This manual will be retired as of 06/01/2025. Its contents are contained within M20A

PJM Manual 20:

PJM Resource Adequacy Analysis

Revision: 15

Effective Date: June 27, 2024

Prepared By
Resource Adequacy Planning

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Approval

Approval Date: 06/25/2024~~07/14/2023~~
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Resource Adequacy Planning

Current Revision

Revision 15 (06/27/2024):

- Manual will be retired as of 6/1/2025. Its contents are contained within M20A.

~~**Revision 14 (07/26/2023):**~~

- ~~A general note was added to the Introduction section to describe how the new changes impact existing customers' ISAs.~~
- ~~Section 4.3 #13 – Reference to ISA is updated to Generation Interconnection Agreement (GIA).~~

Introduction

Welcome to the PJM Manual for ***PJM Resource Adequacy Analysis***. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see “About PJM Manuals”).
- What you can expect from this PJM Manual (see “About This Manual”).
- How to use this manual (see “Using This Manual”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and Transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The PJM Manual for ***PJM Resource Adequacy Analysis***is one of a series of manuals within the Reserve manuals. This manual focuses on the process and procedure for establishing the amount of generating capacity required to supply customer load with sufficient reserve for reliable service.

The PJM Manual for ***PJM Resource Adequacy Analysis*** consists of four sections. The sections are as follows:

- Section 1: Resource Adequacy Planning
- Section 2: Capacity Review Process by Generation Owners
- Section 3: PJM Installed Reserve Margin (IRM) and Reliability analysis
- Section 4: PJM Capacity Emergency Transfer Objective (CETO) analysis

Note:

Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM's transmission system, which used term "Interconnection Customer" to refer to generation interconnection customers, similar to the Project Developer. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM's transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM's Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this second condition happened last, this date establishes the Transition Date.

Intended Audience(s)

The intended audiences for the PJM Manual for ***PJM Resource Adequacy Analysis*** are:

- *Electric Distribution Company (EDC) resource planners* - The EDC resource planners are responsible for supplying load and generator data in the required format, and for input data verification.
- *PJM Capacity Resource Owners* - Owners of PJM-qualified Capacity Resources are responsible for supplying generator data in the required format, and for input data verification.
- *PJM Planning Staff* - PJM planning division staff is responsible for the calculation of the Installed Reserve Margin, Forecast Pool Requirement, Capacity Emergency Transfer Objective (CETO), and the Winter Weekly Reserve Target.
- *PJM Market Services Staff* - PJM Market Services staff is responsible for the operation and settlement of the PJM Capacity Market.
- *PJM Audit Staff* - PJM Audit staff is responsible for ensuring that reserve sharing requirements guidelines are unbiased and consistent among the PJM Members.
- *Resource Adequacy Analysis Subcommittee Members* – The Resource Adequacy Analysis Subcommittee (RAAS) reports to the Planning Committee and is responsible for reviewing modeling and analysis techniques used in the annual Reserve Requirement Study (RRS) , Capacity Emergency Transfer Objective (CETO) studies, and other LOLE analyses. The RAAS provides reports and recommendations on modeling practices and study techniques to the Planning Committee.
- *Planning Committee members* - The Planning Committee (PC) is responsible for reviewing the techniques used to evaluate PJM reliability and determine capacity obligations. The PC also provides a recommendation for the Installed Reserve Margin, Forecast Pool Requirement, and the Winter Weekly Reserve Target.

- *Markets and Reliability Committee members* - The Markets and Reliability Committee (MRC) members are responsible for the approval of rules, methods and parameters associated with the PJM Reserve Requirement. The MRC also provides a recommendation for the Installed Reserve Margin and Forecast Pool Requirement.
- *Members Committee* – The Members Committee reviews the recommendation of the MRC and provides its recommendation to the PJM Board of Managers concerning the Installed Reserve Margin and Forecast Pool Requirement.
- *PJM Board of Managers* – The PJM Board of Managers reviews the assessments and recommendations and approves the Installed Reserve Margin and Forecast Pool Requirement.

References

The References to other documents that provide background or additional detail directly related to the PJM Manual for ***PJM Resource Adequacy Analysis***are:

- The Energy Policy Act of 2005 (EP Act 2005)
- PJM Reliability Assurance Agreement – (Posted at this link)
- PJM Operating Agreement – (Posted at this link)
- PJM Manual 13 – Emergency Operations
- PJM Manual 14B – Generation and Transmission Interconnection Planning, Attachment E.
- PJM Manual 18 – PJM Capacity Market
- PJM Manual 19 – Load Forecasting and Analysis
- PJM Manual 21 – Rules and Procedures for Determination of Generating Capability
- PJM Manual 22 – Generator Resource Performance Indices
- PJM eGADS User Guide – on line help function within eGADS.
- PJM Manual 29 – Billing
- Reserve Requirement Study reports (Posted at this link)
- PJM Generation Adequacy Analysis: Technical Methods – (Posted at this link).
- World Modeling Region – Technical Issues
- PJM Planning Division Capacity Model
- Reliability*First*'s Standard BAL-502-RFC-03 (Posted at this link).
- Reinventing a Legacy System using SAS, the Web and OLAP reporting. (Posted at this link)
- Resource Adequacy Analysis Subcommittee Team Charter
- PJM Manual 34 – PJM Stakeholder Process
- Reliability Pricing Model, Auction User Information, per delivery year. (Posted at this link)

Using This Manual

Because we believe that explaining concepts is just as important as presenting the procedures, we start each section with an overview. Then, we present details and procedures. This philosophy is reflected in the way we organize the material in this manual. The following paragraphs provide an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents
- An approval page that lists the required approvals and revision history
- This introduction
- Sections containing the specific reliability requirements, guidelines, and procedures including PJM actions and PJM Member actions.

Section 1: Resource Adequacy Planning

Welcome to the Resource Adequacy Planning section of the PJM Manual for **PJM Resource Adequacy Analysis**. In this section you will find the following information:

- The purpose of providing resource adequacy (see “Overview”).
- A description of the process for establishing the required amount of resource adequacy (see “Resource Adequacy Planning Process”).

1.1 Overview

The reliable supply of electric services within the PJM RTO depends on adequate and secure generation and transmission facilities. This manual focuses on the supply of electricity; specifically, the process of determining the amount of generating capacity required to:

- provide electrical energy to satisfy customer load, especially during peak demand periods such as a heat wave or cold snap
- ensure an acceptable level of generation system reliability – Adequacy

The general requirements and obligations concerning PJM resource adequacy are defined in the Reliability Assurance Agreement (RAA) among Load Serving Entities in the PJM Region. PJM is responsible for performing a study to calculate the amount of resource capacity that meets the defined reliability criteria. This calculation process is reviewed by the Resource Adequacy Analysis Subcommittee. This process satisfies the ReliabiltyFirst’s Standard BAL-502-RFC-03 for the PJM region, as PJM is the Planning Coordinator of which this Standard applies. Following a period of review and comment from the Planning Committee, the Markets and Reliability Committee, and the Members Committee, the PJM Board of Managers approves the final reserve margin value. The final reserve margin value is then the basis for defining the RTO Reliability Requirement for use in the Reliability Pricing Model (RPM) Base Residual Auction.

The Reliability Pricing Model (RPM) is a multi-auction structure designed to procure resource commitments to satisfy the region’s unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- Base Residual Auction - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region’s unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- Incremental Auctions – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.

- The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM Auction process. The bilateral market is facilitated through the eRPM system.

1.2 Resource Adequacy Planning Process

The Resource Adequacy Planning process includes establishing planning parameters such as the reserve margin requirement, forecasting the peak load, establishing the reliability requirement (reserve margin times forecast peak load) and conducting a Base Residual Auction and residual to procure resources required. See *PJM Manual 18 – PJM Capacity Market* for details regarding the RPM Base Residual Auction to procure resources three years prior to the delivery year. To address procurement resource changes, if needed, due to a change in forecast peak load or committed resources the First, Second and Conditional Incremental Auctions have the following stipulations:

- The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement.
- A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

Typically, the RPM planning parameters for the delivery year are posted by February 1 prior to the base residual auction[1], and can change per updated RRS assessment characteristics. Per PJM Transmission Planning Division staff judgment, updated assessment characteristics for an LDA might cause re-determination of load deliverability values (Capacity Emergency Transfer Objective, CETO and Capacity Emergency Transfer Limit, CETL).

The RPM auction clearing process uses a Variable Resource Requirement (VRR) curve (also known as a demand curve) that defines the maximum price the load is willing to pay for a given level of resources procured. This process may result in procuring more resources than those required to meet the reliability requirement if the resources' offer prices are below the VRR curve price. Any such additional resources procured will be allocated as capacity obligations to LSEs. Some LSEs may select a Fixed Resource Requirement (FRR) alternative which means their obligation would be based on their obligation peak load times the reserve requirement (FPR to determine the daily unforced capacity obligation). The planning parameters – IRM and FPR– developed in the resource adequacy planning process are also applicable to FRR Entities.

[1] For the full RPM auction time, see PJM Manual 18, Section 5.2

The typical schedule of the steps in the reserve requirement study planning process is shown in Exhibit 1. Some steps include; 1) May, 4 years before Delivery Year— The Planning Committee (PC), with RAAS input, establishes the assumptions and modeling parameters for the upcoming study. 2) October — PC reviews analysis results and the Study report in September and, at their October meeting, recommends the Installed Reserve Margin and Forecast Pool Requirement that the PJM RTO requires for the future delivery year. The PC also recommends a winter weekly reserve target to the Operating Committee for the upcoming winter period. 3) November - January — The MRC and then the MC review the study results and PC recommendation and the MC provides a recommendation for the given delivery year to the PJM Board of Managers. The PJM Board of Managers approves and establishes the planning parameters (IRM and FPR) for posting on the PJM web site by February 1.

1.2.1 PJM Responsibilities

PJM has the overall responsibility of establishing and maintaining the integrity of electricity supply within the PJM RTO. The Operating Agreement and Reliability Assurance Agreement set down the specific rules and guidelines for determining the required amount of generating capacity. The process is summarized as follows:

- Determine the Load Forecast — PJM determines load forecasts per PJM Manual 19. The most recently published PJM Load Forecast prior to the Base Residual Auction is used for the delivery year.
- Determine the calculated PJM Reserve Requirement — PJM determines the calculated reserve requirement for the PJM RTO based on:
    - The industry guidelines and standards for reliability, as established by the North American Electric Reliability Corporation (NERC) and the ReliabiltyFirst (RF). Specifically the applicable RF Standard is BAL-502-RFC-03.
    - The annual reliability analysis methods described in Section 3 of this manual. This analysis is performed by PJM staff and reviewed by the RAAS and PC.

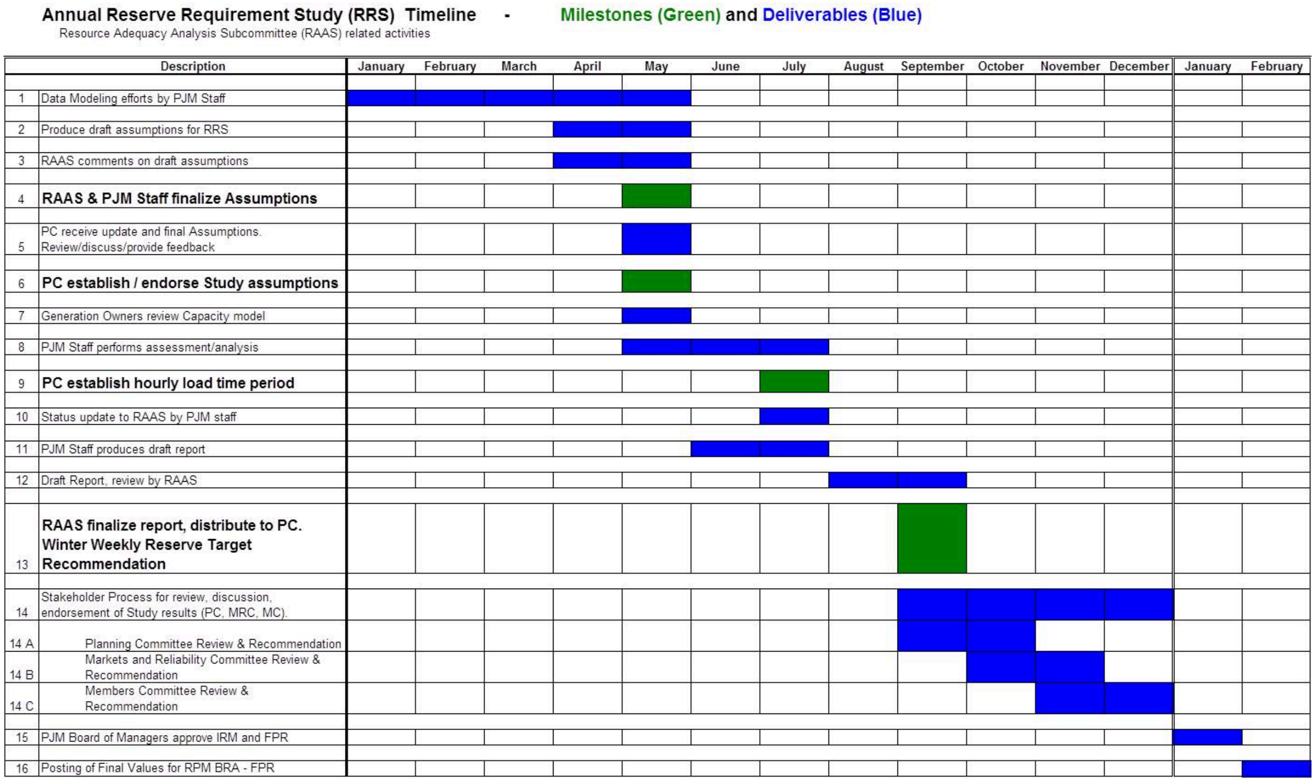

Exhibit 1: Timeline for Reserve Requirement Study

1.3 Parameters Reviewed in the Stakeholder Process

The following factors are used to establish capacity requirements and obligations. These factors are established 3 years prior to the applicable delivery year.

- *IRM* — The Installed Reserve Margin is the installed capacity percent above the forecasted peak load required to satisfy a Loss of Load Expectation (LOLE) of, on average, 1 Day / 10 Years. For a given delivery year, IRM is one of the two primary inputs needed for calculating the Forecast Pool Requirement (FPR).
- *FPR* — The Forecast Pool Requirement is a key factor that is used across the entire PJM RTO capacity marketplace. The calculation of the FPR is based on the IRM and the pool wide average equivalent demand forced outage rate (EFORd)[2]. For Delivery Years prior to 2018, this EFORd does not include the events Outside Management Control (OMC); with the implementation of Capacity Performance in 2018, OMC events are phased out. This

2 Average EFORd does not include Outside Management Control generator outage events

definition of EFORd[3] is consistent with that used in the capacity market to establish the unforced capacity value of individual generators.

1.4 PJM Installed Reserve Margin (IRM)

The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain a loss of load expectation of one occurrence every ten years. The Probabilistic Reliability Index Study Model (PRISM) program is the principal tool used to calculate the PJM Reserve Requirement. The PJM Reserve Requirement is calculated using a PRISM two-area model. PJM is modeled in Area #1 and a composite World representation consisting of parts of SERC, RF, MISO and NPCC is modeled in Area #2. The PJM Installed Reserve Margin value is used in the determination of the Forecast Pool Requirement.

In addition to the determination of the standard RPM related calculation factors, the PJM Reserve Requirement Study includes sensitivity analyses to assess the principal factors that affect PJM reliability. Examples of these analyses could include a measure of the sensitivity of the PJM Reserve Requirement to changes in the system average unit forced outage rate, changes in the PJM load forecast error factor, variations of PJM import capabilities, and alternative maintenance scenarios. Assessment of contributing characteristics to the calculated IRM and FPR include: unit performance, load uncertainty, transmission (CBM), ambient impact on units, other factors such as unit planned outages, tie limits, and peak demand. The specific sensitivity analysis required for a particular study is driven by the study results and any significant changes in results or conclusions from previous studies.

Judgment must always be used in assessing the correct level of IRM to establish for future delivery years. Long-term trends and the influence of different modeling practices and assumptions should be important considerations in establishing the IRM. The recent practice endorsed by the RAAS has been to use the base case’s calculated IRM value.

1.5 Forecast Pool Requirement (FPR)

The determination of the Forecast Pool Requirement is based on two parameters. The first is the PJM Installed Reserve Margin (IRM). The IRM is approved by the PJM Board of Managers based on analysis performed by PJM and reviewed through the stakeholder process. The second parameter needed to calculate the FPR is the pool-wide average Equivalent Demand

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3 IEEE Standard 762-2006: IEEE Standard definition for use in reporting electric generating unit reliability, availability and productivity. IEEE Std-2006 (revision of IEEE Std 762-1987) - approved 9/16/2006 by IEEE-SA Standards Board. To obtain a copy: http://standards.ieee.org/findstds/standard/762-2006.html)

Forced Outage Rate (EFORd)[4] of the units used in the analysis. This average rate is based on a lagging five-year historical period. The Forecast Pool Requirement is calculated as follows:

$$ForecastPoolRequirement = (1 + IRM)^{*}\left(1 - Pool\ AverageEFOR_{d}\right)$$

It is important to note that the IRM and the FPR represent the identical level of reserves but are expressed at different availability status levels. The IRM is expressed in units of installed capacity whereas the FPR is expressed in units of unforced capacity. Unforced capacity is defined in the RAA to be the MW level of a generating unit's capability after removing the effect of forced outage events.

1.6 Winter Weekly Reserve Target

Maintaining adequate winter weekly reserve levels after scheduling generator planned maintenance outages ensures that the Reliability*First* (RF) LOLE Standard is met with the approved IRM. In calculating PJM's installed capacity reserve requirement, the PRISM and Multi Area Reliability Simulation (MARS) program schedule unit planned outages on a weekly levelized reserve basis (reserve margins are held nearly the same from week to week). Reserves are intended to cover load forecast uncertainty and random unit forced outages. PJM RTO winter reserves are generally greater than those of the summer period, partly because winter unit ratings are generally greater and winter weekly peak loads are generally less than the corresponding values over the summer period.

It is desirable to maintain a negligible loss of load risk over the winter period because virtually all the RTO region's LOLE (99.9%) is concentrated in the summer weeks, despite the complete absence of unit planned outages in the summer. Since the summer risk cannot be reduced further (without installing additional Capacity Resources), winter reserve levels must be held greater than those over the summer to ensure the desired yearly RTO LOLE. PJM coordinates equipment outages to obtain the desired LOLE while minimizing the need for additional generating capacity.

LOLE calculations are performed to determine the lowest winter reserve level at which PJM still maintains an LOLE of one in ten years. This reserve level is then reviewed with the PJM Planning Committee and the Operating Committee before being implemented as the winter weekly reserve target.

Further details are given in the Reserve Requirement Study report, as posted on the Planning Committee portion of the PJM web site.

4 Average EFORd does not include Outside Management Control generator outage events

1.7 Compliance with *ReliabilityFirst* (RF)

The reliability standard for resource adequacy is expressed as a Loss of Load Expectation (LOLE) for the entire PJM RTO Region. Loss of Load is defined as invoking emergency operations procedures beyond demand resources and interruptible load for reliability. LOLE is expressed in terms of occurrences per year. The LOLE planning criterion of 1-in-10 which is stated in the RF Standard, BAL-502-RFC-03 effective January 1, 2018, and approved by Federal Energy Regulatory Commission (FERC) effective October 16, 2017, as:

R.1. The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [Violation Risk Factor: Medium]:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).

This standard is based on a frequency metric and does not consider event duration or magnitude. The LOLE criterion for PJM can be expressed as 0.1 occurrences per delivery year.

This standard was approved by the Federal Energy Regulatory Commission making it applicable to all Planning Coordinators in the Reliability*First* region. PJM is a Planning Coordinator in the Reliability*First* region.

BAL-502-RFC-03 is consistent with the version 1 language of this Standard which stated in section R1; “*The Loss of Load Expectation (LOLE) for any load in RFC due to resource inadequacy shall not exceed one occurrence in ten years”*. Working with the PJM stakeholders, PJM Staff is committed to the 1 in 10 LOLE Adequacy criteria. These efforts are reflected in the PJM stakeholder process concerning the annual Reserve Requirement Study (RRS) and numerous load deliverability tests (CETO/CETL) for RPM and RTEP

For further details of how the RRS provides compliance with RF Standard, BAL-502-RFC-03, please reference the historical Reserve Requirement Studies posted on the PJM web site.

1.8 Modeling Tools

PJM’s PRISM program is the primary modeling tool used for conducting the resource adequacy studies. PRISM is classified as a “two-area” model that simulates the PJM RTO and areas adjacent to PJM’s footprint, called the “World”. PRISM was in part built from and developed from an older two-area reliability model developed by General Electric (GE) and Baltimore Gas and Electric (BGE) called "GEBGE". The original GEBGE and its successor, PRISM, have been used by PJM since the 1970s.

PJM also is a licensed user of General Electric's MARS (Multi-Area Reliability Simulation) program and uses this multi-area program to enhance the analytical capabilities of PRISM.

The PRISM program is used to calculate the LOLE of up to two interconnected systems with a single transfer link. PRISM is used to calculate the IRM.

Other supporting programs and reports include:

- *ARC* – Applications for Reliability Calculations. This web based application coordinates all databases and applications used to calculate generation Adequacy. All programs and reports are initiated and submitted by this PJM Intranet application.
- *WeekPeakFreq* – Produces the Peak Load Ordered Time Series (PLOTS) load model(s) used by PRISM. Once the required input parameters are given, this application produces 52 weekly mean and standard deviations for the defined study model. Input parameters include the historic time period, geographic region subzones, forecast start year, forecast end year, forecast report to use, 5 or 7 day model, and holidays to exclude.
- *SYSPAR* – A report that summarizes the models' capacity characteristics.
- *Forecast Reserves* – A report that summarizes the model load, capacity and resulting reserves.
- *Other LOLE tools* – These tools are employed to provide more flexibility in the LOLE calculation than that provided by PRISM.

One of the key objectives in conducting the RRS is to develop the base case (or Baseline) scenario. This case is used in determining the IRM and FPR. Examples of the various assumptions that are used to derive the Base Case are presented in Appendix A of the RRS report. The RRS reports can be found at this PJM planning, reserve requirement development process link.

The Sensitivity cases of the above reports, which start with the base case, are typically listed in Appendix B. The base case, sensitivities, and engineering judgments (Appendix Section of the reports) are all necessary to endorse the IRM and FPR. The recent practice, endorsed by the RAAS, has been to use the base case's calculated IRM value for these determinations.

1.9 Development and Approval Process

PJM has the overall responsibility of establishing and maintaining the Adequacy and Security of electricity supply within the PJMRTO. The Operating Agreement (OA) and Reliability Assurance Agreement (RAA) define the specific rules and guidelines for determining the required amount of generating capacity.

PJM Staff initiates a study each spring to calculate the IRM. This study is initially reviewed by the Resource Adequacy Analysis Subcommittee (RAAS). The study uses a probabilistic model that recognizes, among other factors, historical load variability, load forecast error, scheduled maintenance requirements for generating units, forced outage rates of generating units and the capacity benefit of interconnection ties with other regions. Study results are reviewed through the PJM Committee structure and the PJM Members Committee forwards its recommendation for the IRM and FPR to the PJM Board of Managers. The PJM Board of Managers is ultimately responsible for approving the PJM IRM and FPR.

Resource adequacy planning begins at least four years in advance of the applicable delivery year. Early in the timeline, resource owners review the statistical modeling parameters of their generation units involved in the creation of the capacity model. During this time, PJM Staff provides load forecasts to determine peak load demand. PJM also determines the calculated reserve requirement for the PJM RTO based on industry guidelines and standards for reliability, as established by the North America Electric Reliability Corporation (NERC) and Reliability*First* (RF).

In accordance with the PJM Reliability Assurance Agreement (RAA), the assumptions and study activities are primarily developed by the PJM Resource Adequacy Analysis Subcommittee (RAAS) and endorsed by the PJM Planning Committee (PC). The principal duties and timetable of the RAAS are:

1. The assumptions letter for the upcoming RRS
2. RPM requirements move the start of this effort to March.
3. The IRM and FPR Analysis Report
4. RPM requirements move the completion date to October.
5. The Winter Weekly Reserve Target.
6. This is part of the October report.
7. Review and make recommendations regarding the modeling and analysis techniques used in the various PJM Resource Adequacy studies that examine the RTO region and Locational Deliverability Areas (LDAs)
8. As directed by the PC, review the modeling and analysis techniques used in CETO studies, determinations of reliability requirements, and other LOLE analyses performed to support the Reliability Pricing Model (RPM) and the Regional Transmission Expansion Planning (RTEP) process.

Section 2: Capacity Review Process by Generation Owners

Welcome to the *Capacity Review Process by Generation Owners* section of the PJM Manual for ***PJM Resource Adequacy Analysis***. In this section you will find the following information:

- Description of the process used to review, submit changes, and approve the generation model used by PJM staff in the calculation process for the PJM RTO generating capacity requirement including RRS and capacity emergency transfer objectives (CETO). See "Overview of the Generation Model Review Process".

2.1 Overview of Generation Model Review Process

The PJM RTO generation model is one of the inputs to the reserve requirement study. Review of the generation model by the owners' representatives ensures the data integrity of these important modeling parameters. Annually, by notification of the PJM staff, all generation owners submitting GADS data to PJM are solicited to review the statistical modeling parameters of their generation units. This activity is aligned with the RAAS and PC efforts to finalize the reserve requirement study model assumptions

Section 3: PJM Installed Reserve Margin and Reliability Analysis

Welcome to the *PJM Installed Reserve Margin (IRM) and Reliability Analysis* section of the PJM Manual for ***PJM Resource Adequacy Analysis***. In this section you will find the following information:

- An overview of PJM's reliability analysis (see "Overview").
- A description of load and capacity modeling (see "Load & Capacity Models").
- A description of PJM's reliability calculation (see "Reliability Calculations & Analysis")

3.1 Overview

Generating capacity reserve margin above the forecast peak load is required to meet the load demand considering load variability due to weather and forecast uncertainty and outages of generating units. The goal of the PJM RTO is to maintain a degree of reliability that is consistent with utility industry standards in meeting the system load.

The primary tool used for the annual reliability analysis is a computer program called Probabilistic Reliability Index Study Model (PRISM). The program is used to calculate the following:

- the loss-of-load expectation (LOLE) of up to two interconnected systems with a single transfer link
- the installed capacity reserve margin needed to provide a user-specified level of reliability

There are several detailed reference materials for this manual used by the PJM staff:

- ARC technical documentation
- ARC's on-line Help screens.
- "PJM Reserve Requirements and Related Studies" document. This older documentation provides clear descriptions of general principles still in use.
- How -To documentation stored on PJM's internal LAN.

All of these documents are maintained by PJM Staff in the Resource Adequacy Planning Department. These documents do not specify a strict, inflexible procedure, but rather provide a guide for fostering consistency from year to year and across all related analysis. All procedures are consistent with RAAS review and oversight. This section of the manual summarizes the more detailed information contained in these documents.

3.2 Load & Capacity Models

The reliability analysis depends to a great extent on the computer modeling of the load and generation within both the PJM RTO and its adjacent regions (commonly referred to as the "World"). These models provide the characteristics of the customer load demand pattern and generating capacity availability over the time period of the study. This subsection describes the input data and the models that are used by the PRISM program.

Regional Modeling

The study examines the combined PJM footprint area (Exhibit 2) that consists of the PJM Mid-Atlantic Region (PenElec, ME, JCPL, PPL, PSEG, RE, AEC, PECO, DPL, BGE, PEPCO) plus APS (Allegheny Power System), ComEd (Commonwealth Edison), AEP (American Electric Power), Dayton (Dayton Power and Light), Dominion (Dominion Virginia Power), Duquesne (DLCO), ATSI, Duke Energy Ohio/Kentucky (DEOK), East Kentucky Power Cooperative (EKPC) and Ohio Valley Electric Corporation (OVEC).

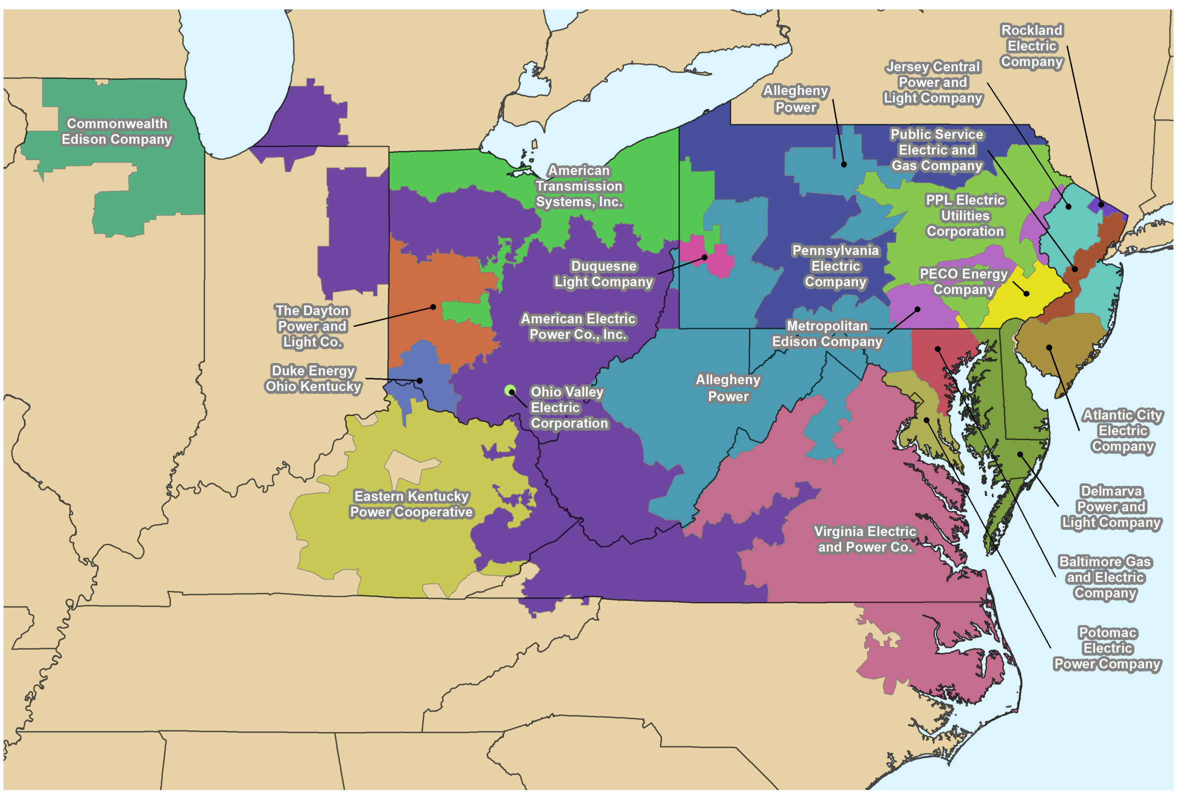

Exhibit 2: PJM RTO Region Modeled

Areas adjacent to the PJM Region are referred to as the "World" and consist of the non-PJM portion of RF and of the Southeastern Electric Reliability Council (SERC), a portion of the

Northeast Power Coordinating Council (NPCC) territory and a portion of MISO (the specific definition of the “World” is determined prior to each year’s study). Areas outside of PJM and the World are not modeled in this study. However, sensitivities are periodically run to assess if all the appropriate areas are included in the World model.

3.2.1 Load Model

The load model requires the following input data:

- PJM RTO — The PJM RTO portion of the load model is based on PJM historical hourly load data. The most recent time period comprising at least seven historical delivery years for which both PJM and World hourly load data are available, is used. The PJM Load Forecast Report supplies the PJM peak and seasonal load forecasts. The PJM load forecast is developed by PJM staff and reviewed by the Load Analysis Subcommittee and the Planning Committee. World — Historical hourly load data are obtained from the surrounding NERC Regional Reliability Councils: RF, SERC & MISO, & NPCC. PJM Staff gathers data from publicly available sources on the FERC web site.

The load model used in PRISM studies is called PLOTS (Peak Load Ordered Time Series) and is maintained by the WeekPeakFreq program. The load model consists of 52 week’s daily peak load distributions and through the use of a mean and standard deviation for each week. It is based on a user-specified number of years of the latest available historical loads, consistent with World load data. For individual PJM RTO load deliverability areas, these loads are obtained from the internal PJM system telemetered data stored in the PJM Information Warehouse (PIW). Typically, holiday and weekend loads are excluded but a seven day load model can also be performed.

The PLOTS load model provides PRISM with relationship of expected weekly peak loads across all 52 weeks of the delivery year and with a measure of the daily peak load variability within each individual week. This measure of peak load variability translates to an assessment of daily peaks within each week. PLOTS is a magnitude-ordered, as opposed to a calendar-ordered, load model. The distinction between the two is that a magnitude-ordered load model re-orders the given years of historical data, on a seasonal basis, so that the peaks of each of the given years are combined (regardless of their actual calendar placement), the second highest peaks are combined and so on down to the last highest daily peak in the given season. A calendar-ordered load model combines loads chronologically and so maintains a proper correlation to the calendar. The magnitude-ordered approach used in PLOTS results in a “peaky” annual load shape that tends to concentrate most of the loss-of-load risk in a few summer weeks. A magnitude-ordered load model is appropriate for determining an annual index such as the Installed Reserve Margin but is not ideal for performing studies that examine weekly, monthly, or seasonal LOLE risk.

21 point Standard Normal weekly distribution.

- PRISM’s load model is a daily peak load model aggregated by week. PRISM computes the daily LOLE, aggregating values of these distributions for each week. The RRS uses a standard normal distribution as the appropriate forecast weekly distribution. This distribution is based on 5 peak weekdays. The standard normal distribution is represented using 21 points with the values shown in Exhibit 3.

- Exhibit 5 graphically shows how the distribution in Exhibit 3 is overlaid onto the Expected Weekly Maximum (EWM) to determine the LOLE for each week. This technique uses an order statistic of 5 which represents the 5 daily weekday peaks. See the paper "PJM Generation Adequacy Analysis: Technical Methods", available on the PJM website, for further discussion of how the order statistic, when n= 5, is used in the determination of the EWM and how the 21 points are used to determine the daily LOLE.

Normal Distribution Values

Sigma	Probability
4.2	0.000033
3.78	0.000145
3.36	0.000638
2.94	0.002351
2.52	0.007273
2.1	0.01894
1.68	0.0414
1.26	0.07608
0.84	0.11749
0.42	0.15248
0	0.16634
-0.42	0.15248
-0.84	0.11749
-1.26	0.07608
-1.68	0.0414
-2.1	0.01894
-2.52	0.007273
-2.94	0.002351
-3.36	0.000638
-3.78	0.000145
-4.2	0.000033

Normal Distribution Graph

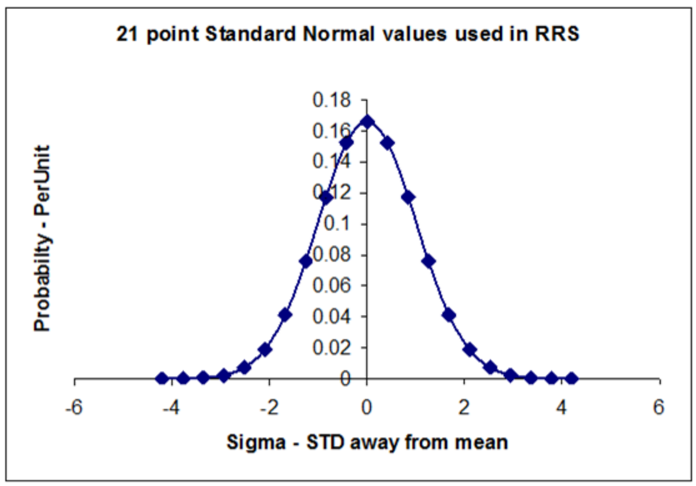

Exhibit 3: Normal Distribution

Week Peak Frequency (WKPKFQ) Parameters.

- WKPKFQ currently uses historical data to obtain a daily peak mean and standard deviation for each week of the study period. For each year, the historical data is per-unitized on the annual peak, magnitude ordered (highest to lowest) and then averaged across years to replicate actual load experience. Forecasted weekly unrestricted peaks are obtained by replacing the historic growth rate with the forecasted growth rate. The daily restricted peak and the WKPKFQ mean and standard deviation are used to develop daily standard normal distributions for each week of the study period. The definition of the load model, per the input parameters necessary to submit a WKPKFQ run, defines the modeling region and basis for all adequacy studies. Input parameters required for a WKPKFQ run include:

- Historic time period of the model.
- Sub-zones or geographic regions that define the model.
- Load Forecast Report to use.
- Start and end year of the forecast study period.

- Specification of 5 or 7 days to use in the load model. All RRS studies use a 5 day model, excluding weekends.
- Holidays to exclude from hourly data. These include Labor Day, Independence Day, Memorial Day, Good Friday, New Year's Day, Thanksgiving, Black Friday, and Christmas Day.

PRISM uses a 21-point normal probability density function to represent the distribution of each weekday's expected peak load. The number of points to represent the probability density function can be selected by the user. Studies typically use the 21 points of the normal probability density function; values plus and minus 4.2 standard deviations from the mean. Based on the inputted forecast loads, PRISM calculates a load and associated probability of occurrence for each of the 21 points used to represent each day's expected peak load. From the PLOTS daily mean and standard deviation values, each day's expected weekly maximum (EWM) load is calculated using the order statistic based on n = 5 (or 5 daily peaks in one week). The mathematical calculation for the EWM is shown in Exhibit 4.

$$EWM_x = \mu_x + 1.16295 * \sqrt{\sigma_x^2 + FEF^2}$$

Where :

μ_x = Weekly Mean,

1.16295 = A Constant, the Order Statistic when n=5

σ_x^2 = Weekly variance

FEF = Forecast Error Factor, for given delivery Year

x ranges from 1 to 52

Exhibit 4: Expected Weekly Maximum Equation

The quantity $\sqrt{\sigma_X^2 + FEF^2}$ is called the total sigma, where is the weekly standard deviation. A graph of these daily peak load values, EWM, overlaid with the 21 point distribution, is shown in Exhibit 5.

The peak load values evaluated are at each of the 21 load values where: Peak Load = 50 / 50 forecast annual peak (MW) x Mean (Per Unit of EWM) x (1+(No. of Sigma from Mean x Total Sigma). See the annual Reserve Requirement Study Reports and the PJM Generation Adequacy Analysis: Technical Methods paper for further details. The PLOTS daily load model parameters (for each week), mean and standard deviation, are combined with the 21 point probability density distribution. Each point is associated with a particular load level and probability of occurrence.

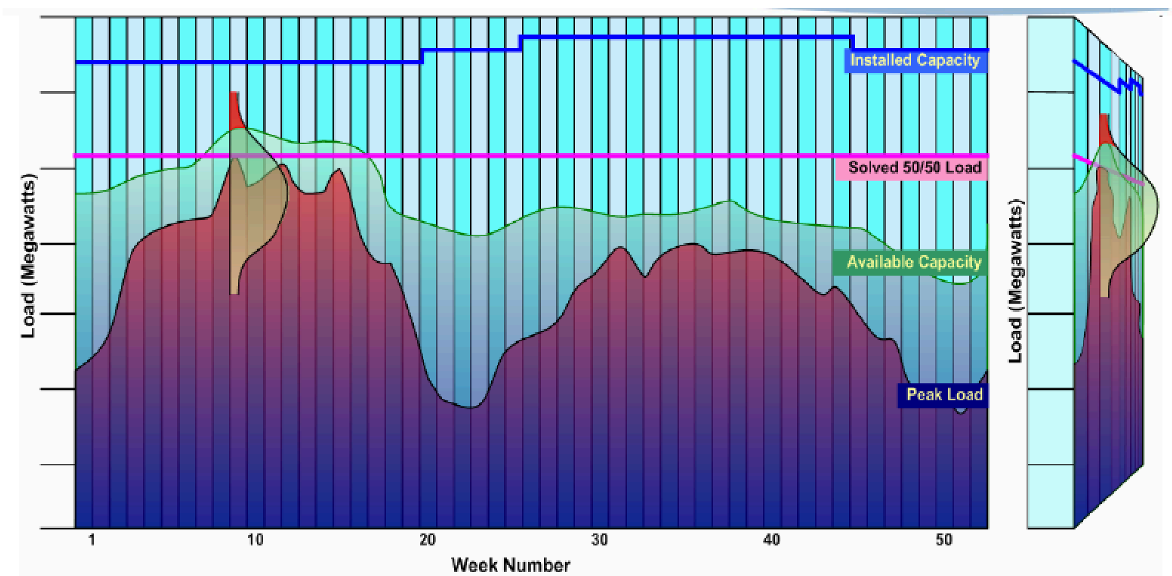

Exhibit 5: Daily Load Distribution

3.2.2 Capacity Model

The capacity model is built with a set of generation units determined prior to each year's Reserve Requirement study and requires the following input data:

- PJM — Unit outage performance data for existing generation is supplied by each generation owner. This data is typically provided through the PJM web-based applications (eRPM and eGADS) and the annual NERC data submission process. The data is entered into the capacity model in the 1st quarter. PJM generator planning outage rates are supplied according to rules established by PJM Manuals 21 and 22. This data is primarily supplied via the eGADS' GORP report. This application is available using PJM suite of tools on the PJM web site.

- Specific data required for existing and future units include:
  - Effective Equivalent Demand Forced Outage Rates (EEFORd)
  - Unit Variance (in MW)
  - Equivalent Planned Outage Factor (EPOF)
  - Equivalent Demand Forced Outage Rate (EFORd)
  - Equivalent Maintenance Outage Factor (EMOF)
  - Ratings (Summer and Winter) of unit

Performance data for future units is assumed to be PJM class-average based on unit type and size. Final data is issued per the annual reserve requirement assumptions approved by the PC.

For units that do not have a full five years of historic GADS events, the years that are missing are assumed to be equivalent to the appropriate category of PJM class average values. Blending of the class average data with the actual GADS event data gives a complete five years of data on which the generator's performance statistics are based.

- World — World generating units do not provide PJM with outage data. These units, therefore, are assigned PJM class average data. PJM develops class average data for all NERC defined categories of units that are located in PJM. These categories are based on size, type and primary fuel. The class average data is from the PJM fleet of units' actual event data as reported in eGADS. The class average table is updated by PJM staff every year.

The source for a complete update of the World Capacity model is the annual Electric Supply and Demand data report from NERC.

GADS Data and eGADS Procedures.

- The principal modeling parameters in the RRS are those that define the generator unit characteristics. All generation units' performance characteristics are derived from PJM's eGADS web based system. For detailed information on PJM Generation Availability Data System (GADS), see the eGADS User Guide available in the help menu within the eGADS application or the NERC GADS website. The eGADS system is based on the IEEE Standard 762-2006.

GADS Data and PJM Fleet Class Average Values

- For units with missing or insufficient GADS (Generating Availability Data System) data, PJM utilizes "class average" data developed from PJM's RTO fleet-based historical unit performance statistics. Such "class averaging" is therefore used for future units, neighboring system units, and for those PJM units with less than 5 years of GADS events.

- The process of combining the GADS data with “class average data” is called blending. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated. The five-year period is used to calculate the various statistics (EFORd, EEFORd, EMOF, Two State Variance, POF) used in the study model.
- The actual generator unit outage events are blended with the class average values according to the generator class category for that unit. For example, a unit that has three years of its own reported outage history will have two years of class average values used in blending. The statistics, based on the actual reported outage history, will be weighted by a factor of 3/5 and the class average statistics will be weighted by a factor of 2/5. The values are added together to get a statistical value for each unit that represents the entire five-year time period.
- The class average categories and statistical values are based on PJM’s fleet of units, updated annually. A five-year period is used for the statistics. The five-year period is based on the data available in the NERC Brochure or in PJM's eGADS, using the latest time period. A generator class category is given for each unit type, primary fuel and size of unit. The class average statistical values are posted on the PJM website.

Modeling of Generating Units’ Ambient Deratings

- Per the approved rules in place for Operations, Planning and Markets, a unit can operate at less than its Summer Net Dependable (SND) rating and not incur a GADS outage event. As discussed above, all units in the model are based on eGADS submitted data. The ambient derate modeling assumption and the eGADS data allow all observed outages to be modeled as seen by PJM Operations staff.
- Derating of generating units affected by hot and humid summer conditions is captured by this evaluation. This modeling practice is intended to capture the increased risk due to limited output from certain generators caused by more extreme than expected ambient weather conditions. Expected conditions are based on that unit’s site averaged over the past 15 years.
- Per the RRS assumptions determined annually, a set of units is derated in the peak summer period to model this risk. This value is consistent with analysis of the Summer Verification Test data. This verification test is performed once every summer for each PJM Capacity resource. The derating is implemented in the RRS model by scheduling planned maintenance of PJM units in the summer operating period. The particular units scheduled to be out in the study have average characteristics for the given classification of units affected and the outages span the full length of the high-risk summer period, typically 10 weeks. PJM will continue to analyze the Summer Verification Test data to assess the impact of these ambient weather conditions on generator output.

Forced Outage Rates: EFORd and EEFORd

All forced outages are based on eGADS reported events.

- Effective Equivalent Forced Outage Rate on Demand (EEFORd) – This forced outage rate is used for reliability and reserve margin calculations. There are three general categories for GADS reported events: forced outage (FO), maintenance outage (MO) and planned outage (PO). The PRISM program can only model two categories (FO and PO). The EEFORd statistic is a solution for modeling all GADS events. A portion of the MO outages are placed within the FO category, while the other portion is placed within the PO category. In this way, all reported GADS events are modeled. The statistic used for MO is the equivalent maintenance outage factor (EMOF). For a more complete discussion of these equations see Manual 22.
- Equivalent Demand Forced Outage Rate (EFORd) – This forced outage rate is used in reliability and reserve margin calculations. See Manual 22 and RAA Schedule 4 and Schedule 5 for more specific information for defining and using this statistic. The EFORd forms the basis for the EEFORd and is the statistic used to calculate the unforced capacity (UCAP) value of generators used in the capacity market. UCAP is used in the Reliability Pricing Model (RPM). However, the EFORd values used in the RRS are different from those used in the marketplace. This is due to the fact that a five year period is used for the values modeled in the RRS and a one year period is the basis for determining the UCAP value of generators in the capacity market.

Once an updated capacity model has been created, representatives of generation owners review the model as discussed in Section 2. This review allows the generation owners to provide feedback on the data models used by PJM staff in the reserve requirement determination, CETO analysis and Interregional studies. This provides the representatives a reference of the models used for their units for planning study purposes. The program creates a single area or two area capacity model for whatever combination of load delivery areas (LDA) is desired. Some examples of tables that can be produced are:

- single area of PJM RTO
- single area of any of the PJM Load Delivery Area (a part of a zone, a zone or combination of zones)
- single area of one or all of the World sub region

• Two area capacity models can also be produced with each area containing any of the single area models.

3.2.3 Application for Reliability Calculations (ARC) Application

PJM staff uses the ARC and SAS Enterprise Guide applications to organize base capacity data and a capacity expansion plan into the format required by the various analytical programs. As shown in Exhibit 6, ARC combines several data sources into a single data source that directly creates the file parameters for PRISM and other applications.

ARC provides a GUI for processing the needed phases in the RST process to create an updated capacity model. This database is facilitated by the use of SAS data marts and SAS Enterprise Guide. The specifics of the stored data are documented in the ARC technical documentation.

PRISM is the main tool used in the reserve requirement study and CETO analysis. GEBGE can be used to verify certain modeling parameters such as the system parameters and overall model integrity. Both MARS and GEBGE, alongside other LOLE tools developed by PJM, play a role in performing some related analysis.

MARS is the primary tool used for Interregional Studies, such as that performed in cooperation with neighboring regions. MARS proves to be a very useful tool in many cooperative LOLE study efforts as it allows an ability to share data in a known and widely understood format. Several neighboring regions use MARS including MISO, NYISO, ISONE, SERC, IESO, and Hydro Quebec.

ARC is a Java based web application deployed on the PJM intranet. ARC System Administration allows for many administrative functions to be automated. These are focused on data administration tasks.

The PJM Information Warehouse (PIW) contains the Oracle tables that are used to develop the SAS tables used by ARC. ARC tracks when these tables are updated and if there are any needed actions by PJM staff members.

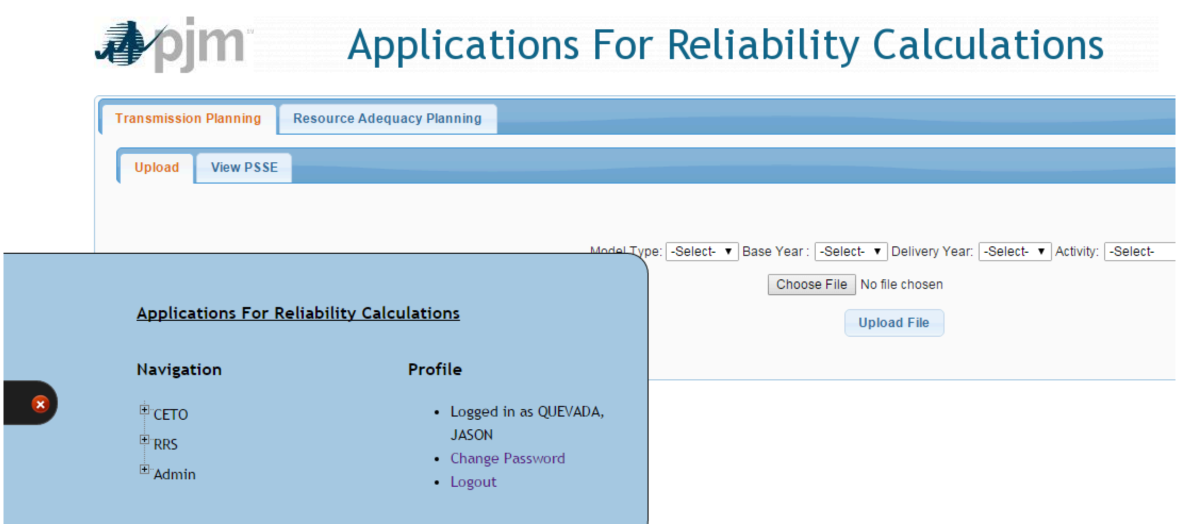

Exhibit 6: Applications for Reliability Calculations

3.3 Reliability Calculations and Analysis

The capacity model used in PRISM, GEBGE and MARS is probabilistic. For each week of the year, except the winter peak week, the PRISM model uses each individual generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, to better account for the risk caused by the volume of concurrent outages observed historically during this week, the cumulative capacity outage probability table is created using historical forced outage data, aggregated across the RTO. Also for the winter peak week, the amount of planned generator outages will be based on the average historical planned outages aggregated across the RTO.

The specific historical period to be used for the winter peak week modeling will be reviewed by the Planning Committee on an annual basis as part of the Reserve Requirement Study process.

Planned maintenance scheduling can be specified by the user or performed by the program based on one of two approaches:

- *Levelized Reserves Option* — uses the capacity of units on planned maintenance to attempt to levelize the MW amount of available reserves for each week.
- *Levelized Risk Option* — follows the same approach but uses a modified MW value for each unit based in part on the reliability of the unit. This method results in scheduling units on maintenance that are less reliable for the more critical weeks.

The Levelized Reserve Option has been used in recent studies. Because most of the risk occurs in the summer when very little maintenance is scheduled, the results of the two options are nearly identical. Also, actual planned maintenance scheduling of the units is not based on unit reliability; therefore, that characteristic of the levelized risk option is not an advantage.

Outage statistics of generating units are reported ranging from unit "full available" to "full out". PRISM cannot yet specifically model partial outages. (MARS can specifically model these partial outages.) The PRISM solution to this limitation is the use of a modified two-state representation for partial outages. This modified two-state representation is based on GADS event data for each unit. A capacity variance for each unit is inputted. This variance is used by PRISM to modify both the unit capacity and the effective equivalent demand forced outage rate to provide a statistically accurate representation of partial outages. PRISM still only models a unit either full available or full out, but with the modified capacity the effect of partial outages is captured. The result is a significantly better representation of system reliability than would be provided by a strictly two-state model that does not consider partial outage events (see Manual 22's Section 3, Item C and Item E).

After scheduling planned maintenance, PRISM calculates a cumulative capacity probability table for every week of the year, except for the winter peak week, based on the units which are not scheduled on a planned outage. This table shows the probability of different amounts of capacity being available (i.e. not on a forced outage) typically in increments of 10 MW. PRISM then calculates the system loss of load probability for each load level using the available reserves and the cumulative capacity probability table. Each of the daily load levels has an associated probability of occurring and that factor is applied to each daily load level. (See discussion concerning 21 points in the load model section.) The probability of available capacity being less than “the installed capacity less planned outages minus load” multiplied by the load’s probability of occurring is the loss of load probability for that load level. The determination of the cumulative capacity probability table for a system as large as PJM uses the largest portion of the solution time in PRISM.

Any combination of load and available capacity that results in the load level exceeding the available generation level contributes to the probability of a negative capacity margin (loss-of-load).

In a two area PRISM model, PRISM calculates a given area’s LOLE at a given daily load level. The program calculates, on a weekly basis, the probability of every possible load level (21 separate points) occurring simultaneously with every possible generation availability level (from the cumulative capacity probability table). PRISM calculates a cumulative capacity probability table for every week of the delivery year based on the units in service and not on planned maintenance.

In a two-area calculation, the probability that the other area will have an excess capacity margin, within the value of the tie size, to eliminate the loss of load in the given area is appropriately subtracted from the given area’s probability of loss of load.

The probability of loss of load (zero margin or less) is summed for each of the daily 21 load points to determine the loss of load probability for each day and then is multiplied by 5 (5 weekdays per week, we assume that weekends have negligible LOLE) to give the loss-of-load expectation (LOLE) for that particular week. The individual weekly LOLEs are then summed over the entire year to determine the annual LOLE. RFC Standard BAL-502-RFC-03, calls for performing the study applying the annual LOLE standard currently set to one occurrence, on average, every ten years or 0.100 days per delivery year. The PJM IRM is the reserve as a percentage of annual peak load that results in an LOLE adhering to this standard. Reserve is expressed as a percentage by dividing (the total installed capacity - the peak load) by the peak load. The peak load is adjusted up or down until the calculated LOLE meets the standard. The IRM and FPR are reserve levels calculated with respect to this adjusted peak load.

3.3.1 ReliabilityFirst Region Considerations

The RF’s assessment process should consider the PJM RTO Regional Transmission Expansion Planning Process (RTEPP). The RTEPP is overseen by PJM’s Transmission Expansion Advisory Committee (TEAC). Please see the PJM web site here for further details:

The PJM RTO is also a recognized Planning Coordinator within RF. The annual reserve requirement analysis and process outlined in this manual complies with the study requirements defined in the RF Standard BAL-502-RFC-03. The criteria pertaining to generation adequacy, defined in that document, are tested using the probabilistic tools described in previous sections of this manual.

The PJM staff coordinates and submits data for the PJM RTO to adhere to RF requests including the annual EIA-411 filings.

Section 4: PJM Capacity Emergency Transfer Objective Analysis

Welcome to the *PJM Capacity Emergency Transfer Objective (CETO) Analysis* section of the PJM Manual for ***PJM Resource Adequacy Analysis*** In this section you will find the following information:

- An overview of PJM's CETO analysis (see "Overview").
- A description of the load deliverability method (see "Load Deliverability method").
- A description of PJM's CETO modeling specifics used in the calculations (see "modeling specifics")

4.1 Overview

A fundamental assumption of the PJM Reserve Requirement Study is the absence of any transmission constraints within PJM that could result in "bottled" generation. This assumption is tested by Load Deliverability Analysis based on the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) tests. These tests are applied to electrical areas (called Locational Deliverability Areas or LDAs in the RPM process) within the PJM RTO to ensure that the needed capacity resources are deliverable to load. The CETO is defined to be the import capability required by the area to comply with a Transmission Risk LOLE of one event, on average, in 25 Years. The CETL is defined to be the actual emergency import capability of the test area. The CETO is driven largely by the level of generation reserves, unit performance, and load shape characteristics within the test area. An area passes the deliverability test if its CETL is equal to or greater than its CETO. A detailed description of modeling for these tests is contained in this Manual's references and summarized below. See PJM Manual 14B, Attachment E for further details.

The Load Deliverability Method requires the selection of a transmission risk level to define the CETO. This risk must be very small when compared to the one day in ten year LOLE applicable to generation risk. A transmission LOLE of 1 D/ 25 Y was judged to be sufficiently small. This risk refers to the probability of having to shed load due solely to insufficient transmission import capability, not a shortage of generation resources. The one day in 25 year LOLE is subject to periodic review.

4.2 Load Deliverability Method

The approved CETO procedure is referred to in the Load Deliverability Method of PJM Manual 14B. In this method, only the study area is modeled. The CETO for each area in the PJM RTO is determined separately. The computer models are based on the latest load and capacity data available at the time of the study. All of the load and capacity electrically within the study area is modeled. The physical nature inherent in operating the bulk electric grid is considered in the Load Deliverability Method modeling.

4.3 Modeling Specifics

The specific modeling details and CETO procedures are coordinated with the PJM Reserve Requirement Studies as reviewed by the RAAS and PC. Capacity Emergency Transfer Objective (CETO) modeling includes the following list of guidelines:

1. A loss of load expectation (LOLE) which is considered much smaller compared to the generation LOLE, is used to evaluate the import capability risk. The generation LOLE, defined in the RF BAL-502-RFC-03 Standard, is one occurrence, on average, in ten years.
2. The CETO is the import capability required for the area to meet a risk level of one day, on average, in 25 years. This risk specifically refers to the probability of an LDA shedding load due solely to its inability to import needed capacity assistance.
3. The PJM reliability program PRISM is used. Only a single area, the study area, is modeled.
4. PJM currently considers LDAs that are composed of either single zones, sub-zones or combinations of contiguous zones. Single zones or sub-zones are referred to as Zonal LDAs while combinations of contiguous zones are referred to as Global LDAs. All Zonal and Global LDAs for which PJM calculates a CETO are defined in Attachment C of Manual M14b.
5. The most recent PJM Load Forecast Report is used for modeling loads.
6. The area's unrestricted peak load forecast (non-coincident peak), adjusted for forecasted load management, energy efficiency and behind-the-meter load, is used.
7. Resource data is consistent with the most recent annual reserve requirement study and the CETL analysis.
8. Monthly load profile values and unit capacity factors are inputted and verified to capture the difference between winter and summer values.
9. Summer planned generator maintenance is not permitted.
10. See the PJM paper on PJM Generation Adequacy Analysis: Technical Methods and the Reserve Requirement Study posted on the PJM web site. Further information is documented per the Application for Reliability Calculation's technical documentation and is available upon request.
11. Unit retirements are consistent with those posted at: https://www.pjm.com/planning/services-requests/gen-deactivations.aspx.
12. A unit with a Reliability Must Run (RMR) contract for part of or for the entire delivery year is modeled consistent with the RTEPP. A unit scheduled to be retired with no RMR contract is not modeled.
13. A planned generation resource addition or planned increase in rating that has executed a Generation Interconnection Agreement (GIA) is modeled.
14. A unit that was previously mothballed but committed to serve RPM or FRR load at the time of the study is modeled.

Section 5: PJM Effective Load Carrying Capability Analysis

Welcome to the *PJM Effective Load Carrying Capability (ELCC) Analysis* section of the PJM Manual for ***PJM Resource Adequacy Analysis*** In this section you will find the following information:

- An overview of PJM’s ELCC analysis (see “Overview”).
- A description of the load model used in the ELCC analysis (see "Load Model”).
- A description of the resource performance modeled in the ELCC analysis (see “Resource Performance”)
- A description of the Loss of Load Expectation (LOLE) calculation performed in the ELCC analysis (see “Loss of Load Expectation (LOLE) Calculation”)
- A description of the calculation of the ELCC Portfolio UCAP (see “Calculation of ELCC Portfolio UCAP”)
- A description of the calculation of ELCC Class UCAP and ELCC Class Rating values (see “Calculation of ELCC Class UCAP and ELCC Class Rating values”)

5.1 Overview

The Effective Load Carrying Capability (ELCC) analysis provides key parameters to the determination of the Accredited UCAP value of ELCC Resources. The model employed to perform the ELCC analysis is probabilistic and requires inputs associated with load uncertainty and resource performance uncertainty. The model calculates hourly loss of load probability (LOLP) so that the 1-day-in-10-years loss of load expectation (LOLE) criterion is met. The output of the model is the Portfolio UCAP. A heuristic is then performed to allocate the Portfolio UCAP to each ELCC Class, determining the Class UCAPs and the Class Ratings.

5.2 Load Model

The first input into the ELCC analysis is the Load Model. The Load Model is intended to capture a wide range of load scenarios, in other words to capture load uncertainty for an entire future delivery year. Since the ELCC model is hourly, each load scenario in general is a collection of 8,760 values (however, if a specific scenario is constructed with data from a leap year, then such a scenario covers 8,784 hours). The Load Model has the following components:

Hourly Load Shape

Hourly Load Shapes (HLS) are derived consistent with: (i) actual weather experienced during past delivery years; and (ii) the most recent PJM load forecast model. Specifically, the actual hourly weather data during past years is input into the PJM load forecast model to derive a set of HLS for each future target delivery year included in the ELCC analysis. The HLS are derived with weather data from each delivery year in the period 2012/2013 Delivery Year through the most recent past delivery year preceding the timing of the ELCC analysis. Note that the HLS are not actually simulated in the ELCC model; however, they are key to determine the Hourly Load Scenarios (which are effectively simulated in the ELCC model) and the Probability for each Hourly Load Shape (which is used to calculate LOLP).

Probability for each Hourly Load Shape

Each HLS has an associated probability of occurrence (PHLS), which is calculated using the following procedure:

1. Gather the monthly peak load values produced by the weather scenarios used in the PJM load forecast process.
2. Calculate the summer and winter peak loads for each of the weather scenarios, then use a clustering algorithm to group the weather scenarios represented by pairs (summer peak, winter peak) into a limited set of clusters. For example, the result of this step provides information such as: there are X% of the weather scenarios in cluster C that is representative of extreme summer peaks and extreme winter peaks.
3. Determine the summer and winter peaks in each HLS. For instance, if there are n HLS, there will be n pairs (summer peak, winter peak).
4. For each pair in the previous step, determine the most representative cluster based on the summer and winter peak values. For instance, if year 1 has an HLS with an extreme summer peak and an extreme winter peak, then year 1's HLS is representative of the cluster that contains extreme summer and extreme winter peaks (say, cluster C). The probability assigned to year 1 is P1%, which is the share of weather scenarios in cluster C (out of the total quantity of weather scenarios considered in the most recent PJM Load Forecast).

Hourly Load Scenarios

The Hourly Load Scenarios (HLSc) are intended to represent the possible variations around each HLS and therefore, the possible variations representative of the cluster of weather scenarios associated with each HLS. The HLSc derivation process employs the monthly peak load values from the weather scenarios in the representative cluster. For instance, if the HLS for year 1 is representative of cluster C, then the monthly peak load values from the weather scenarios in cluster C are used to derive the HLSc for year 1's HLS. The procedure to derive the HLSc is as follows:

1. Identify the monthly peaks from the weather scenarios in the cluster that each HLS is representative of.
2. Using the 12 monthly peak load values from the weather scenarios in the representative cluster, determine the parameters of a multivariate normal distribution. A multivariate normal distribution is used instead of a normal distribution to account for the correlation between monthly peak loads.

3. Using Monte Carlo sampling and the multivariate normal distribution, derive 1,000 HLSc for each of the HLS.

5.3 Resource Performance

This is the second key input into the ELCC analysis. Modeling resource performance uncertainty in the ELCC model entails deriving the hourly output of each resource in the ELCC Model associated with each HLSc. The procedure to derive the hourly output differs by resource category and/or resource class.

Unlimited Resources

The metrics that are key to model the hourly availability/unavailability patterns of Unlimited Resources are the Effective Equivalent Forced Outage Rate – Demand (EEFORd), the Equivalent Planned Outage Factor (EPOF), and the Equivalent Maintenance Outage Factor (EMOF). Jointly, these metrics capture all the types of outages that Unlimited Resources experience. Two additional metrics that underlie the EEFORD calculation are also derived for each unit: the Mean Time to Failure (MTTF) and the Mean Time to Repair (MTTR). All these metrics are calculated for each unit based on historical Generator Availability Data System (GADS) data from the most recent 5-year period prior to running the ELCC analysis.

Monte Carlo sampling is employed to derive the hourly availability/unavailability patterns related to forced outages (using the MTTF, MTTR and EEFORd metrics) while a deterministic scheduling algorithm is employed to derive the availability/unavailability patterns related to planned and maintenance outages (using the EPOF and EMOF metrics).

Variable Resources

The development of the hourly output for variable resources entails producing an Hourly Output Shape (HOS) based on the historical weather years used in the construction of the HLSc. As detailed below, the HOS for an ELCC Class of variable resources (e.g., wind) comprises actual and backcasted output from existing members of the class and backcasted output from planned members of the class.

If there are N HLS (and associated HLSc) based on N historical weather years, then there will be N HOS for each ELCC class belonging to the variable resources category. The derivation of HOS based on a historical weather year H for a future delivery year F prior to 2025/2026 is described as follows:

1. Calculate hourly actual metered output in MW from all units that were classified as existing in year H and are expected to still be in service in year F.
2. Calculate hourly total backcasted output in MW from all units that were classified as planned in year H and are expected to be in service in year F.

3. Calculate the hourly total output in MW (by including actual and backcasted outputs from the two steps above) and hourly total MFO for future delivery year F.
4. For each hour, divide the hourly total output by the hourly total MFO. The result constitutes the Hourly Output Shape (HOS) based on historical weather year H for future delivery year F.

Starting with the 2025/2026 delivery year, each unit's hourly actual metered output in step 1 above is adjusted to reflect the unit's actual curtailments during year H and is capped at: (i) the greater of the unit's CIR MW value, or the transitional system capability awarded for year F during hours in the months of June through October and the following May of the delivery year, and (ii) the unit's winter deliverability MW value for year F during hours in the months of November through the following April of the delivery year. The same capping procedure is applied to the hourly backcasted output in step 2 above.

Limited Duration Resources and Combination Resources

The hourly output of Limited Duration Resources and Combination Resources is derived by using a simulated dispatch procedure that takes into account the rest of system conditions (load, other resources' output) simulated in the ELCC model. The simulated dispatch procedure also incorporates the charging or charging-equivalent process whereby Limited Duration Resources and Combination Resources replenish their storage components. Limited Duration Resources and Combination Resource components that have the same impact on LOLE as the same quantity of perfect resource are modeled as perfect resources (the "perfect resource" concept refers to a hypothetical resource with no outages and always available producing output at its Effective Nameplate Capacity). The procedure to derive the simulated dispatch for Limited Duration Resources and Combination Resources applied to each hour prior to 2025/2026 is the following:

1. Calculate the Margin Threshold as total available resources prior to dispatching Limited Duration Resources and Combination Resources minus load.
2. Calculate the Nameplate Threshold as the total estimated available Effective Nameplate Capacity of Limited Duration Resources and Combination Resources minus the targeted Primary Reserves assumed to be provided by Limited Duration Resources and Combination Resources.
3. Calculate the Dispatch Threshold as the absolute value of the Margin Threshold minus the Nameplate Threshold.

4. If the Margin Threshold is greater than zero, charging for resources that require charging can proceed. However, the charging can only occur to the extent that the additional load in the system does not cause the Margin Threshold to be less than zero. The charging step recognizes differences between classes within the Limited Duration Resources and Combination Resources category regarding the charging or charging-equivalent process. This entails using hourly streamflow data to replenish the storage component of resources within the Hydropower With Non-Pumped Storage class, charging the storage component in closed-loop solar-storage resources only to the extent that the solar component can support that charging, and reflecting charging constraints on standalone storage resources and storage components in open-loop solar-storage resources.
5. If the Margin Threshold is less than zero, the Limited Duration Resources and Combination Resources are assigned a targeted dispatch. If the Dispatch Threshold is less than zero, Limited Duration Resources and Combination Resources are assigned to supply load commensurate with the full Margin Threshold. Demand Resources receive no assignment. If the Dispatch Threshold is greater than or equal to zero, Limited Duration Resources and Combination Resources are assigned to supply load commensurate with the Nameplate Threshold. Demand Resources receive an assignment equal to the Margin Threshold minus Nameplate Threshold (i.e., the portion of the margin that was not assigned to Limited Duration Resources and Combination Resources).
6. The previous step determines the load assignment for the entire Limited Duration Resources and Combination Resources category. The load assignment for each ELCC Class within the category is determined based on a ratio which is calculated as that class's estimated available Effective Nameplate Capacity divided by the total estimated available Effective Nameplate Capacity of Limited Duration Resources and Combination Resources.
7. If a load assignment cannot be partially or fully supplied by an ELCC Class because of power or energy limitations, Demand Resources will receive the unsupplied portion of the assignment. If all Demand Resources are exhausted, the other ELCC Classes will receive the assignment based on an availability-derived order, from most-available class to less-available class.
8. For ELCC Classes that require specific modeling of the individual units in the Simulated Dispatch (e.g., Hydropower With Non-Pumped Storage), the load assignment received by the class will be further allocated to the individual units in the class based on the same logic described in vi and vii (the two immediately preceding steps).

Starting with the 2025/2026 delivery year, the above procedure also applies, with the following addition for Combination Resources: the hourly output of a Combination Resource is capped at (i) the greater of the resource's CIR MW 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, (ii) the resource's winter deliverability MW value during hours in the months of November through the following April of the delivery year.

Demand Resources

The simulated dispatch of Demand Resource is governed by steps v and vii described above for the simulated dispatch of Limited Duration Resources and Combination Resources. The amount of Demand Resources available to perform during each hour of the simulation is calculated as Nominated DR Value (a constant value for an entire delivery year) times r, where r is defined as the ratio of simulated hourly load (in MW) to 50/50 peak load (in MW).

5.4 Loss of Load Expectation (LOLE) Calculation

As indicated in 5.2.3, there are 1,000 HLSc for each HLS. If there are N HLS, then the total number of HLSc is N times 1,000. The probability of each HLSc, PHLSc, is calculated by using the PHLS described in 5.2.2. For example, if the HLS based on year 1 has PHLS equal to P1, then each of the 1,000 HLSc created based on year 1’s HLS has a PHLSc equal to P1 divided by 1,000.

In the ELCC analysis, a loss of load occurs when the hourly load is greater than the hourly output of all the resources considered available in the simulation. LOLE is calculated as follows:

1. For each HLSc, count the number of days in a delivery year that include at least one hour of loss of load.
2. Multiply the quantities from the previous step by the corresponding PHLSc.
3. Add up all the quantities calculated in the previous step. The result is the LOLE of the simulated system.
4.

5.5 Calculation of ELCC Portfolio UCAP

The calculation of the ELCC Portfolio UCAP requires simulating the system twice. The first simulation (PJM Case “Including”) includes the ELCC Resources in addition to the Unlimited Resources and Demand Resources. The second simulation (PJM Case “Excluding”) excludes the ELCC Resources, but includes Unlimited Resources, Demand Resources, and a variable amount of perfect resources (the “perfect resource” concept refers to a hypothetical resource with no outages and always available producing output at its Effective Nameplate Capacity). The PJM Case “Including” is run until an LOLE of 0.1 days per year is achieved. At that point, the peak load value for the case is recorded. The PJM Case “Excluding” is then run by inputting the peak load value from the PJM Case “Including” and determining the amount of perfect resources necessary to add to the system in order to achieve an LOLE of 0.1 days per year. This added amount of perfect resources is the ELCC Portfolio UCAP (i.e. the ELCC of the entire group of ELCC Resources included in the simulation).

5.6 Calculation of ELCC Class UCAP and ELCC Class Rating values

The allocation of the ELCC Portfolio UCAP to the ELCC Classes, and ultimately determining the ELCC Class UCAP and ELCC Class Rating values, is performed according to the incremental value of each class measured in the absence of the other ELCC Classes adjusted to reflect the diversity interaction of the ELCC Class with all the other modeled ELCC Classes. The procedure is as follows:

1. Each ELCC Class has a **representative incremental quantity** whose hourly output is determined consistent with the output of the subject class.
2. For each ELCC Class, the "**Last-In ELCC UCAP**" (in MW) is defined as the difference between (a) the ELCC Portfolio UCAP of a portfolio that includes all classes and resources in the ELCC model plus the representative incremental quantity of the subject ELCC Class and (b) the ELCC Portfolio UCAP of a portfolio that includes all classes and resources in the ELCC model.
3. For each ELCC Class, the "**Last-In ELCC Rating**" (in percent) is equal to [Last-In ELCC UCAP]/[Effective Nameplate Capacity of the increment].
4. For each ELCC Class, the "**First-In ELCC UCAP**" (in MW) is defined as the ELCC Portfolio UCAP of a portfolio consisting solely of the representative incremental quantity of the subject ELCC Class.
5. For each ELCC Class, the "**First-In ELCC Rating**" (in percent) is equal to [First-In ELCC UCAP]/[Effective Nameplate Capacity of the increment].
6. For the entire ELCC Portfolio, the "**Portfolio Diversity Interaction**" (in MW) is defined as the difference of (a) the sum across all classes in the model of the product of [the aggregate Effective Nameplate Capacity of the class] times [the First-In ELCC Rating of the class]; minus (b) the ELCC Portfolio UCAP of a portfolio that includes all classes and resources in the ELCC model.
7. For each ELCC Class, the "**Class Delta Rating**" (in percent) is the Last-In ELCC Rating minus the First-In ELCC Rating.
8. For each ELCC Class, the "**Class Delta UCAP**" (in MW) is the Class Delta Rating times the aggregate Effective Nameplate Capacity of the class.
9. For the entire ELCC Portfolio, the "**Total Delta UCAP**" (in MW) is the sum of the Class Delta UCAP values of all classes.
10. For each ELCC Class, the "**Class Delta Share**" (in percent) is equal to [Class Delta UCAP] divided by [Total Delta UCAP].
11. For each ELCC Class, the "**Class PDI Share**" (in MW) is the product of the [Portfolio Diversity Interaction] times the [Class Delta Share].
12. For each ELCC Class, the "**Class Rating Adjustment**" (in percent) is the Class PDI Share divided by the aggregate Effective Nameplate of the class.
13. For each ELCC Class, the "**ELCC Class Rating**" (in percent) is the First-In ELCC Rating minus the Class Rating Adjustment.
14. For each ELCC Class, the ELCC Class UCAP is the ELCC Class Rating times the aggregate Effective Nameplate Capacity of the resources in the model that belong to the subject class.

Revision History

Revision 14 (07/26/2023):

- A general note was added to the Introduction section to describe how the new changes impact existing customers' ISAs.
- Section 4.3 #13 – Reference to ISA is updated to Generation Interconnection Agreement (GIA).

Revision 13 (04/10/2023):

- Manual ownership changed from Thomas Falin to Andrew Gledhill
- Section 5.3 Resource Performance: Conforming revisions for FERC Order ER23-1067-000 to cap hourly output and adjust for historical curtailments in the ELCC analysis.

Administrative Change (03/23/2022): Approved by Tom Falin

- Correct/Remove exhibit language in sections 1.2, 3.2, 3.2.1, 3.2.3

Revision 12 (08/25/2021):

- Revisions proposed as a result of a Cover to Cover Periodic Review.
  - Revisions needed to clean-up outdated language and ensure language follows current processes.
  - Minor revisions to correct grammar, spelling, punctuation, consistency of terms and document references.
  - Based on the above, the following sections include revisions: 1.2, 1.4, 1.6, 1.7, 1.8, 1.9, 2.1, 3.2, 3.3 and 4.3.
  - Section 5.2 and 5.3 were updated for format changes only.

Revision 11 (07/28/2021):

- Added Section 5 that describes key elements of the Effective Load Carrying Capability (ELCC) methodology. This methodology is used to determine the Accredited UCAP values of ELCC Resources.

Revision 10 (03/21/2019):

- Revisions proposed as result of a Cover to Cover Periodic Review
  - Revisions needed to clean-up outdated language and ensure language follows to current processes
  - Minor revisions needed to correct grammar, spelling, punctuation, consistency of terms and document references.
- Removed references to Demand Resource Factor due to implementation of Capacity Performance.

- Deleted Section 5: DR Reliability Target Analysis Procedures and Section 6: Limited-Availability Resource Constraints Procedures due to implementation of Capacity Performance.
- Updated references of ReliabilityFirst's Standard BAL-502-RFC-02 to ReliabilityFirst's Standard BAL-502-RFC-03 to reflect new version.

Revision 09 (06/21/2018):

- Revised Section 3.3 to reflect new methodology for developing the winter peak week's capacity model.

Revision 08 (07/01/2017):

- Revised Section 4.3 to align language with Zonal and Global LDA definitions presented in Attachment C of Manual 14b.

Revision 07 (08/01/2016):

- Revisions proposed as result of a Cover to Cover Periodic Review
  - Revisions needed to clean-up outdated language and ensure language follows to current processes
  - Minor revisions needed to correct grammar, spelling, punctuation, consistency of terms, and document references
- Revisions needed to clarify the implementation of Capacity Performance

Revision 06 (08/01/2015):

- Added Section 6 that describes the procedures used to establish Limited-Availability Resource Constraints for use in RPM. These procedures are in effect for only the 2018/2019 and 2019/2020 Delivery Years. Changes were endorsed at the July 23, 2015 MRC meeting.

Revision 05 (02/01/2013):

- Revised Section 5: DR Reliability Target Analysis Procedures to add Test 2 for the six-hour duration requirement for the Limited DR product. Test 2 will become effective in the 2016/2017 Delivery Year.

Revision 04 (06/01/2011):

- Added Section 5: DR Reliability Target Analysis Procedures.
- Updated the entire manual to reflect current analysis and modeling methods.

Revision 03 (06/01/2007):

- Reviewed for consistency pertaining to all Manual changes related to implementation of the Reliability Pricing Model (RPM).
- Updated to reflect formation of NERC's *ReliabiltyFirst* Corporation (RFC).

- Removed duplication of information shown in other Manuals.

Revision 02 (05/30/2004):

- Reformatted this document to reflect new PJM format.
- Changed reference to PJM Manual for Accounting Obligation to reflect the current title of PJM Manual Capacity Obligation.

Revision 01 (01/01/01):

- This revision primarily reflects changes due to full implementation of the Reliability Assurance Agreement (RAA).
- Removed Attachment A: Definitions and Abbreviations. Attachment A is being developed into a PJM Manual for ***Definitions and Abbreviations (M-35)***.

Revision 00 (08/19/97):

- This revision is the preliminary draft of the PJM Manual for ***PJM Resource Adequacy Analysis***.