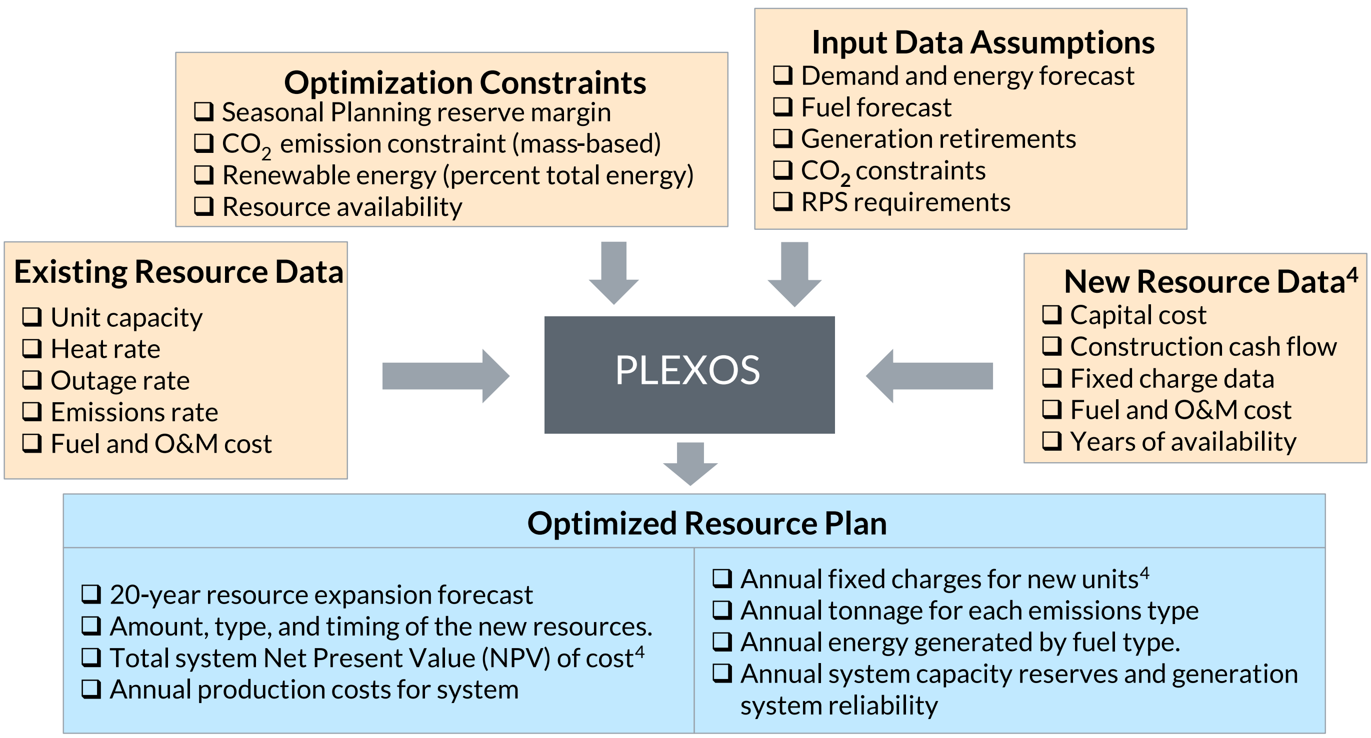

Figure 4: PLEXOS analysis inputs and outputs.

MISO will also use PLEXOS to develop the resource forecasts used in the [MISO Futures,](#) the forward-looking planning scenarios MISO and its stakeholders use for the transmission-planning process. Although some of the IRP

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[3] Policy-Driven resources refer to computer-model simulation resources selected to fulfill anticipated renewable/carbon free generation and decarbonization need resulting from member and state policy objectives.

[4] Capital costs are only assumed for computer-model simulation (policy-driven) resources. Member planned resources gathered from the RRA survey and other publicly available sources do not include capital cost assumptions given their investment decision is fixed within the model.

information and generator parameter assumptions in the base system model came out of the Futures process, the assumptions used in the Futures process differ in some respects from the assumptions used for the RRA's Resource expansion modeling. These differences include study years, costs, retirements, and renewable energy-production hourly profiles.

4.1 Seasonal construct and accreditation

The initial resource expansion utilized seasonal resource accreditation based on 2023 Attributes work that is a function of class-installed capacity. Thermal and Hydro resources were accredited based on their GADs forced outage rates multiplied by installed capacity. The final resource expansion utilized the calibrated direct loss of load (DLOL) % for wind, solar, and battery from the initial LOLE resource adequacy assessment (Left, Table 1). Final DLOL percentages were calculated in the final LOLE assessment following the final resource expansion (Right, Table 1). DLOL metrics of all fuel class except for Gas stayed stable between the initial LOLE resource adequacy and the final LOLE resource adequacy iterations.

		Initial LOLE Assessment – DLOL %					Final LOLE Assessment – DLOL %				
Resource Class	LOLE Study Year	ICAP (GW)	Spring	Summer	Fall	Winter	ICAP (GW)	Spring	Summer	Fall	Winter
Wind	2030	90	11	11	11	11	82	11	12	12	12
	2033	99	10	10	13	15	91	10	11	15	16
	2043	185	11	8	9	11	181	11	9	9	11
Solar	2030	64	3	5	3	1	74	2	4	2	1
	2033	75	3	5	4	0	85	2	4	3	0
	2043	134	1	2	1	0	140	1	2	1	0
4-hour Battery	2030	15	97	96	100	79	15	99	97	100	84
	2033	23	81	96	95	77	23	86	97	98	77
	2043	53	75	82	77	31	53	75	83	77	30

Table 1. Final resource expansion input DLOL % from initial LOLE resource adequacy assessment as a function of installed capacity (Left). Final and calibrated DLOL % from final LOLE resource adequacy assessment as a function of installed capacity (Right).

4.2 Additional Parameters utilized in the Resource expansion model

Unit-level heat rates and emission rates were leveraged from the PowerBase database, which is also used as the base for MISO's Futures work. Powerbase units were mapped to the RRA system model, consisting of existing and planned units identified in the 2024 survey. Existing units unable to be matched or planned units not in the PowerBase dataset were assigned averages based on fuel class, size, and age.

Table 2 outlines the detailed assumptions for all relevant parameters used in the Resource expansion models.

Table 2: Relevant parameters used in the Resource expansion models.

Area	Assumption
Scope	• MISO-level Resource expansion, with LRZ level computer-model simulation (policy-driven) candidates. Selection of LRZ-level candidates driven by policy objectives within each LRZ and renewable resource profiles. • Scope for the 2024 RRA differs from previous RRA cycles, given primary objective for 2024 is to provide MISO-wide DLOL PRMR and DLOL accreditation forecast. Previous cycles of the RRA performed 10 separate, LRZ level Resource expansions.

Study Period	• Model simulation period: 2024-2043. • Reporting Period: 2029 -2043.
Chronology	• PLEXOS allows for the use of sampled chronology to reflect realistic production cost impacts. • For the 2024 RRA, a 3 day per month sampling selection methodology was utilized. • Within PLEXOS, sampling is done statistically such that "like" periods are removed leaving a sample set that is representative of the variation in the original load.
Load Forecast	• Load growth assumptions match Future 2A (not member IRP assumptions). • Load files used non-coincident peak, net Energy Efficiency, and utility-incentive distributed generation (UDG), for each LRZ
Member Plans and Goals	• Includes publicly available member plans (through February 2024) for generation additions and retirements, derived primarily from stakeholder engagement in the RRA survey. • Assumes all renewable and emissions goals will be met at the year specified, legislated or non-legislated. Goals were modeled at the individual entity level (either load serving entity (LSE) or state). • **Note:** Renewable and emissions goals were not enforced until 2027, to allow for the model to solve given lead time assumed for installation of computer simulation policy-driven resources. • If IRPs include new resources in the next four years (i.e., by 2024), attempts were made to map those units to Generation Interconnection queue applications for capacity of a matching type and approximate location to avoid double-counting
Renewable or Carbon Free Energy Requirements	• RPS and CES goals were modeled at the individual entity (either load serving entity (LSE) or state) level. Overlapping goals allow for eligible generation to count towards multiple goals. I.e. eligible generation can count towards both a LSE and state goal. Eligible generation can count towards both a renewable portfolio standard and clean energy standard requirement. • Assumes entities will meet renewable energy requirements utilizing generators they own or PPAs they've identified as utilizing in the survey. Computer simulation policy-driven resources contribute to individual goals based on the entities' load ratio share. Resources located within a state count towards the State's goal, regardless of utility ownership. • Existing, committed, and generic units all contribute to renewable energy calculations. • Eligible technology differs from goal to goal, with some entities allowing biomass, hydroelectricity, and nuclear to count towards goal achievement along with wind and solar generation. • Goals are implemented as a percentage of annual energy production (not a percentage of capacity)
Carbon Trajectories	• Carbon reduction or intensity goals were modeled at the individual entity (either load serving entity (LSE) or state) level. • Mass-based limit was placed on collection of generators owned by either the individual LSE or located within the state of the specified goal. • Unlike previous rounds of the RRA, there was not a singular LRZ or MISO-wide limit. Generators not subject to a goal were left unconstrained. • Most emissions data was collected via the RRA survey • 2005 carbon baseline calculation, unless otherwise specified by the company: bottom-up aggregation of EPA unit data

	• The constraint is modeled as millions of tons of CO_2 • Stepwise trajectories were implemented unless member provided linear trajectory with intermediate milestone year values in RRA survey or via publicly available information.
Retirement Assumptions	• Retirement years submitted via survey were used; no additional retirement assumptions such as assumptions based on the age of a resource • All retirements assumed to occur on Dec. 31 of the year of announced retirement
Rated Capacity in Model (Thermal)	• Apply derates during summer months for thermal units.
Wind and Solar Profiles	• Historic wind and solar data from 2018 were used to generate hourly capacity factors for each resource. In PLEXOS these shapes are aggregated at the LRZ level to the same effect, to reduce calculation times needed for individual units. • In lieu of siting resources, the Future 2A geographic mix of wind and solar resources was assumed for RRA wind and solar hourly shapes.
Seasonal Reserve Capacity	• The initial resource expansion utilized seasonal resource accreditation based on 2023 Attributes work that is a function of class-installed capacity. • Thermal and Hydro resources were accredited based on their GADs forced outage rates multiplied by installed capacity. • The final resource expansion utilized the calibrated, seasonal direct loss of load (DLOL) % for wind, solar, and battery from the initial LOLE resource adequacy assessment. Table 1 shows the assumed input accreditation % for wind, solar, and battery as a function of installed capacity for the final resource expansion.
DER and DSM Programs	• Member-submitted distributed energy resources (DER)/demand-side management (DSM) programs and base-level DER assumptions from the Futures Refresh were both used in the model. • Energy Efficiency and UDG were netted from load; Demand Response (DR) and Distributed Generation Photovoltaic (DGPV) were included as generation resources.
Generating Unit and Base Model Unit Additions	• Interruptible loads were included (Direct Control Load Management (DCLM) units), extracted from PROMOD Futures model
Capital Costs	• 2023 NREL Annual Technology Baseline (ATB) with a 2024 base year

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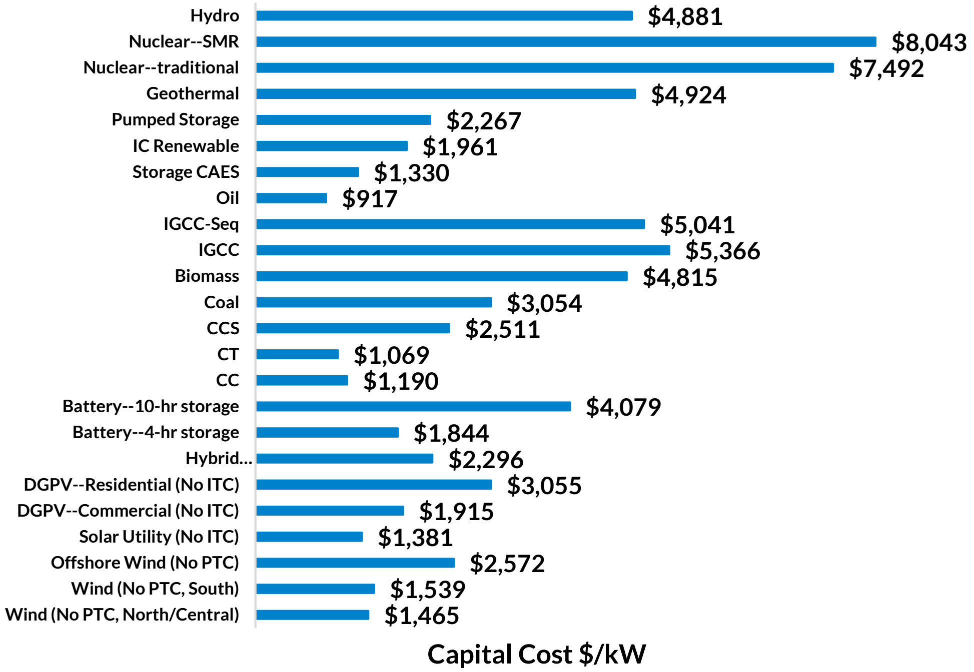
<tr><td></td><td>
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<tr><td>Fuel Costs</td><td>Natural gas prices were updated using the Q1 2024 Gas Pipeline Competition Model (GPCM).</td></tr>
<tr><td>Seasonal Planning Reserve Margin Requirements</td><td>The initial resource expansion utilized a seasonal PRMR based on PY2024-2025 UCAP, scaled to Future 2A load for the full 20-year study period.
The final resource expansion utilized the calibrated DLOL-based PRMR resulting from the initial LOLE resource adequacy assessment conducted on study years 2030,2033, and 2043. PRMR was linearly extrapolated for study years 2031-2032, and 2034 – 2042.</td></tr>
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5. Resource Adequacy Assessment Modeling

Resource adequacy analysis, as required by the North American Electric Reliability Council (NERC) Standard BAL-502-RFC-02[5], aims to ensure sufficient installed generation capacity to meet electric load, measured against a prescribed target. The objective of the resource adequacy analysis in the RRA is to understand how the risk of loss of load changes with the evolving resource mix over the next 10 and 20 years. The resource adequacy analysis in the RRA calculates the seasonal MISO-wide Planning Reserve Margin Requirement (PRMR) and DLOL based accreditation for all resource classes except LMRs.

The RRA LOLE analysis performs a Sequential Monte Carlo probabilistic simulation covering weather years 2007-2021, excluding 2013, to captures load and weather profiles correlations. MISO determines the adjustment to perfect capacity in the probabilistic model that would bring the MISO system to 1 day in 10 years LOLE target on an annual basis. When a season shows no risk, MISO then adjusts the season to a 0.01 LOLE. This process is defined in

[5] NERC, BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation. Available at: https://www.nerc.com/files/BAL-502-RFC-02.pdf

MISO's seasonal construct design, as detailed in the Planning year 2023-2024 Loss of Load Expectation Study Report[6].

5.1 Study Inputs and Assumptions

Resource Adequacy analysis was performed for the years 2030, 2033, and 2043— and the study inputs were aligned with the outputs from the Resource Expansion assessment (**Error! Reference source not found.**). The assumptions on the hourly load, renewable generation, generation outages and batteries are summarized in Table 3.

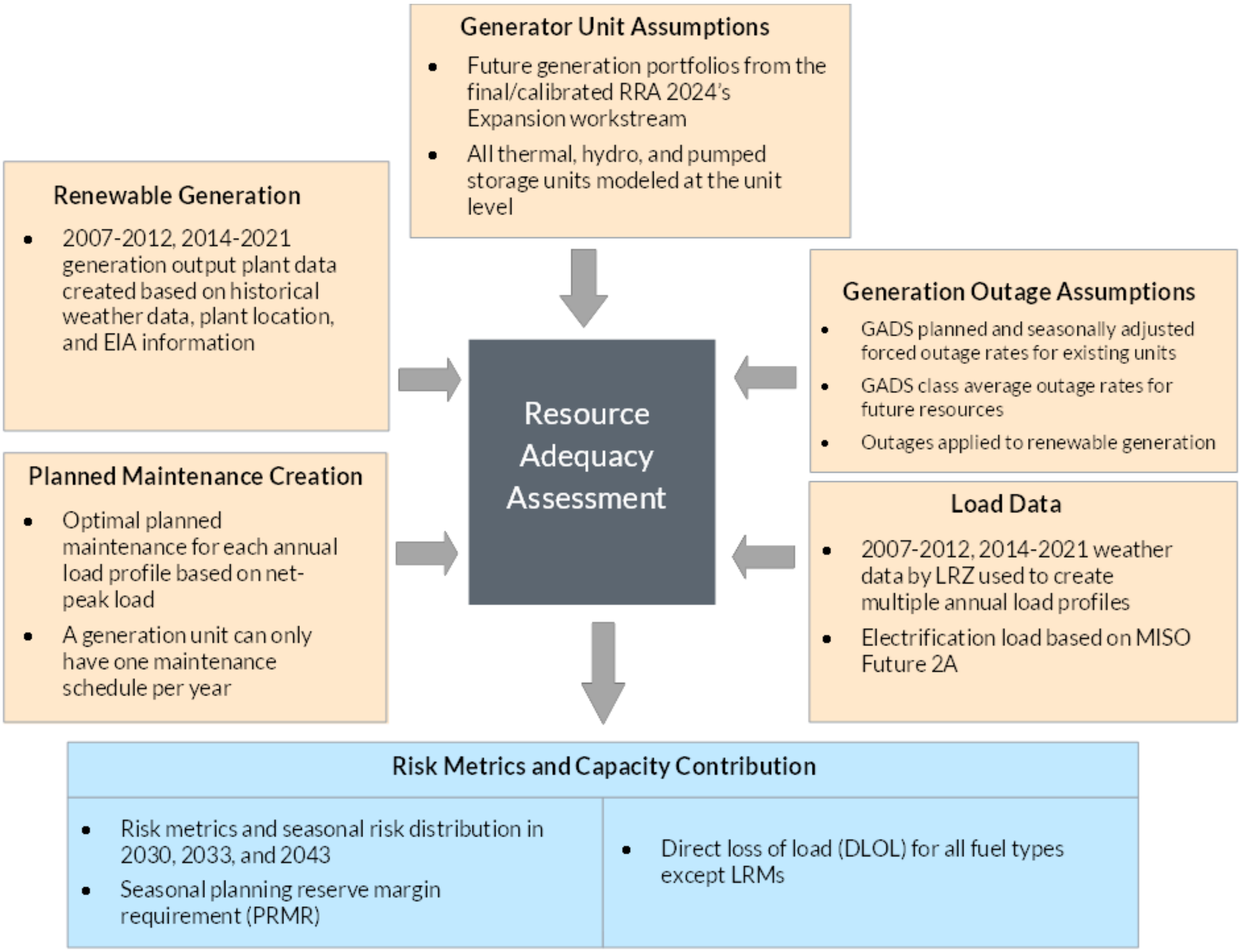

Figure 5: RRA Resource Adequacy analysis inputs and outputs

[6] https://cdn.misoenergy.org/PY 2023-2024 LOLE Study Report626798.pdf

Consideration	Assumption
Load	2007-2012; 2014-2021 weather data by LRZ used to create annual load profiles using the standard business practice associated with Resource Adequacy. Load forecast and electrification is included based on MISO Future 2A
Renewable energy production	Wind and solar profiles created using the NREL dataset for 2007-2012 and VCE dataset for 2014-2021. Wind and solar generation were aggregated by LRZ
Generator forced outages	NERC's Generating Availability Data System (GADS): existing units use planned and current seasonally adjusted forced outage rates; future thermal and renewable units use class-average outage rates
Gas and coal weather-dependent forced outages	Profiles of forced outage was generated for each weather year via linear regression. Temperature of the hour and installed capacity of generators were used in the regression as control variables.
Planned Maintenance	Planned maintenance schedules created for each weather year by optimizing the operating margin across all hours of the year, assuming perfect one-day foresight. The optimization uses a maintenance sculpting factor of 90%, which results in a strong bias of scheduling maintenance in periods of high-capacity reserves but still allows for some randomness with some maintenance outages occurring outside of the high-reserve periods

Table 3: Key Assumptions for the Resource Adequacy Analysis

5.2 Battery Modeling

Battery storage is modeled as a price-responsive aggregated unit, assuming a four-hour duration and an 85% roundtrip efficiency. Maximum charge and discharge capability is restricted to the nameplate capacity and the state of charge is carried over to the next day. The LOLE simulation assumes perfect foresight, extending the optimization window to 48 hours.

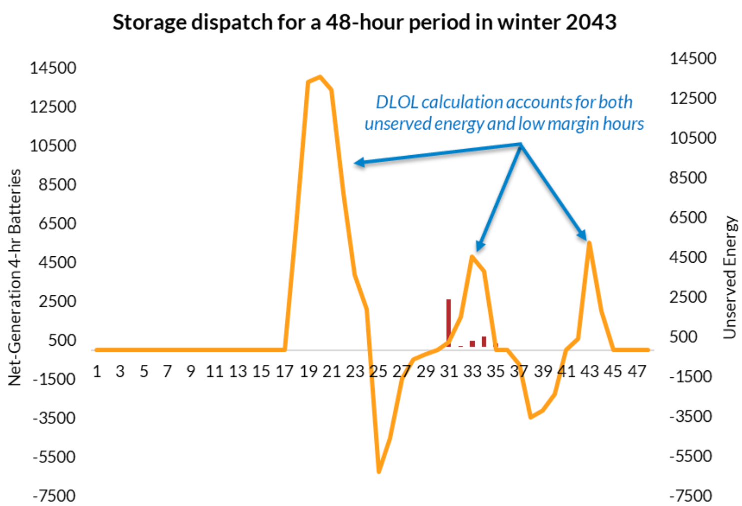

Figure 6: Sample battery dispatch in 2043

5.3 LOLE Feedback Loop Performance

Figure 7 illustrates the change in PRMR and DLOL based accreditation values between the iterations. PRMR metric suggests the iterative feedback loop minimizes the gap between the assumed and actual PRMR of the system. DLOL metrics of all fuel class except for Gas fuel class stayed stable between iterations. Due to the dispatch assumption of Gas relative to other fuel classes during the LOLE study, Gas fuel class accreditation was shown to be sensitive towards the difference in expansion of other fuel classes, particularly towards Battery's expansion.

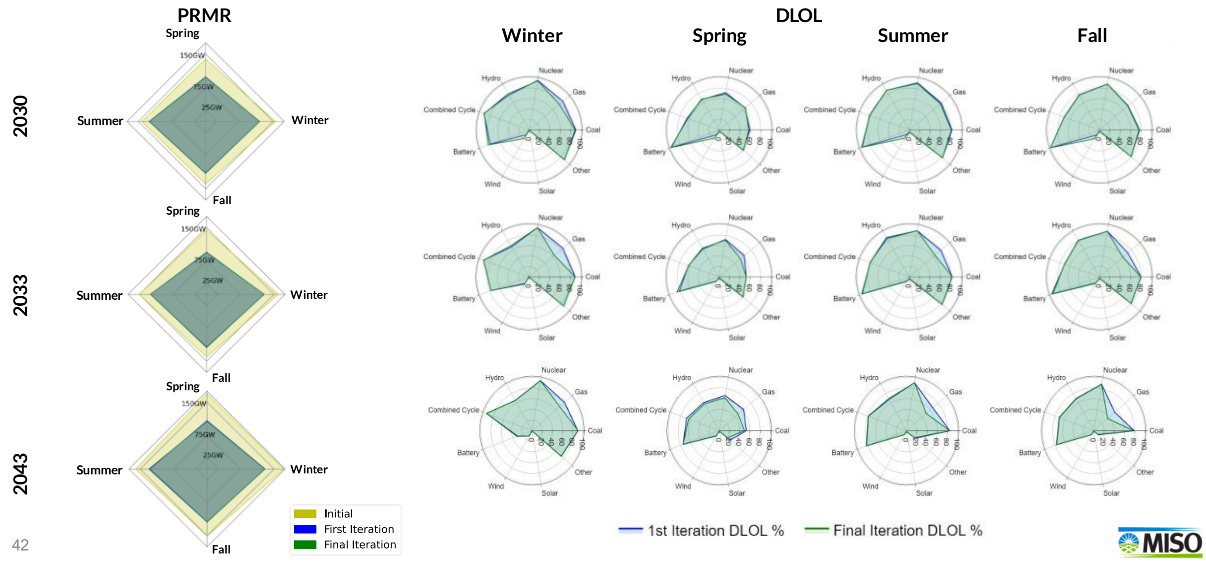

Figure 7 Comparison of PRMR of MISO region and DLOL per fuel class between first and final iteration of expansion to adequacy feedback loop.

5.4 Seasonal DLOL Results in Tabular Form

The final class-level DLOL results corresponding to future years 2030, 2033, and 2043 are included in Table 4.

Table 4: Seasonal DLOL Results

		Coal	Oil	Gas	Nuclear	Hydro	Combined Cycle	Battery	Wind	Solar	Other
2030	Spring	58	71	68	70	69	69	99	11	2	61
	Summer	83	80	82	91	90	89	97	12	4	83
	Fall	78	79	75	90	80	79	100	12	2	80
	Winter	87	80	79	94	94	92	84	12	1	89
2033	Spring	54	72	75	72	65	68	86	10	2	60
	Summer	85	80	87	91	89	87	97	11	4	83
	Fall	82	80	81	90	83	78	98	15	3	79
	Winter	87	80	84	95	94	93	77	16	0	87
2043	Spring	49	70	62	63	64	65	75	11	1	21
	Summer	88	82	85	92	90	88	83	9	2	21
	Fall	82	80	80	89	81	78	77	9	1	11
	Winter	88	80	82	94	91	92	30	11	0	75

6. Flexibility Assessment

The Flexibility Assessment work builds upon the generation expansion assessment conducted under the Resource expansion and calibrated in the Resource Adequacy assessment. First, historical data was collected comprising the MISO system load, as well as wind and solar production. Next, “actual” future profiles were generated for wind and solar units based on the work done under the Resource expansion. Data from MISO Future 2A was used to obtain projections of future “actual” load. Using assumptions, “forecast” load and renewable profiles were generated from the future “actual” load and renewable profiles for 2030, 2033 and 2043. All these elements were combined using data analytics and visualization techniques to answer key questions regarding system flexibility needs for future portfolios. Finally, the variability and uncertainty datasets were used to analyze the potentially stressed periods.

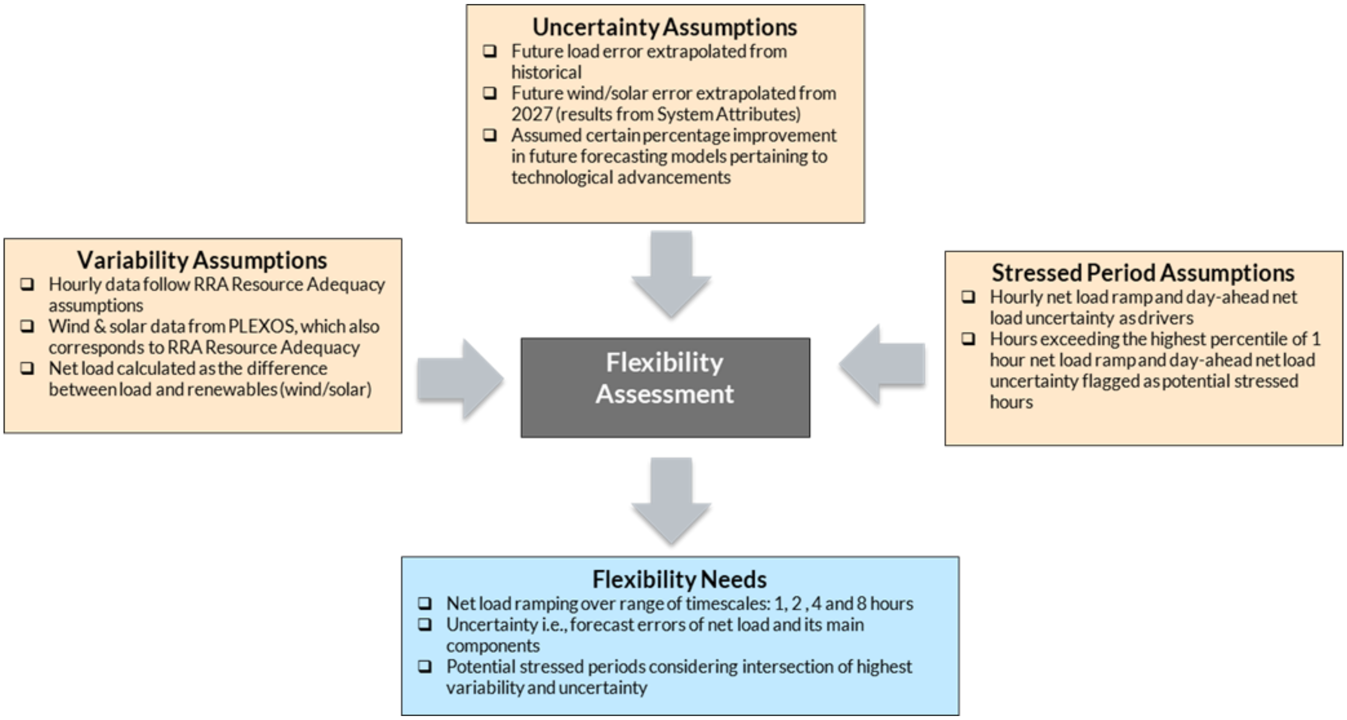

Figure 8: Flexibility Assessment key inputs and outputs.

The assumptions on the load, and renewables are summarized in Table 5.

Table 5: Methodology for Uncertainty Calculations

Consideration	Assumption
Future "Actual" Load	Using the 2018 weather year the historical LRZ-level load was normalized as the base shape. Then electrification data based on MISO Future 2A was added to create LRZ-level annual load profiles at hourly granularity for 2030, 2033 and 2043. Using historical LRZ to LBA load ratios, the LRZ-level load profiles were converted to LBA-level, and then aggregated to regions as well as systemwide.
Future "Forecast" Load	Future "Forecast" Load is generated by adding projected forecasting errors to the Future "Actual" Load. We assume while weather-related errors may persist in future years, the model-related errors can be reduced over time with improved technology. Hence, the total percentage errors in future assumes reduction in the modeling errors by 50%.
Renewable energy production	Historic wind and solar data from 2018 were used to generate hourly capacity factors for each resource. In PLEXOS these shapes are aggregated at the LRZ level to the same effect, to reduce calculation times needed for individual units. In lieu of siting resources, the Future 2A geographic mix of wind and solar resources was assumed for RRA wind and solar hourly shapes.
Renewable energy forecast	Renewable energy 6 hours ahead (6 HA) hourly forecast is generated by adding projected forecasting errors to the actual hourly renewable profiles. Then, historical DA/6 HA uncertainty ratio is used to get the DA renewable forecast.

The uncertainty analysis under flexibility assessment requires both actual and forecast profiles for load, wind, and solar components. This section describes the assumptions used in generating the DA and 6 HA profiles for each component. In this analysis two timeframes were considered: day-ahead (DA) and 6 hours ahead (6 HA).

6.1 Load Uncertainty: Steps and Assumptions for DA and 6 HA

MISO used the following approach to generate the hourly 6 HA and DA load forecast data for the future years. For $\boldsymbol{i = 1, 2, 3, \dots, 8760}$ hours -

1. The historical Day-ahead (DA) and Real-time (RT) datasets were used to calculate the *Total Error* in the historical load forecast.

$$DA\ Total\ Error(i) = \frac{RT\ Load(i) - DA\ Load(i)}{RT\ Load(i)} \tag{1.1}$$

2. A *back-cast (BC)* dataset was used which excludes the impacts of weather forecast errors from the load forecast model, and thereby providing the Model error.

$$DA\ Model\ Error(i) = \frac{RT\ Load(i) - BC\ Load(i)}{RT\ Load(i)} \tag{1.2}$$

- Assuming the forecast errors were additive, the weather error was calculated as the difference between the total error and the model error

$$DA\ Weather\ Error(i) = \text{DA}\ Total\ Error(i) - \text{DA}\ Model\ Error(i) \tag{1.3}$$

3. The average ratio of weather error's contribution to the total error is calculated as the DART ratio.

$$DART\ ratio = \frac{1}{8760}\sum_{i=1}^{8760}\frac{DA\ Weather\ Error(i)}{DA\ Total\ Error\ (i)} \tag{1.4}$$

4. Assuming the same DART ratio also applies to the 6 HA case, the 6 HA historical weather error and model error were obtained.

$$6\ HA\ Weather\ Error(i) = DART\ ratio \times 6\ HA\ Total\ Error(i) \tag{1.5}$$

$$6\ HA\ Model\ Error(i) = (1 - DART\ ratio) \times 6HA\ Total\ Error(i) \tag{1.6}$$

5. MISO assumed that in the future the weather error remains the same, while the model error could reduce by half due to improvements in forecasting techniques[7]. Thus, the total future DA and 6 HA load error is obtained using –

$$Future\ 6\ HA\ Load\ Total\ Error(i) = 6\ HA\ Weather\ Error(i) + 50\% \times 6\ HA\ Model\ Error(i) \tag{1.7}$$

$$Future\ DA\ Load\ Total\ Error(i) = DA\ Weather\ Error(i) + 50\% \times DA\ Model\ Error(i) \tag{1.8}$$

6. This total error % is applied to the future 'actual' load profile to get the 'forecast' for each of 8760 hours.

$$Future\ 6\ HA\ Load(i) = Future\ Actual\ Load(i) \times \big(1 - Future\ 6HA\ Load\ Total\ Error(i)\big) \tag{1.9}$$

$$Future\ DA\ Load(i) = Future\ Actual\ Load(i) \times \big(1 - Future\ DA\ Load\ Total\ Error(i)\big) \tag{1.10}$$

6.2 Wind/Solar Uncertainty: Steps and Assumptions for DA and 6 HA

The following steps and assumptions were used to create the 6 HA and DA forecast profiles for wind and solar.

1. Starting with the 6 HA wind and solar percentage errors calculated for 2027 as a part of the Systems Attributes study[8], MISO assumed that by 2030 and 2033, the forecasting technology will have slightly improved reducing the total percentage error by 5%. For 2043, MISO assumed that the total percentage error would reduce by 30 %. Thus, 95% of the 2027 total percentage errors is used to generate the wind and solar forecast data for 2030 and 2033, and 70% of it is used to generate these data for 2043.
2. For future DA wind and solar errors, MISO scaled the 6 HA errors using the ratios of the historical day-ahead error to the historical 6 HA error. For example, if in a particular hour of the year the historical 6 HA error is 3% and the historical DA error is 4%, then a scaling factor of 4/3 = 1.333 is applied to scale

[7] The 2022 RRA assumed the future DA model error reduction by 30% while the 6HA reduction by 50%. MISO Report Template

[8] MISO Attributes Roadmap Technical Appendix

the future 6 HA error to obtain the future DA error. A similar calculation is applied for each of the 8760 future hours in 2030 and 2033 to obtain the respective DA uncertainty profiles for the wind and solar.

6.3 Methodology for Stressed Period Analysis

Potential flexibility needs could arise during periods when high net load variability and forecast uncertainty occurs in the same operating hour. The flexibility assessment defines variability as net load ramp, and in this analysis the net load is defined as load minus wind minus solar. This analysis also defines uncertainty as the difference between real-time net load and day-ahead forecasted net load.

For each season and current/future year, the stressed period analysis screens each pair of net load variability and uncertainty of an operating hour and identifies hours of high net load variability and high forecast uncertainty as potential stressed periods as follows:

1. Find the hours with highest variability (net load ramp in GW/hour) considered to be the hours above the 95th percentile of net load variability
2. Find the hours with highest uncertainty (net load forecast error in GW) considered to be the hours above the 98th percentile of net load uncertainty
3. Among the hours identified in Step 1 and Step 2, find common hours and flag them as stressed hours.

6.4 Caveats of the Flexibility Assessment

Important caveats of 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.
- Sub-hourly flexibility analysis was not performed due to input data being at hourly granularity.
- Future 'forecast' load, wind and solar profiles were MISO-generated based on assumptions made on historical percentage errors.

7. Questions and Answers from the December Workshop

Additional questions that were asked during the December workshop are included in Table 6 together with MISO's responses.

Table 6: Q&A from the December Workshop

Question	Response
Slide 21. Why does DLOL accredited capacity in the Winter decrease between 2033 and 2043?	The sum of the accredited capacity (based on DLOL) is lower in the Winter of 2043 (vs. 2033) because of the reduction in 4-hr Battery accreditation. Slides 22, 25 and 40 include additional supporting material related to the Battery accreditation results.
Can someone send the link for the DLOL values all resources in 2025-2026?	PY 2025-2026 Indicative DLOL based Resource Class accreditation results
Would MISO consider a sensitivity analysis where storage dispatch prioritizes highest accreditation value first and energy arbitrage value as a secondary priority?	MISO staff will have a more focused discussion at RASC under *LOLE Modeling Enhancements - Storage Modeling*

What are the marginal resource defines the capacity prices in year 2030, 2033, and 2043? Are they 4-h Battery, CT or something else?	Capacity pricing forecast is out of scope in RRA.
It appears the battery shapes assume that batteries are being charged by solar generation during the day and then the batteries are discharged in the evening hours on the same day. Are batteries in the model allowed to charge today and then hold their charge for deployment on the next day? On the surface this appears to be the why the risk shifts to the morning hours in 2043.	Yes, battery carries over its energy charge from the previous day.
At slide 19 MISO shows 4-hr storage DLOL accreditation at ~25% for spring as of the present. I believe you suggested that this relatively low accreditation is attributable to shortage events with a long duration relative to storage duration. Under that explanation, doesn't 25% capacity credit for a 4-hour storage resource imply that the length of the risk events between recharging periods is something like 16 hours? This is difficult for me to reconcile with present-day operating conditions—I think present-day spring risk is probably mostly hot late-May weekdays, concentrated during 1600-2000 hours, or something similar, with significantly lower demand in other hours. Even when spring risk is on a cold March day we don't see such lengthy high-risk periods, and recharging should be easy in any hour outside of LOL risk with today's very low storage penetrations.	MISO staff will have a more focused discussion at RASC under *LOLE Modeling Enhancements - Storage Modeling*
Is there any kind of penalty on top of just covering round trip efficiency that drives the scheduling?	Storage "offer" price is assumed to be $0/MWh and there is no penalty on top.
Will the final RRA report break out the DLOL accreditation for gas and dual fuel gas separately?	No, because the information about dual fuel capabilities was not included in the RRA Survey.
Do the PLEXOS-derived DLOL values in the RRA align with the SERVM-derived DLOL values for Planning Year 2025-2026?	A high-level benchmark was performed in last year's Attributes work. Refer to Attributes Whitepaper for additional information
Is the members-only portfolio sufficient to meet reliability requirements?	The resource adequacy assessment focused on the final portfolio, which meets policy and reliability targets. Additional sensitivities related to the members-only portfolio were out of scope.
Since DLOL accreditation values for batteries seem to depend on how much solar is added going forward, can MISO provide a rule of thumb or any insights about how DLOL accreditation values for batteries could be impacted if a bunch of solar drops out of the queue?	MISO staff will have a more focused discussion at RASC under *LOLE Modeling Enhancements - Storage Modeling*
In slide 25, what are MISO's assumptions regarding how batteries will be dispatched? If dispatch is price-sensitive, what delta is MISO assuming between the cost of charging and the price to sell? Also, is there an assumption about line losses that impacts when batteries are dispatched?	Section 5.2 includes details about the dispatch assumptions of storage adopted in the 2024 RRA.