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Resource Accreditation in U.S. Resource Adequacy Mechanisms

Emerging Challenges and Solutions

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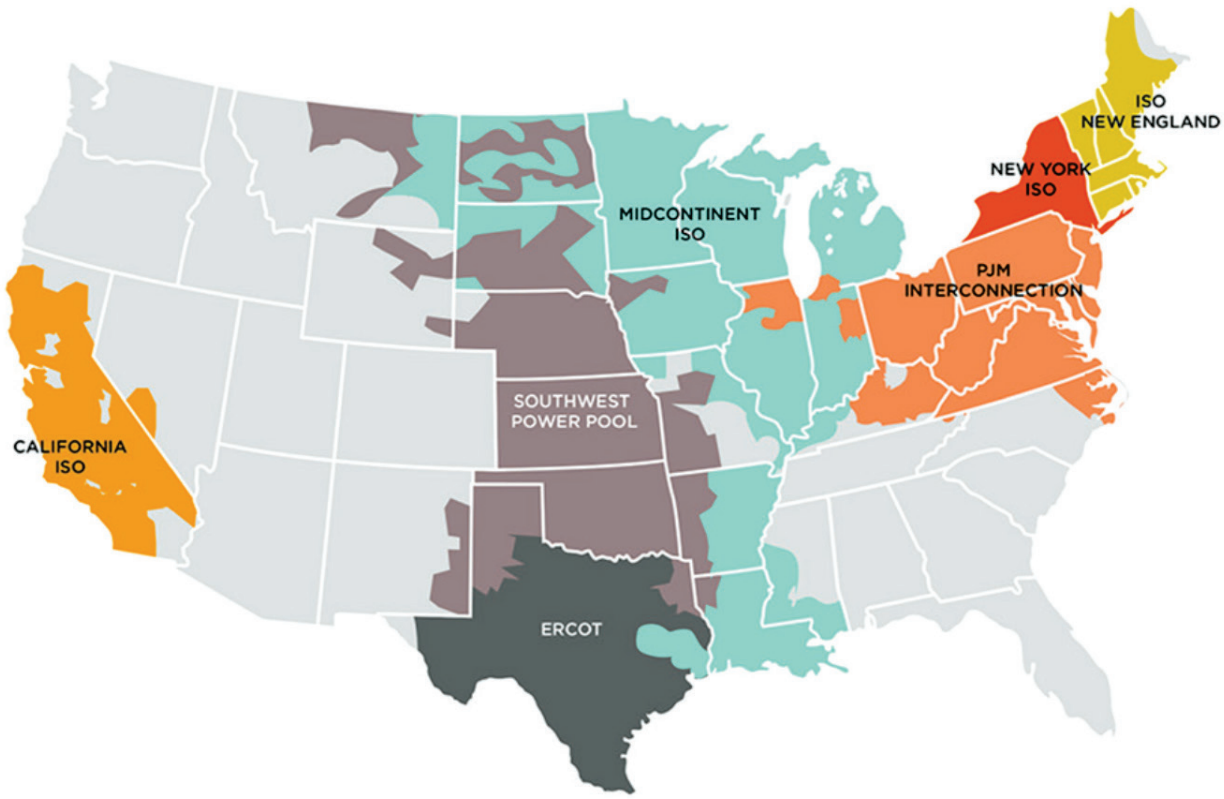
1. Introduction

Resource adequacy (RA) mechanisms in the U.S. are currently undergoing significant changes, to address several emerging challenges: an increase in extreme weather events, higher reliance on intermittent and energy-limited resources, retirement of older generation, and data center load growth. A key part of these changes is in how resources are credited toward RA needs ("resource accreditation").

This paper provides an overview of resource accreditation in U.S. RA mechanisms, the drivers behind recent changes in accreditation methods, and recent and forthcoming changes in resource accreditation in two regions: California and the Midcontinent Independent System Operator (MISO) region (see map, below). Other regions, including the PJM and ISO-NE regions, are also implementing major changes to their RA mechanisms, but California and MISO are most advanced in implementing changes to resource accreditation. The paper also discusses PJM's current approach to resource accreditation, as an illustration of a region that is currently considering changes in its RA mechanism.

Map of U.S. Independent System Operators



Source: https://www.ferc.gov/media/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission

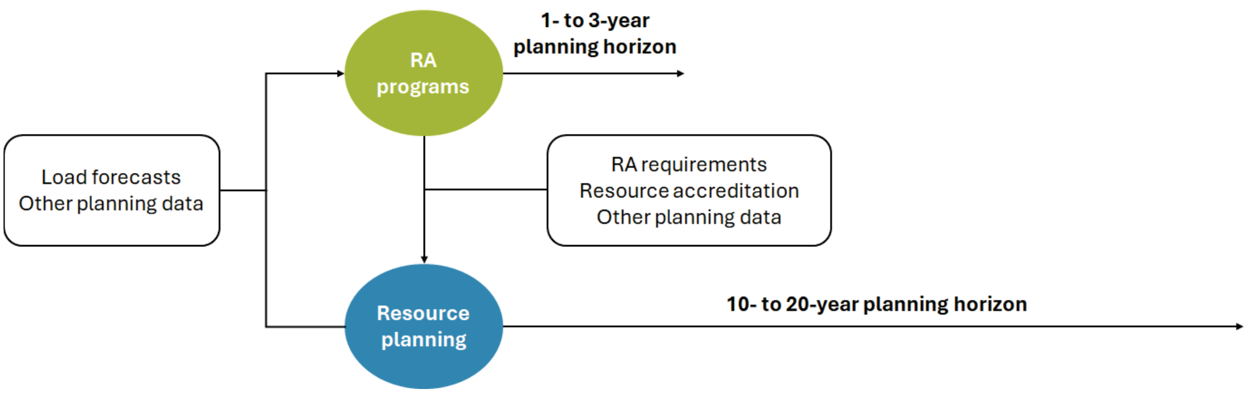
2. Background on RA Mechanisms and Resource Accreditation

Most U.S. regions – including six of the seven independent system operator (ISO) regions – have RA mechanisms. These mechanisms play an important role in supporting balance between supply and demand during infrequent periods when demand is high or energy resource availability is low.

In RA mechanisms, planners first determine the amount of resources needed to meet reliability targets and then allocate responsibility for meeting these targets, either directly as obligations or indirectly through the allocation of RA costs. To ensure that there are adequate resources to meet these targets, either: (a) government agencies or system operators require load serving entities (LSEs) to demonstrate that they have adequate reosurces to meet their share of total RA needs, or (b) system operators operate capacity markets to procure needed resources, or .

RA mechanisms have important interactions with LSE resource planning (Figure 1). RA mechanisms set RA requirements for LSEs and accredit resources, both of which LSEs use to determine if they will need to build or procure new resources. RA mechanisms often use LSE load forecasts and, in some cases, use LSE planning data. RA mechanisms tend to have shorter (1- to 3-year) planning horizons, whereas resource planning horizons may be as long as 20 years. This means that resource plans often need to develop longer-term forecasts of RA requirements and resource accreditation than are used in RA mechanisms.

Figure 1. Illustration of Interactions Between RA Mechanisms and Resource Planning

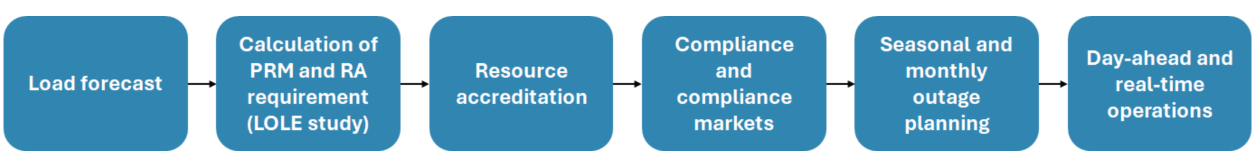


A key benefit of both RA mechanisms and resource plans is transparency. They determine whether local or regional electricity systems need new resources, how much different kinds of resources can be relied on for reliability, and the extent to which different regions can rely upon each other for reliability.

2.1 Overview of RA Mechanisms

Different regions have diverse approaches to RA program design, but the key steps in the RA process are similar across regions. These key steps include: load forecast, loss-of-load expectation (LOLE) study and planning reserve margin (PRM) setting, resource accreditation, compliance and compliance markets, seasonal and monthly outage planning, day-ahead and real-time operations (Figure 2).

Figure 2. Key Steps in RA Mechanisms



Planners use the load forecast and the PRM to determine annual, seasonal, or monthly RA requirements – the total amount of firm capacity in each time period needed to meet a reliability target. This RA requirement could be allocated directly to load serving entities (LSEs), as in California's RA mechanisms, or it could be used to clear a capacity market, as in ISO-NE, MISO, NYISO, and PJM's RA mechanisms.

Different kinds of resources contribute different levels of their nameplate capacity toward the RA requirement, based on their expected availability during periods of system stress. For instance, solar PV facilities will be mainly limited by available insolation, whereas coal generation facilities will be mainly limited by forced outages and, in some cases, fuel availability. To capture expected contributions to RA, planners use resource accreditation methods to credit different kinds of resources toward the RA requirement. The below box provides examples of RA requirement and capacity crediting calculations.

Example Resource Adequacy Calculations

Consider an electricity system that has forecasted summer peak demand of 10,000 MW and forecast peak transmission losses of 7%. The system operator conducts an LOLE study that indicates that system would need a PRM of 10%, in unforced capacity (UCAP)* terms, to meet an LOLE target of 1-day-in-10 years. The system's RA requirement will be 11,828 MW (= 10,000 MW / [1 – 0.07] × [1 + 0.10]).

The system operator runs a capacity market to procure adequate capacity. Resources are credited in the capacity market based on the system operator's accreditation studies. The system only has coal and wind resources. Coal generation units have an average forced outage rate of 5% and are credited at 0.95. Wind generation has an average output during peak demand periods of 0.2 MW per each 1 MW of installed capacity. Each 1,000 MW of coal capacity will count 950 MW toward the RA requirement (11,828 MW). Each 1,000 MW of wind will count 200 MW toward the requirement.

* UCAP is installed capacity (ICAP) adjusted for forced outage rates and generator availability. The relationship between ICAP and UCAP will be ICAP = UCAP × (1 – α), where α is the average forced outage rate and availability for all generators. PRMs could be based on ICAP or UCAP. PRMs based on ICAP will also incorporate availability for wind, solar, hydropower, energy storage, and demand response resources but will not incorporate forced outage rates. PRMs based on UCAP will be lower than those based on ICAP because UCAP incorporates forced outage rates.

2.2 Resource Accreditation

Historically, RA planners used one of three approaches for RA accreditation:

- **Average capacity factors**, in which resources are credited based on their average output during previous years' peak demand periods.
- **Exceedance probabilities**, in which resources are credited based on the probability that they will exceed a given level of output during peak demand periods.
- **Effective load carrying capability (ELCC)**, in which resources are credited based on the amount of additional load that they can "carry" while maintaining an LOLE target.

Illustrations of Different Resource Accreditation Methods

Average capacity factor method. In the past three years, an electricity system has had an average of 3,000 MW of installed wind generating capacity that generated an average of 467 MW during peak demand periods, defined as hour ending 15:00 to 19:00 during the five highest load days during summer months. The system operator gives wind a class average capacity credit of 0.156 (= 467 MW / 3,000 MW).

Exceedance probability method. A system operator uses a 70% exceedance probability to credit wind resources. Using five years of weather data, the system operator determines that, for each 1 MW of installed wind capacity, wind output would exceed 0.162 MW in 70% of time intervals during peak demand periods. The system operator gives wind a class average capacity credit of 0.162.

ELCC method. A system operator conducts an ELCC study using 10 years of weather data. The system operator's study finds that serving 1 MW of additional load while maintaining the LOLE (1-day-in-10 years) would require 6.33 MW of wind. The system operator gives wind a "class average" (given to all wind) capacity credit of 0.158 (= 1 MW / 6.33 MW). This is a marginal ELCC value.

Notes: These calculations are simplified for ease of understanding. In some cases calculations for each method will be region specific.

3. Emerging Challenges

The goal of RA planning is to ensure that adequate resources are available to meet demand in real-time operations. Effective RA planning thus requires that (1) the time periods used to calculate the RA requirement match up with the periods of real-time operational stress, and (2) accreditation of resources in planning approximately matches up with real-time availability of different resources. Changes in resource accreditation – and more broadly in RA mechanisms – in the U.S. are being driven by recent real-time operating experience, in which one or both of these conditions did not hold.

3.1 California's 2020 Heat Wave

In August 2020, California experienced a 1-in-30 year heat wave. During this event, demand for electricity exceeded supply and the California Independent System Operator (CAISO) was forced to institute rotating outages. In 2021, CAISO published a *Root Cause Analysis*,[1] which determined that the need for rotating outages was driven by three main factors:

- The PRM was too low and based on California's gross peak demand hours rather than its net peak hours.
- A significant amount of generation and demand response that was expected to be available, based on RA capacity credits, was not available.
- Operational challenges, including load forecast incentives and market software issues.

[1] CAISO, 2021, Root Cause Analysis Mid-August 2020 Extreme Heat Wave.

Even before this event, in 2020, California had begun to explore significant changes to its RA mechanism (see next section). Key lessons from California's experience were the need to better align: (a) planning and real-time operations, and (b) resource accreditation and actual resource performance.

3.2 MISO's Shift to Seasonal RA Concerns

Beginning in 2016, MISO recognized that an increasing large share – 60% between 2016 and 2021 – of its "max gen" events were occurring outside of its summer peak months.[2] Max gen events are emergency events in which reserve margins are low and MISO requires "maximum generation" from all available sources to avoid load outages. Because MISO's RA mechanism was designed to meet summer peak load, this meant that the RA mechanism was not addressing the correct periods of RA concern.

MISO cited four main factors that were behind this mismatch between MISO's summer peak-focused RA mechanism and its emerging RA challenges:

- Retirement of traditional, baseload generation
- Planned and forced outages in non-summer months
- Increased reliance on intermittent generation, and
- An increase in extreme weather events.[3]

A particular concern for MISO was that resources that had received RA credits did not perform during real-time emergencies due to planned outages. MISO began a shift to a seasonal RA construct, with a greater emphasis on performance, in 2022 to address these issues (see next section). As in California, MISO's concerns highlighted the need for RA mechanisms to better align: (a) planning and real-time operations, and (b) resource accreditation and actual resource performance.

4. Emerging Solutions

4.1 California Slice of Day Method

California began to explore to a new approach to resource accreditation in 2020, in response to concerns over the implications of a continued shift to energy-limited resources and potential retirements of thermal resources. In 2022, the California Public Utilities Commission (CPUC), which oversees the state's RA mechanism, adopted a "slice of day" (SOD) method for crediting resources and demonstrating compliance with RA obligations.

Under the SOD method, LSEs must demonstrate that they have adequate resources under contract to meet their RA obligations for each hour of the "worst day" in each month. The worst day is defined as the day with the highest forecasted gross coincident peak (CP) demand in each month. RA obligations are defined as an LSE's share of forecasted coincident peak demand plus a PRM in each hour.
The SOD methodology for crediting resources continues to use the CPUC's two-step approach. In the first step, the CPUC calculates the qualifying capacity (QC) of different resource types. QC calculations under the SOD are significantly different than the CPUC's previous approach, in

[2] See FERC's approval of MISO's proposed seasonal RA construct.
[3] *Ibid*.

part because resource credits must be calculated for 288 hours (= 12 months × 24 horus), consistent with the “worst day” framework.

The CPUC’s methods for calculating the QC of different resource types under the SOD are as follows.

- **Wind and solar resources.** Wind and solar resource credits for each hour are based on a 70% exceedance probability. Exceedance probability calculations use six years of historical data and vary by resource zone.
- **Dispatchable resources.** Dispatchable resources are credited at maximum output (Pmax).[4]
- **Hydropower resources.** Hydropower credits are based on historical average hydro availability during periods of system stress.[5]
- **Energy storage resources.** Energy storage resources are credited based on the level at which the resource is able to discharge for four or more consecutive hours, but their RA value is mainly in being able to shift generation over the course of the day (see below).
- **Hybrid resources.** Hybrid resources are credited based on the sum of the QC values of the individual resources.[6]
- **Demand response resources.** Demand response resources are credited based on their contracted availability during four consecutive hours in peak demand periods.
- **Imports.** Imports are credited based on either (a) resource-specific values that are the same as within-state resources, or (b) non-resource-specific contracted capacity that can perform for at least four hours.[7]

The second step in the CPUC’s methodology de-rates the QC values to net QC (NQC) values. Derates can occur if either the tested or deliverable capacity is less than the QC value. Deliverable capacity refers to transmission deliverability – the ability to deliver a resource to system loads over the transmission system during peak demand periods. If a generation owner requests deliverability during interconnection, CAISO determines through studies whether any transmission upgrades will be necessary to deliver the generator’s output and initially charges the owner for those upgrades, refunding the charges to the owner over time.

Generation owners can also choose to be deliverable at less than their maximum QC value, for instance if transmission charges would be excessively high, in which case the CAISO would also derate their QC value.

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[4] Maximum output is determined by CAISO through testing.

[5] QCs for dispatchable hydropower are based on the amount of capacity bid or self-scheduled into the CAISO market during the CAISO’s availability assessment hours over the past 10 years, discounting mechanical derates. Using these values, the CPUC then calculates 50% and 10% exceedance probabilities for each month. The final QC for hydro is a weighted average of 80% of the 50% exceedance probability and 20% of the 10% exceedance probability. See the CPUC’s *2020 Qualifying Capacity Methodology Manual* for more detail.

[6] For instance, a solar PV plus battery hybrid resource would be credited based on the sum of the individual solar PV and battery QC values.

[7] For more methods for individual resources, see the CPUC’s *2026 Resource Adequacy and Slice of Day Guide*.

LSEs are required to demonstrate compliance with the CPUC's RA mechanism in regular "showings." In October of the year before the compliance year, LSEs are required to demonstrate compliance with 90% of their monthly RA obligations for the next year. Forty-five days before each month, LSEs must show compliance with 100% of system RA obligations.[8] Failure to show compliance results in penalties on the LSE. Previously, LSE showings were a simple accounting of whether the sum of an LSE's credited resources was equal to or exceeded its share of CP demand plus the PRM. Under SOD, LSEs must show credited resources (non-storage) and dispatch of energy storage over the course of forecasted CP days in each month. This requirement for storage dispatch ensures that portfolios have adequate projected capacity and energy over the compliance days.

The figure below shows an illustrative example for an August (peak month) showing. In this example, an LSE in northern California has a 2,000 MW peak demand (August) and meets its RA obligations using a combination of natural gas generation (800 MW), solar PV generation (1,500 MW), wind generation (1,500 MW), and battery storage (800 MW). The load charges its battery with excess solar PV NQC during the morning and early morning afternoon hours. The battery storage covers the portion of the LSE's demand in the morning and evening hours when solar availability is low or zero. The LSE must cover both its load and storage charging. Unlike the CPUC's previous method, SOD thus explicitly accounts for energy limits in energy storage resources.

Figure 3. Illustrative Slice of Day Showing that Meets RA Obligations

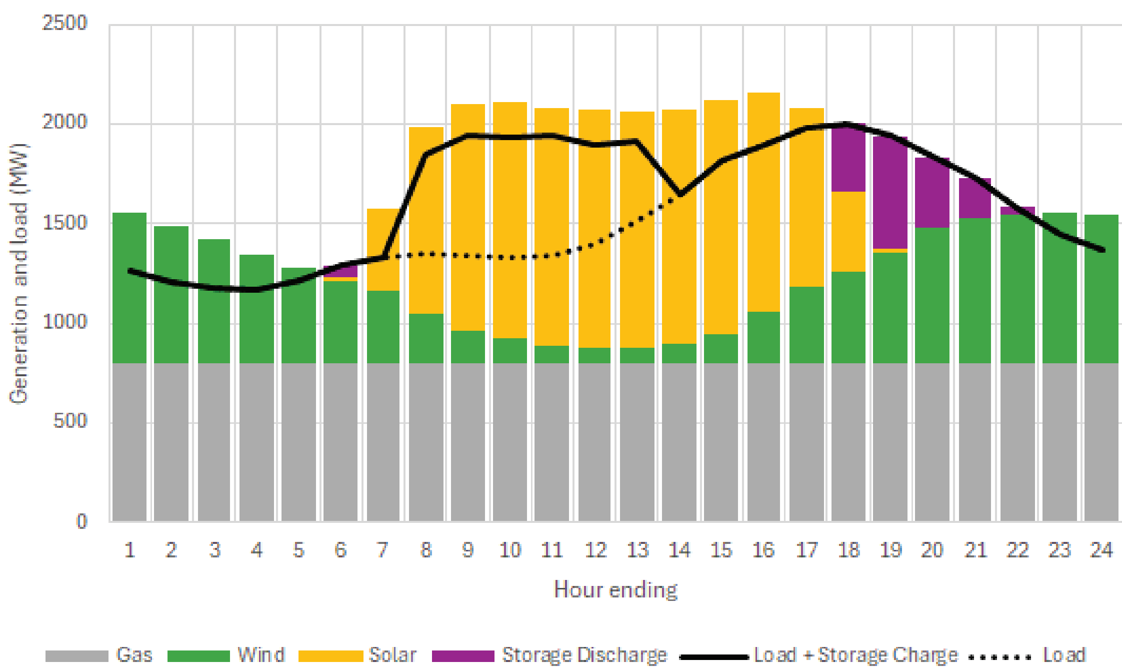

Figure sources and notes: Load profile is based on California Energy Commission forecasts of PGE's hourly average load profile for its zonal peak demand (August 20) in 2025. Solar and wind NQC values are based on the CPUC's VER exceedance profiles for "solar tracking" and "wind" for August (Norcal zone). This portfolio is meant to be illustrative; it is not optimized.

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[8] LSEs must also demonstrate compliance with local RA requirements. For more on compliance requirements, see the CPUC's Resource Adequacy Homepage.

Under CAISO rules, accredited resources have a must-offer obligation (MOO) in the CAISO markets. The MOO provides a bridge between resource accreditation, which is part of planning, and real-time operations.

4.2 MISO's Seasonal RA Construct

MISO began to transition to a seasonal RA construct in 2022, to address the emerging challenges discussed in the previous section. MISO's seasonal RA construct has four seasons (summer, fall, winter, spring) and includes:

- Seasonal PRMs and RA requirements
- Seasonal crediting for resources
- Shift to more of a performance-based approach to crediting resources.[9]

MISO's prior approach to resource accreditation had used different methods for different resources: forced outage rates for thermal, ELCC for wind, Pmax for storage, average capacity factor for solar PV. Under the seasonal RA construct, MISO is developing a consistent methodology – the direct loss-of-load (DLOL) method – for crediting all resources.

The DLOL method includes two components: (1) a seasonal resource class-level average unforced capacity (UCAP) value, based on expected average availability for different resource technology types; and (2) a seasonal unit-level performance-based component based on the ratio of each individual resource's performance to the average performance of similar resources during periods of system stress. "Class" refers to resource class – for instance, batteries, biomass, coal, gas turbines, geothermal, reservoir hydro, run-of-river hydro, nuclear, oil, onshore wind, offshore wind, pumped hydro, fixed solar PV, tracking solar PV, and solar thermal

Figure 4. Two Components of MISO's Direct Loss-of-Load (DLOL) Method for Resource Accreditation

The seasonal class average UCAP component (1) of DLOL is based on MISO's simulations of system operations and resource performance during "critical hours." MISO uses 30 years of correlated load and weather data to perform these simulations. It defines critical hours as hours with unserved energy (lost load) or low (< 3%) operating reserve margins, with a maximum of 65 hours per season (~3% of hours) per weather year (1,950 total hours = 65 hours × 30 weather years).

[9] For more on MISO's approach to calculating seasonal PRMs and RA requirements, see MISO's *Planning Year 2026-2027 Loss of Load Expectation Study Initial Report*.

The class average UCAP values for different resource types are based on a resource type's average availability during critical hours, weighted by the severity of reserve scarcity and load forecast error. Load forecast error is included in the weighting to provide more value to hours in which hours in which historical load forecast error has been high. The box below provides more detail on MISO's weighting calculations and illustrative examples.

MISO's Weighting Calculations for DLOL and Illustrative Examples

MISO calculates weightings for class average DLOL values by first calculating an hourly effective margin (EM_h), defined as the maximum margin among the critical hours in each season minus the margin in each critical hour, or $EM_h = \max(M) - m_h$, where M is a vector with the critical hour margins and m_h is the margin in each hour. The final weighting is done by multiplying effective margins by hourly load forecast error probabilities [$P(\varepsilon)_h$] and dividing by sum of weights, or $W_h = \frac{P(\varepsilon)_h \times EM_h}{\sum_h P(\varepsilon)_h \times EM_h}$.

As a simple example of these calculations, consider a scenario with three* critical hours and 1%, 2%, and 3% margins in each hour. The maximum margin is 3% and the EMh values are 2%, 1% and 0% (= 3% - 1%, 3% - 2%, and 3% - 3%). If the load forecast errors in each hour are 2%, all with an equal probability of occurring, the weighting for the first hour will be $W_1 = \frac{2\% \times 2\%}{2\% \times 2\% + 2\% \times 1\% + 2\% \times 0\%} = 67\%$, $W_2 = \frac{2\% \times 1\%}{2\% \times 2\% + 2\% \times 1\% + 2\% \times 0\%} = 33\%$, $W_3 = \frac{2\% \times 0\%}{2\% \times 2\% + 2\% \times 1\% + 2\% \times 0\%} = 0\%$.

MISO applies the weightings to average simulated output during critical hours. If average output for wind in these three hours was 100 MW, 150 MW, and 200 MW and installed wind capacity included in the simulations was 800 MW, the class average UCAP capacity credit for wind would be 0.146 (= [67% × 100 MW + 33% × 150 MW + 0% × 200 MW] / 800 MW).

* As described in the text, MISO's analysis will include significantly more than three hours and is done for each season. The calculations here are only intended to be illustrative.

The seasonal performance-based component (2) of DLOL is a ratio based on (a) each individual resource's performance in real-time markets over the past three years during "RA hours," and (b) the average performance of all resources of that resource type (class) during RA hours. MISO calls both of these values 'interim seasonal accredited capacity' (ISAC); the ratio between them is the ISAC ratio.

MISO defines RA hours as hours in which it declares Max Gen events (system emergencies) or hours in which it has operating reserve margins of less than 25%, up to 65 hours (3% of hours) per season.[10] MISO calculates individual ISAC (a, the numerator) using the average offered capacity (MW) in MISO's real-time market during RA hours and non-RA hours over the previous three years, with an 80% weight on RA hours and a 20% weight on non-RA hours. For new resources or resources that do not have three years of historical data, MISO applies estimates of average ISAC values for each resource type. MISO calculates average ISAC (b, the denominator) using the average of all resources of that resource type. The performance-based component of DLOL is thus a ratio of each individual resource's historical real-time availability

[10] If the number of Max Gen events exceeds 65 hours per season, the number of RA hours could exceed 65. If the number of hours with reserve margins less than 25% is less than 65, the number of RA hours could be less than 65.

relative to the average availability of that resource type. The box below provides examples of MISO's ISAC ratio calculations.

Examples of MISO's Performance Ratio Calculations for DLOL

During the past three winters, a 200 MW wind generator had an average of 50 MW cleared in the real-time market during non-RA hours and 40 MW cleared during RA hours. The wind generator's individual ISAC for winter will be 42 MW (= 20% × 50 MW + 80% × 40 MW).

All wind generators had an average ISAC of 48 MW during the past three winters. The winter ISAC ratio will be 0.88 (= 42 MW / 48 MW).

The final capacity credit for each resource will be its class average value, based on the critical hour analysis, multiplied by the ISAC ratio, based on the RA hour analysis. The box below shows an example of how the class average value and ISAC ratio are combined to arrive at a final seasonal capacity credit.

Final Seasonal Accredited Capacity Calculations in DLOL

In the DLOL approach, the final seaonal accredited capacity for a resource i (SAC_i) is its installed capacity ($ICAP_i$) multiplied by its class average UCAP capacity credit and by its ISAC ratio.

$$SAC_i = ICAP_i \times UCAP \times \frac{ISAC_i}{ISAC}$$

As an example, consider a year in which wind generation has a UCAP value of 0.165 and an individual wind generator has an ISAC ratio ($ISAC_i$/ISAC) of 1.05, meaning that the generator is more available in real-time than the average wind generator. The individual wind generator's SAC will be 0.173 (= 0.165 × 1.05).

MISO uses the seasonal accredited capacity values from its DLOL calculations to clear its capacity market. For instance, a resource with 200 MW of installed capacity and a summer capacity credit of 0.3 will clear 60 MW for summer in the capacity market. Capacity market prices are in $/MW-day, so if summer prices are $400/MW-day, the resource will receive $2.2 million (= $400/MW-day × 92 days × 60 MW) for summer in the capacity market. Other seasons will clear separately, with different capacity credits and capacity market prices.

MISO expects to begin full implementation of the DLOL framework in its 2028-2029 planning year. To provide market participants with more intuition on what the DLOL class average UCAP values might be, MISO has begun to publish regular estimates of these values for each planning year. The below table shows DLOL estimates and installed capacity and counts for different resources in the MISO region.

Table 1. MISO Estimates of DLOL UCAP Values for Planning Year 2026-2027

PY 2026-2027	DLOL-Based UCAP %				ICAP				Count of Units
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	End of PY
Biomass	90%	82%	84%	82%	452	462	459	437	33
Coal	88%	72%	69%	63%	35,952	35,714	36,170	32,758	145
Combined Cycle	95%	77%	74%	71%	27,686	28,608	30,987	30,022	142
Dual Fuel Oil/Gas	89%	73%	67%	71%	7,335	7,686	7,928	7,546	72
Gas	91%	73%	63%	64%	28,195	29,381	31,924	29,674	415
Nuclear	95%	85%	85%	78%	11,375	11,479	11,719	12,366	17
Oil	84%	77%	52%	56%	1,206	1,207	1,189	1,192	133
Pumped Storage	96%	74%	85%	68%	2,628	2,671	2,594	2,632	14
Reservoir Hydro	97%	87%	94%	87%	476	448	459	473	29
Run-of-River Hydro	93%	83%	86%	78%	768	604	701	798	66
Solar	40%	4%	2%	7%	18,772	19,782	24,162	25,141	347
Storage	55%	70%	74%	99%	1,114	1,134	1,475	1,733	67
Wind	7%	12%	24%	15%	29,338	29,358	30,111	30,111	312

Source: *MISO's Indicative DLOL-Based Unforced Capacity and Planning Reserve Margin Requirement Results*

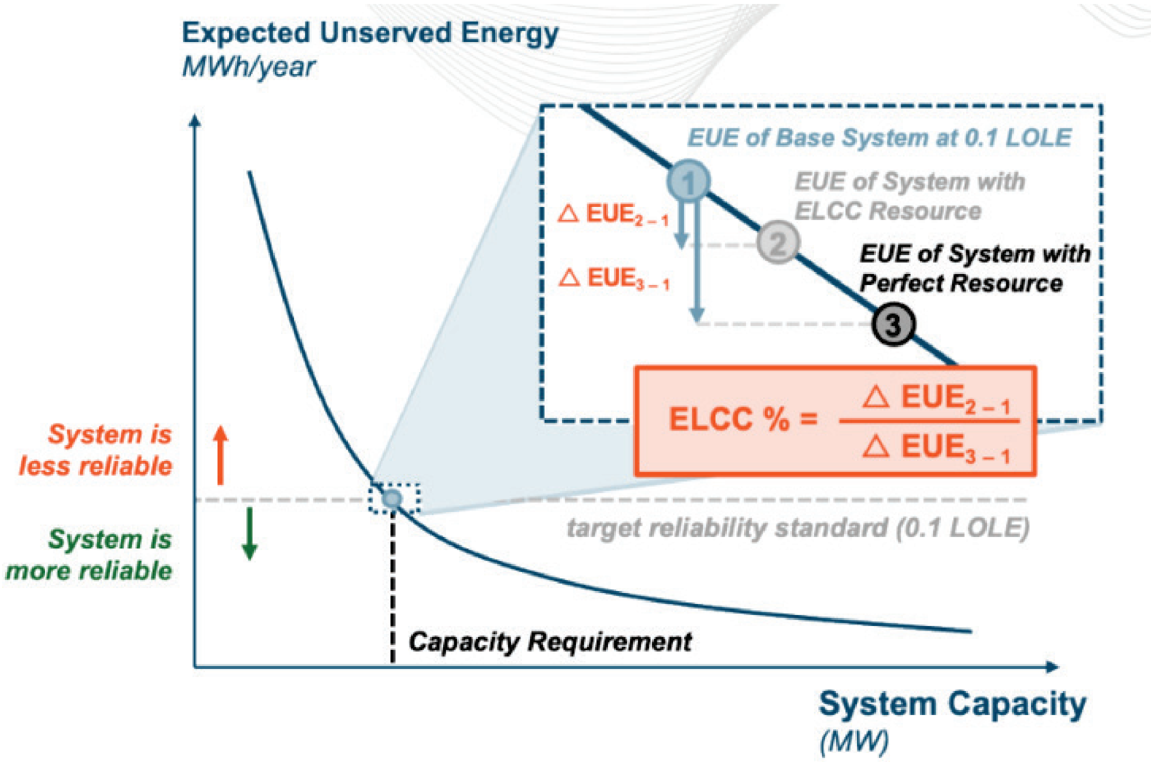
MISO's DLOL calculations explicitly incorporate real-time resource performance and provide a strong incentive to be at least as available as the average resource. For instance, a coal generator that has a 90% winter UCAP value may have a 45% individual winter SAC value if it is only available half as much (ISAC ratio of 50%) as the average coal generator in real-time during historical winter years.

4.3 PJM's ELCC-Based Approach

PJM is currently transitioning to a seasonal RA construct with summer and winter resource accreditation. However, its proposed approach is not yet as developed as those in California or the MISO region.

Currently, PJM credits all resources for their contribution to summer peak needs using two components: (1) a marginal ELCC class rating, and (2) a performance adjustment. PJM's calculates ELCC class ratings using four main steps: (1) solve an LOLE model to the target value of 1-day-in-10 years, (2) calculate the additional reduction in expected unserved energy (EUE) from (1) by adding 100 MW of resources in a resource class, (3) calculate the additional reduction in EUE from (1) by adding 100 MW of perfect capacity (always available, no outages), and (4) divide the EUE reduction in (2) by the EUE reduction in (3). The value in step (4) is the ELCC class rating. Figure 5 illustrates PJM's method for calculating ELCC class ratings. PJM is currently the only entity to credit all resources using the same method.

Figure 5. Illustration of PJM's Method for Calculating ELCC Class Ratings



Source: [2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS)](#).

The table below shows PJM's ELCC class ratings for delivery years 2026/2027 and 2027/2028.

Table 2. PJM ELCC Class Ratings for Delivery Years 2026/2027 and 2027/2028

ELCC Class	2026/2027 Rating	2027/2028 Rating	Difference
Onshore Wind	41%	41%	0%
Offshore Wind	69%	67%	-2%
Fixed-Tilt Solar	8%	7%	-1%
Tracking Solar	11%	8%	-3%
Intermittent Landfill Gas	50%	48%	-2%
Intermittent Hydropower	38%	39%	+1%
Capacity Storage Resource (4-hr)	50%	58%	+8%
Capacity Storage Resource (6-hr)	58%	67%	+9%

ELCC Class	2026/2027 Rating	2027/2028 Rating	Difference
Capacity Storage Resource (8-hr)	62%	70%	+8%
Capacity Storage Resource (10-hr)	72%	78%	+6%
Demand Resource	69%	92%	+23%
Nuclear	95%	95%	0%
Coal	83%	83%	0%
Gas Combined Cycle	74%	74%	0%
Gas Combustion Turbine	60%	61%	1%
Gas Combustion Turbine Dual Fuel	78%	77%	-1%
Diesel Utility	91%	92%	1%
Steam	73%	72%	-1%
Waste to Energy Steam	n/a	83%	n/a
Oil-Fired Combustion Turbine	n/a	80%	n/a

Source: 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS).

PJM's performance adjustment is based on two components: (1) a unit-specific performance factor, based on the unit's average historical availability during hours in which the LOLE model experienced loss-of-load events, (2) a class-level performance factor, based on a resource class' average historical availability during these events. The performance adjustment factor is (1) divided by (2), and is multiplied by the ELCC class rating to get the final accreditation value for each individual resource. PJM is currently in discussions with stakeholders to include separate accreditation for winter.

5. Conclusions and Key Takeaways

Resource accreditation plays an important role in U.S. RA mechanisms. Approaches to accreditation are evolving to address emerging RA challenges. Changes in California's approach to resource accreditation have focused on how to better incorporate energy limits related to storage in accreditation methods. Changes in MISO's approach have focused on how to better incorporate seasonal resource performance into accreditation methods. In both regions, and throughout the U.S., accreditation methods will continue to evolve with as generation, loads, and operating conditions change.

The discussion in this paper highlights three main takeaways from recent U.S. experience with RA mechanisms.

RA mechanisms can improve resource planning transparency. RA mechanisms provide a forum for making a range of local and regional planning inputs, methods, and assumptions more transparent, most importantly those related to load forecasts, planning reserve margins, and resource accreditation. More transparency can help to identify when local or regional electricity systems have inadequate or excess generating capacity, both in the nearer and longer term. Transparency in RA planning can also help system operators adapt to changing conditions – such as load growth, changes in generation mix, or changes in climate and extreme weather – by understanding how different drivers are changing planning inputs.

RA mechanisms can help to coordinate reliability and investment needs. Changes in generation mix and generator performance can make it difficult to ensure that generation companies are investing in the right amounts and kinds of generation. For instance, if thermal plants have lower performance in the winter, should generation companies add more generation capacity to ensure that adequate resources will be available in the winter? Or, as another example, what kinds of storage (2-hour, 4-hour, longer duration) should generation companies invest in? How much can storage contribute to reliability? RA mechanisms can help to coordinate between system operators' reliability needs and generation investment, particularly as conditions change.

RA planning should be linked to real-time operations. Recent reliability challenges in the U.S. illustrate the importance of (a) feedback between real-time operations and RA planning and (b) incentives to align planning and real-time performance. Feedback from real-time operations to planning can help to benchmark and adjust planning parameters. For instance, operational data can inform resource accreditation and load forecast error parameters used in RA planning. Performance incentives can also help to link planning and operations, for instance by improving coordination of planned outages and periods of reliability need. Closer linkages between RA planning and operations may require coordination across agencies, if RA planning is not the responsibility of the system operator.