



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

PJM Resource Adequacy Planning

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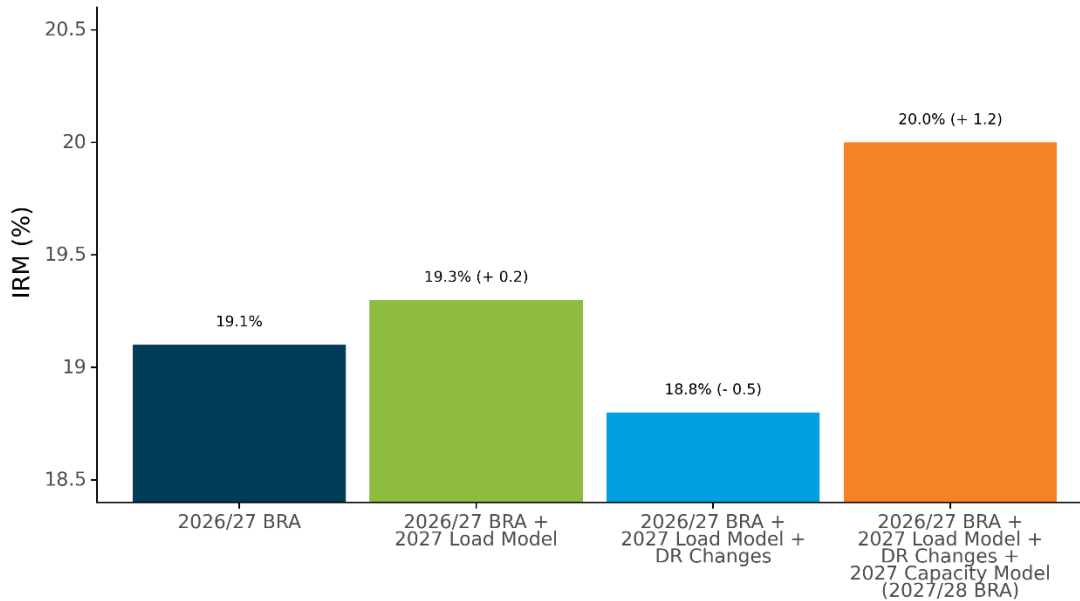
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Executive Summary

- The PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS) provides information about resource adequacy parameters, such as the Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR) and ELCC Class Ratings for future Delivery Years (DY). In accordance with the Reliability Pricing Model (RPM) auction schedule, this study includes parameters to be used in the Base Residual Auction (BRA) for the 2027/2028 DY. In addition, parameters for DY other than 2027/2028 are also included for informational purposes only.
- PJM publishes this report to satisfy the North American Electric Reliability Corporation (NERC)/ReliabilityFirst (RF) Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation. This standard requires that the planning coordinator performs and documents a resource adequacy analysis that uses a Loss of Load Expectation (LOLE) of one occurrence in ten years.
- PJM calculated the values included in this report using its own resource adequacy software tool. The tool simulates supply and demand in the RTO area on an hourly basis. For more details on the tool, see the Model Overview section.
- The Capacity Benefit of Ties (CBOT) was administratively set at 1.5%, the same value that has been used in the most recent planning parameter calculations.
- PJM staff recommends, and the PJM Board approved, an FPR equal to **0.9260 for the 2027/2028 Delivery Year**. This FPR value is a key parameter for the Reliability Requirement calculation in RPM.
- The IRM value associated with the above FPR value for the 2027/2028 DY is 20.0%.
- The main input/assumption changes between the study performed for 2027/2028 and the study performed earlier in the year for 2026/2027 are:
 - 2027/2028 hourly load profiles (“2027/2028 Load Model”) instead of 2026/2027 hourly load profiles
 - Demand Response (DR) availability rule changes (FERC docket ER25-1525), which include the removal of the DR performance window (making DR a 24/7 resource) and updates to the DR winter performance shape
 - 2027/2028 resource portfolio and associated expected performance (“2027/2028 Capacity Model”) instead of the 2026/2027 resource portfolio
 - The addition of two new ELCC Classes (FERC docket ER25-1813): Oil Fired Combustion Turbine Class and Waste to Energy Steam Class

- The 20.0% IRM for 2027/2028 represents an increase of 0.9 percentage points relative to the IRM calculated for 2026/2027 (19.1%). The increase in the IRM can be explained as a function of the above input/assumption changes in **Figure 1**, which illustrates the impact of adding the changes one by one. While the quantification of each individual impact depends on the order of quantifying impacts, the total aggregate impact (+0.9%) does not:

Figure 1. Impact to IRM due to changes from 2026/2027 BRA to 2027/2028 BRA



- Adding the 2027 Load Model to the 2026/2027 BRA run increases the IRM by 0.2 percentage points (green bar in **Figure 1**). This occurs because the hourly load shapes for 2027/2028 include higher extreme winter loads (as a share of the 2027/2028 forecasted annual median peak) than the hourly shapes for 2026/2027.
- The addition of the DR changes to the previous run decreases the IRM by 0.5 percentage points (light-blue bar in **Figure 1**). This occurs because the DR Changes: i) expand the availability of DR to be a 24/7 resource and ii) for 2027/2028, result in a DR winter performance shape that is superior to that used in the 2026/2027 BRA run. Both changes improve resource adequacy of the system.
- The cumulative addition of the 2027/2028 Capacity Model to the previous run results in an increase to the IRM of about 1.2 percentage point (orange bar in **Figure 1**; this is the 2027/2028 BRA run). This occurs because the main difference between the 2027/2028 Capacity Model and the 2026/2027 Capacity Model is the addition of new solar resources, which do not provide the same resource adequacy value per ICAP as the fleet for a system that has the majority of risk concentrated in the winter season. In other words, new solar resources are being added to the system, increasing the total installed capacity, but not providing a commensurate increase in the amount of load that the system can serve; since the IRM is the ratio between total installed capacity and the amount of load that the system can serve, the IRM increases.

- The 0.9260 FPR for 2027/2028 represents an increase of 0.009 relative to the FPR calculated for 2026/2027 (0.9170). Changes in the FPR value cannot be interpreted in isolation and should be analyzed in conjunction with changes in the overall accreditation of the resource mix. This is because the FPR is used to determine total amount of Accredited UCAP (AUCAP) required by the system, and it can be the case that the FPR increases simply because the accreditation of the resource mix increases. In other words, an increased IRM does not necessarily mean the system is tighter if Total Accredited UCAP is increasing commensurately. Therefore, to assess the impact of the input/assumption changes in the 2027/2028 values, **Table 1** provides the values for the FPR, pool-wide average Accredited UCAP Factor (AUCAP Factor), illustrative 2027/2028 Reliability Requirement, illustrative 2027/2028 total Accredited UCAP (AUCAP), and illustrative 2027/2028 BRA supply/demand tightness for each of the same four runs used to explain the change in IRM above.

Table 1. Additional Impacts due to changes from 2026/2027 BRA to 2027/2028 BRA

	2026/2027 BRA	2026/2027 BRA + 2027/2028 Load Model	2026/2027 BRA + 2027/2028 Load Model + DR Changes	2026/2027 BRA + 2027/2028 Load Model + DR Changes + 2027/2028 Capacity Model (2027/2028 BRA)
FPR	0.917	0.9047 (-0.0123)	0.9288 (+0.0241)	0.926 (-0.0028)
AUCAP Factor	0.7699	0.7583 (-0.0116)	0.7818 (+0.0235)	0.7717 (-0.0101)
Illustrative 2027/2028 BRA Total AUCAP (MW)*	152,732	150,431 (-2,301)	155,093 (+4,662)	153,089 (-2,004)
Illustrative 2027/2028 BRA Reliability Requirement (MW)**	150,559	148,539 (-2,020)	152,496 (+3,957)	152,036 (-460)
Illustrative 2027/2028 BRA Supply/Demand Tightness (MW)***	2,173	1,892 (-281)	2,597 (+705)	1,053 (-1,544)

* Calculated as Total ICAP in 2027/2028 Run (198,379 MW) times AUCAP Factor row

** Calculated as 2027/2028 Forecasted Peak Load (164,186 MW) times FPR row

*** Calculated as Illustrative 2027/2028 BRA Total AUCAP row minus Illustrative 2027/2028 BRA Reliability Requirement row

- Adding the 2027/2028 Load Model to the 2026/2027 BRA run decreases the FPR by 0.0123, but the pool-wide Accredited UCAP Factor (i.e., the overall accreditation of the resource mix) also decreases by 0.0116. The decrease in pool-wide Accredited UCAP Factor is caused by the higher extreme winter loads in the hourly load shapes for 2027/2028, which decrease the overall accreditation of the 2026/2027 BRA resource mix (i.e., the same quantity of Accredited UCAP MW when measured against higher extreme winter loads yield a smaller pool-wide Accredited UCAP Factor). However, this accreditation reduction is accompanied by a lower FPR, which reduces the targeted procurement of Accredited UCAP. Once the change in “Illustrative 2027/2028 BRA Total UCAP” and “Illustrative 2027/2028 BRA Reliability Requirement” are taken into account, it can be observed that the system becomes tighter by about 281 MW of Accredited UCAP (from 2,173 MW to 1,892 MW) due to adding the 2027/2028 Load Model to the 2026/2027 BRA run. This is consistent with the increase in IRM due to the addition of the 2027/2028 Load Model described earlier, given that an increase in IRM is a sign of more risk in the system (which should result in a system becoming tighter).
- The addition of the DR changes to the previous run increases both pool-wide Accredited UCAP Factor and FPR. However, the associated increase in “Illustrative 2027/2028 BRA Total UCAP” is larger than the associated increase in “Illustrative 2027/2028 BRA Reliability Requirement” resulting in a system that has a surplus of 2,597 MW. In other words, the addition of the DR Changes to the previous run makes the system less tight by about 705 MW of Accredited UCAP (from 1,892 MW to 2,597). This is consistent with the decrease in IRM due to the addition of the 2027/2028 Load Model and DR Changes.
- The cumulative addition of the 2027/2028 Capacity Model to the previous run decreases both pool-wide Accredited UCAP Factor and FPR. Overall, the system becomes tighter because the reduction in Illustrative 2027/2028 BRA Total Accredited UCAP (2,004 MW) is greater than the reduction in “Illustrative 2027/2028 BRA Reliability Requirement” (460 MW), resulting in a tightness metric equal to 1,053 MW (a reduction of -1,544 MW relative to the run prior adding the 2027/2028 Capacity Model).
- The addition of two new ELCC Classes– Oil Fired Combustion Turbine Class and Waste to Energy Steam Class – does not impact the IRM or FPR calculation, as all the units in these two classes were included in both runs, 2026/2027 BRA and 2027/2028 BRA, and their performance histories in both runs are identical (the units were only grouped differently to calculate the respective ELCC Class Ratings).
- The ELCC Class Ratings for 2027/2028 compared to those for 2026/2027 are presented in **Table 2**.

Table 2. ELCC Class Ratings for 2027/2028 compared to those for 2026/2027

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

- The most significant changes in 2027/2028 ELCC Class Ratings relative to the 2026/2027 values are observed for Demand Response and the Capacity Storage Resource classes. In the case of Demand Response, the increase is a direct result of eliminating the DR performance window (making DR a 24/7 resource). In the 2026/2027 run, the performance of DR was assumed to be zero outside the DR performance window, putting downward pressure on the class rating. In the case of Capacity Storage Resource classes, the increase is an indirect result of eliminating the DR performance window: if there is no performance window, DR can be dispatched in more hours than in the 2026/2027 case, which delays the deployment of Capacity Storage Resource classes (because DR is dispatched before Limited Duration resources in the model), enabling Capacity Storage Resources to provide more output during actual loss of load hours.
- The analysis was performed using PJM's internally developed loss of load probability tool. The tool models the RTO without internal transmission constraints as an isolated area.
- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Power (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light Company (Dayton), Virginia Electric and Power Company (Dominion), Duquesne Light Company (DLCO), American Transmission Systems, Incorporated (ATSI), Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (DEOK), East Kentucky Power Cooperative, Inc. (EKPC) and Ohio Valley Electric Corporation (OVEC).
- The 2027/2028 resource portfolio was developed:
 - Including Planned Resources that submitted a Notice of Intent to Offer for the 2027/2028 BRA
 - Including Installed Capacity ratings reflecting awarded 2027/2028 transitional system capability
 - Excluding Resources with announced deactivations scheduled to occur before June 1, 2028
 - Including Capacity Resources that have withdrawn their deactivation notice or are in the process of reactivating

The above resulted in an overall increase of 4,641 MW ICAP in the 2027/2028 resource portfolio relative to the ICAP in the 2026/2027 resource portfolio.

- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-03, Resource Planning Reserve Requirements, the 2025 RRS provides a ten-year resource adequacy projection for the planning horizon that begins June 1, 2026, and extends through May 31, 2035. (See **Table 4**)
- Since FERC’s approval of the resource adequacy reforms in docket ER24-99-000, PJM has calculated the IRM and FPR values shown in **Table 3**:

Table 3. Approved IRM and FPR values

Study Month/Year	Target Auction	IRM	FPR
March 2024	2025/2026 BRA	17.8%	0.9387
January 2025	2025/2026 3IA	17.8%	0.9380
March 2025	2026/2027 BRA	19.1%	0.9170

Introduction

Purpose

The PJM Reserve Requirement Study (RRS) is developed for the following purposes:

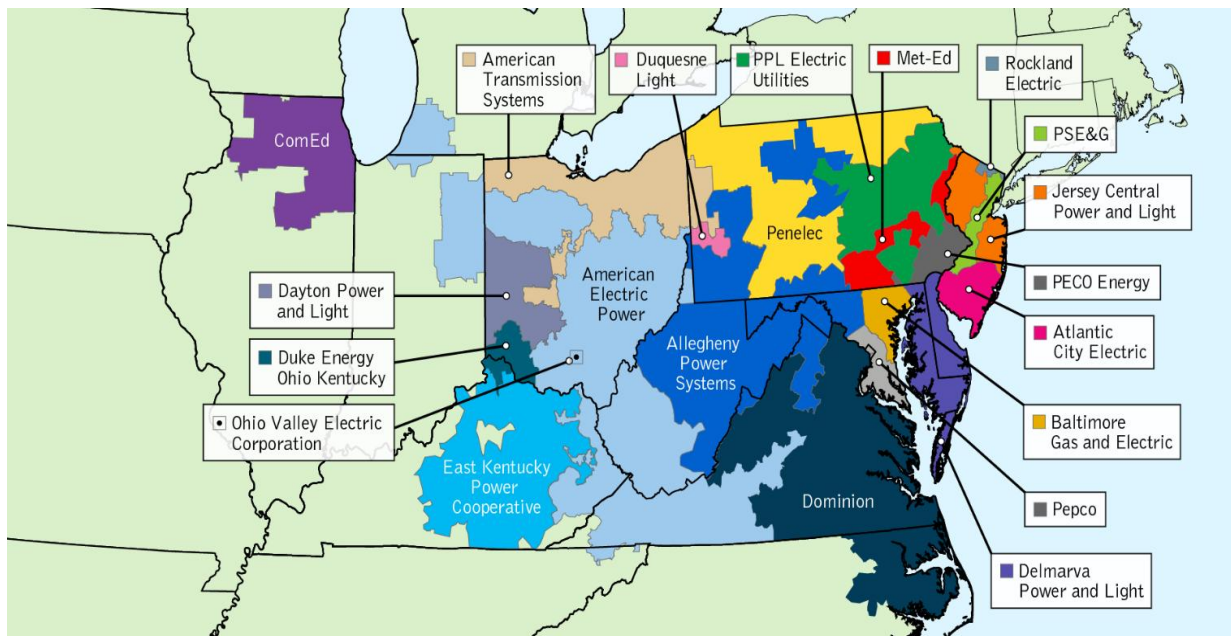
- Comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-03.
- Provide stakeholders with explanation and background for recently calculated RPM planning parameters as well as informational values for future Delivery Years.
- Provide stakeholders with information about the loss of load tool used by PJM to perform the above calculations including the underlying assumptions of the model.

Regional Modeling

This analysis examines the combined PJM footprint area (shown in **Figure 2**) that consists of the PJM Mid-Atlantic Region plus Allegheny Power (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light Company (Dayton), Virginia Electric and Power Company (Dominion), Duquesne Light Company (DLCO), American Transmission Systems, Incorporated (ATSI), Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (DEOK), East Kentucky Power Cooperative, Inc. (EKPC) and Ohio Valley Electric Corporation (OVEC).

Areas adjacent to the PJM Region are not modeled in this study. Instead, the Capacity Benefit of Ties (CBOT), which is used to decrease the targeted amount of capacity procured in RPM, was administratively set at 1.5% of the 50/50 peak load.

Figure 2. Combined PJM Region Modeled



Summary of RRS Results

Eleven-Year RRS Results

Table 4 shows a ten-year-forward projection from the study for informational purposes. The Delivery Years for which the parameters were/are used in RPM auctions are highlighted in yellow.

Table 4. Eleven-Year Reserve Requirement Study

Delivery Year	Total ICAP (MW)	Total UCAP (MW)	IRM (%)	Pool Wide Avg AUCAP Factor (%)	FPR	Forecasted Peak Load (MW)	Total ICAP Requirement (MW)	Total UCAP Requirement (MW)	ICAP Surplus (MW)	UCAP Surplus (MW)*
2026/2027	193,738	149,149	19.1	76.99	0.917	158,937	189,294	145,745	4,444	3,404
2027/2028	198,379	153,095	20.0	77.17	0.926	164,186	197,023	152,036	1,356	1,059
2028/2029	199,676	152,075	20.7	76.16	0.9193	169,981	205,167	156,264	-5,491	-4,189
2029/2030	198,586	148,375	22.5	74.72	0.9153	176,094	215,715	161,179	-17,129	-12,804
2030/2031	205,022	150,552	24.7	73.43	0.9157	183,883	229,302	168,382	-24,280	-17,830
2031/2032	214,423	154,315	26.4	71.97	0.9097	192,647	243,506	175,251	-29,083	-20,936
2032/2033	221,659	155,497	27.4	70.15	0.8937	200,507	255,446	179,193	-33,787	-23,696
2033/2034	228,227	158,039	29	69.25	0.8933	204,197	263,414	182,409	-35,187	-24,370
2034/2035	233,588	158,396	31	67.81	0.8883	207,253	271,501	184,103	-37,913	-25,707
2035/2036	238,525	159,258	32.7	66.77	0.886	209,923	278,568	185,992	-40,043	-26,734

* The UCAP Surplus does not account for the fact that in RPM the offers of resources are capped at CIRs. CIRs can be lower than the Accredited UCAP of resources. This means that, in RPM, the UCAP Surplus can be lower than in the table above.

- The IRM and FPR provide information about the amount of ICAP and UCAP, respectively, that is necessary for the PJM system to meet the LOLE criterion of 1 day in 10 years (if the emergency imports from neighboring regions into PJM, i.e., the CBOT, are included as reserves)
- Specifically, multiplying the “Forecasted Peak Load” column times one plus the “IRM” column produces the “Total ICAP Requirement” column. Similarly, multiplying the “Forecasted Peak Load” column times the “FPR” column produces the “Total UCAP Requirement” column.
- The “FPR” column is derived by multiplying one plus the “IRM” column times the “Pool Wide Avg AUCAP Factor”. Therefore, the “Pool-Wide Avg AUCAP Factor” can be thought of as the Accredited UCAP rating of the resource portfolio for each Delivery Year.
- The “Forecasted Peak Load” column values are taken from the [2025 PJM Load Forecast Report](#) and represent the 50/50 (i.e., median) peak loads.

- The “Total ICAP” and “Total UCAP” columns provide the assumed amount of ICAP and UCAP values, respectively. Both columns include Demand Resources and assumed external firm capacity purchases and sales.
- “ICAP Surplus” column is the difference of the “Total ICAP” and “Total ICAP Requirement” columns. Similarly, the “UCAP Surplus” is the difference between the “Total UCAP” and “Total UCAP Requirement” columns.
- The “ICAP Surplus” and “UCAP Surplus” columns show that the PJM system has enough resources to meet the LOLE criterion of 1 day in 10 years in Delivery Years 2026/2027 and 2027/2028. For the rest of the Delivery Years, the ICAP Surplus and UCAP Surplus values are negative given the consistently increasing Forecasted Peak Load Values as well as the consistently increasing IRM values.
- The IRM values consistently increase because the changes in the assumed resource portfolio consider additions of resources that have lower Accredited UCAP than the resources that are retired.
- The “Pool-Wide Avg UCAP Factor” values are reflective of availability patterns of resources in the resource portfolio during critical hours (i.e., hours where additional energy reduces system unserved energy). Factors that impact availability patterns include:
 - Forced, Planned and Maintenance Outages for Unlimited Resources (non-correlated as well as correlated)
 - Ambient derates for Unlimited Resources
 - Unavailability of Variable Resources (non-correlated and correlated)
 - Energy constraints of Limited Duration Resources and Combination Resources
 - Forced Outage Rates of Limited Duration Resources and Combination Resources
 - Expected performance of Demand Resources
- The “Total ICAP” and “Total UCAP” columns:
 - For 2026/2027 and 2027/2028, the values include Planned Resources that submitted a Notice of Intent to Offer and Capacity Resources that have withdrawn their deactivation notice or are in the process of reactivating while excluding Resources with announced deactivations.
 - For the rest of the Delivery Years, the values include projected additions and retirements developed by a vendor.

Recommendations

- Installed Reserve Margin (IRM) – based on the study results and the additional considerations mentioned above, PJM recommends, and the PJM Board approved, an IRM value of 20.0% for the 2027/2028 Delivery Year.
- Forecast Pool Requirement (FPR) – the IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:

$$FPR = (1 + IRM) * (Pool-wide Average Accredited UCAP Factor)$$

- Based on the IRM values, the resulting FPRs are:

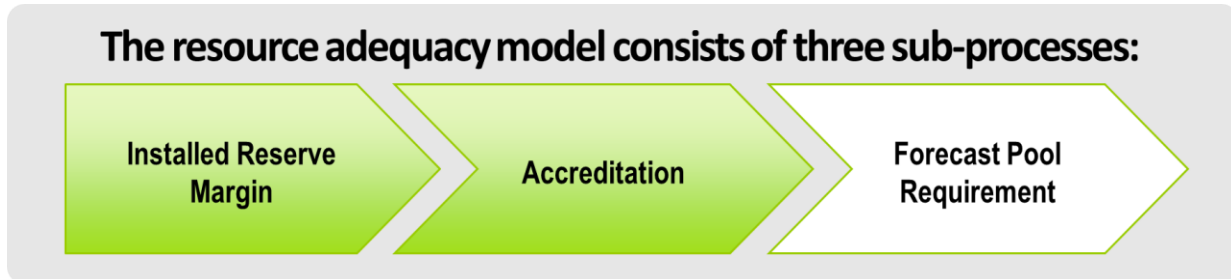
2027 / 2028 Delivery Year	$FPR = (1 + 0.200) * (0.7717) = 0.9260$
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Model Overview

General Overview

As shown in **Figure 3**, the process to calculate the IRM and FPR for a given Delivery Year can be divided into three subprocesses:

Figure 3. Model Process Overview



The IRM Subprocess determines via probabilistic modeling the 50/50 “solved” peak load that a given resource portfolio for a given Delivery Year can serve while meeting the LOLE criterion of 1 day in 10 years. Since the total ICAP of the resource portfolio is an input to the process and the CBOT value is administratively set, the IRM can be calculated by finding the 50/50 “solved” peak load.

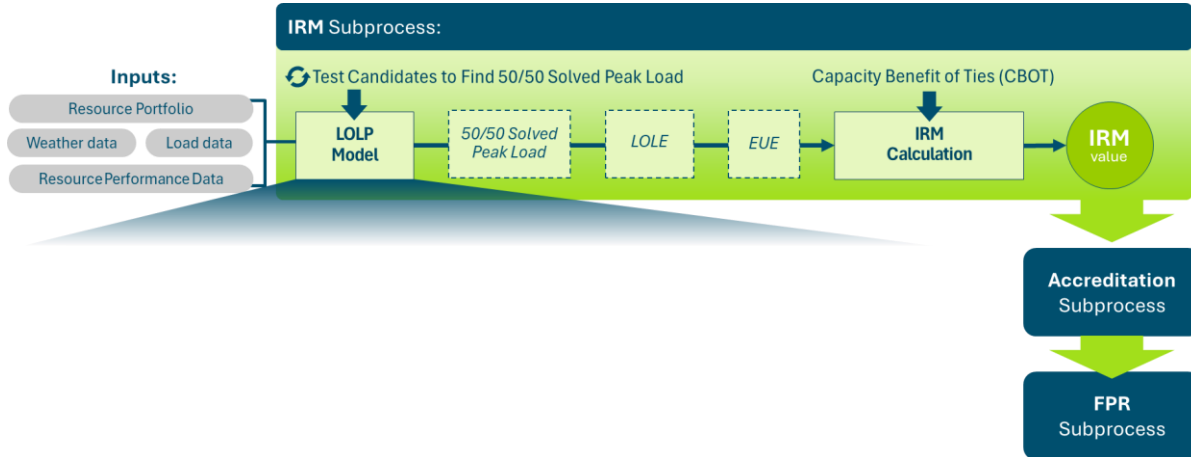
The Accreditation Subprocess determines via probabilistic modeling the Accredited UCAP of each resource included in the resource portfolio. This entails identifying the ELCC Class Ratings and the Unit-Specific ratings, which in turn are calculated by determining the Expected Unserved Energy (EUE) improvement that an incremental quantity of an ELCC Class or Unit, as appropriate, provides to the PJM system when the LOLE criterion of 1 day in 10 years is met, relative to the EUE improvement that an incremental quantity of perfect capacity provides to the system.

The FPR Subprocess is the simplest of the three subprocess, as the FPR is calculated by directly using outputs from the two previous subprocesses: the IRM and the total AUCAP in the system.

Underlying the three subprocesses is PJM’s Loss of Load Probability (LOLP) Model. While described in further detail later in the report, the LOLP Model is a probabilistic model that calculates resource adequacy metrics, such as Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE), by simulating the balance of supply and demand in the PJM system chronologically hour by hour under multiple annual scenarios. Supply and demand are modeled as a function of weather (Temperature Humidity Index, specifically), using historical resource performance data to reflect resource availability, and reflecting the energy constraints of certain resources. The IRM Subprocess can be thought of as a calibration of the LOLP Model to meet the LOLE criterion of 1 day in 10 years while the Accreditation Subprocess can be thought of as the standard with which resources’ resource adequacy contributions are compared to each other depending on their modeled performance during the critical hours identified by the LOLP Model when the system meets the criterion.

IRM Subprocess

Figure 4. IRM Subprocess Overview



The IRM Subprocess depends on several inputs including resource portfolio, weather data, load data and resource performance data. These inputs are fed into the core of the IRM Subprocess, the LOLP Model. Since the 50/50 Forecasted Load that the resource portfolio can serve while meeting the Reliability Criteria is unknown, a candidate solved load is iteratively input into the LOLP model until the model finds 50/50 solved peak load that meets the Reliability Criteria. Once the 50/50 solved peak load is found, the IRM Calculation can proceed by subtracting the administratively set Capacity Benefit of Ties.

Inputs

Resource Portfolio

A resource portfolio for each studied Delivery Year is an input into the model. In the 2025 RRS, for Delivery Years 2026/2027 and 2027/2028, the portfolio includes existing¹ resources, planned resources that submitted a Notice of Intent for the respective BRA, and resources that have withdrawn deactivation notices or that are in the process of reactivating prior to the start of the respective Delivery Year and excludes resources with announced deactivations scheduled to occur before the end of each of the respective Delivery Years. For the other Delivery Years in the 2025 RRS, the resource portfolios are derived by using a forecast of additions and deactivations produced by a vendor.

Table 5 shows the resources portfolios for Delivery Years 2026/2027 and 2027/2028 in the 2025 RRS. The resource portfolios for the rest of the Delivery Years are available upon request to ELCC@pjm.com.

¹ Existing Generation Capacity Resources as well as external resources that are pseudo-tied to PJM

Table 5. Resource Portfolio for the 2026/2027 and 2027/2028 Delivery Years

ELCC Class	Effective Nameplate Capacity 2026/2027 (MW)	Effective Nameplate Capacity 2027/2028 (MW)	Installed Capacity 2026/2027 (MW)	Installed Capacity 2027/2028 (MW)
Onshore Wind	11,650	12,862	3,549	3,956
Offshore Wind	Small Sample Size	Small Sample Size	Small Sample Size	Small Sample Size
Solar Fixed	2,367	2,901	1,189	1,494
Solar Tracking	13,321	17,657	8,713	11,612
Intermittent Landfill	167	146	118	103
Intermittent Hydropower	736	736	519	519
Capacity Storage Resources (4, 6, 8, 10-hour duration)	5,834	5,938	5,834	5,938
Solar-Storage Hybrid	Small Sample Size	Small Sample Size	Small Sample Size	Small Sample Size
Demand Resources	n/a	n/a	8,184	8,439
Nuclear	n/a	n/a	32,144	32,181
Coal	n/a	n/a	35,779	35,964
Gas Combined Cycle (Single and Dual Fuel)	n/a	n/a	57,664	57,560
Gas Combustion Turbine	n/a	n/a	11,030	10,970
Gas Combustion Turbine Dual Fuel	n/a	n/a	13,158	13,249
Diesel Utility	n/a	n/a	329	334
Steam	n/a	n/a	10,004	9,283
Waste to Energy Steam	n/a	n/a	n/a	719
Oil-Fired Combustion Turbine	n/a	n/a	n/a	2,852
Hydropower with Non-Pumped Storage	2,034	2,057	1,969	1,992
Other Unlimited Resources	n/a	n/a	3,041	450
TOTAL	209,124	216,814	193,738	198,379

Note that the ICAP ratings in **Table 5** include any transitional system capability that was awarded for the respective Delivery Year. Also, in **Table 5**, some Effective Nameplate Capacity and Installed Capacity values are either non-applicable (n/a) or cannot be released due to confidentiality rules (small sample size of resources/owners in the ELCC Class). Note that the ICAP values and ENC values are annual and as such, are not assumed or modeled to vary by season.

Weather Data

The weather data used in the 2025 RRS is hourly Temperature Humidity Index (THI) for the period June 1, 1993, through May 31, 2024 (i.e., DY 1993 through DY 2023).

The above weather data is used in two ways:

On the load side: the PJM Load Forecast team develops hourly load scenarios for the entire RTO using weather data (temperature, humidity, wind speed) for each of the PJM transmission zones. It does so by first estimating the hourly load for each transmission zone and then hour by hour adding the zonal values to calculate the RTO values. The zonal process is performed by solving the hourly zonal equations (which are estimated via a zonal regression model) using the above weather data as well as distributed solar generation, forecast adjustments (data centers and peak shaving), behind-the-meter battery storage, and electric vehicles. In addition, to capture the fact that historical weather patterns that occurred on a certain day could also have occurred in surrounding days, each yearly weather pattern is shifted moving forward six days and backward six days, providing 13 different weather scenarios for each historical year. More details about this methodology can be found in the [2025 PJM Long-Term Load Forecast Supplement](#).

On the resource performance side: for each hour in the period June 1, 1993, through May 31, 2024, a load-weighted RTO THI value is determined (load-weighted because the THI data is at the zonal level). Then, the maximum hourly RTO-wide THI is determined for each summer day in the above period, while for each winter day in the above period, the minimum hourly RTO-wide THI is determined.² The objective of this step in the process is to associate each day in the period June 1, 1993, through May 31, 2024, with a single hourly RTO-wide THI value. The summer days are then separated from the winter days and grouped in Weather Bins (the same is done for the winter days) based on the maximum hourly RTO-wide THI values (in the case of winter, this is done using the minimum hourly RTO-wide THI values). This is accomplished by feeding the collection of maximum hourly RTO-wide THI values to the Freedman Diaconis algorithm, an algorithm commonly used to derive histograms. The same is done with the collection of minimum hourly RTO-wide THI values for the winter days.

As discussed in the load section above, weather data starting on June 1, 1993, is used to develop the load scenarios. On the resource performance side, specifically for Unlimited Resources and Variable Resources, the model uses data starting on June 1, 2012. This is because data prior to June 1, 2012, was either unavailable or deemed not representative of the current characteristics of the resources in the resource portfolio. Therefore, to differentiate the bins that include days back to June 1, 1993 (i.e., the Weather Bins), Resource Performance Bins include days dating back to June 1, 2012.

In the 2025 RRS, the output of the Freedman Diaconis algorithm for winter and summer resulted in Weather Bins and Resource Performance Bins with small sample sizes, especially for the Resource Performance Bins. To avoid this outcome, PJM merged some of the Weather Bins as follows.

Merging of Winter min0, min1, min2, min3, min4, min5 (bins covering winter days with low RTO-wide THI)

Table 6 shows the winter bins that cover days with low RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 6. Pre-merging winter bins covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Winter	min0	-10.57	-8.18	1	0	min5

² Winter comprises the months of November, December, January, February, March and April. Summer comprises the rest of the months.

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Winter	min1	-8.18	-5.80	0	0	min5
Winter	min2	-5.80	-3.41	1	0	min5
Winter	min3	-3.41	-1.03	2	1	min5
Winter	min4	-1.03	1.36	7	2	min5
Winter	min5	1.36	3.75	7	4	min5

The post-merging Winter min5 Weather Bin and Resource Performance Bin have the following characteristics, shown in **Table 7**:

Table 7. Post-merging winter bin covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Winter	min5	-10.57	3.75	18	7

Merging of Winter min31, min30 (bins covering winter days with high RTO-wide THI)

Table 8 shows the winter bins that cover days with high RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 8. Pre-merging winter bins covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Winter	min30	61.00	63.38	15	6	min30
Winter	min31	63.38	65.77	2	0	min30

The post-merging Winter min30 Weather Bin and Resource Performance Bin has the following characteristics, shown in **Table 9**:

Table 9. Post-merging winter bin covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Winter	min30	61.00	65.77	17	6

Merging of Summer max17, max18, max19 (bins covering summer days with low RTO-wide THI)

Table 10 shows the summer bins that cover days with low RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 10. Pre-merging summer bins covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Summer	max17	41.22	43.49	3	0	max19
Summer	max18	43.49	45.76	5	1	max19
Summer	max19	45.76	48.03	13	3	max19

The post-merging Summer max19 Weather Bin and Resource Performance Bin has the following characteristics, shown in **Table 11**:

Table 11. Post-merging summer bin covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Summer	max19	41.22	48.03	21	4

Merging of Summer max35, max36 (bins covering summer days with high RTO-wide THI)

Table 12 shows the summer bins that cover days with high RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 12. Pre-merging summer bins covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Summer	max35	82.08	84.35	73	27	max35
Summer	max36	84.35	86.62	6	1	max35

The post-merging Summer max35 Weather Bin and Resource Performance Bin has the following characteristics, as shown in **Table 13**:

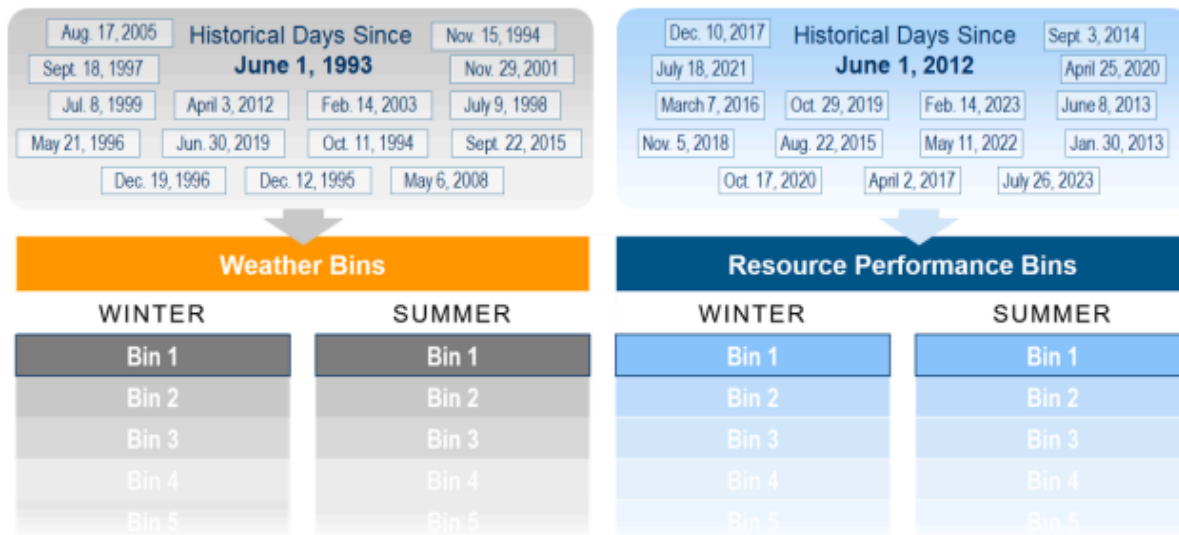
Table 13. Post-merging summer bin covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Summer	max35	82.08	86.62	79	28

All Weather Bins, for summer and winter, pre-merging and post-merging, as well as the days included in each bin are posted on the [Load Forecast Development Process](#) page on PJM.com.

A schematic of Weather Bins and Resource Performance Bins is shown in **Figure 5**.

Figure 5. Example of Weather Bins and Resource Performance Bins



Load Data

As described above in the Weather Data subsection, the hourly load scenarios for the entire RTO are developed by the PJM Load Forecast team by aggregating the hourly load scenarios developed for each transmission zone. The hourly load scenarios are specific for each Delivery Year studied given that other variables impacting forecasted load are likely to differ for different Delivery Years.

The hourly load scenarios used in the 2025 RRS are calculated based on weather data from the period June 1, 1993, through May 31, 2024 (i.e., DY 1993 through DY 2023). As noted earlier, each yearly weather pattern is shifted moving forward six days and backward six days, providing 13 different weather scenarios for each historical year. Therefore, considering that there are 31 Delivery Years in the period June 1, 1993, through May 31, 2024, there are $31 \times 13 = 403$ hourly load scenarios in the 2025 RRS.

In addition, to account for the error between observed daily peak loads and the fitted daily peak loads produced by the PJM Load Forecast regression model, the hourly loads of each day in each hourly load scenario are adjusted randomly by a factor, determined for each day, derived by randomly sampling from a normal distribution. In the 2025 RRS, the normal distribution utilized was one with a mean equal to 0 and a standard deviation equal to 1.2%. This is implemented as illustrated by **Figure 6** showing the first two days of an hourly load scenario derived with weather data from Delivery Year 1993. The Original Load column show the values as provided by the PJM Load Forecast team. The Adjustment Factor column shows the random factors derived from the above normal distribution for each day; note that the values can be positive or negative. The Final Load column shows the loads used in the model;

those loads adjusted by a factor greater than 1 will increase relative to the values provided by the PJM Load Forecast team while those adjusted by a factor less than 1 will decrease.

Figure 6. Example of hourly load scenario derived with weather data from Delivery Year 1993

Weather Day/HourBeginning	Original Load	Adjustment Factor	Final Load
June 1st 1993 0:00	L0	+0.3%	1.003 * L0
June 1st 1993 1:00	L1	+0.3%	1.003 * L1
...
June 1st 1993 23:00	L23	+0.3%	1.003 * L23
June 2nd 1993 0:00	L24	-0.5%	0.995 * L24
June 2nd 1993 1:00	L25	-0.5%	0.995 * L25
...
June 2nd 1993 23:00	L47	-0.5%	0.995 * L47

All 403 [hourly load scenarios for 2027/2028 adjusted by the Adjustment Factor](#) are posted on the ELCC webpage. Note that the posted values have been per unitized on the 50/50 Forecasted Peak Load for 2027/2028 (in other words, to convert to megawatt values, the values in the file should be multiplied by the 50/50 Forecasted Peak Load or a Candidate 50/50 Forecasted Peak Load, as suitable).

Resource Performance Data

Different resource performance inputs are required based on the type of resource included in the resource portfolio.

Unlimited Resources – Forced Outages and Ambient Derates

For each resource in the Unlimited Resources category, an hourly time series showing the ICAP share of the resource on a forced outage is required. In the 2025 RRS, the time series covers all hours in the period June 1, 2012, through May 31, 2024. A resource that has been in service for the entirety of this period is labeled as Mature; a resource that has been in service for a portion of the period is labeled as Immature; a resource that has not been in service for any portion of the period is labeled as Planned. For Mature resources, the time series is developed using forced outage data submitted to eGADS; for hours in the period in which Immature and Planned resources do not have forced outage data, a putative value is calculated using forced outage data from eGADS for all other units in the class that were in service during that hour. **Table 14** illustrates the forced outages time series for four units in an illustrative ELCC Class X. Two of the units are Mature (Unit 1 and Unit 2), Unit 3 is Immature and Unit 4 is Planned. The time stamps in which data is not available are marked with an “-” symbol.

Table 14. Example of forced outages time series for four units

Time Stamp (HB)	Unit 1 in Class X with ICAP I1 (Mature)	Unit 2 in Class X with ICAP I2 (Mature)	Unit 3 in Class X with ICAP I3 (Immature)	Unit 4 in Class X with ICAP I4 (Planned)
June 1, 2012, 0:00	0.4	0.2	-	-
June 1, 2012, 1:00	0.2	0.1	-	-
June 1, 2012, 2:00	1.0	0.0	0.7	-
...
May 31, 2024, 23:00	0.8	0.9	0.4	-

Table 15 illustrates the process of developing putative data for the time stamps in which data is not available for the Immature and Planned units. The process uses forced outage data from all other units that were in service during that hour.

Table 15. Example of developing putative data in forced outages time series for immature and planned units

Time Stamp (HB)	Unit 1 in Class X with ICAP I1 (Mature)	Unit 2 in Class X with ICAP I2 (Mature)	Unit 3 in Class X with ICAP I3 (Immature)	Unit 4 in Class X with ICAP I4 (Planned)
June 1, 2012, 0:00	0.4	0.2	$(0.4 \times I1 + 0.2 \times I2) / (I1 + I2)$	$(0.4 \times I1 + 0.2 \times I2) / (I1 + I2)$
June 1, 2012, 1:00	0.2	0.1	$(0.2 \times I1 + 0.1 \times I2) / (I1 + I2)$	$(0.2 \times I1 + 0.1 \times I2) / (I1 + I2)$
June 1, 2012, 2:00	1.0	0.0	0.7	$(1.0 \times I1 + 0.0 \times I2 + 0.7 \times I3) / (I1 + I2 + I3)$
...
May 31, 2024, 23:00	0.8	0.9	0.4	$(0.8 \times I1 + 0.9 \times I2 + 0.4 \times I3) / (I1 + I2 + I3)$

A Forced Outage time series for an entire ELCC Class can also be developed by calculating an ICAP-weighted hourly forced outage rate (after all missing values for Immature and Planned units have been calculated). In the example shown in **Table 15**, such a time series can be determined by calculating the ICAP-weighted average value for each row in the table.

The [hourly forced outage time series for the ELCC Classes classified as Unlimited Resources](#) in the 2025 RRS is posted on the ELCC webpage. Note that the forced outage time series for ELCC Classes under unit-specific treatment are not included in the above posting.

The process to calculate the hourly ambient derate time series is identical to the process to develop the hourly forced outage time series save for the fact that the source of the data is eDART. The [hourly ambient derate time series for the ELCC Classes classified as Unlimited Resources](#) in the 2025 RRS are posted on the ELCC webpage.

Unlimited Resources – Planned Outages and Maintenance Outages

For each resource in the Unlimited Resources category, the planned and maintenance outage requirement is calculated in terms of MW*week / year. This requirement is calculated by using planned and maintenance outage data from eGADS in the period June 1, 2012, through May 31, 2024. For Mature units, the calculation of the requirement is based on all the hours during the period that the unit registered a planned or maintenance outage. For Immature units, the calculation is performed based on a weighted average of the requirement calculated with: i) the planned and maintenance outage data after the unit came in service and ii) a class average requirement calculated using planned and maintenance outage data from in-service units in the same ELCC Class. The weights in the weighted average calculation are: i) the share of hours in the period in which the unit was in service and ii) one minus the previous quantity. For Planned units, the requirement corresponds to the class average requirement calculated using planned and maintenance outage data from in service units in the same ELCC Class.

Variable Resources

For each resource in the Variable Resources category, an hourly time series showing the Effective Nameplate Capacity (ENC) share of the resource that is available is required. In the 2025 RRS, the time series covers all hours in the period June 1, 2012, through May 31, 2024. A resource that has been in service for the entirety of this period is labeled as Mature; a resource that has been in service for a portion of the period is labeled as Immature; a resource that has not been in service for any portion of the period is labeled as Planned. For Mature resources, the time series is developed using PJM Settlements data showing the historical availability of the resource; for hours in the period in which Immature and Planned resources do not have forced outage data, a putative value is calculated by using an availability backcast that is derived based on historical weather data consistent with the particular site conditions and generator configurations for each resource.

Furthermore, since the ENC values for Variable Resources can exceed the assessed deliverability of such resources, the values in the above hourly availability time series are capped by: (i) the greater of the unit's CIR megawatt value, or the transitional system capability awarded for the applicable Delivery Year during hours in the months of June through October and the following May of the Delivery Year and ii) the unit's assessed deliverability as defined in PJM Manual 14B: PJM Region Transmission Planning Process for the applicable Delivery Year during hours in the months of November through April of the Delivery Year. Specifically, for winter hours beginning 0, 1, 2, 3, 4, 5, 6, 7, 8, 18, 19, 20, 21, 22, 23, the cap is the winter deliverability megawatts, while for winter hours beginning 9, 10, 11, 12, 13, 14, 15, 16, 17, the cap is the light load deliverability megawatts. Also, the hourly availability time series of a Variable Resource is adjusted to reflect a unit's actual historical curtailments. As shown in Table 16, in the 2025 RRS, the assessed deliverability for Variable Resources are as follows (note that for resources other than Variable Resources the assessed deliverability throughout the entire year is the maximum of CIRs and transitional CIRs and therefore, the hourly output during any hour of the year for those resources is capped at this value):

Table 16. Assessed Deliverability caps for wind and solar ELCC Classes

ELCC Class	Zone	Summer Deliverability	Winter Deliverability MW (as percent of ENC)	Light Load Deliverability MW (as percent of ENC)
Onshore Wind	MAAC	Max(CIR, Transitional Deliv)	71%	64%
Onshore Wind	PJMWEST	Max(CIR, Transitional Deliv)	84%	80%
Onshore Wind	DOM	Max(CIR, Transitional Deliv)	77%	70%
Offshore Wind	MAAC	Max(CIR, Transitional Deliv)	95%	88%
Offshore Wind	DOM	Max(CIR, Transitional Deliv)	97%	92%
Solar Fixed	MAAC	Max(CIR, Transitional Deliv)	5%	51%
Solar Fixed	PJMWEST	Max(CIR, Transitional Deliv)	5%	56%
Solar Fixed	DOM	Max(CIR, Transitional Deliv)	5%	54%
Solar Tracking	MAAC	Max(CIR, Transitional Deliv)	5%	53%
Solar Tracking	PJMWEST	Max(CIR, Transitional Deliv)	5%	51%
Solar Tracking	DOM	Max(CIR, Transitional Deliv)	5%	58%

The Landfill Intermittent ELCC Class and Intermittent Hydropower ELCC Class are not included in **Table 16** because resources in those classes are studied for deliverability, under all studied scenarios, at their ICAP. Therefore, ICAP is the value at which the output of these resources is capped during all hours of the Delivery Year.

Limited Duration Resources

For each resource in the Limited Duration Resources category, an EFORD value is required. The EFORD value is calculated using the most recent five-year period of data submitted to eGADS. For the 2025 RRS, the data period used was October 1, 2019 through September 30, 2024.

Demand Resources

Demand Resources are modeled in bulk. In other words, no data for specific DR providers is required. The only input required for Demand Resources performance is the expected hourly availability in the aggregate as a function of the Nominated ICAP for a Delivery Year. This performance varies by season, specifically, in the 2025 RRS:

For summer, the total hourly availability is calculated as the Nominated ICAP times F, where F is defined as the ratio of simulated hourly load to 50/50 peak load. **Table 17** shows an illustration of the above where F varies by hour as illustrated in the A1993 Load Scenario column.

Table 17. Example of Hourly DR Availability in Summer Season

Hour	A1993 Load Scenario	Nominated DR ICAP for DY	DR Available In Hour
1	0.515	Y	0.515 x Y
2	0.499	Y	0.499 x Y
3	0.489	Y	0.489 x Y
...
929	1.038	Y	1.038 x Y

For winter, the total hourly availability is calculated based on the following 24-hour DR availability shape, which is applied to each day of the winter season regardless of load level in the load scenarios. This availability shape is estimated based on the most recent DR registrations in RPM. Table 18 shows the hourly DR availability shape used in the 2025 RRS, column named DR Availability in Winter Hour.

Table 18. Example of Hourly DR Availability in Winter Season

Hour	DR Availability in Winter Hour (as share of Nominated ICAP)	Nominated DR ICAP for DY	DR Available In Hour
1	0.785	Y	0.785 x Y
2	0.769	Y	0.769 x Y
3	0.772	Y	0.772 x Y
4	0.783	Y	0.783 x Y
5	0.801	Y	0.801 x Y
6	0.831	Y	0.831 x Y
7	0.927	Y	0.927 x Y
8	0.963	Y	0.963 x Y
9	1.000	Y	1.000 x Y
10	1.014	Y	1.014 x Y
11	1.020	Y	1.020 x Y
12	1.027	Y	1.027 x Y
13	1.020	Y	1.020 x Y
14	1.026	Y	1.026 x Y
15	1.002	Y	1.002 x Y
16	0.989	Y	0.989 x Y
17	0.968	Y	0.968 x Y
18	0.946	Y	0.946 x Y
19	0.938	Y	0.938 x Y
20	0.922	Y	0.922 x Y

Hour	DR Availability in Winter Hour (as share of Nominated ICAP)	Nominated DR ICAP for DY	DR Available In Hour
21	0.909	Y	0.909 x Y
22	0.870	Y	0.870 x Y
23	0.839	Y	0.839 x Y
24	0.825	Y	0.825 x Y

Combination Resources Except Hydro With Non-Pumped Storage

For each resource in the Combination Resources category, an EFORd value is required. The EFORd value is calculated using the most recent five-year period of data submitted to eGADS. For the 2025 RRS, the data period used was October 1, 2019 through September 30, 2024.

In addition, for each resource in the Combination Resources category except Hydro with Non-Pumped Storage, PJM needs to know if it can charge from the grid (i.e., open-loop) or if it cannot (i.e., closed-loop).

The ICAP of each Combination resource sets the cap for the maximum hourly output in the model.

Combination Resources – Hydro with Non-Pumped Storage

For each Hydro with Non-Pumped Storage resource, an EFORd value is required. The EFORd value is calculated using the most recent five-year period of data submitted to eGADS. For the 2025 RRS, the data period used was October 1, 2019 through September 30, 2024.

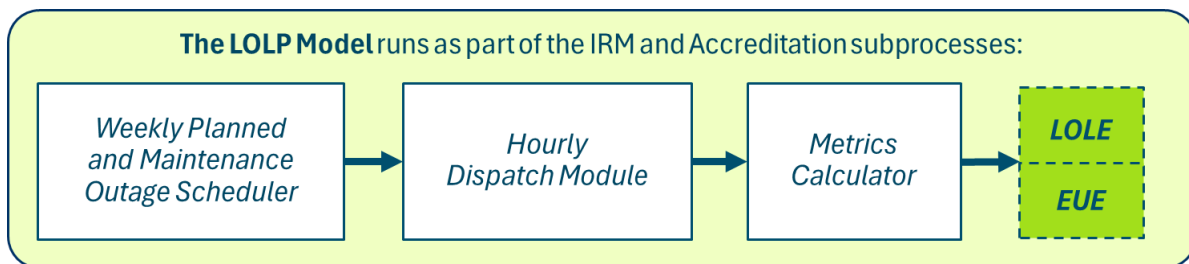
In addition, for the 2025 RRS, the following data inputs are used for Hydro with Non-Pumped Storage resources to model the intermittent component of these resources as well as the limited-duration (i.e. storage) component:

- Hourly Maximum Power for each month in the period June 1, 2012, through May 31, 2024. This value, if lower than the amount of CIRs of a resource, establishes the maximum available output to be modeled for the resource when using performance from a specific month in the historical period (the dispatch of resources is discussed later in the report).
- Minimum Allowable Water Flow for each day in the period June 1, 2012, through May 31, 2024. This value establishes the amount of water (in cubic feet of water) that is available to a resource to be converted into power for each hour in the historical period but that cannot be used to refill the storage component of the resource.
- Monthly average values for the ratio of the number of cubic feet of water required to produce a single megawatt-hour for each month in the period June 1, 2012, through May 31, 2024. This is used to convert the Minimum Allowable Water Flow above into megawatts to be used in the model.
- 24-hour rolling average streamflow data in cubic feet per hour for each hour in the period June 1, 2012, through May 31, 2024. This value, in conjunction with the monthly average values that can be used to convert water into power, establishes the historical hourly megawatts that resources in this ELCC Class have available to produce electricity or to refill their storage component.

- Ordinary Water Storage and Exigent Water Storage capability for each month in megawatt-hours. These monthly values determine the monthly maximum amount of megawatt-hours that each resource in the ELCC class can store in the model.
- Any cascading relationship to Hydropower with Non-Pumped Storage plants on the same river system in megawatts. In the model, water discharges from upstream hydro plants with cascading relationships will be available to downstream hydro plants for generation or storage. Also, the number of hours that the upstream water discharges take to arrive to the downstream plant is required as input.

LOLP Model

Figure 7. LOLP Model Overview



The LOLP model can be subdivided in three separate sub-processes as shown in **Figure 7**: i) the Weekly Planned and Maintenance Outage Scheduler, which schedules those outages on a weekly basis based on each load scenario, ii) the Hourly Dispatch Module, which dispatches hour by hour all the resources in the system to meet load in each load scenario, and iii) the Metrics Calculator, which calculates LOLE and EUE after all the load scenarios have been analyzed.

Weekly Planned and Maintenance Outage Scheduler

As its name indicates, the Weekly Planned and Maintenance Outage Scheduler uses the hourly load scenarios for the entire RTO and an estimated IRM value to develop the planned and maintenance outage schedule. The hourly load scenarios are converted to megawatt values (instead of being per-unitized) by multiplying the per-unitized values by the forecasted 50/50 annual peak. Note that this conversion is done using the forecasted 50/50 annual peak instead of a Candidate 50/50 Forecasted Peak Load, as the resulting schedule is not very sensitive to the choice of 50/50 annual peak load being used. The estimated IRM value (which could be the one calculated the previous time the model was run) is required because the objective of the scheduler is to levelize weekly installed reserves within each load scenario, and therefore, an estimated ICAP value must be calculated [the forecasted 50/50 annual peak * (1 + estimated IRM)]. The levelization process is accomplished by choosing a schedule that minimizes the sum of the square differences between the installed reserve percent for each week and the minimum of the 52 weekly installed reserve percent values. The installed reserve percent values are calculated with respect to the corresponding weekly peak load values. The following steps describe the scheduler.

1. For each load scenario in megawatts:
 - a. Initialize maintenance schedule for load scenario with 0 MW for all weeks.
 - b. For each week in load scenario:

- i. Determine weekly peak load.
- ii. Determine total estimated ICAP reserves as estimated ICAP minus weekly peak load.
- c. For each unit in Unlimited Classes (sorted from unit with greatest MW*week/year maintenance requirement to lowest):
 - i. Based on the number of planned/maintenance outages required R, determine the number of ways in which the R weeks can be scheduled contiguously in the Delivery Year (in general this will be $52 - R - 1$).
 - ii. For each of the $52 - R - 1$ ways in which the R weeks can be scheduled:
 1. For each week in load scenario:
 - a. Determine updated estimated ICAP reserves after scheduling planned and maintenance outages of current unit as share of weekly peak load.
 2. Determine the minimum weekly updated estimated ICAP reserves.
 3. For each week in load scenario:
 - a. Calculate the square difference of the updated estimated ICAP reserves as share of weekly peak load and the minimum weekly updated estimated ICAP reserves as share of weekly peak load.
 4. Calculate the sum of the square differences across the 52 weeks.
 - iii. The way to schedule the R weeks for the current unit is the one with the lowest sum of the square differences across the 52 weeks.
 - iv. Update the weekly total estimated ICAP reserves based on the previous step.
 - v. Update the maintenance schedule based on the decision for the current unit.

In addition to the planned and maintenance outages scheduled by the above reserve-levelizing heuristic, which results in most planned and maintenance outages scheduled during periods of lower loads, the model includes planned and maintenance outages intentionally scheduled to take place during high-risk periods. This step is taken to at least replicate planned and maintenance outage patterns observed during past historical events that have posed risk to the PJM system. **Table 19** shows the historical days as well as the level of planned and maintenance outages scheduled in the 2025 RRS.

Table 19. Planned and Maintenance Outage Scheduled During High-Risk Periods

Load Scenarios derived with weather data from DY	Season	Historical Planned/Maintenance Peak Seasonal Pattern replicated	Percent of Unlimited Installed Capacity On Planned/Maintenance Outage during Season's peak week
1993	Summer	Summer 2013	1.3%
1993	Winter	Polar Vortex 1	0.8%
1995	Summer	Summer 2013	1.3%
1995	Winter	Polar Vortex 1	0.8%
1996	Winter	Polar Vortex 2	5.0%
1999	Summer	Summer 2012	0.7%
2001	Summer	Summer 2012	0.7%
2002	Summer	Summer 2013	1.3%
2002	Winter	Polar Vortex 1	0.8%
2004	Winter	Polar Vortex 2	5.0%
2006	Summer	Summer 2012	0.7%
2010	Summer	Summer 2012	0.7%
2011	Summer	Summer 2012	0.7%
2012	Summer	Summer 2012	0.7%
2013	Summer	Summer 2013	1.3%
2013	Winter	Polar Vortex 1	0.8%
2014	Winter	Polar Vortex 2	5.0%
2022	Winter	Winter Storm Elliott	2.4%

If the reserve-levelizing heuristic schedules planned and maintenance outages in the peak week of the combination Delivery Year/season shown in the first two columns of **Table 19** that are less than the level shown in the far-right column, then the heuristic value is overwritten by the value in the far-right column. For example, using the first row of **Table 19**, if the heuristic produces planned and maintenance outages that are less than 1.3% of the total ICAP of Unlimited Resources during the summer peak week of the 13 scenarios associated with weather from Delivery Year 2013, then the quantity of outages in the summer peak weeks is set to 1.3% of the total ICAP of Unlimited Resources (if that is not the case, then the results from the heuristic are kept).

Hourly Dispatch Module

This module is the core of the LOLP model, as it determines the difference between total available supply and total demand for each hour, in each load scenario. Furthermore, the module identifies if an hour is flagged as a loss of load hour or if it does not. Finally, for resources that require “charging” (such as Limited Duration Resources and Combination Resources), this module also handles the decision to allow that charging to take place in an hour.

As shown above in **Figure 4**, this module requires a candidate solved load as an input since the 50/50 Forecasted Load that the resource portfolio (an input to the model) can serve while meeting the Reliability Criteria is unknown. These candidate solved loads are iteratively processed until the model finds the one that meets the Reliability Criteria.

Overall, the hourly dispatch module first determines the load value for the hour and then the available supply for the hour. The determination of available supply has roughly two steps: i) determining the megawatts available from Unlimited Resources, Variable Resource and the Variable Resource Component of Combination Resources and ii) if additional supply is needed for the hour, dispatching the rest of the resources in the following order

- Demand Resources
- 10-hour Storage
- 8-hour Storage
- 6-hour Storage
- 4-hour Storage
- Hydropower with Non-Pumped Storage
- Solar-Storage (4-hour) Hybrids Open-Loop
- Solar-Storage (4-hour) Hybrids Closed-Loop
- 4-hour Storage

The above order seeks to rank classes from "more available" to "less available", until the hourly load is met or a loss of load event occurs in the simulation.

Also, note that the hourly dispatch module also determines the hourly charging for Limited Duration Resources and Limited Duration Components in Combination Resources.

The following steps describe in detail the hourly dispatch module when a candidate solved load is input into the module³.

1. For each load scenario (1 to 403) in per-unitized terms:
 - a. For each hour h in the load scenario (1 to 8,760):
 - i. Make a random draw α from a normal distribution with mean 0 and standard deviation equal to 1.2% to determine forecast error applied to hourly loads (this draw is made daily).

³ Pseudo-code is provided in Appendix 1

- ii. Determine the modeled hourly load as the original per-unitized load times the Candidate Solved Load times $(1 + \alpha)$.
- iii. Determine temperature bin B that contains historical day D in which hour h is located.
- iv. For each Resource Performance Scenario r (1 to 100):
 1. Make a random draw of a day β from temperature bin B to determine historical performance that is used in the resource performance scenario r.
 2. For each class c in Unlimited Resources:
 - a. Determine the total amount of ICAP in each class c that is available (not on a forced outage or ambient derate) based on the forced outages and ambient derates in the corresponding hour in historical day β .
 3. Determine the total amount of available Unlimited Resources in hour h by adding up all the available megawatts for each class c in previous step and subtracting the amount of planned and maintenance outages scheduled in the week of load scenarios that contains h (this amount is provided by the Weekly Planned and Maintenance Outage Scheduler).
 4. For each resource v in Variable Resources classes:
 - a. If v is not in Hydropower Intermittent class:
 - i. Determine the total amount of the ENC (for wind and solar classes) and ICAP (for Landfill Intermittent) that is available by using the availability data in the corresponding hour in historical day β .
 - ii. Cap the value from the previous step at the corresponding deliverability caps.
 - b. Else if v is in Hydropower Intermittent class:
 - i. Based on the Delivery Year underlying load scenario s, determine the most similar Delivery Year Y in the period 2012–2023 (based on seasonal peak loads from the corresponding A scenarios). Then use the total amount of ICAP that is available by using the availability data at hour h in Delivery Year Y.
 - ii. Cap the value from the previous step at the corresponding deliverability caps.
 5. Determine the total amount of available Variable Resources in hour h by adding up all the available megawatts for each resource v in previous step.
 6. Add up the total amount of available Unlimited Resources and the total amount of available Variable Resources in hour h.

7. Determine the current supply/demand margin by subtracting the modeled hourly load from the value calculated in the previous step.
8. For each unit in the Hydropower with Non-Pumped Storage class, determine if the storage component needs to be refilled and use hourly streamflow data to refill. The refilling need is calculated as the difference between the storage megawatt-hour capacity and the current megawatt-hour state. Update state of storage and determine if there are excess megawatts due to storage being full (this will occur if the streamflow is greater than the refilling need). Note that historical streamflow data from Delivery Year Y in hour h is used, where Y is the most similar Delivery Year in the period 2012–2023 to the Delivery Year that underlies load scenario s (based on seasonal peak loads from the respective A scenarios).
9. Update the current supply/demand margin by adding: i) the minimum outputs and excess megawatts from units in the Hydropower with Non-Pumped Storage class and ii) the output of the variable component in the units in the Open-Loop Combination Resources classes.
10. If current supply/demand margin in the hour is greater than 0:
 - a. Set LOLE flag for the hour equal to 0 (and the EUE value equal to 0).
 - b. Determine the recharge needs of the Limited Duration Component in units in the Closed Loop Combination Resources. If there is need, proceed to recharge based on available output in the Variable Resource Component (modeled output follows the same methodology as Variable Resources with the exception that hourly availability is not capped), update storage component state of charge. If there is no need (or if there is leftover available output in the Variable Resource component), update the current supply/demand margin by adding the available output of the Variable Resource Components.
 - c. Determine the total recharge need within the Limited Duration classes and the Limited Duration Component in the units in the Open Loop Combination Resources. The recharge need is the total storage capability in megawatt-hours minus the current state of charge of the resources in the respective class. Note that the recharge need of a unit in an hour is capped at $ICAP \times (1 - EF_{Ord})$.
 - d. Determine the ratio: current supply/demand margin to total recharge need from previous step.
 - e. If ratio is greater than or equal to 1, proceed to fully recharge, update storage component state of charge. If ratio is less than 1, multiply the individual recharge needs by the ratio, and the result is the partial recharge allowed for each class. Update storage component state of charge.
 - f. Continue with next hour.

11. If current supply/demand margin in the hour is less than 0:
 - a. Compare the current supply/demand margin with the amount of available Demand Resources in the hour.
 - b. If the amount of Demand Resources in the hour is greater than or equal to the current supply/demand margin, set the amount of dispatched Demand Resources to the current supply/demand margin value. Set current supply/demand margin equal to zero. Set the LOLE flag for the hour equal to 0 (and the EUE value equal to 0).
 - c. If the amount of Demand Resources in the hour is less than the current supply/demand margin:
 - i. Set the amount of dispatched Demand Resources to the amount of available Demand Resources in the hour. Update current supply/demand margin reduced by the amount of dispatched DR.
 - ii. For each class/resource in the sorted list of Limited Duration and Combination Resources classes:
 1. If total available output of resources in class, capped at ICAP x (1-EFOrd), is greater than the current supply/demand margin. The available megawatts are impacted by the storage component state of charge, and: i) in the case of Hydropower with Non-Pumped Storage by the minimum outputs and excess megawatts from units in the class in the hour and ii) in the case of Combination Resources by the available output of the Variable Resource components.
 - a. Set class output equal to current supply/demand margin.
 - b. Update storage component state.
 - c. Set current supply/demand margin equal to zero. Set the LOLE flag for the hour equal to 0 (and the EUE value equal to 0).
 - d. Exit For Loop as there is no need to continue dispatching the other classes.
 2. Else, if total available output of resources in class, capped at ICAP x (1-EFORd), is less than the current supply/demand:
 - a. Set class output equal to total available output of resources in class.
 - b. Update storage component state.

- c. Update current supply/demand margin.
- d. Continue with next class/resource in the sorted list of Limited Duration and Combination Resources classes.
- e. If there are no more class/resource in the sorted list of Limited Duration and Combination Resources classes:
 - i. Set the LOLE flag for the hour equal to 1 (and the EUE value equal to current supply/demand margin).
- iii. Continue with next hour.

Metrics Calculator

After the Hourly Dispatch Module has completed going over all the hours in the load scenarios and resource performance scenarios, the module will output a matrix with 8,760 rows and 31 x 13 x 100 (40,300) columns with LOLE flag values and a matrix with the same dimensions filled with EUE values. **Table 20** shows a schematic of the LOLE matrix.

Table 20. Example of Hourly LOLE Matrix

Hour	Load Scenario 1 – Resource Performance Scenario 1	...	Load Scenario 1 – Resource Performance Scenario 100	...	Load Scenario 403 – Resource Performance Scenario 1	...	Load Scenario 403 – Resource Performance Scenario 100
1	0	...	1	...	0	...	1
2	0	...	1	...	0	...	0
3	0	...	0	...	1	...	0
...
8,760	0	...	0	...	1	...	1
Total days with any loss of load (days/year)	0	...	5	...	1	...	10

The calculation of the LOLE is performed by using the values in the matrix above. First, the 8,760 values in each of the columns are grouped in days (group of 24 values). If any of the 24 values is a 1 (i.e., if any hour of the day had loss of load), the counter of days with loss of load for the scenario is increased. The maximum amount that the counter can take in a scenario is 365 (i.e., every day of the year had at least one hour with loss of load) while the minimum is 0 (i.e., no hour with loss of load was observed in the scenario). The output of the LOLE counter for each scenario is illustrated by the bottom row in **Table 20**.

Each of the scenarios is weighted equally in PJM’s model. Therefore, the LOLE of the system is calculated as the average of the LOLE counter values. Because the counter for each scenario is in days/year, the average value (i.e., LOLE of the system) will also be in terms of days/year.

Table 21 shows a schematic of the EUE matrix.

Table 21. Example of Hourly EUE Matrix

Hour	Load Scenario 1 – Resource Performance Scenario 1	...	Load Scenario 1 – Resource Performance Scenario 100	...	Load Scenario 403 – Resource Performance Scenario 1	...	Load Scenario 403 – Resource Performance Scenario 100
1	0	...	100	...	0	...	15,000
2	0	...	2,500	...	0	...	0
3	0	...	0	...	1,000	...	0
...
8760	0	...	0	...	2,000	...	4,500
Total EUE (MWh/year)	0	...	10,000	...	5,000	...	25,000

The calculation of the EUE is performed by using the values in the matrix above. The EUE of each scenario is the sum of the EUE observed in each of the hours in the scenario. The output of the EUE counter for each scenario is illustrated by the bottom row in Table 21. As mentioned above, each of the scenarios is weighted equally in PJM’s model. Therefore, the EUE of the system is calculated as the average of the EUE counter values. Because the counter for each scenario is in megawatt-hours/year, the average value (i.e., EUE of the system) will also be in terms of megawatt-hours/year.

A final step in the calculation of the EUE, required because the RTO-EUE is an input to the calculation of the Capacity Emergency Transfer Objective (CETO) for Locational Deliverability Areas, is to adjust the EUE value calculated using the 50/50 Solved Peak Load. This adjustment is needed because the 50/50 Solved Peak Load is likely to be different from the Forecast Peak Load for a future Delivery Year. Therefore, to account for this difference, the EUE value calculated using the 50/50 Solved Peak Load is divided by the ratio of 50/50 Solved Peak Load to Forecast Peak Load.

Capacity Benefit of Ties (CBOT)

The Capacity Benefit of Ties (CBOT) represents the external emergency assistance that PJM relies on in the Installed Reserve Margin calculation. In the current model, the CBOT is an administratively set value to the IRM Calculation. In the 2025 RRS, the CBOT value was set at 1.5% of the 50/50 peak load. This value has remained constant for several years now. Effectively, the IRM would be 1.5 percentage points higher if the CBOT were set to zero.

IRM Calculation

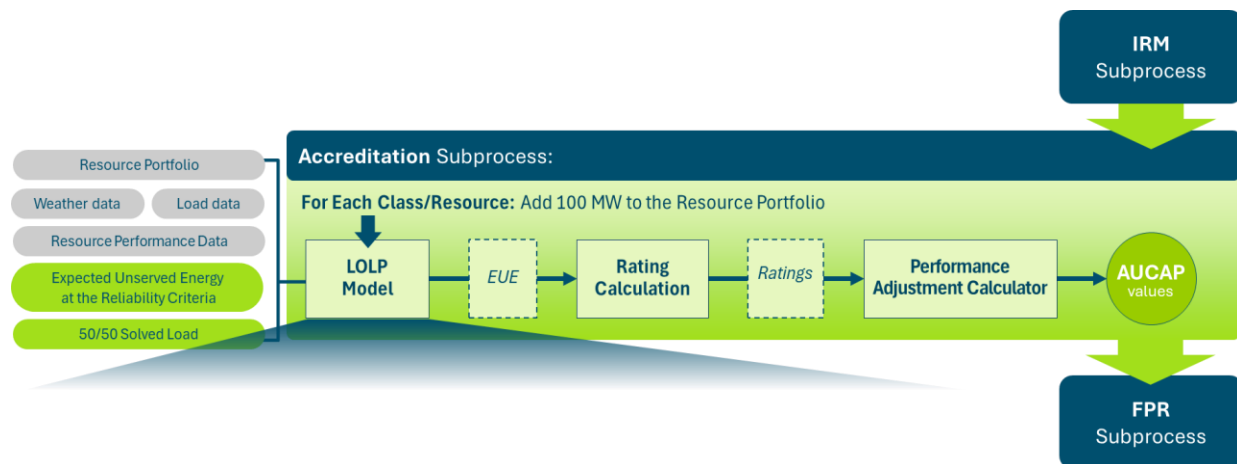
The IRM Calculation is the final step in the IRM Subprocess. This calculation uses the 50/50 Solved Peak Load output by the LOLP Model, the total ICAP in the resource portfolio, and the administratively set CBOT as follows to determine the IRM which expressed as a percentage:

Equation 1

$$IRM = \left(\frac{\text{Total ICAP in Resource Portfolio}}{\frac{50}{50} \text{ Solved Peak Load}} - 1 \right) - CBOT$$

Accreditation Subprocess

Figure 8. Accreditation Subprocess Overview



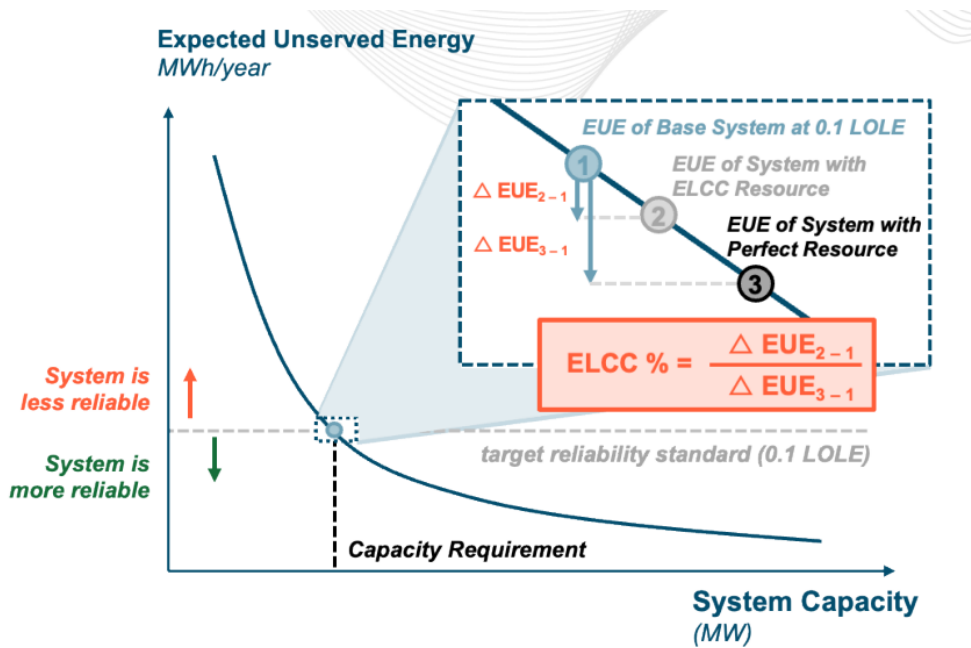
The Accreditation Subprocess requires inputs that are also inputs to the IRM Subprocess (e.g., Resource Portfolio) and outputs of the IRM Subprocess (50/50 Solved Peak Load and EUE at reliability criteria). The ELCC Accreditation Model then outputs the Accredited UCAP Values, which are key inputs into the FPR Subprocess.

This ELCC Accreditation Model has two different components: i) ELCC Class Ratings and Resource-Specific ELCC values are determined using the LOLP model followed by, ii) the calculation of a Performance Adjustment Factor for resources belonging to an ELCC Class for which an ELCC Class Rating is calculated.

LOLP Model and ELCC Class Ratings and Resource-Specific ELCC Values

ELCC Class ratings and Resource-Specific ELCC Values are based on incremental improvement of the EUE in the system compared against the incremental improvement determined by adding perfect capacity. In order to get the EUE in the applicable run, the LOLP model is run utilizing the same resource portfolio as the IRM run with one exception of adding an incremental quantity of 100 megawatts to the applicable ELCC Class/resource being run. The marginal benefit of each run is then determined based on the delta between the EUE in the applicable run versus the EUE in the IRM run (i.e., the run at the reliability criteria) as shown in **Figure 9**.

Figure 9. Determination of Marginal EUE Benefit Example



Perfect Capacity Run

Perfect capacity is represented in the model by adding 100 megawatts ICAP of an Unlimited Resource with no outages to the resource portfolio so that anytime it is needed it provides the full 100 megawatt output. The addition of this perfect capacity will result in a new EUE value, which is then compared against the RTO EUE to determine the incremental benefit or, more specifically, the reduction in EUE due to adding this perfect capacity.

ELCC Class Run

The ELCC class run is used to determine the Class Ratings portion of accreditation and is conducted for each ELCC Class⁴ separately. Each class run determines the reduction in EUE that results from adding 100 megawatt ICAP (or ENC, as applicable) of the ELCC Class. The 100 megawatt addition of the applicable ELCC Class is modeled with no adjustments to the availability rates used in the IRM run to calculate the RTO EUE (i.e., if in a given hour an ELCC Class was modeled as being 40% available in the IRM run, then in that hour only 40 megawatt of the 100 megawatt added will be modeled as available). The reduction in EUE after adding the 100 megawatt constitutes the marginal benefit of the ELCC Class, which is then compared against the marginal benefit of the perfect capacity run to ultimately determine the Class Rating as the ratio between the two.

⁴ No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

Figure 10. Equation to Determine Class Ratings



Resource-Specific Run

Resources that belong to an ELCC Class where no ELCC Class Rating is determined will receive a resource-specific ELCC value. This value is calculated by determining the benefit of adding 100 megawatt ICAP of the specific resource being evaluated. The 100 megawatt addition of the applicable resource is modeled with no adjustments to the availability rates used in the IRM run to calculate the RTO EUE. The reduction in EUE after adding the 100 megawatt constitutes the marginal benefit of the ELCC resource, which is then compared against the marginal benefit of the perfect capacity run to ultimately determine the Class Rating as the ratio between the two.

Figure 11. Equation to Determine Resource-Specific Ratings



ELCC Resource Performance Adjustment

Each resource belonging to a class that received an ELCC Class Rating, as described above, has an ELCC Resource Performance Adjustment factor calculated to allocate their share of the ELCC Class's total Accredited UCAP. This factor is based on the resources' average historical performance relative to the average performance of the class during hours and weather conditions (temperature bins) in which the system experienced loss of load in the IRM run.

In order to calculate this factor, the average availability across all observations in that hour and temperature bin are used to determine the resource's average availability. Next, the class's average availability is calculated by taking the average availability across all observations in that hour and temperature bin for all resources in that class. The relative risk-weighting of each hour and bin is calculated as a share of the total risk. This weighted risk is then applied to both the resource's average availability and the class's average ability across all hours and bins, which are then summed up to determine the weighted average resource availability and weighted average class availability, respectively. Lastly, the weighted average resource availability is divided by the weighted average class availability to

determine the ELCC Resource Performance Adjustment. **Figure 12** provides a schematic of the Performance Adjustment calculation.

Figure 12. Example Performance Adjustment Calculation

Bin <i>b</i>	Hour of day <i>h</i>	Weight <i>R_{bh}</i>	Unit's average availability <i>A_{ubh}</i>	Class's average availability <i>A_{cbh}</i>
winter1	1	0	0.98	0.80
winter1	2	0.3	0.95	1.00
winter1	3	0.2	0.95	0.89
⋮	⋮	⋮	⋮	⋮
winter1	24	0	0.84	0.99
winter2	1	0	0.89	0.91
winter2	2	0.2	0.98	0.81
winter2	3	0	0.95	0.90
⋮	⋮	⋮	⋮	⋮
winter2	24	0	0.92	0.99
winter3	1	0	0.88	0.87
winter3	2	0	0.85	0.90
winter3	3	0	0.96	0.95
⋮	⋮	⋮	⋮	⋮
winter3	24	0	0.94	0.96
⋮	⋮	⋮	⋮	⋮
summer34	1	0	0.98	0.89
summer34	2	0	0.96	0.89
summer34	3	0.3	0.99	0.96
⋮	⋮	⋮	⋮	⋮
summer34	24	0	0.95	0.94
Weighted Averages			0.97	0.93
Resource Performance Adjustment				1.04

Computation Reference:

- For each temperature bin (*b*) & hour of day (*h*):
 - Unit's (*u*) average availability across all observations in that bin & hour: A_{ubh}
 - Class's (*c*) average availability across all observations in that bin & hour: A_{cbh}
 - Relative risk weighting of the bin & hour (as a share of total risk): R_{bh}
- Weighted average of unit availability across all bin/hour pairs:

$$A_u = \sum_{b,h} R_{bh} \cdot A_{ubh}$$
- Weighted average of class availability across all bin/hour pairs:

$$A_c = \sum_{b,h} R_{bh} \cdot A_{cbh}$$
- Resource Performance Adjustment: $\frac{A_u}{A_c}$

Accredited UCAP and Accredited UCAP Factor

Accredited UCAP is the quantity of unforced capacity that an ELCC Resource can provide in a given Delivery Year.⁵

For resources that belong to an ELCC Class that has an ELCC Class Rating published, the Accredited UCAP will equal the following:

Table 22. Accredited UCAP Calculation for Resource's Belonging to a Class with a Published Class Rating

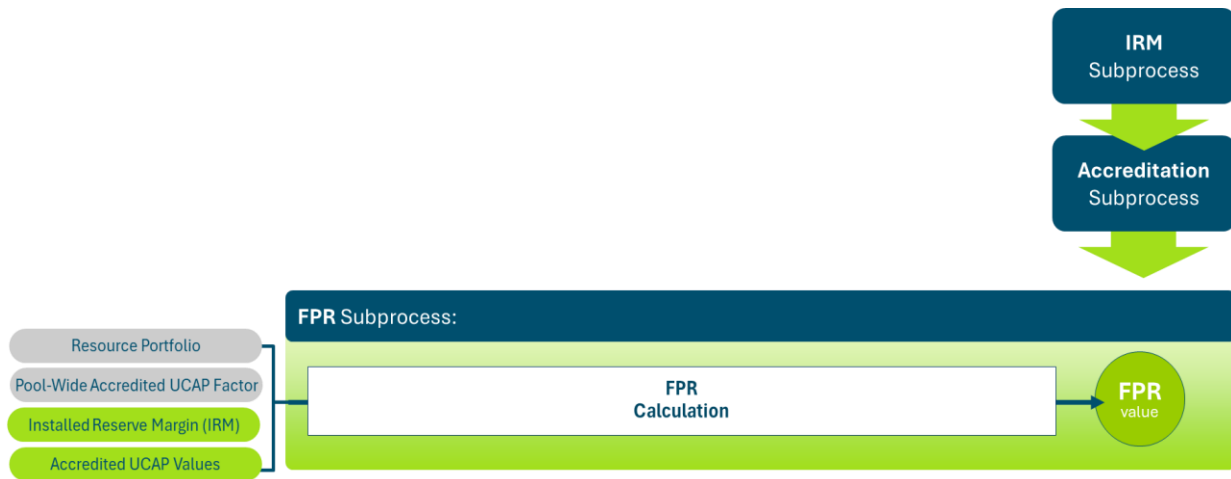
Resource Type	Accredited UCAP Calculation
Variable and Limited Duration Resources	Effective Nameplate Capacity x ELCC Class Rating x ELCC Resource Performance Adjustment
Unlimited Resources	Installed Capacity (ICAP) x ELCC Class Rating x ELCC Resource Performance Adjustment
Demand Resource	Nominated ICAP x ELCC Class Rating

⁵ Accredited UCAP cannot exceed the resource's Capacity Interconnection Rights including any transitional deliverability or winter CIRs awarded for the applicable time period.

For resources that belong to an ELCC Class for which no ELCC Class Rating has been determined, the Accredited UCAP shall be based on a resource-specific ELCC value based on the resource’s unique parameters as discussed above.

FPR Subprocess

Figure 13. FPR Subprocess Overview



As shown in Figure 13, the FPR Subprocess requires inputs that are outputs of the IRM Subprocess (i.e., IRM) and the Accreditation Subprocess (i.e., AUCAP Values) as well as the Resource Portfolio (also an input to the IRM Subprocess).

FPR Calculation

The Forecast Pool Requirement (FPR) can be viewed as the equivalent of the IRM in Accredited UCAP terms. In other words, if the IRM is the requirement in units of Installed Capacity to meet the RTO Reliability Criteria, the FPR is the requirement in units of Accredited Unforced Capacity (UCAP). As such, the mathematical formula to derive the FPR depends on the IRM and a factor that converts the total ICAP in the Resource Portfolio to total Accredited UCAP. That factor is the pool-wide Average Accredited UCAP Factor. This factor can be interpreted as the ELCC rating that the overall resource portfolio receives. Therefore,

Equation 2

$$FPR = (1 + IRM) \times \text{pool – wide average Accredited UCAP Factor}$$

Where the pool-wide Accredited UCAP Factor is calculated as:

Equation 3

$$\text{pool – wide average Accredited UCAP Factor} = \frac{\text{Total AUCAP in Resource Portfolio}}{\text{Total ICAP in Resource Portfolio}}$$

Discussion of Results

Delivery Years 2026/2027 and 2027/2028

Table 23 shows value for key inputs and outputs for Delivery Years 2026/2027 and DY 2027/2028. The values included in this report for those two Delivery Years are official values used in RPM activities. Therefore, the results for the rest of the Delivery Years included in this report are explained separately as informational only.

Table 23. Reliability Metrics for the 2026/2027 and 2027/2028 Delivery Years

DY	Total ICAP in Resource Portfolio (MW)	50/50 Solved Peak Load (MW)	CBOT (%)	IRM (%)	Total AUCAP in Resource Portfolio (MW)	Pool Wide Avg AUCAP Factor	FPR
2026/2027	193,738	160,682	1.5	19.1	149,149	0.7699	0.9170
2027/2028	198,379	163,224	1.5	20.0	153,095	0.7717	0.9260

Table 24 shows the ELCC Class Ratings for DY 2026/2027 and DY 2027/2028 as well as the EUE values resulting from adding an incremental quantity of each class (“EUE in ELCC Class Run”) and the EUE reduction in each case, which is calculated relative to the EUE resulting from the 1 in 10 cases (1,963.2 in 2026/2027 and 1,809.3 in 2027/2028). The ratings for each ELCC Class are calculated by dividing the corresponding EUE reduction by the EUE reduction generated by adding an incremental quantity of Perfect Capacity (shown in first row of **Table 24**).

Table 24. Class Ratings for the 2026/2027 and 2027/2028 Delivery Years

ELCC Class	2026/2027 EUE in ELCC Class Run	2026/2027 EUE Reduction	2026/2027 Rating	2027/2028 EUE in ELCC Class Run	2027/2028 EUE Reduction	2027/2028 Rating
Perfect Capacity	1,915.2	48.1	100%	1,768.7	40.6	100%
Onshore Wind	1,943.5	19.7	41%	1,792.8	16.5	41%
Offshore Wind	1,930.0	33.2	69%	1,782.1	27.2	67%
Fixed-Tilt Solar	1,959.2	4.1	8%	1,806.6	2.7	7%
Tracking Solar	1,958.0	5.3	11%	1,806.0	3.3	8%
Intermittent Landfill Gas	1,939.1	24.2	50%	1,790.0	19.3	48%
Intermittent Hydropower	1,944.8	18.5	38%	1,793.3	16.0	39%
Capacity Storage Resource (4-hr)	1,939.3	24.0	50%	1,785.6	23.7	58%
Capacity Storage Resource (6-hr)	1,935.3	27.9	58%	1,782.0	27.3	67%
Capacity Storage Resource (8-hr)	1,933.3	30.0	62%	1,780.9	28.3	70%
Capacity Storage Resource (10-hr)	1,928.7	34.5	72%	1,777.4	31.8	78%
Demand Resource	1,930.0	33.2	69%	1,772.0	37.3	92%
Nuclear	1,917.6	45.7	95%	1,770.7	38.6	95%

ELCC Class	2026/2027 EUE in ELCC Class Run	2026/2027 EUE Reduction	2026/2027 Rating	2027/2028 EUE in ELCC Class Run	2027/2028 EUE Reduction	2027/2028 Rating
Coal	1,923.4	39.8	83%	1,775.6	33.7	83%
Gas Combined Cycle	1,927.6	35.7	74%	1,779.2	30.1	74%
Gas Combustion Turbine	1,934.3	28.9	60%	1,784.6	24.7	61%
Gas Combustion Turbine Dual Fuel	1,925.8	37.5	78%	1,777.9	31.4	77%
Diesel Utility	1,919.4	43.8	91%	1,772.0	37.3	92%
Steam	1,928.3	34.9	73%	1,780.0	29.3	72%
Waste to Energy Steam	n/a	n/a	n/a	1,775.8	33.5	83%
Oil-Fired Combustion Turbine	n/a	n/a	n/a	1,777.0	32.3	80%

PJM’s study is performed analyzing an entire Delivery Year. The pool-wide Average Accredited UCAP Factor, FPR and the ELCC Class Ratings are useful to identify the annual value and the seasonal split for the calculated reliability metrics.

Table 25. Seasonal Resource Adequacy Metrics for 2026/2027 and 2027/2028 Delivery Years

Metric	2026/2027 Annual Value	2026/2027 Summer Share (%)	2026/2027 Winter Share (%)	2027/2028 Annual Value	2027/2028 Summer Share (%)	2027/2028 Winter Share (%)
LOLE (day/year)	0.1	35.0%	65.0%	0.1	24.4%	75.6%
LOLH (hours/year)	0.397	17.6%	82.4%	0.352	13.1%	86.9%
EUE (MWh/year)	1,963.3	6.1%	93.9%	1,809.3	4.6%	95.4%

As shown in Table 25, by design, the annual LOLE value is 0.1 days/year in both Delivery Years. The LOLE seasonal split for both Delivery Years shows that much of the LOLE is in the winter season, with the winter share increasing in the 2027/2028 Delivery Year compared to the 2026/2027 Delivery Year. The other two metrics, LOLH and EUE, are lower in the 2027/2028 Delivery Year than in the 2026/2027 Delivery Year, but both metrics in both Delivery Years show a marked winter slant, with increasing winter shares in the 2027/2028 Delivery Year compared to the 2026/2027 Delivery Year.

To understand these results, the focus should be on analyzing the inputs to the model.

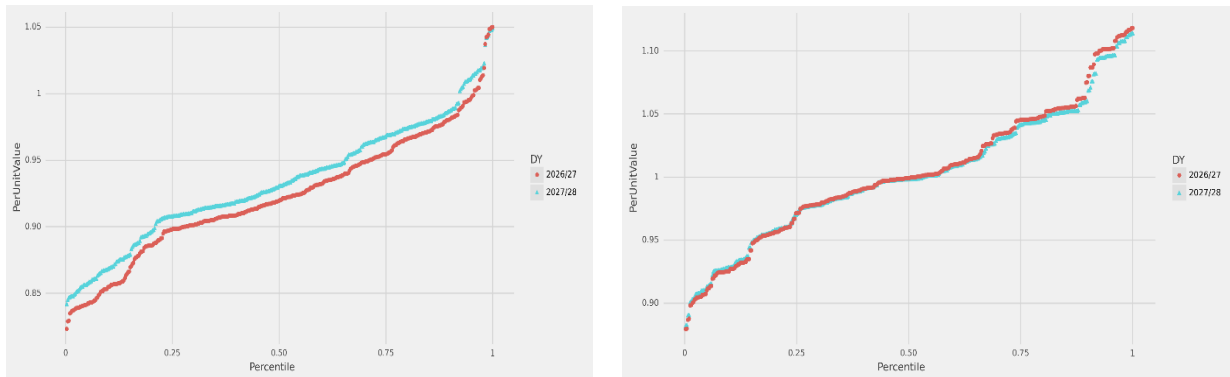
Inputs

Differences in the inputs on both the demand and supply side have an impact on the model and thus impact the results. First, we will discuss changes in load followed by changes to the resource portfolio and the underlying performance of the resources in that portfolio.

Load

Figure 14 shows the winter and summer peak load cumulative distribution functions (CDF) in per-unitized values (as share of the annual peak) for both Delivery Years.

Figure 14. Summer (right) and winter (left) peak load cumulative distribution functions



The winter CDF shows that except for the very few points in the extreme of the distribution, all other winter peak load values in the distribution are greater in magnitude in the 2027/2028 Delivery Year versus the 2026/2027 Delivery Year. The summer CDF shows, on the other hand, that starting around the 70th percentile, the 2027/2028 summer peak load values in the distribution are less than those in the 2026/2027 distribution. In other words, the winter peak load distribution is more conservative in the 2027/2028 Delivery Year, while the summer peak load distribution is less conservative in 2027/2028 Delivery Year compared to the distributions for the 2026/2027 Delivery Year. This, in principle, is one factor that explains the higher share of winter risk in the 2027/2028 Delivery Year for all metrics in Table 25.

Resource Performance:

The resource availability/unavailability patterns that tend to drive the loss of load risk in the model are those modeled on days in which seasonal loads are high. Therefore, to understand the higher winter risk shown in Table 25, the focus of this subsection is on the resource availability/unavailability patterns during such days. As described earlier in this report, historical days are grouped in bins based on THI. Since temperature is highly correlated with load, to model resource availability/unavailability patterns on days with high seasonal loads, resource availability/unavailability patterns are chosen from the coldest and hottest bins based on the weather of the relevant load scenario. For instance, Jan. 19, 1994, was a very cold day and therefore is placed in the coldest bin. As shown in Table 26, there are seven days post-2012 in that bin from which the modeled resource availability/unavailability patterns for days located in the coldest bin such as Jan. 19, 1994, are derived. The seven days are listed in Table 26 as well as the seven different availability rates for the total set of Unlimited Resources modeled in the runs for the 2026/2027 and 2027/2028 Delivery Years based on historical performance of resources in the corresponding resource portfolio at hour beginning 7 a.m. from the respective days.

Table 26. Modeled Unlimited Resource Availability/Unavailability Patterns for Days Located in the Coldest Bin (Hour Beginning 7)

Historical Day in Coldest Bin from which performance pattern is derived for modeled loads with weather from 1994-01-19	2026/2027 Modeled Availability Rate for Unlimited Resources at HB 7 (before reductions due to planned and maintenance outages)	2027/2028 Modeled Availability Rate for Unlimited Resources at HB 7 (before reductions due to planned and maintenance outages)
2014-01-07	76%	77%
2014-01-22	89%	89%
2014-01-28	90%	90%
2015-01-08	91%	92%
2015-02-20	92%	92%
2019-01-30	97%	97%
2019-01-31	90%	90%

Whenever the model simulates Jan. 19, 2027 (or 2028 in the 2027/2028 run), under the 13 load scenarios that use weather data from Delivery Year 1993, the model makes a random draw from the seven days shown in **Table 26**. Each of the days has identical probability of being selected, $1/7 = 14.3\%$. When the day is randomly drawn, the entire 24-hour availability rate pattern for Unlimited Resources (before modeling reductions due to planned and maintenance outages) is derived based on the drawn day. The availability rates at 7 a.m., to be used in days in the coldest bin, range from 76%–77% to 97% (unavailability rates ranging from 3% to 23%–24%).

As an example of a day in the hottest bin, one of the hottest days in the last 31 years was July 21, 2011. This day is placed in the hottest bin. As shown in **Table 27**, there are 28 days post-2012 in that bin from which derives the modeled resource availability/unavailability patterns for days located in the hottest bin, such as July 21, 2011. The 28 days are listed in **Table 27** as well as the 28 different availability rates for the total set of Unlimited Resources modeled in the runs for the 2026/2027 and 2027/2028 Delivery Years based on historical performance of resources in the corresponding resource portfolio at hour beginning (HB) 18 (6 p.m.) from the respective days.

Table 27. Modeled Unlimited Resource Availability/Unavailability Patterns for Days Located in the Hottest Bin (Hour Beginning 18)

Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2026/2027 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2026/2027 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2026/2027 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2026/2027 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)
2012-06-29	94%	94%	2016-08-13	96%	96%
2012-07-04	97%	97%	2018-06-18	96%	97%
2012-07-06	96%	96%	2018-07-01	97%	97%
2012-07-07	94%	94%	2018-08-28	97%	97%
2012-07-17	92%	92%	2018-09-04	98%	98%
2012-07-18	92%	92%	2018-09-05	97%	97%
2012-07-26	96%	96%	2019-07-19	97%	97%
2013-07-17	94%	94%	2019-07-20	97%	97%
2013-07-18	94%	94%	2019-07-21	96%	96%
2013-07-19	94%	94%	2021-06-29	94%	94%
2016-07-23	96%	96%	2021-08-12	96%	96%
2016-07-25	94%	94%	2022-07-24	95%	95%
2016-08-11	96%	96%	2023-07-27	95%	95%
2016-08-12	96%	96%	2023-07-28	94%	94%

Whenever the model simulates July 21, 2027 (or 2028, in the 2027/2028 run), under the 13 load scenarios that use weather data from Delivery Year 2011, the model makes a random draw from the 28 days shown in **Table 27**. Each of the days has identical probability of being selected, $1/28 = 3.6\%$. When the day is randomly drawn, the entire 24-hour availability rate pattern for Unlimited Resources (before modeling reductions due to planned and maintenance outages) is derived based on the drawn day. The availability rates at 6 p.m., to be used in days in the hottest bin, range from 92%–98% (unavailability rates ranging from 2%–8%).

Tables 28 and 29 show the corresponding values the availability of Variable Resources in the 2026/2027 and 2027/2028 Delivery Year model runs for the coldest and hottest bins at hour beginning 7 a.m. and 6 p.m., respectively.

Table 28. Modeled Variable Resource Availability/Unavailability Patterns for Days Located in the Coldest Bin (Hour Beginning 7)

Historical Day in Coldest Bin from which performance pattern is derived for modeled loads with weather from 1994-01-19	2026/2027 Modeled Availability Rate for Variable Resources at HB 7	2027/2028 Modeled Availability Rate for Variable Resources at HB 7
2014-01-07	27%	26%
2014-01-22	18%	18%
2014-01-28	15%	15%
2015-01-08	25%	24%
2015-02-20	23%	23%
2019-01-30	25%	23%
2019-01-31	10%	9%

Table 29. Modeled Variable Resource Availability/Unavailability Patterns for Days Located in the Hottest Bin (Hour Beginning 18)

Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2026/2027 Modeled Availability Rate for Variable Resources at HB 18	2027/2028 Modeled Availability Rate for Variable Resources at HB 18	Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2026/2027 Modeled Availability Rate for Variable Resources at HB 18	2027/2028 Modeled Availability Rate for Variable Resources at HB 18
2012-06-29	21%	22%	2016-08-13	21%	21%
2012-07-04	25%	26%	2018-06-18	35%	35%
2012-07-06	26%	29%	2018-07-01	32%	33%
2012-07-07	25%	27%	2018-08-28	29%	30%
2012-07-17	31%	33%	2018-09-04	17%	18%
2012-07-18	23%	23%	2018-09-05	15%	15%
2012-07-26	29%	28%	2019-07-19	34%	35%
2013-07-17	25%	27%	2019-07-20	37%	38%
2013-07-18	26%	28%	2019-07-21	26%	26%
2013-07-19	34%	35%	2021-06-29	27%	27%
2016-07-23	28%	29%	2021-08-12	28%	28%
2016-07-25	21%	23%	2022-07-24	31%	30%
2016-08-11	24%	25%	2023-07-27	25%	27%
2016-08-12	25%	25%	2023-07-28	27%	28%

In the case of the coldest bin, the availability rates of Variable Resources range from 9%–10% to 26%–27%. In the case of the hottest bin, the range is from 15% to 37%–38%.

Clearly, availability rates for both Unlimited Resources and Variables Resources tend to be lower in the coldest bin compared to those in the hottest bin.

Using per-unitized load values for January 19, 2027, 7 a.m. from load scenario A1993 and for July 21, 2027, 6 p.m. from load scenario A2011, as well as the 50/50 Peak Solved Load for the 2027/2028 run (163,224 MW), we can get an idea of the supply/demand margin when using the worst-case availability values for Unlimited and Variable Resources from the tables above.

Table 30. Illustrative comparison of supply/demand margin for a day in coldest bin and a day in hottest bin

Time Stamp	Scenario	Per-Unitized Load Value x 50/50 Peak Solved Load	Total ICAP for Unlimited Resources	Total ENC for Variable Resources	Day in Respective Bin showing lowest combined availability for Unlimited and Variable Resources	Lowest combined availability for Unlimited and Variable Resources	Margin when using lowest combined availability for Unlimited and Variable Resources
January 19, 2028, 7 a.m.	A1993	1.05 x 163,224 = 171,385	163,563	36803	2014-01-07	77% x 163563 + 26% x 36803=135512	-35,873
July 21, 2027, 6 p.m.	A2011	1.11 x 163,224 = 181,179	163,563	36803	2012-07-18	92% x 163563 + 23% x 36803=158943	-22,236

Winter Risk vs. Summer Risk

Table 30, while not including the available DR, Limited Duration and Combination Resources, and also not accounting for the planned and maintenance outages of Unlimited Resources in the calculation of the margin, provides an illustrative insight into why the model identifies more winter risk than summer risk. The margin on January 19, 2028, 7 a.m., is significantly less than the margin on July 21, 2027, 6 p.m. This is driven mainly by the lower availability of Unlimited Resources in the day in the respective temperature bin that shows the lowest combined availability for Unlimited and Variable Resources, i.e., 77% on 2014-01-07 (for worse performance day in the coldest bin) vs. 92% on 2012-07-18 (for worse performance day in the hottest bin), which largely offsets the lower demand observed in the winter day compared to the summer day. In general, the day with the worse performance in the hottest bin (2012-07-18) is expected to be drawn more often than the day with the worse performance in the coldest bin (2014-01-07):

Expected number of days that performance from 2012-07-18 will be drawn = Number of days in the hottest bin x Probability of drawing 2012-07-18 from hottest bin = 79 x 3.6% = 2.84

Expected number of days that performance from 2014-01-07 will be drawn = Number of days in the coldest bin x Probability of drawing 2014-01-07 from coldest bin = 18 x 14.3% = 2.57

However, the difference is diminutive (2.84 vs. 2.57), and the margin for the winter day when accounting only for Variable Resources and Unlimited Resources Availability is larger than that for the summer day as shown in **Table**

30. The implication of the latter point is that it is less likely that, during the winter day, the resources not yet accounted for in the calculation (DR, Limited Duration and Combination Resources) will be able to bring the margin to a positive value and avoid the loss of load.

Top Performance Patterns Contributing to Loss of Load Events

Following on the discussion of winter risk vs. summer risk, the resource performance patterns that drive the loss of load events in the model can be identified. In the 2027/2028 run, this can be done by analyzing the [Info for Loss of Load Hours](#) (XLS) posted file, specifically the ActualPerfDay column. **Table 31** provides the top 10 resource performance patterns that drive loss of load in the model as well as the share of the LOLH that each of them contribute.

Table 31. Top Ten Resource Performance Patterns that Drive Loss of Load

Resource Performance Pattern	LOLH Share
2014-01-07	36.0%
2022-12-24	21.3%
2014-01-08	7.8%
2022-12-25	4.9%
2022-12-26	3.5%
2022-12-23	2.9%
2014-01-22	2.4%
2019-01-31	1.5%
2012-07-18	1.2%
2014-01-03	1.2%

Given the larger share of winter risk in the three resource adequacy metrics (LOLE, LOLH, EUE), it is not surprising to see the majority of the top 10 resource performance patterns driving risk in the model to be from winter days (there is only one summer performance pattern from 2012-07-18, which is the worst summer performance pattern as discussed earlier). It is important to distinguish the contribution that each of these performance patterns provide to observe loss of load in the model from how often these performance patterns are simulated in the model. For example, as discussed above, the 2014-01-07 (2014 Polar Vortex) performance pattern is simulated only when a day in the coldest bin is selected (there are only 18 days in this bin in the period), and then the conditional probability of selecting the performance pattern from 2014-01-07 is 14.3%. The fact that the contribution of the 2014-01-07 is 36% means that the loss of load events that the model identifies are driven by the few times the 2014-01-07 performance pattern is simulated in the model due to the high volume of forced outages that such performance pattern includes. Other performance patterns tend to be simulated more often, such as the performance from 2012-07-18 as discussed above; however, that performance pattern does not include a high volume of forced outages and therefore its contribution to LOLH as shown in **Table 31** is only 1.2%.

Duration and Size of Daily Loss of Load Events

Table 32 provides statistics, by season, about the number of hours in a day that see loss of load (not necessarily contiguous hours) in the 2027/2028 Delivery Year run. Note that the statistics were calculated excluding days that did not have loss of load.

Table 32. Seasonal Statistics Regarding Number of Hours in a Day Experiencing Loss of Load

Season	Average (hours)	Minimum (hours)	25 th Percentile (hours)	50 th Percentile (hours)	75 th Percentile (hours)	Maximum (hours)
Winter	4.1	1	1	3	6	18
Summer	1.9	1	1	2	2	6

Table 33 provides statistics, by season, about the number of megawatt-hours in a day that go unserved (i.e., event size) in the 2027/2028 run. Note that the statistics were calculated excluding days that did not have loss of load.

Table 33. Seasonal Statistics Regarding Megawatt-hours in a Day Experiencing Loss of Load

Season	Average (MWh)	Minimum (MWh)	25 th Percentile (MWh)	50 th Percentile (MWh)	75 th Percentile (MWh)	Maximum (MWh)
Winter	22,839	17	2,302	7,954	26,836	208,609
Summer	3,420	10	667	1,847	4,716	22,158

From earlier discussions, we know that the share of EUE and LOLH (as well as LOLE) in the summer is less than in the winter in the 2027/2028 run. In addition, from **Tables 32 and 33**, we can also conclude that the fewer events in summer are much milder than those events in winter: the 75th percentile for the duration statistics is three times worse in winter (6 hours vs. 2 hours) while the 75th percentile for event size is about five times worse in winter (26,836 MWh vs. 4,716 MWh). These seasonal differences have implications for the accreditation that resources get, especially limited duration resources as discussed later.

Seasonal Risk and ELCC Class Ratings

The larger share of winter risk in the 2026/2027 and 2027/2028 analyses explained above also drives the resulting ELCC Class Ratings shown in **Table 34**. As detailed in the Accreditation Subprocess description, resource accreditation is based on the EUE reduction that a marginal addition of a certain class/resource provides to the system relative to the EUE reduction that a marginal addition of perfect capacity provides. Intuitively, if most of the loss of load risk resides in a given season, then resources that are expected to perform better in such given season will be in a better position to provide the required EUE reduction and therefore get a higher ELCC rating.

On the above point, a 41% ELCC Class Rating in 2027/2028 for Onshore Wind and a 61% ELCC Class Rating in 2027/2028 for Gas Combustion Turbine, for example, can be roughly understood by observing that the three resource adequacy metrics (LOLE, LOLH, EUE) have larger shares in the winter season than in the summer season. Historical performance data shows that Onshore Wind resources perform better during PJM winter risk periods rather

than during PJM summer risk periods, and therefore Onshore Wind’s ELCC Class Rating is increased by the fact that winter risk is predominant in the 2027/2028 run. Conversely, Gas Combustion Turbine resources have historically performed better during PJM summer risk periods rather than during PJM winter risk periods, and therefore Gas Combustion Turbine’s ELCC Class Rating is decreased by the seasonal risk patterns in the 2027/2028 run.

In general, the drivers of the ELCC Class Ratings in the 2027/2028 run can be summarized as shown in **Table 34**.

Table 34. General drivers of the ELCC Class Ratings

ELCC Class	2027/2028 Rating	Driver
Onshore Wind	41%	Better expected performance in winter critical hours than in summer critical hours
Offshore Wind	67%	Better expected performance in winter critical hours than in summer critical hours
Fixed-Tilt Solar	7%	Worse expected performance in winter critical hours than in summer critical hours
Tracking Solar	8%	Worse expected performance in winter critical hours than in summer critical hour
Intermittent Landfill Gas	48%	Stable performance (at rating level) across most of risk hours
Intermittent Hydropower	39%	Stable performance (at rating level) across most of risk hours
Capacity Storage Resource (4-hr)	58%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (6-hr)	67%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (8-hr)	70%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (10-hr)	78%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Demand Resource	92%	Lower DR reduction capability in winter compared to summer
Nuclear	95%	Small frequency of forced outages throughout the year
Coal	83%	Forced outages that tend to be more frequent during winter risk hours as well as planned and maintenance outages
Gas Combined Cycle	74%	Forced outages that tend to be more frequent during winter risk hours
Gas Combustion Turbine	61%	Forced outages that tend to be more frequent during winter risk hours

ELCC Class	2027/2028 Rating	Driver
Gas Combustion Turbine Dual Fuel	77%	Forced outages that tend to be more frequent during winter risk hours
Diesel Utility	92%	Forced outages that tend to be more frequent during winter risk hours
Steam	72%	Forced outages that tend to be more frequent during winter risk hours as well as planned and maintenance outages
Waste to Energy Steam	83%	Forced outages that tend to be more frequent during winter risk hours
Oil-Fired Combustion Turbine	80%	Forced outages that tend to be more frequent during winter risk hours

Loss of Load Hours vs. Non-Loss of Load Hours

As described in the Accreditation Subprocess section, the accreditation of classes and resources is impacted by modeled performance during: i) loss of load hours and ii) other hours in days/periods where the system is energy constrained. The share of the accreditation that can be attributed to modeled performance during loss of load hours can be estimated by identifying the hours in which the EUE reductions resulting from adding an increment of perfect capacity occur. **Table 35** shows the share of this EUE reduction by season and by performance in loss of load hours and non-loss of load hours in the 2027/2028 Delivery Year run. Consistent with what was discussed about seasonal risk shares for LOLE, LOLH and EUE, the majority of the EUE reduction when adding an increment of perfect capacity occur in the winter, 88.8%. Within the winter, a non-negligible share of the EUE reduction occurs during non-loss of load hours, 13.67%, while the rest occur during loss of load hours, 75.13%. In summer, almost all the EUE reductions occur during loss of load hours. This is because EUE reductions due to performance in non-loss of load hours are only relevant during energy-constrained periods, and such periods do not tend to occur during summer.

Table 35. 2027/2028 Delivery Year Share of EUE Reduction by Season

Season	Share of EUE Reduction Occurring in Loss of Load Hours	Share of EUE Reduction Occurring in Non-Loss of Load Hours	Total
Summer	11.17%	0.02%	11.2%
Winter	75.13%	13.67%	88.8%
Total	86.31%	13.69%	100%

Table 35 implies that only 86.31% percent of the accreditation that a class or resource receives depends on modeled performance during the loss of load hours. The remaining 13.69% is attributable to modeled performance during non-loss of load hours in days/periods where the system is energy-constrained by enabling the recharge of storage resources or delaying the deployment of storage so that storage resources can provide additional output during the loss of load hours.

The set of loss of load hours with the associated performance time stamps for the 2027/2028 Delivery Year run can be found in the [Info for Loss of Load Hours](#) (XLS) posted file. Additionally, PJM has identified the set of performance time stamps associated with EUE reduction in Non-Loss of Load Hours. These additional performance time stamps are posted at [Additional Critical Performance Hours](#) (XLS).

Figures 15 and 16 show a heatmap by season and hour beginning for the hours in the Loss of Load Hour set and the Non-Loss of Load Hour set. In Figure 16, it is clear that the majority of the hours in the Non-Loss of Load Hour set are located between the morning and evening peaks in the winter season (i.e., between hour beginning 10 and hour beginning 16).

Figure 15. Heatmap for Loss of Load Hours

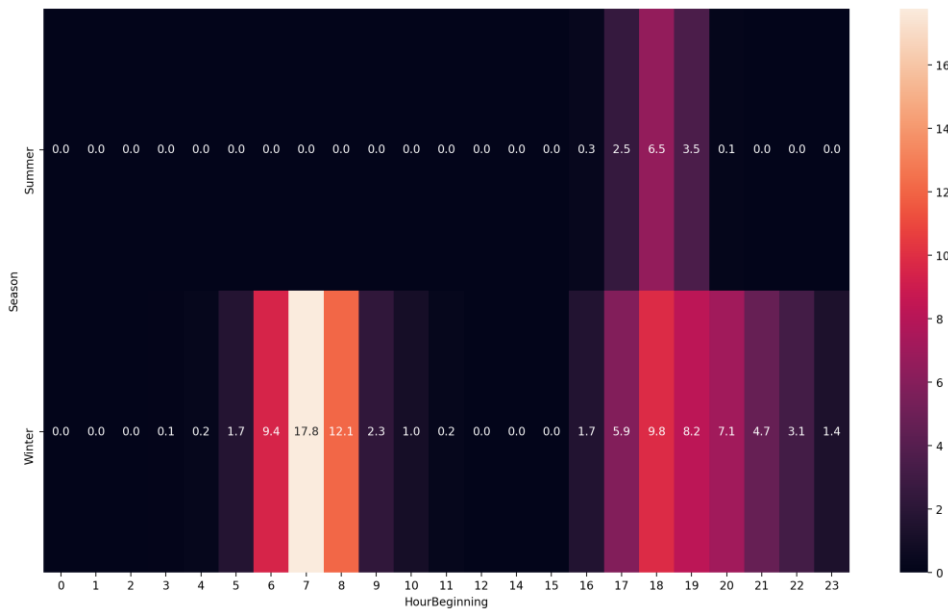


Figure 16. Heatmap for Non-Loss of Load Hours

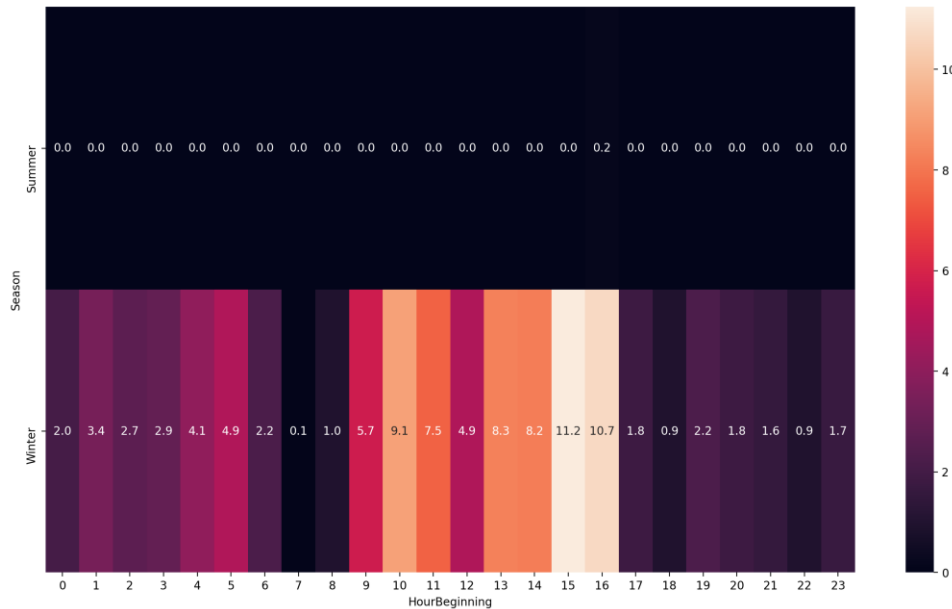


Table 36 summarizes the average performance of ELCC Classes during the Loss of Load Hours and during the hours that show EUE reduction that are not Loss of Load Hours. Using the 86.31% and 13.69% values as weights for performance during Loss of Load Hours and performance during Non-Loss of Load Hours, respectively, the ELCC Class Ratings can be approximated by performing a weighted average calculation.

Table 36. Average Performance of ELCC Classes during Loss of Load Hours and Non- Loss of Load Hours identified as impacting the 2027/2028 accreditation

ELCC Class	Avg. Performance Loss of Load Hours (as % of ENC/ICAP) Weight = 0.8631	Avg. Performance Non Loss of Load Hours (as % of ENC/ICAP) Weight = 0.1369	Rounded Weighted Average	2027/2028 ELCC Class Rating	Difference: Rounded Wgt Avg – Class Rating
Onshore Wind	39.22%	46.41%	40%	41%	-1%
Offshore Wind	64.64%	78.27%	67%	67%	0%
Fixed-Tilt Solar	4.40%	22.24%	7%	7%	0%
Tracking Solar	5.91%	24.38%	8%	8%	0%
Intermittent Landfill Gas	47.52%	46.32%	47%	48%	-1%
Intermittent Hydropower	39.19%	39.16%	39%	39%	0%
Capacity Storage Resource (4-hr)	68.54%	-6.72%	58%	58%	0%
Capacity Storage Resource (6-hr)	77.77%	0.36%	67%	67%	0%
Capacity Storage Resource (8-hr)	77.53%	19.49%	70%	70%	0%

ELCC Class	Avg. Performance Loss of Load Hours (as % of ENC/ICAP) Weight = 0.8631	Avg. Performance Non Loss of Load Hours (as % of ENC/ICAP) Weight = 0.1369	Rounded Weighted Average	2027/2028 ELCC Class Rating	Difference: Rounded Wgt Avg – Class Rating
Capacity Storage Resource (10-hr)	82.74%	44.88%	78%	78%	0%
Demand Resource	95.97%	63.96%	92%	92%	0%
Nuclear	95.11%	94.76%	95%	95%	0%
Coal	83.11%	82.38%	83%	83%	0%
Gas Combined Cycle	74.82%	69.87%	74%	74%	0%
Gas Combustion Turbine	62.02%	53.77%	61%	61%	0%
Gas Combustion Turbine Dual Fuel	77.71%	74.22%	77%	77%	0%
Diesel Utility	91.86%	91.42%	92%	92%	0%
Steam	72.41%	69.81%	72%	72%	0%
Waste to Energy Steam	82.73%	81.37%	83%	83%	0%
Oil-Fired Combustion Turbine	79.81%	77.20%	79%	80%	-1%

The weighted average performance values match the 2027/2028 ELCC Class Ratings for all ELCC Classes except three, and in those three nonmatching cases, the difference is a single percentage point. Note that not all ELCC Class ratings fully match because the above identification of the Non-Loss of Load Hours is performed using the Perfect Capacity run (and each ELCC Class requires its own specific run).

Identifying the set of hours that impact the ELCC Class Ratings as well as the modeled performance for each ELCC Class at such hours provides further insights as to what drives the ratings results. For instance,

- The two solar classes see their ELCC Class Ratings increased by their average performance in the Non-Loss of Load Hours because a large share of such hours is between the morning and evening winter peaks, where solar performance improves relative to the performance during the morning and evening winter peaks (which tend to be where the winter loss of load hours occur).
- The two shorter duration storage classes (4-hr. and 6-hr.) see their ELCC Class Ratings decreased by their average performance in the Non-Loss of Load Hours because storage resources in such hours are recharging (i.e., they are consuming energy from the grid or producing negative output). The two longer duration storage classes (8-hr. and 10-hr.) also see their ELCC Class Ratings decrease due to the above but to a lesser degree because in some hours of the Non-Loss of Load Hours set, they produce output to the grid by virtue of their longer duration.

- The DR ELCC Class Rating is decreased by their average performance in the Non-Loss of Load Hours because Demand Resources cannot be dispatched to recharge storage and therefore, in a large share of the Non-Loss of Load Hours (~30%), the modeled DR output is zero.

The calculations shown in **Table 36** can be performed for several of the ELCC Classes using the posted data as follows:

- For Onshore Wind, Offshore Wind, Fixed-Tilt Solar, Tracking Solar, Intermittent Landfill Gas, find the output of the ELCC class in the applicable column in the file [Hourly Time Series Output for Variable Resources Classes](#) (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Performance in Loss of Load Hours. For the Avg. Performance in Non-Loss of Load Hours, follow the same procedure instead of using the Non-Loss of Load Hours file.
- For Intermittent Hydropower, follow the same procedure as above, but instead use the [Critical Performance Hours Hydro](#) (XLS) posted file. This file has one tab including performance timestamps during loss of load hours and another tab including performance timestamps during non-loss of load hours. Intermittent Hydropower uses different files than other Variable Resources because the class is not subjected to the temperature binning method.
- For ELCC Classes in the Unlimited Resources category:
 - Find the output of the ELCC class in the applicable column in the file [Hourly Time Series Forced Outage for Unlimited Resources Classes](#) (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Forced Outage Rate in Loss of Load Hours. For the Avg. Forced Outage Rate in Non-Loss of Load Hours, follow the same procedure instead using the Non-Loss of Load Hours file.
 - Find the output of the ELCC class in the applicable column in the file [Hourly Time Series Ambient Derate for Unlimited Resources Classes](#) (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Ambient Derate in Loss of Load Hours. For the Avg. Ambient Derate in Non-Loss of Load Hours, follow the same procedure instead using the Non-Loss of Load Hours file.

- To allocate the average amount of planned and maintenance outages (POMO) scheduled during Loss of Load Hours (3,679.87 MW) and the average amount of planned and maintenance outages scheduled during Non-Loss of Load Hours (4,041.99 MW), use the [Share of Scheduled Maintenance and Planned Outages by Unlimited ELCC](#) (XLS) file. For instance, for Coal, the share in the file is 0.366664. In the case of the POMO scheduled during Loss of Load Hours, Coal will get $0.366664 \times 3,679.87 = 1,349.276$ MW of allocation. To convert this value to a rate, divide the POMO megawatt value by the total ICAP of the ELCC Class in the Resource Portfolio. In the case of Coal and POMO scheduled during Loss of Load Hours, $1,349.276 / 35,964 \text{ MW} = 0.037517$. This value is the Avg. POMO Rate in Loss of Load Hours. The same procedure can be used to derive the Avg. POMO Rate in Non-Loss of Load Hours but using 4,041.99 MW instead of 3,679.87 MW.
- To derive the Avg. Performance in Loss of Load Hours in **Table 36**:
 - Avg. Performance in Loss of Load Hours = $1 - \text{Avg. Forced Outage Rate in Loss of Load Hours} - \text{Avg. Ambient Derate in Loss of Load Hours} - \text{Avg. POMO Rate in Loss of Load Hours}$.

To derive the Avg. Performance in Non-Loss of Load Hours, follow the same formula as above but using the values calculated for the Non-Loss of Load Hours.

- For Demand Resources: find the output of the DR class in the file [Info for Loss of Load Hours](#) (XLS) for each of the loss of load hours. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Performance in Loss of Load Hours. For the Avg. Performance in Non-Loss of Load Hours, follow the same procedure instead using the [Simulated DR Performance in Additional Critical Performance Hours](#) (XLS) posted file. In this same file, the Calculations tab illustrates how to use the simulated performance during the non-loss of load hours and the simulated performance during loss of load hours to come up with the weighted average performance during all critical hours.
- For Limited Duration Resources: the calculation is identical to the calculation for Demand Responses. However, due to confidentiality reasons, the output of each Limited Duration ELCC Class cannot be posted publicly.

Delivery Years 2028/2029 Through 2035/2036

PJM also performed analysis for Delivery Years in the period 2028/2029 through 2035/2036.

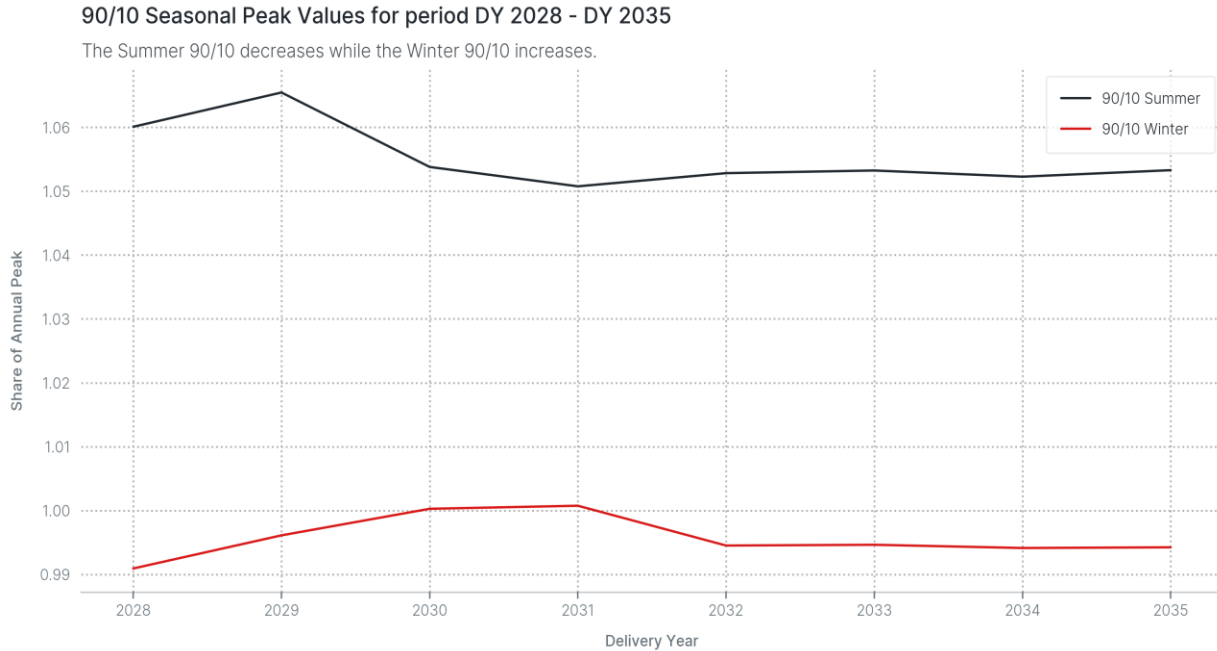
Inputs

Load

The 2025 PJM Load Forecast includes increasing extreme winter loads and decreasing extreme summer loads, which result in upward pressure on winter risk for the PJM system. **Figure 17** shows the 90/10 seasonal peak values for the Delivery Years 2028/2029 through 2035/2036 as a share of the respective 50/50 annual peaks. For the winter values, there is an increasing trend between the 2028/2029 and DY 2031/2032 Delivery Years, while for the summer

values, there is a decreasing trend in the same period. The values for both seasons stabilize after the 2031/2032 Delivery Year.

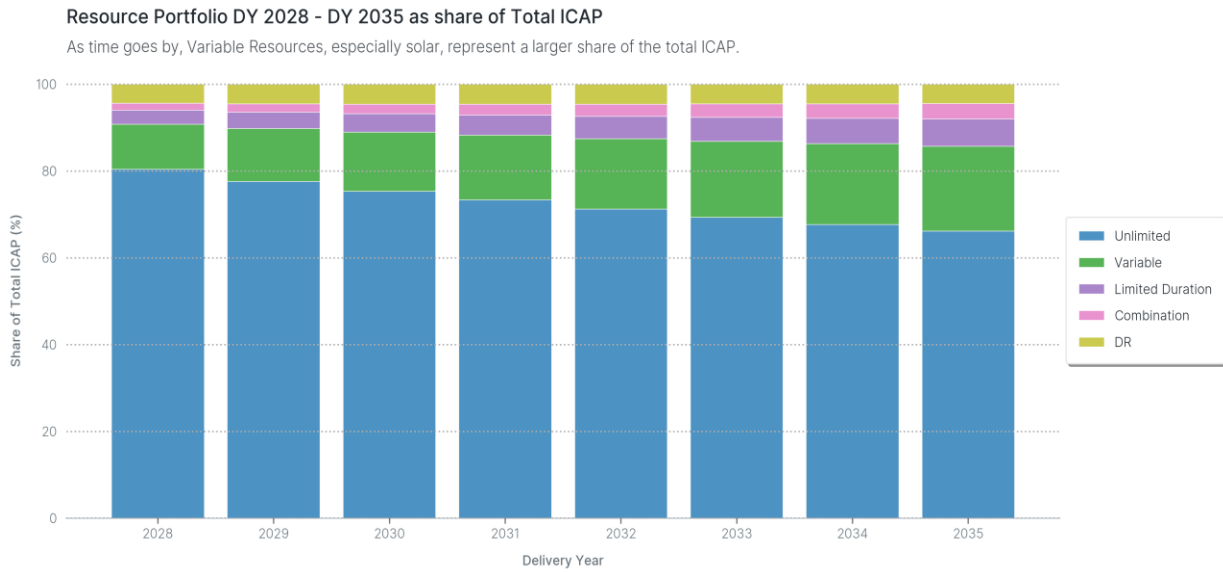
Figure 17. 90/10 Seasonal Peak Values for Delivery Years 2028/2029 through 2035/2036



Resource Portfolios

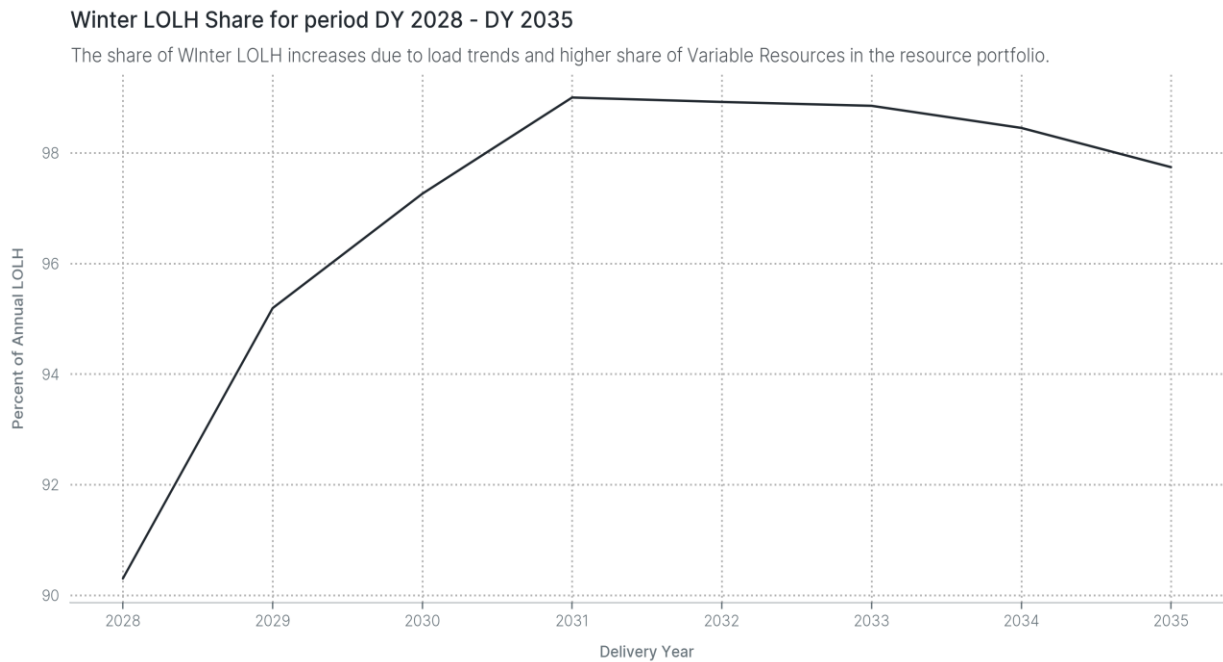
The resource portfolio for each Delivery Year was developed using a forecast of resource additions and retirements produced by a vendor. **Figure 18** shows that the ICAP share of Unlimited Resources decreases throughout the 8-year period while the ICAP share of Variable Resources increases (the majority of the forecasted additions are solar resources). The gradual change in resource portfolio throughout the study period puts upward pressure on winter risk for the PJM system as Unlimited Resources retire and are replaced to a large extent by solar resources.

Figure 18. Resource Portfolio as Share of Total ICAP for Delivery Years 2028/2029 through 2035/2036



Outputs – Seasonal Risk: The combination of the above two inputs in the analysis produces an increase in winter risk as shown in **Figure 19**. The winter LOLH share starts at about 90% in DY 2028, consistently increasing until DY 2031 when the winter LOLH reaches a level close to 99%. After DY 2031, the winter LOLH plateaued at 98%–99%.

Figure 19. Winter LOLH Share for Delivery Years 2028/2029 through 2035/2036



Loss of Load Hours vs. Non-Loss of Load Hours Impact on Accreditation

Figure 20 shows the share of the EUE reduction due to the addition of perfect capacity that is triggered by output during loss of load hours. It can be observed that it starts very high at the beginning of the period (slightly below 80% in 2028/2029 Delivery Year), while it gets reduced drastically as the system faces more winter risk and more energy-constrained days (41% in 2035/2036 Delivery Year).

Figure 20. Share of Accreditation that Depends on Expected Performance During Loss of Load Hours Delivery Years 2028/2029 through 2035/2036

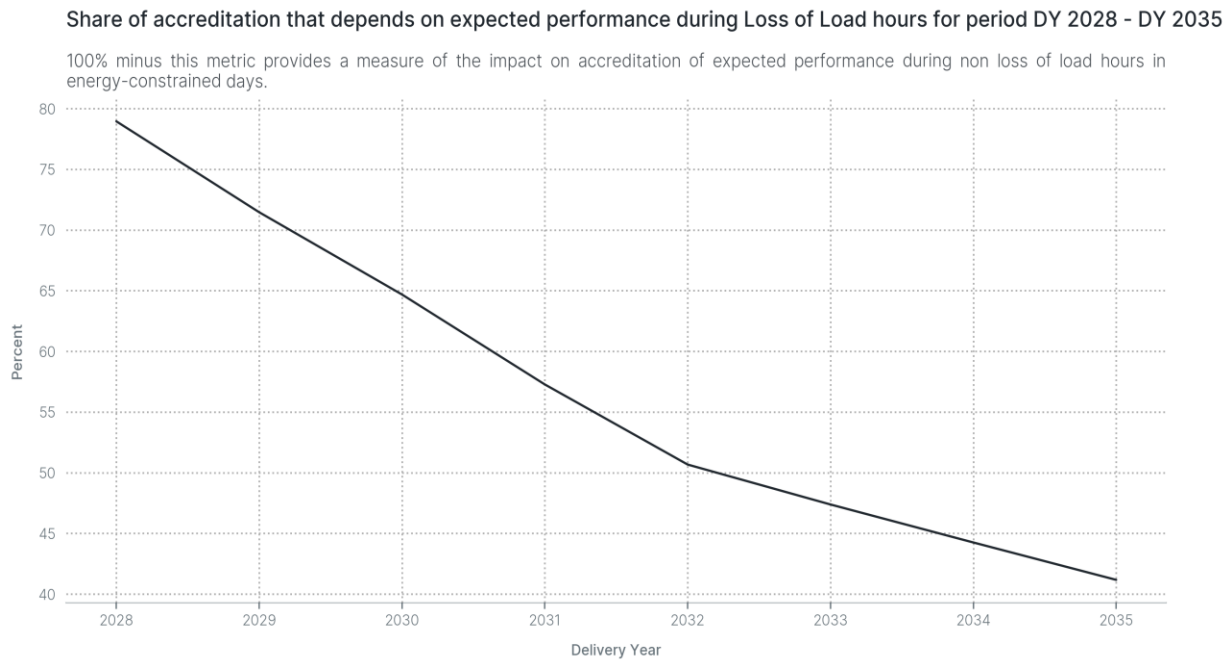


Figure 20 portrays the decrease in ELCC Class Ratings for ELCC Classes that are not modeled as capable of recharge storage (i.e., Demand Resources) or ELCC Classes included in the Limited Duration resources, which face challenges to perform during energy-constrained days. The importance of enabling the charging of storage consistently increases as the system faces more winter risk and more energy-constrained events.

Top Performance Patterns Contributing to Loss of Load Events

Table 37 shows the top five historical performance patterns that drive system risk in 2028/2029 Delivery Year (left-hand side table) and 2035/2035 Delivery Year (right hand side table).

Table 37. Top Five Historical Performance Patterns Driving System Risk in a Delivery Year

Historical Performance Pattern Day	LOLH Share in 2028/2029 Delivery Year	Historical Performance Pattern Day	LOLH Share in 2035/2036 Delivery Year
2014-01-07	38.6%	2022-12-26	34.0%
2022-12-24	16.6%	2014-01-08	25.2%

Historical Performance Pattern Day	LOLH Share in 2028/2029 Delivery Year	Historical Performance Pattern Day	LOLH Share in 2035/2036 Delivery Year
2014-01-08	13.1%	2014-01-07	14.5%
2022-12-26	6.9%	2019-01-31	5.8%
2019-01-31	3.2%	2014-01-22	5.3%

As the resource portfolio changes in the study period, the performance patterns that drive risk in the model also change. This occurs because classes that performed well (i.e., onshore wind) on 2014-01-07 did not perform as well on, say, 2014-01-08. As the wind share of ICAP increases in the resource portfolio, the historical performance pattern of 2014-01-07 will drive less risk in the model, while the historical performance pattern of 2014-01-08 will drive more risk in the model. As wind makes up a larger share of the resource portfolio in the future, the types of events that winter risk is observed on the system tend to shift toward those days that see high correlated unavailability of the wind fleet.

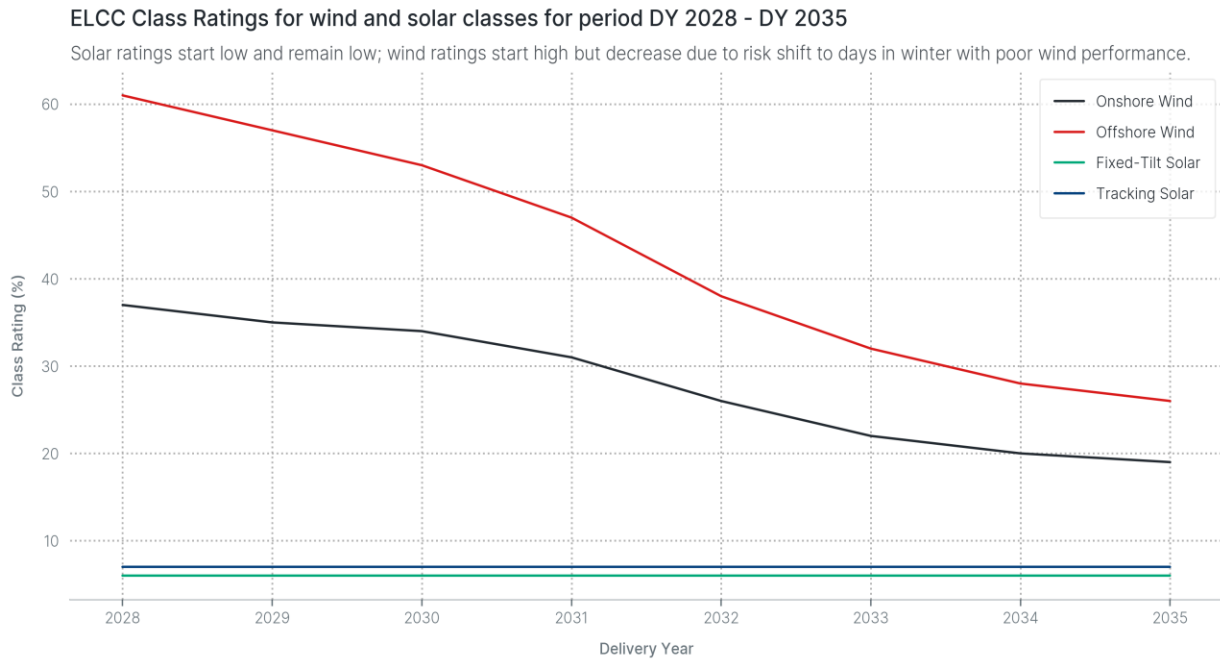
ELCC Class Ratings

Variable Resource Class Ratings

As shown in **Figure 21**, the ELCC Class Ratings for the Tracking Solar Class and Fixed-Tilt Solar Class remain stable at low values during the entire period. This is due to the high level of risk in winter hours, where solar output is relatively low.

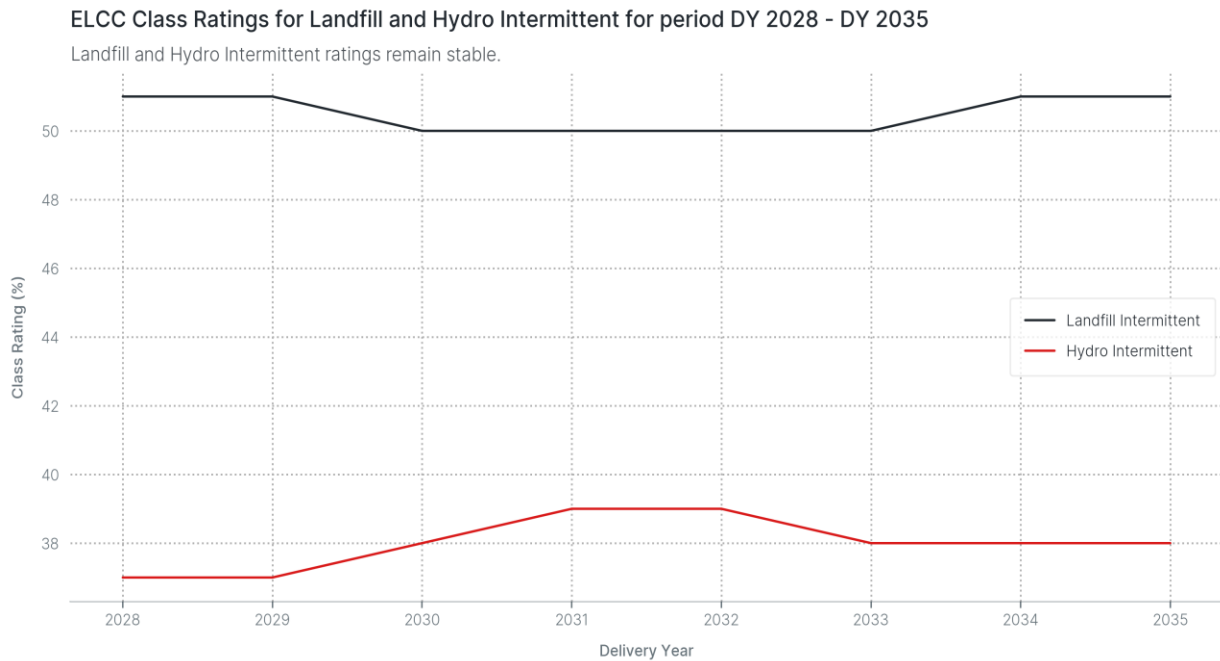
Onshore Wind Class and Offshore Wind Class have ratings that are trending significantly downward progressively through the delivery years. This is driven by resource portfolio changes, specifically the large amount of wind resources added to the system. These additions shift the hours of risk to other winter hours where the performance pattern of wind resources is not as good as during the early Delivery Years in the period.

Figure 21. ELCC Class Ratings for Wind and Solar Classes for Delivery Years 2028/2029 through 2035/2036



As shown in **Figure 22**, Intermittent Landfill Gas Class and Intermittent Hydropower Class Ratings remain relatively stable throughout the Delivery Years due to their performance patterns being overall consistent.

Figure 22. ELCC Class Ratings Landfill and Hydro Intermittent for Delivery Years 2028/2029 through 2035/2036

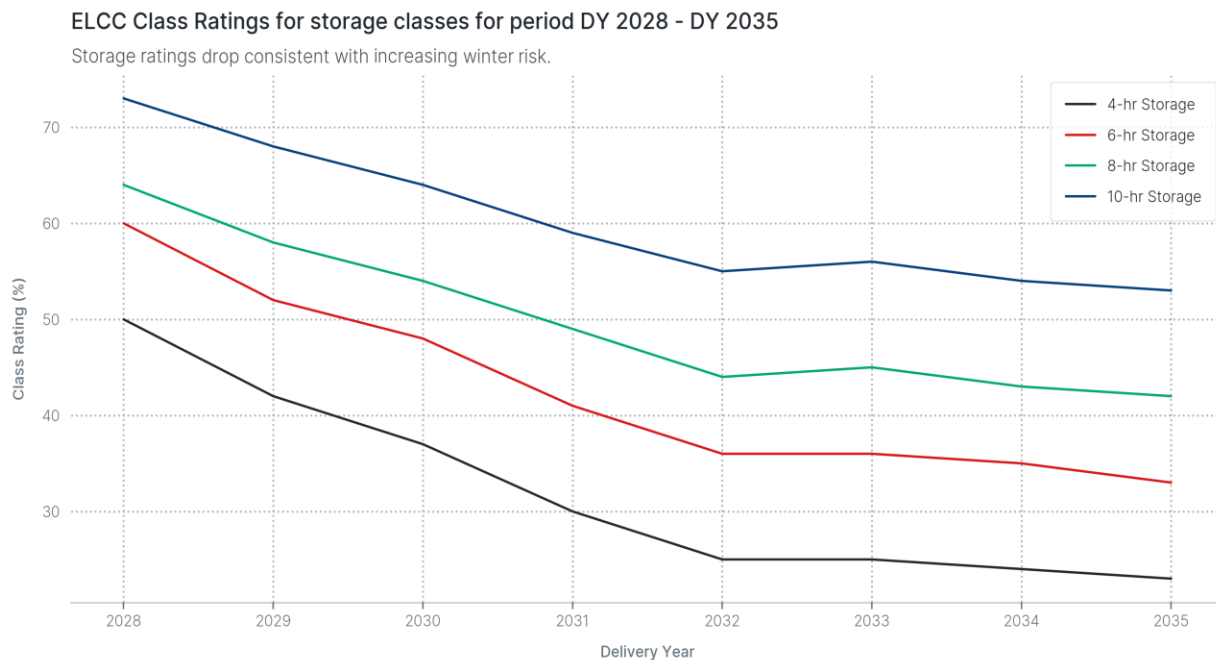


Limited Duration Resource Class Ratings

As shown in **Figure 23**, Limited Duration Resource’s Class Ratings see a consistent decline primarily due to increasing winter risk where winter events tend to last multiple hours due to flat load shapes and the protracted duration of Unlimited Resources’ forced outages under cold weather, which is not conducive to sustained good performance by storage resource for the entire duration of the risk events. Also, the increasing penetration of Limited Duration Resources also contributes to the increase in winter risk, and therefore to the decrease of their own rating.

In addition to the increase in winter risk, the reduction in the Class Ratings for Limited Duration Resources is also impacted by the fact that Limited Duration Resources cannot charge other storage resources during energy-constrained events while providing energy benefits to the system. Therefore, their performance during critical hours that are non-loss of load hours puts downward pressure on their ELCC Class Ratings, and as shown in **Figure 20**, those non-loss of load hours tend to gain more importance in the latter half of the studied period.

Figure 23. ELCC Class Ratings for Storage Classes for Delivery Years 2028/2029 through 2035/2036



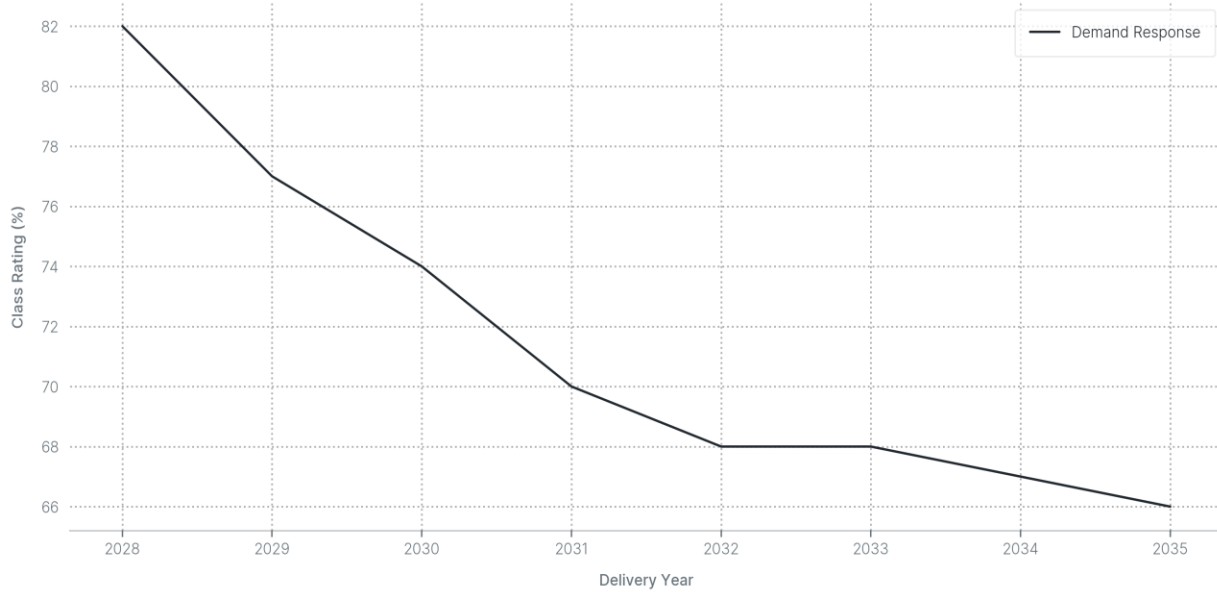
Demand Resource Class Ratings

Demand Resources ELCC Class Ratings consistently decline throughout the studied period due to increasing winter risk. This is due to two factors: i) reduction capability of DR in the winter period is assumed to be less than during the summer period and ii) DR resources are not assumed to be deployed to charge storage resources, and, as shown in **Figure 24**, the ability to charge storage toward the end of the study period becomes more important for accreditation purposes.

Figure 24. ELCC Class Ratings for DR for Delivery Years 2028/2029 through 2035/2036

ELCC Class Ratings for DR for period DY 2028 - DY 2035

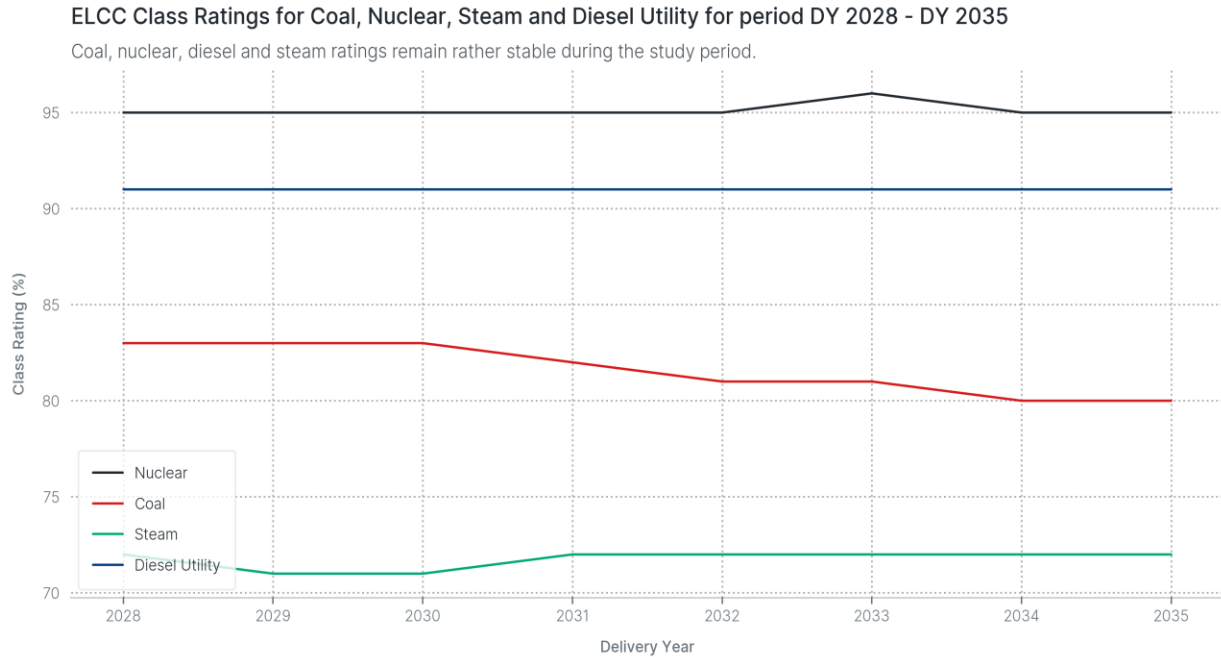
DR rating drops due to increasing winter risk and an increasing number of energy-constrained events in addition to DR resources not assumed to charge storage resources.



Unlimited Resource Class Ratings

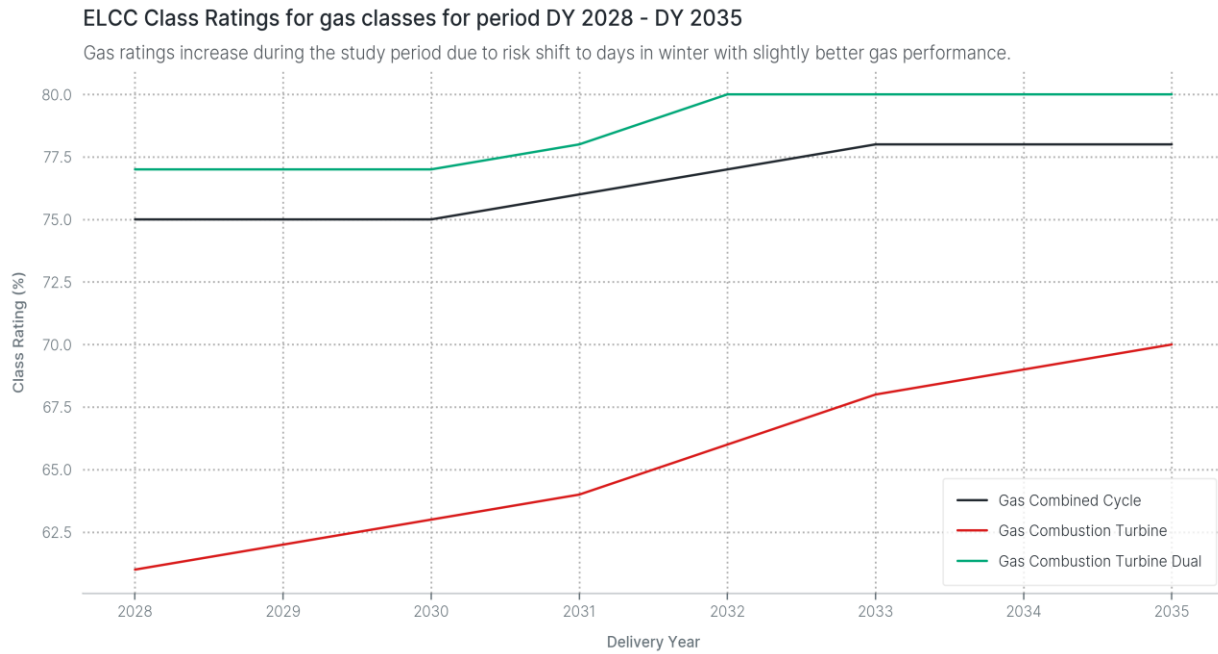
Nuclear, Coal, Steam and Diesel Utility Class Ratings remain rather stable in the study period due to their winter output not being as volatile as that of other classes.

Figure 25. ELCC Class Ratings for Coal, Nuclear, Steam and Diesel Utility for Delivery Years 2028/2029 through 2035/2036



Overall, the ratings for the gas classes see some increase (for Gas Combined Cycle and Gas Combustion Turbine Dual) and a larger increase (for Gas Combustion Turbine) due to a gradual shift in winter historical performance patterns driving the winter risk in the model. For the same but opposite reasons as Variable and Limited Duration Resources see declining class ratings as their penetration increases, as the penetration of gas resources become a smaller share of the system (due to load growth outpacing the additions of these resources), the Accredited UCAP of these resources increase. In other words, these resources being a smaller share of the resource portfolio means their correlated outage events no longer pose the same level of systemic risk as they do in the first half of the studied period.

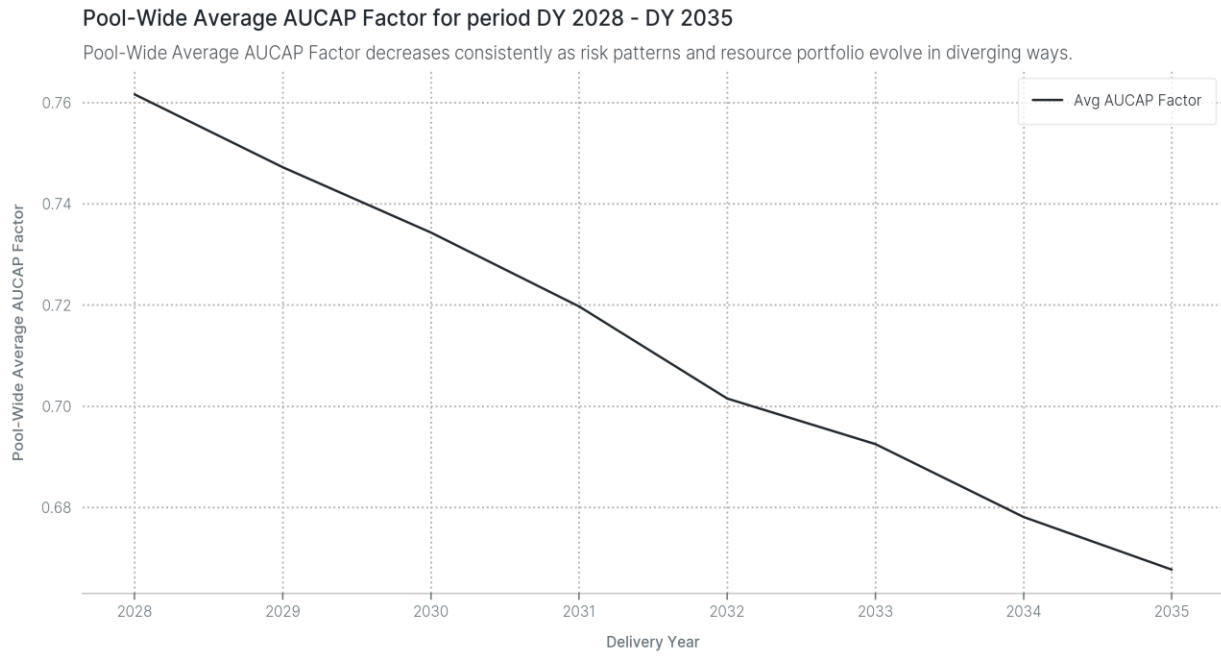
Figure 26. ELCC Class Ratings for Gas Classes for Delivery Years 2028/2029 through 2035/2036



Pool-wide Average Accredited UCAP Factor

The pool-wide Average Accredited UCAP Factor consistently declines due to the diverging evolution of demand and supply. While winter loads tend to increase throughout the studied period at a higher pace than summer loads, the resource portfolio evolves by increasing the share of resources that have poor performance in winter and therefore low Accredited UCAP. This definitionally results in declining pool-wide Average Accredited UCAP Factor.

Figure 27. Pool-wide Average Accredited UCAP Factor for Delivery Years 2028/2029 through 2035/2036



Appendix I: Pseudo-code

Algorithm: LOLE & EUE calculation

Inputs: Load scenarios $Load_{s,h}$, Resource Availability ($A_{s,h,r}$) scenarios, EFORD, THI Bins, ...

Outputs: LOLE & EUE

```

1  for s in 403 Scenarios:
2      for h in 8760 Hours:
3          for r in 100 performance cases:
4               $SDM_{s,h,r} = -Load_{s,h}$                                 #Loads were unitized so
                    that LOLE=0.1
5              for i in resource assets
6                  switch i:
7                      case Unlimited:  $SDM_{s,h,r,i} += ICAP_i - Out_{s,h,r,i}^{unplanned}$ 
8                      case Solar/Wind, Landfill:  $SDM_{s,h,r,i} += \min(A_{s,h,r,i}, Cap_{h,i})$                 #A=(ENC or
                     $ICAP) * AvailRate$ 
9                      case Hydro:  $SDM_{s,h,r,i} += \min(A_{Y^*,h,i}, Cap_{h,i})$                             # Y* is
                    determined by s
10
11                  $SDM_{s,h,r} -= Out_{s,h}^{Planned}$ 
12                 for i in Hydro non-pump                                # hydro non-pump recharge/discharge is
                    independent from SDM
13                      $SDM_{s,h,r} += \sum_i \{MinOutput_{h,i}\}$                                 # add the minimum
                    output of hydro
14                     if  $S_{s,h,r,i} < SCap_i$ :                                # recharge
                    when it's not full
15                          $\Delta S_{s,h,r,i} = \min(Wd_i, SCap_i - S_{s,h-1,r,i}), SDM_{s,h,r} -= \Delta S_{s,h,r,i}, S_{s,h,r,i} += \Delta S_{s,h,r,i}$ 
16                     else:                                #Storage is full, excess output
                    added to grid

```

```

17          $SDM_{s,h,r} += XOutput_{Y^*,h,i}$            #Excess output is determined by the stream
           flow in year Y*

18      $SDM_{s,h,r} += \sum_i A_{s,h,r,i}$            # add variable resource component in open loop
           combination resources

19     for i in VarRsrc Open Loop:  $S_{s,h,r,i}^{hybrid} = A_{s,h,r,i}$            # same variable resource as above

20

21     if  $SDM_{s,h,r} > 0$ 
       #Recharge/Injection

22         for i in Closed-Loop Combo                       # recharged by attached
           Variable Resources

23              $\Delta S_{s,h,r,i} = \min(SCap_i - S_{s,h-1,r,i}, ICap_{inj}, A_{s,h,r,i}^{VarRsc})$ ,           # determine recharge need of
           Lim-Dur Cmpnt

24              $S_{s,h,r,i} = S_{s,h-1,r,i} + \Delta S_{s,h,r,i}, A_{s,h,r,i}^{VarRsc} -= \Delta S_{s,h,r,i}$ ,           # update availability in Var.
           Cmpnt

25

26          $\Delta S_{s,h,r} = 0$ 

27         for i in Lim-Dur. Cmpnt of Open-Loop Combo and other limited duration resources (incl.
           pumped storage)

28              $\Delta S_{s,h,r,i} = \min(ICap_{inj,i}(1 - EFORD_i), SCap_i - S_{s,h-1,r,i})$ 

29              $\Delta S_{s,h,r} += \Delta S_{s,h,r,i}$ 

30         for i in storage assets:  $S_{s,h,r,i} = S_{s,h-1,r,i} + \frac{\min(\Delta S_{s,h,r}, SDM_{s,h,r})}{SDM_{s,h,r}} \cdot \Delta S_{s,h,r,i}$            # pro-rata for
           each battery

31

32     else
       #Discharge/Withdraw

33          $DR_{s,h,r} = \min(A_{s,h}^{DR}, |SDM_{s,h,r}|)$ ,

34          $SDM_{s,h,r} += DR_{s,h,r}$ 

```

35

36

for i in storage assets ordered heuristically

37

if $SDM_{s,h,r} < 0$

38

if i in variable resource open loop:

39

$$\Delta S_{s,h,r,i} = \min(ICap_{s,h,r,i}^{wd}(1 - EFORD_i), SCap_i - S_{i,s,h,r}, |SDM_{s,h,r}|)$$

40

if i in limited duration resources:

41

$$\Delta S_{s,h,r,i} = \min(ICap_{s,h,r,i}^{wd}(1 - EFORD_i), SCap_i - S_{i,s,h,r}, |SDM_{s,h,r}|)$$

42

$$S_{s,h,r,i} = S_{s,h-1,r,i} - \Delta S_{s,h,r,i}$$

43

$$SDM_{s,h,r} += \Delta S_{s,h,r}$$

44

Else

45

Break

46

47

$$LOLH_{s,h,r} = 1\{SDM_{s,h,r} < 0\}, EUE_{s,h,r} = \min\{SDM_{s,h,r}, 0\} \quad \# 1\{\cdot\} = 1 \text{ when true and } 0 \text{ otherwise}$$

48

$$LOLE_{s,r,d} = 1\{\sum_i^{24} LOLH_{s,i,r} > 0\} \quad \# \text{ for the hours in the same day, same load and performance scenario}$$

49

$$50 \quad LOLH = \frac{1}{403 \times 100} \sum_s^{403} \sum_h^{8760} \sum_r^{100} LOLH_{s,h,r}, EUE = \frac{1}{403 \times 100} \sum_s^{403} \sum_h^{8760} \sum_r^{100} EUE_{s,h,r}, LOLE = \frac{1}{403 \times 100} \sum_s^{403} \sum_d^{365} \sum_r^{100} LOLE_{s,d,r}$$

Appendix II: Indicative ELCC Values for ELCC Classes with No Class Rating

Figure 28 and Table 38 show indicative ELCC values for ELCC Classes that do not receive an ELCC Class Rating at the time of this report. Please note that these values are based on an assumed resource mix, are non-binding, and provided only for informational purposes. The actual ELCC value of individual resources within these classes will be based on a resource-specific ELCC calculation and may materially differ from the class-wide or indicative hybrid values shown below. As such, no reliance shall be made on any of the indicative values shown in this Appendix II.

Figure 28. Indicative Values for ELCC Classes with No Class Rating

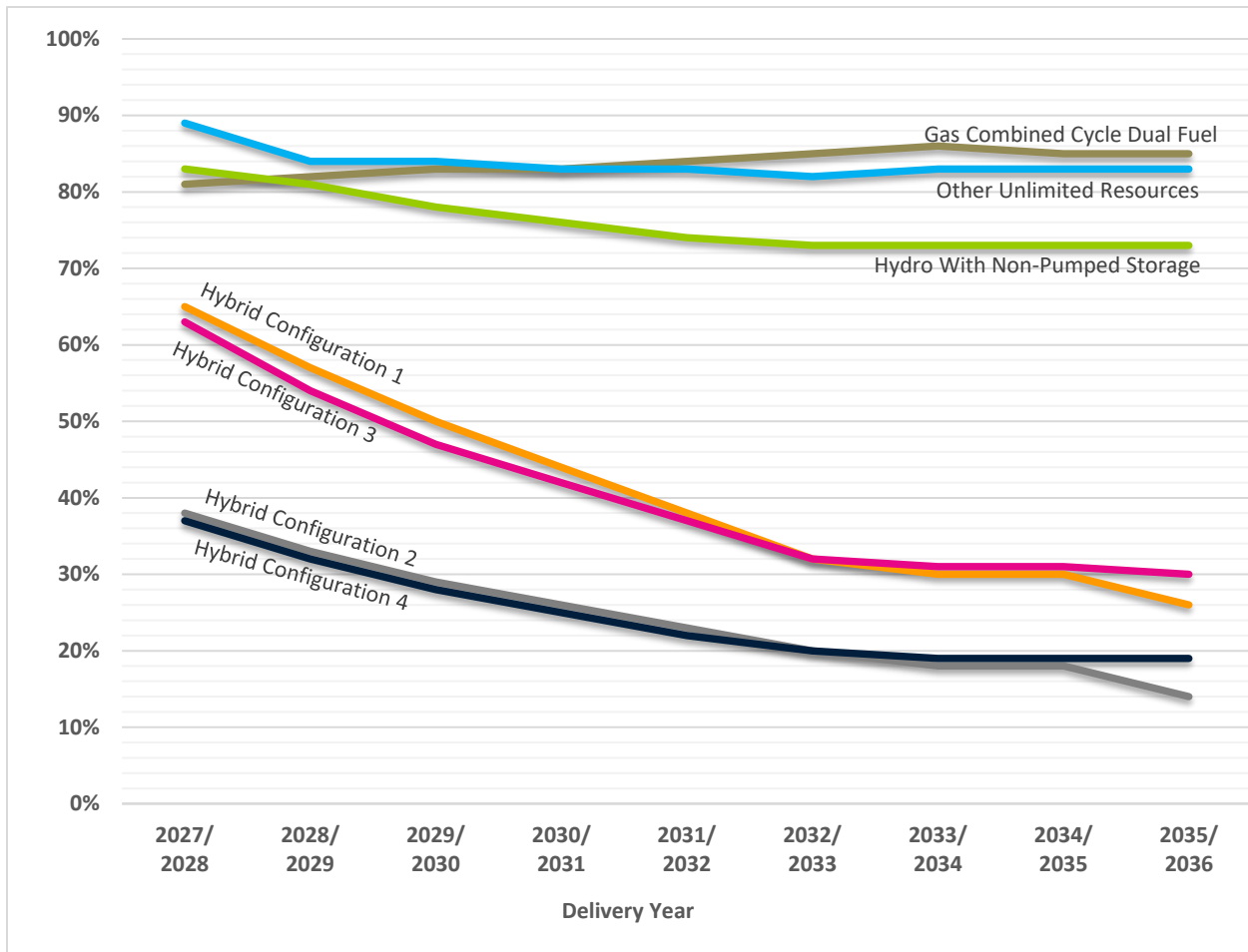


Table 38. Indicative Values for ELCC Classes with No Class Rating

Delivery Year	Gas Combined Cycle Dual Fuel	Hydro With Non-Pumped Storage	Other Unlimited Resources	Hybrid Configuration 1	Hybrid Configuration 2	Hybrid Configuration 3	Hybrid Configuration 4
2027/2028	81%	83%	89%	65%	38%	63%	37%
2028/2029	82%	81%	84%	57%	33%	54%	32%
2029/2030	83%	78%	84%	50%	29%	47%	28%
2030/2031	83%	76%	83%	44%	26%	42%	25%
2031/2032	84%	74%	83%	38%	23%	37%	22%
2032/2033	85%	73%	82%	32%	20%	32%	20%
2033/2034	86%	73%	83%	30%	18%	31%	19%
2034/2035	85%	73%	83%	30%	18%	31%	19%
2035/2036	85%	73%	83%	26%	14%	30%	19%

Table 39 depicts the configurations of the generic hybrids that were used to determine the indicative values in **Figure 28 and Table 38**. Due to the endless configuration possibilities, PJM selected a couple of various configurations based on the current interconnection queue projects.

Table 39. Generic Hybrid Configurations

Configuration	Project MFO	Project CIR	Fuel Type Component 1	ENC Component 1	Fuel Type Component 2	ENC Component 2
Hybrid Configuration 1	100	100	Solar Tracking	100	4-hr storage OL	100
Hybrid Configuration 2	100	100	Solar Tracking	100	4-hr storage OL	50
Hybrid Configuration 3	100	100	Solar Tracking	100	4-hr storage CL	100
Hybrid Configuration 4	100	100	Solar Tracking	100	4-hr storage CL	50

Acronyms

The terms in this section are provided for the convenience of the reader and are in large part based on other sources, as indicated in the “Reference” column.

These references include the following:

- Mxx: [PJM Manuals](#)
- OA: [Operating Agreement](#)
- OATT: [Open Access Transmission Tariff](#)
- RAA: [Reliability Assurance Agreement](#)

Term	Acronym	Reference
Base Residual Auction	BRA	OATT, M18
Capacity Interconnection Rights	CIR	OATT, M21B
Delivery Year	DY	OATT
Demand Resources	DR	OATT, M18
Effective Load Carrying Capability	ELCC	RAA, M20A, M21B
Effective Nameplate Capacity	ENC	RAA, M21B
Expected Unserved Energy (MWh / year)	EUE	M20A
Forecast Pool Requirement	FPR	RAA, M20A
Installed Capacity	ICAP	RAA, M21B
Installed Reserve Margin	IRM	RAA, M20A
Loss of Load Probability	LOLP	M20A
Loss of Load Expectation (days / year)	LOLE	M20A
Loss of Load Hours (hours / year)	LOLH	M20A

Term	Acronym	Reference
Maximum Facility Output	MFO	OATT
Notice of Intent to Offer	NOI	OATT, M18
Reserve Requirement Study	RRS	M20A
Temperature Humidity Index	THI	M19