PJM Manual 20:

PJM Resource Adequacy Analysis

Revision: 09

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Prepared by
Resource Adequacy Planning

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Approval

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Resource Adequacy Planning

Current Revision

Revision 09 (06/21/2018):

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

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 five 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

- Section 5: DR Reliability target analysis Procedures

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, Demand Resource Factor, 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, Demand Resource Factor, 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, Forecast Pool Requirement and Demand Resource Factor.

- *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, Forecast Pool Requirement, and Demand Resource Factor.

- *PJM Board of Managers* – The PJM Board of Managers reviews the assessments and recommendations and approves the Installed Reserve Margin, Forecast Pool Requirement, and Demand Resource Factor.

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 – <u>Generation and Transmission Interconnection Planning</u>, Attachment E.

- PJM Manual 18 – <u>PJM Capacity Market</u>

- PJM Manual 19 – <u>Load Forecasting and Analysis</u>

- PJM Manual 21 – <u>Rules and Procedures for Determination of Generating Capability</u>

- PJM Manual 22 – <u>Generator Resource Performance Indices</u>

- PJM eGADS User Guide – on line help function within <u>eGADS</u>.

- PJM Manual 29 – <u>Billing</u>

- Reserve Requirement Study reports (<u>Posted at this link</u>)

- PJM Generation Adequacy Analysis: Technical Methods – (<u>Posted at this link</u>).

- World Modeling Region – Technical Issues

- PJM Planning Division Capacity Model

- Reliability*First*'s Standard BAL-502-RFC-02 (<u>Posted at this link</u>).

- Reinventing a Legacy System using SAS, the Web and OLAP reporting. (<u>Posted at this link</u>)

- Resource Adequacy Analysis Subcommittee <u>Team Charter</u>

- PJM Manual 34 – <u>PJM Stakeholder Process</u>

- Reliability Pricing Model, Auction User Information, per delivery year. (<u>Posted at this link</u>)

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 calculating the amount of resource capacity required to meet the defined reliability criteria. This calculation process is reviewed by the Resource Adequacy Analysis Subcommittee. This process satisfies the ReliabiltyFirst'sStandard BAL-502-RFC-02 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.

The RPM auction timeline is shown in Exhibit 1. The planning parameters for the delivery year are posted by February 1 prior to the base residual auction, 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 (CETO/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) alternate 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, FPR, DR Factor – developed in the resource adequacy planning process are also applicable to FRR Entities.
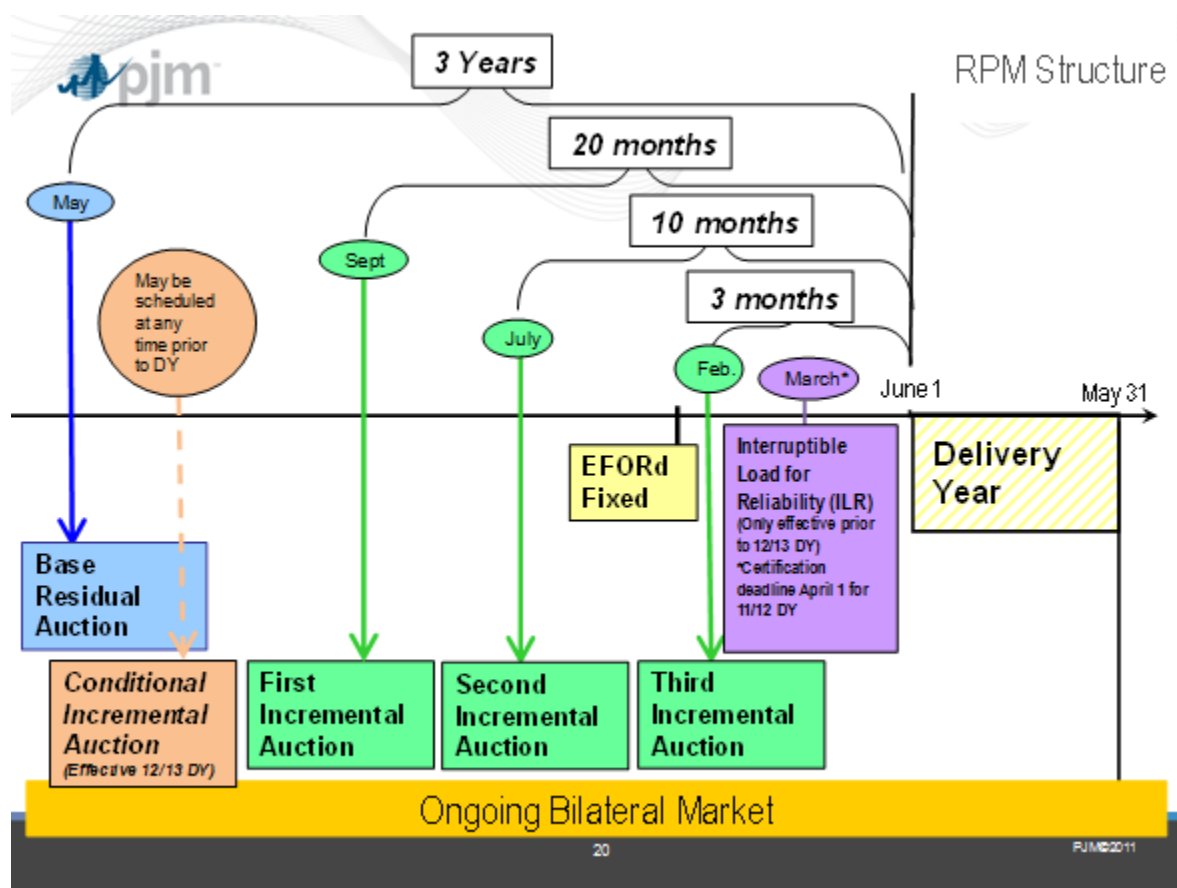
Exhibit 1: Timeline for RPM Auctions

The schedule of the steps in the reserve requirement study planning process is shown in Exhibit 2. These 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, Forecast Pool Requirement, and DR Factor 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, FPR, and DR Factor) 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:

  o 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-02.

  o 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 2: 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) and DR factor.

- *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)[1]. 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 definition of EFORd[2] is consistent with that used in the capacity market to establish the unforced capacity value of individual generators.

- *DR* Factor — The Demand Resource Factor is used to determine the reliability value of load management and energy efficiency. The megawatt amount of load management and energy efficiency will vary between zones but the DR Factor is constant across the entire PJMRTO for a given delivery year. The Unforced Capacity value of load management and energy efficiency is the product of three factors: the megawatt level of load reduction, the DR Factor and the FPR. The DR factor is dependent on the value of IRM. Note that the DR Factor is eliminated with the introduction of the Capacity Performance product to RPM in the 2018/2019 Delivery Year.

$$LM(UCAP) = LM(MW) * DRFactor * FPR$$
$$UCAP \text{ value of EE Resource } = \text{Nominated EE Value} * DRFactor * FPR$$

$$Where:$$
$$UCAP = \text{Unforced Capacity}$$
$$LM(UCAP) = \text{Unforced Capacity Value of Load Management}$$
$$LM(MW) = \text{Load Management value given in megawatts}$$
$$FPR = \text{Approved Forecast Pool Requirement (per-unit value)}$$
$$DRFactor = \text{Demand Resource Factor (value between 0 and 1.00)}$$
$$EE = \text{Energy Efficiency (EE)}$$
$$\text{Nominated EE Value} = See PJM Manual 18, Section 4.4.1.$$

1.4 PJM Installed Reserve Margin (IRM)

The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management. 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.

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[1] Average EFORd does not include Outside Management Control generator outage events

[2] 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)

The PJM Installed Reserve Margin value is used in the determination of the Forecast Pool Requirement and DR factor.

The installed reserve requirement for the PJM RTO is established by running PRISM studies. The two area PRISM data file created for the base case is also used to create a single-area file for use in determining the DR Factor. See the Reserve Requirement Study Reports for further details.

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 would 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 of the calculated IRM 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 Forced Outage Rate (EFORd)[3] 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:

$$ForecastPoolRequirement = (1 + IRM) * (1 - Pool\ AverageEFOR_d)$$

Note that the Pool average EFORd in the above equation does not consider outside management control events.

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 Demand Resource Factor

The value of load management and energy efficiency in the RPM construct is determined by calculating the DR Factor. This factor is used to determine the reliability benefit of load management and energy efficiency programs and to assign an appropriate value under RPM.

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

The DR Factor is typically less than 1.0 where 1.0 indicates a 100% reliability benefit for load management and energy efficiency.

PRISM is used to calculate the value of the DR Factor, based on the load carry capability of the identified amount of load management and energy efficiency. The analysis is based on a single-area PRISM base case.

Note that the DR Factor is eliminated with the introduction of the Capacity Performance product to RPM in the 2018/2019 Delivery Year.

1.7 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.

The MARS tool is used 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.

1.8 Compliance with *ReliabilityFirst* (RF)

The required 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. PJM has adopted an LOLE planning criterion of 1-in-10 which is stated in the RF Standard, BAL-502-RFC-02 effective December 4, 2008, and approved by Federal Energy Regulatory Commission (FERC) effective May 23, 2011, 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 year1 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 median2 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 recently approved by the Federal Energy Regulatory Commission making it mandatory and applicable to all Planning Coordinators in the Reliability*First* Corporation region. PJM is a Planning Coordinator in the Reliability*First* Corporation region.

The PJM interpretation of BAL-502-RFC-02 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 adherence of this interpretation of 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-02, please reference the historic Reserve Requirement Studies (typically Appendix C) posted on the PJM web site.

1.9 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. PJM uses the MARS program for developing case sensitivities, coordinating study models and results with neighboring regions, participating in interregional studies, and performing the winter weekly reserve target analysis.

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 and the DR factor.

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.

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, FPR and DR Factor. The recent practice, endorsed by the RAAS, has been to use the base case's calculated IRM value for these determinations.

1.10 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, FPR, and DR factor to the PJM Board of Managers. The PJM Board of Managers is ultimately responsible for approving the PJM FPR and DR factor.

Resource adequacy planning begins at least four years in advance of the applicable delivery year. Early in the timeline, resource owners submit their capacity plans including expected outages for the capability period. 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, FPR, Demand Resource Factor (DR Factor) 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.

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Section 2: Capacity Review Process by Generation Owners

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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 contains the most significant modeling parameters for the calculation process. 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

- the DR Factor for Load Management

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 3) 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, and Duke Energy Ohio/Kentucky (DEOK).
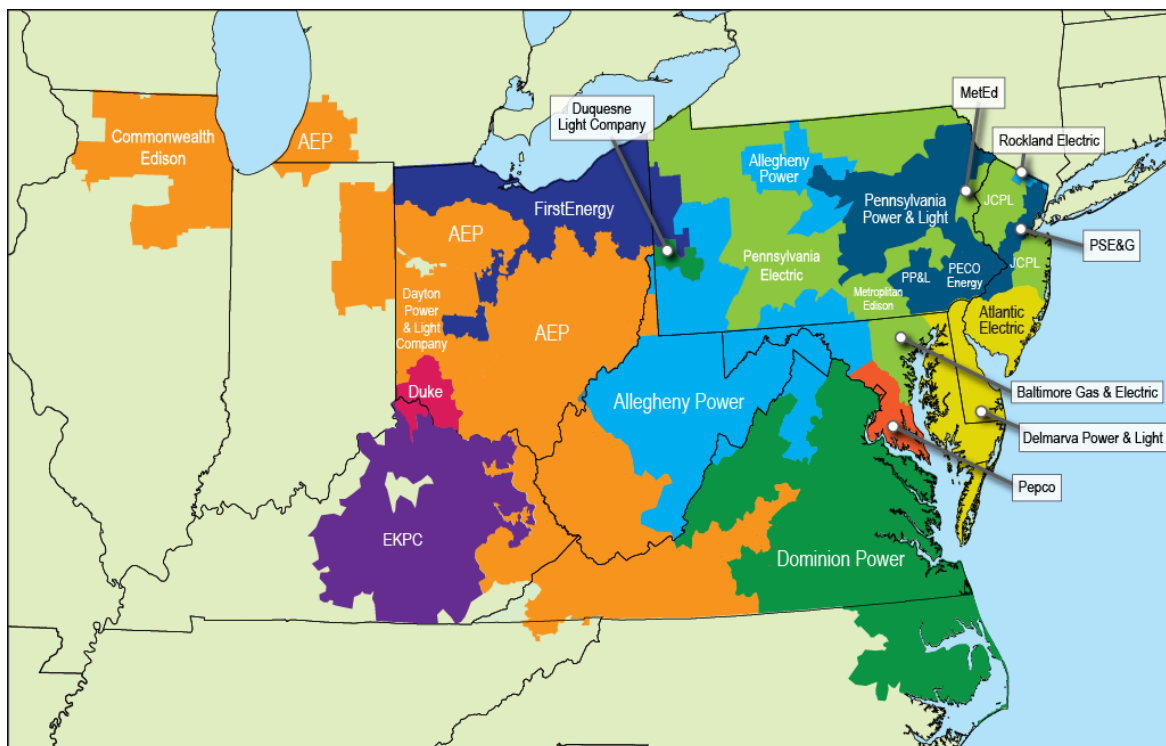
Exhibit 3: PJM RTO Region Modeled

Areas adjacent to the PJM Region are referred to as the "World" (Exhibit 4 – Yellow region) and consist of the non-PJM portion of RF and of the Southeastern Electric Reliability Council (SERC), much of the Northeast Power Coordinating Council (NPCC) territory and the U.S. portion of the Midwest Reliability Organization. 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.
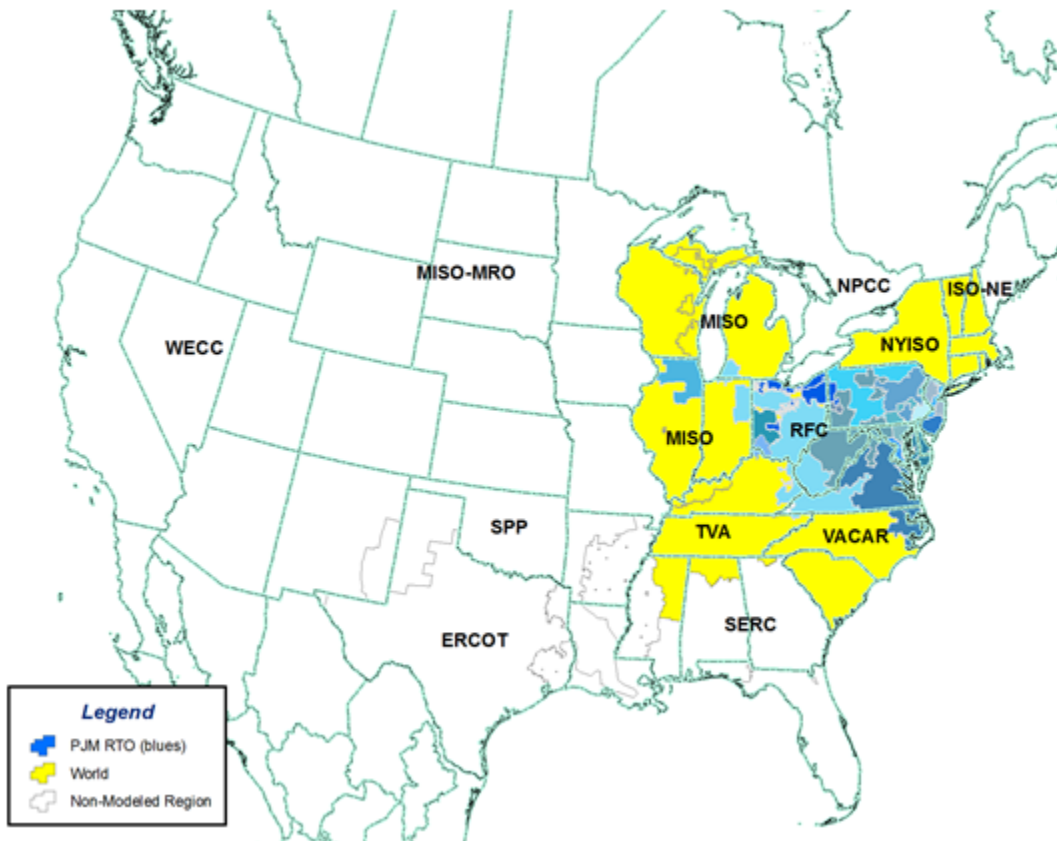
Exhibit 4: PJM RTO, World and Non-Modeled Regions

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 seven to ten historic delivery years for which both PJM and World hourly load data are available, is used. The hourly load history files can be updated any time prior to a reliability study. 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. The PJM staff also complies and submits data for the annual RF regional reports and for the EIA-411.

- World — Historical hourly load data are obtained from the surrounding NERC Regional Reliability Councils: RF, SERC, MISO, & NPCC (including Canada). PJM Staff gathers data from publicly available sources on the FERC web site.

The load model used in most 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.

Different load models are used with PRISM depending on the purpose of a particular study. PLOTS is the load model used for the Reserve Requirement Study (RRS) and CETO studies. Seven to ten years of historic hourly loads are typically used, based on a recommendation by the Load Analysis Subcommittee.

TREND is very similar to PLOTS. The only difference is that TREND is a calendar ordered load model. It combines historical loads based on their actual placement within the calendar year and not on their relative magnitudes. TREND, therefore, produces a "flatter" load shape than PLOTS. The TREND load model calculations are a preliminary step for producing the PLOTS load model.

MARS uses a deterministic 8760 hourly load model. The hourly load model is from a historic year judged to be most representative of the system for LOLE studies. Currently the 2002 calendar year is used for this hourly load shape. MARS uses a Load Uncertainty Table to model variability of daily load occurrence.

The TREND and MARS load models can be used for studies that examine reliability indices for individual seasons within the delivery year.

The PLOTS and TREND load models are probabilistic models based on a daily distribution (aggregated by week) derived from hourly historical loads and load forecasts. PRISM's use of a probabilistic load model distinguishes it from other reliability programs, such as MARS, which use a deterministic approach to model loads.

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 5.

- Exhibit 6 graphically shows how the distribution in Exhibit 5 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
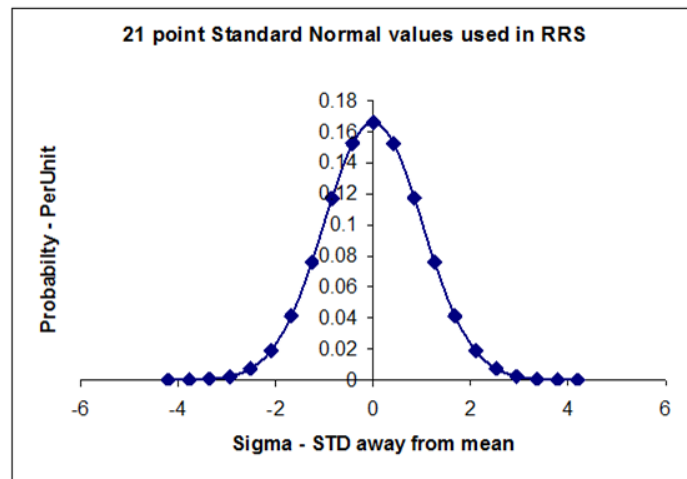
Exhibit 5: Normal Distribution

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:

  o Historic time period of the model.

  o Sub-zones or geographic regions that define the model.

  o Load Forecast Report to use.

o   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. Based on appropriate load analysis, non-normal distributions for each of the 52 weeks can be modeled as well. 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 6.

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

$Where:$

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 6: 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 7.

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 and TREND 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.
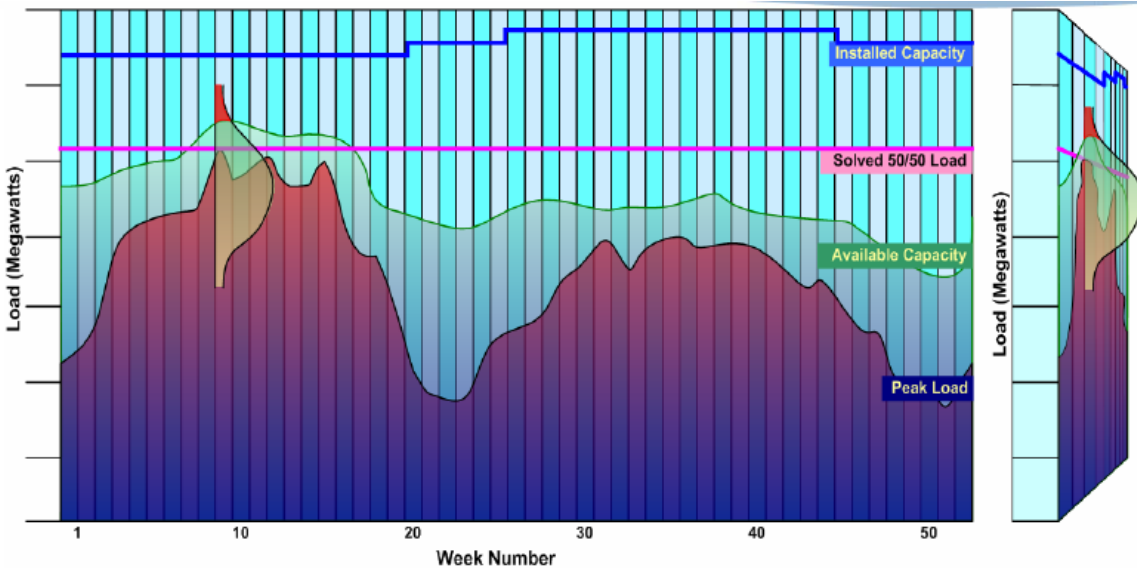
Exhibit 7: Daily Load Distribution

3.2.2 Capacity Model

The capacity model 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)

  - Planned maintenance cycles including start year for maintenance cycle and second year maintenance (given in weeks/year) yielding a planned outage factor (POF)

  - 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. Currently RF, MISO, NPCC, and SERC comprise the World representation. This update is targeted for the Fall or early Winter.

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. IEEE Standard 762 – 2006 is available by going to the (http://www.ieee.org/portal/site) => Standards => Buy Standards => Type 762 in the search window.

- The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting. The RAA is available at the PJM web site.

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. Recent improvements to PJM's fleet-based statistics include:

  o The ability to check on specifics of underlying data

  o The ability to verify specifics of statistical calculations

  o Identification of necessary data that is independent of outside resources.

- With recent market integration activities, the PJM RTO Region has significantly increased its number of generating units. This increase has mitigated the need for assistance from the world region and improved the reliability of PJM on a stand- alone basis. Less than ten percent of the units in PJM continue to use class average data for at least part of their five-year history. It's important to note that the modeling of PJM class average data in the study for these new units may not reflect their actual future performance.

- 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 are from NERC's Brochure, with the values determined from PJM's fleet of units. A five-year period is used for the statistics, with 72 unique generator class keys. 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 numbers of units for each category give an indication of how many units the average values are based on. The unit years value allows for an indication of how many units (and for how many years) were part of the total five-year reporting period. The class average statistical values are available via the web based application discussed in the previous section, capacity review process by generation owners.

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, 2,500 MW 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 unitsscheduled 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: The equation for the EEFORd is as follows:

• 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. In addition, for delivery years prior to 2018, the EFORd used to determine the UCAP value of generators does not include the events Outside Management Control (OMC).); with the implementation of Capacity Performance in 2018, OMC events are eliminated.

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 8, ARC combines several data sources into a single data source that directly creates the file parameters for PRISM and other applications. The RST (Short for R-Study) process, which has several phases, is used to provide the capacity modeling values into the SAS data mart which is used by all analysis tools.

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 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.
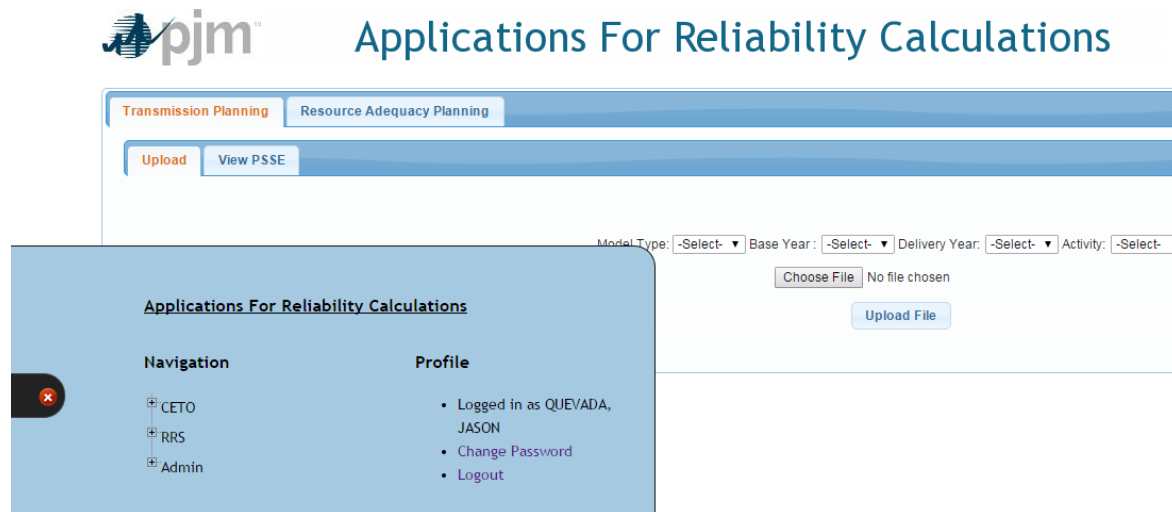
Exhibit 8: Applications for Reliability Calculations

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 maintained for twelve outage states ranging from unit "full available" to "full out". PRISM cannot yet specifically model these 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 the 12 partial outage states reported in the 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 the reported 12 partial outage states. 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 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. As mandated in the RFC Standard BAL-502-RFC-02, the annual LOLE standard is 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 is the reserve corresponding to this adjusted peak load.

3.3.1 Interregional Studies and Analysis

PJM Planning Division staff is involved with interregional assessments, coordination of study models and discussion of technical methods and practices used in LOLE studies.

The tool used for these interregional efforts is MARS. Among the various regions' staffs, MARS seems to be the most widely used tool in performing LOLE studies. Therefore MARS allows a common basis for the various regions' staffs to address specific modeling and technical practices.

The Inter-Regional Planning Stakeholder Advisory Committee (IPSAC) is one of the groups PJM staff is involved with for interregional efforts. This group includes members from the three Northeast RTOs (PJM, NYISO and ISO-NE). Please see this web site for further details.

PJM staff also participates with NPCC's CP-8 Working Group. The CP-8 Working Group uses MARS to perform its assessments of adequacy and compliance with NPCC Standards. NPCC uses a similar standard[4] of LOLE of 1 occurrence, on average, every 10 years or .1 days per year. All interregional models and assessments are coordinated with the other ARC models and technical methods employed by the PJM Planning division staff.

3.3.2 ReliabiltyFirst 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 measures compliance with the reliability criteria defined in the RF Standard BAL-502-RFC-02. The criteria pertaining to generation adequacy, defined in that document, are tested using the probabilistic tools described in previous sections of this manual.

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4 NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" (December 1, 2009) - section 5.2, page 9

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-02 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 on the at: http://www.pjm.com/planning/generation-deactivation.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. [Note: Per RPM business rules, an RMR unit with a part year contract must offer into the auction at its Avoidable Cost. If it clears, it should be kept in service for the entire year.] 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 an Interconnection Service Agreement (ISA) 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.

15. Energy Only and Behind-The-Meter units can be modeled per agreement between the zone's TO staff and the PJM Transmission Planning department staff.

Section 5: DR Reliability Target Analysis Procedures

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

- • An overview of PJM's DR Reliability Target Analysis Procedures.

- • A description of the Limited DR Product Procedure.

- • A description of the Extended Summer DR Product Procedure

5.1 Overview

The procedures described below are performed prior to each RPM Base Residual Auction and Incremental Auction. The procedures use the most recent IRM Study model, CETO/CETL models and PJM load forecast model applicable to the Delivery Year (DY) being evaluated. DR Reliability Targets are established for both the Limited DR Product and the Extended Summer DR Product. The Annual DR Product does not require establishment of a Reliability Target. Targets are established for the RTO and for any LDA that is modeled as a separate area in the RPM auction. The DR Reliability Targets are posted with the other planning parameters prior to each RPM auction. The Targets are used to establish the minimum amount of Unlimited Resources that is required to maintain system reliability. The procedures become effective with the 2014/2015 Delivery Year.

5.2 Limited DR Product

This section details the procedure used to determine the DR Reliability Target associated with a demand resource product that is available for interruption up to ten times per delivery year, with each interruption lasting no more than six hours. The criterion to establish the Reliability Target is to ensure that the Limited DR product does not have a negative impact on system reliability. The resource's compliance is measured over the summer period only (June 1 – September 30). The procedure uses the most recent IRM Study model, CETO/CETL models and PJM load forecast model applicable to the Delivery Year being evaluated.

5.2.1 RTO Procedure

Ten Interruption Requirements
The requirements for ten interruptions are shown in three categories: Load Model, Capacity Model, and Analysis.

Load Model

1. The summer forecast distributions for the applicable Delivery Year are obtained for the 20 CP (coincident peak) days from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. For a given weather scenario, the CP1 day represents the highest load forecasted for the summer of the forecast year. The CP2 day represents the 2nd highest load forecasted, etc.

2. The median load value from the CP1 day corresponds to the 50/50 forecasted RTO peak for the applicable Delivery Year. The 20 CP distributions are per-unitized on the median of the CP1 day peak. In other words, the ratio of each weather scenario load to

the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows the 20 CP day distributions to be shifted up or down by altering the forecasted summer peak load.

Capacity Model

1. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage. The capacity distribution from the peak week is assumed to be constant for the entire period of 20 CP days. This assumption is made because there are no planned or maintenance outages over the summer period and the generator EFORds are modeled as constant across the Delivery Year.

2. DR is assumed to be a single, 100% available resource that is available to assist the system whenever PJM operating reserves fall below a certain margin. The operating reserve is thus the margin between load and available capacity at which DR is expected to be invoked. An operating reserve margin of 1,300 MW is assumed for the RTO. This value is documented in Section 2.2 of PJM Manual 13 and represents the RTO's synchronized/spinning reserve requirement that is based on the loss of the largest PJM generating unit.

Analysis

1. The cumulative capacity probability table from step 3 and the normalized distributions from step 2 are combined to establish the approved Installed Reserve Margin (with no DR assumed) for the applicable Delivery Year. This is done by iteratively increasing or decreasing the peak load until the approved reserve level between peak load and installed capacity is established. This case forms the base case.

2. The 20 CP days from each of the weather scenarios are derived from various weather patterns that simulate the need for invoking DR. At the assumed operating reserve margin, the following occur:

   a. If the margin between load and an available capacity state is greater than the operating reserve, no Loss of Load (LOL) occurs and no DR is invoked.

   b. If the margin between load and an available capacity state is less than the operating reserve, all DR in the study area is invoked if available. No LOL occurs until the margin becomes less than or equal to zero. For each of the 20 CP days, the first instance (or capacity state) in which the margin falls below the operating reserve is used to determine the probability DR will be invoked on a particular day. For a CP day, DR can be invoked with a probability between zero and one depending on the capacity state at which the margin falls below operating reserve. The probability of DR invocation is calculated for all 20 CP days in a weather scenario and is then summed. This sum represents the expected number of DR invocations in that scenario.

   c. If, after invoking DR, the margin becomes less than zero for certain states, LOL occurs.

3. Using the 1,300 MW operating reserve margin, the amount of DR is progressively increased. The increase in DR is modeled as 100% available generation and the additional DR replaces an equal amount of generation resources so that the IRM is held constant. Thus, as the amount of DR increases in the system, more generation is displaced and also the expected number of times DR is invoked increases.

A histogram of the expected DR invocations from the weather scenarios is developed for each level of DR penetration. The histogram represents the frequency with which DR is implemented X number of times as X is varied from zero to 20. The histogram is then aggregated into a cumulative probability curve that represents the likelihood that DR is implemented X or fewer times. A 90% probability of requiring ten or fewer DR interruptions is used to define the DR Reliability Target. This Target is expressed as a percent of forecasted peak load.

Six Hour Duration Requirement
For Delivery Years prior to 2016/2017, Test 1 described below is applied. For 2016/2017 and subsequent Delivery Years, both Test 1 and Test 2 are applied.

Test 1:

1. PJM examines the last five calendar years and identifies any day which is an annual peak load day and/or a day with an unrestricted peak load greater than the 50/50 weather normalized peak and/or a day on which RTO-wide load management was implemented. These days would be most likely to require invocation of DR

2. The unrestricted hourly loads for each of the days identified in step 1 are ranked from highest to lowest. The MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is computed.

3. For each day examined in step 2, the MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is divided by the forecasted 50/50 peak load for that particular summer. The resulting percentages are tabulated for all days that qualify per step 1. The average of these percentages is the DR Reliability Target based on the 6 hour duration requirement. Any day with a peak load well below the 50/50 peak may be excluded from this calculation as it is not representative of a day that would require implementation of DR.

Test 2:

1. The hourly loads are developed using the distributions for the 20 CP (coincident peak) days from the latest PJM load forecast as follows (note that each one of these distributions is based on an X number of historical weather scenarios):

   a. Per unitize the X values for each of the 20 CP days with respect to the median of CP 1, the day with the highest forecasted load.

   b. Find the mean of the X per unitized values of each CP day. These mean values are used to obtain the relative size of each CP day peak.

   c. Obtain the historic hourly to daily (HTD) peak ratios for an extreme summer day, with the focus only being on the 7 top hours. An extreme summer day is defined as the top 25 non-holiday summer weekdays by cooling degree days (CDD) since 1998.

    d. Apply the average of the 25 HTD ratios to the mean values computed in Step 1b. As a result, there will be 140 (20 CP x 7 hours) per unitized hourly loads. These per unitized hourly loads are then shifted based on the forecasted summer peak load.

    e. Place the 20 CP days (with its 7 hourly loads) in the month of July. Make all the other loads of the year equal to 0.

2. The uncertainty associated with the hourly loads is computed as follows.

    a. GE-MARS allows for adding load uncertainty on a monthly basis. To this effect, seven pairs of load level and probability of occurrence of the load level are used for the month of July. No uncertainty is considered for the rest of the months since the loads are zero.

    b. Create a histogram with 7 equally-sized bins using the X values from the CP1 distribution. The bin-length is obtained by subtracting the minimum of the X values from the maximum of the X values, and dividing this difference by 7. Each load level corresponds to the mid-point of each bin whereas the probability of occurrence of each load level is determined by the proportion of values that are contained within each bin.

3. The amount of generation considered in the analysis is consistent with the calculated single-area Installed Reserve Margin (IRM) for the year been studied as per the latest Reserve Requirement Study. In MARS, the units' forced outages are modeled chronologically by taking the equipment out of service for contiguous hours.

4. A total of 2500 MW of generation are removed from the case to account for ambient deration. This is consistent with the Reserve Requirement Study assumptions. In addition, a total of 1300 MW are considered as operating reserves (this value is documented in Section 2.2 of PJM Manual 13 and represents the RTO's synchronized/ spinning reserve requirement that is based on the loss of the largest PJM generating unit).

5. DR is modeled as an emergency operating procedure which is initiated whenever operating reserves fall below the specified level. Therefore, DR is assumed to be a 100% available resource.

6. Obtain the base case run by assuming DR is 0 MW and by adjusting the peak load until the difference between generation and peak load is the single-area IRM. Then, run several scenarios with varying amounts of DR. For each MW of DR that is added in each scenario, subtract an equal amount of generation (via increasing operating reserves in MARS) so as to preserve the starting reserve margin (the single-area IRM).

7. For each of the DR scenarios, obtain the proportion of the time DR was used more than 6 hours in each of the 20 CP days.

8. When the proportion reaches 10% in one or more of the 20 CP days, record the amount of DR that was added in the scenario. Divide this amount by the forecasted peak load. The result of this division is the 6-hour DR target (expressed as percentage of the forecasted peak load).

RTO Operative DR Reliability Target

For Delivery Years prior to 2016/2017, the operative DR Reliability Target is the lower of the targets based on either: 1) the ten interruption requirement or 2) the six hour duration requirement (Test 1). The operative DR Reliability Target is used in the applicable RPM auction.

For 2016/2017 and subsequent Delivery Years, the operative DR Reliability Target is the lowest of the targets based on either: 1) the ten interruption requirement or 2) the six hour duration requirement (Test 1) or 3) the six hour duration requirement (Test 2). The operative DR Reliability Target is used in the applicable RPM auction.

5.2.2 LDA Procedure

Ten Interruption Requirements

Any LDA that is modeled as a separate area in the RPM auction is examined. The ten interruption analysis procedure described above for the RTO is applied to each of these modeled LDAs with the two modifications identified in steps 1 and 2 below:

1. The LDA's generation level is set to its internal generation plus its Capacity Emergency Transfer Limit (CETL). This is the maximum amount of resources expected to be available to the LDA during a local capacity emergency. The CETO/CETL cases include energy-only resources and behind-the-meter (BTM) generation.

2. The operating reserve margin at which DR is assumed to be implemented is zero MW. This approach assumes that DR is initiated for LDA related problems only at the point of avoiding an actual loss of load event (or a negative reserve margin).

3. The load model and capacity model for each LDA is developed as described above in steps 1 through 4 for the RTO analysis. The unrestricted load forecast for the LDA is adjusted to include the BTM load. Thus the LDA reserve levels are established using the formula: LDA Reserve Margin = (Installed capacity + CETL) / (Unrestricted Peak Load + BTM load adjustment). The DR Reliability Target is then determined for an LDA similar to the RTO as described in steps 5 through 7 in the RTO procedure.

4. Each DR Reliability Target determined in step 3 is converted to a MW amount by multiplying the Reliability Target percentage by each LDA's forecasted non-coincident peak load (NCP). The resulting MW Reliability Target is then divided by each LDA's forecasted coincident peak (CP) load. This Reliability Target percentage is used in the RPM auction. The NCP and CP forecasts are obtained from the B and C Tables from the most recent PJM Load Forecast Report

Six Hour Duration Requirement

For Delivery Years prior to 2016/2017, Test 1 described below is applied. For 2016/2017 and subsequent Delivery Years, both Test 1 and Test 2 are applied.

Test 1:

1. PJM examines the last five calendar years and identifies any day which is an LDA annual peak load day and/or a day with an unrestricted peak load greater than the 50/50 weather normalized LDA peak and/or a day on which load management was implemented in that particular LDA. These days would be most likely to require invocation of DR.

2. The unrestricted hourly loads for each of the days identified in step 1 are ranked from highest to lowest. The MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is computed.

3. For each day examined in step 2, the MW difference between the day's unrestricted hourly peak load and its seventh highest unrestricted hourly load is divided by the forecasted 50/50 LDA peak load for that particular summer. The resulting percentages are tabulated for all days that qualify per step 1. The average of these percentages is the DR Reliability Target based on the 6 hour duration requirement. Any day with a peak load well below the 50/50 LDA peak may be excluded from this calculation as it is not representative of a day that would require implementation of DR.

4. Each DR Reliability Target determined in step 3 is converted to a MW amount by multiplying the Reliability Target percentage by each LDA's forecasted non-coincident peak load (NCP). The resulting MW Reliability Target is then divided by each LDA's forecasted coincident peak load (CP). This Reliability Target percentage is used in the RPM auction. The NCP and CP forecasts are obtained from the most recent PJM Load Forecast Report

Test 2:
The Test 2 procedure to obtain the DR Targets for the LDAs is similar to the RTO six hour duration requirement Test 2 procedure with the following adjustments:

1. The distributions for the 20 CP days used to develop the hourly loads are specific to each LDA. Similarly, the HTD ratios are computed using historic data specific to each LDA.

2. The unrestricted load forecast for the LDA is adjusted to include the BTM load. This value is then used to shift the per unitized loads.

3. The amount of capacity for each LDA is equal to the LDA's internal generation plus the LDA's Capacity Emergency Transfer Limit (CETL). The difference between this amount of capacity and the LDA's unrestricted forecasted peak load is the LDA's starting reserve margin.

4. The amount of generation removed in each LDA as a consequence of ambient deration is obtained by computing the proportion of the LDA's total internal generation to the total generation (in areas where ambient deration is assumed to occur) and then applying this proportion to the 2500 MW mentioned in Step 4 above.

5. No operating reserves are considered for the LDAs (in contrast to the 1300 MW of operating reserves considered for the RTO).

6. The resulting 6 hour DR Target is expressed as a percentage of the LDA's forecasted coincident peak (CP) load.

LDA Operative DR Reliability Target
For Delivery Years prior to 2016/2017, the operative DR Reliability Target is the lower of the targets based on either: 1) the ten interruption requirement or 2) the six hour duration requirement (Test 1). The operative DR Reliability Target is used in the applicable RPM auction.

For all Delivery Years 2016/2017 and later, the operative DR Reliability Target is the lowest of the targets based on either: 1) the ten interruption requirement or 2) the six hour duration

requirement (Test 1) or 3) the six hour duration requirement (Test 2). The operative DR Reliability Target is used in the applicable RPM auction.

5.3 Extended Summer DR Product

This section details the procedure used to determine the DR Reliability Target associated with a demand resource product that is available for interruption an unlimited number of times from May 1 through October 31 but is not interruptible over the November 1 through April 30 time period. Each interruption may last up to ten hours. The criterion to establish the Reliability Target is to ensure that the Extended Summer DR product does not have a negative impact on system reliability. The procedure uses the most recent IRM Study model, CETO/CETL models and PJM load forecast model applicable to the Delivery Year being evaluated.

5.3.1 RTO Procedure

The procedure requirements for the RTO assessment are shown in three categories: Load Model, Capacity Model, and Analysis

Load Model

1. The daily load forecast distributions for the applicable Delivery Year are obtained for all weekdays from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. This results in approximately 260 daily load distributions.

2. The maximum load value from each weather scenario's summer period (June 1 – August 31) is determined. The median of the distribution of all these maximum load values represents the 50/50 forecasted summer RTO peak for the applicable Delivery Year.

3. The daily load distributions from step 1 are per-unitized on the 50/50 peak load value determined in step 2. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows all the daily load distributions to be shifted up or down by altering the forecasted summer peak load.

Capacity Model

1. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained for all 52 weeks of the applicable Delivery Year. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage.

2. The daily load distributions from step 3 are mapped to the corresponding weekly capacity distribution from step 4.

Analysis

1. As described in step 3, the daily load distributions are iteratively shifted to equal the IRM established for the applicable DY.

2. A reference annual LOLE is determined based on the daily load distributions from step 6 and the capacity distributions from step 4. The resulting case is the Base Case.

3. To simulate the impact of extended summer-only DR, varying amounts of DR (expressed as a percent of the unrestricted peak load) are modeled to be interruptible from May 1 through October 31 while being unavailable for the November 1 through April 30 period. The DR is represented as a 100% available resource and is assumed to displace an equal amount of 100% available generation for the entire year.

4. At each DR amount, the annual LOLE is determined and the percent increase in risk from the reference annual LOLE is calculated.

5. The DR Reliability Target is equal to the DR amount at which the percent increase from the reference LOLE computed in step 9 is 10%. The DR Reliability Target in MW is expressed as a percent of the forecasted unrestricted peak.

5.3.2 LDA Procedure
The procedure requirements for each LDA assessment are shown in three categories: Load Model, Capacity Model, and Analysis

Load Model

1. The daily load forecast distributions for the applicable Delivery Year are obtained for all weekdays from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. This results in approximately 260 daily load distributions.

2. The maximum load value from each weather scenario's summer period (June 1 – August 31) is determined. The median of the distribution of all these maximum load values represents the 50/50 forecasted summer LDA peak for the applicable Delivery Year.

3. The daily load distributions from step 1 are per-unitized on the 50/50 peak load value determined in step 2. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows all the daily load distributions to be shifted up or down by altering the forecasted summer peak load. The load distributions are adjusted to match a load level equal to the unrestricted forecasted LDA peak plus a behind-the-meter load adjustment.

Capacity Model

1. The cumulative capacity probability table from the most recent CETO/CETL Study is obtained for all 52 weeks of the applicable Delivery Year. (The CETO/CETL cases include energy-only resources and behind-the-meter generation.) The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance, or planned outage.

2. The daily load distributions from step 3 are mapped to the corresponding weekly capacity distribution from step 4.

Analysis

1. A Base Case is established that sets the reserve margin based on the following formula:
    LDA Reserve Margin = (Installed capacity + CETL) / (Unrestricted Peak Load + behind-
    the-meter load adjustment).

2. A reference annual LOLE is determined based on the daily load distributions from the
    Base Case established in step 6 and the capacity distributions from step 4.

3. To simulate the impact of summer-only DR, varying amounts of DR (expressed as
    a percent of the unrestricted peak load) are modeled to be interruptible from May 1
    through October 31 while being unavailable for the November 1 through April 30 period.
    The DR is represented as a 100% available resource and is assumed to displace an
    equal amount of 100% available generation for the entire year.

4. At each DR amount, the annual LOLE is determined and the percent increase in risk
    from the reference annual LOLE is calculated.

5. The DR penetration percentage at which the percent increase from step 9 is equal to
    10% is determined. The DR Reliability Target in MW is expressed as a percentage of the
    forecasted unrestricted peak (adjusted by BTM load) used in the study.

6. The DR penetration percentage determined in step 10 is then multiplied by the LDA's
    forecasted non-coincident peak load (NCP). The resulting MW amount is then divided by
    the LDA's forecasted coincident peak load (CP) to determine the LDA Reliability Target
    as a percent of the LDA's CP. This Reliability Target, expressed as a percentage of the
    LDA's forecasted CP load, is used in the RPM auction. The NCP and CP forecasts are
    obtained from the PJM Load Forecast Report.

5.4 Annual DR Product

The Annual DR Product must be available on any day of the year and for an unlimited number
of interruptions during the year. Due to its very high level of availability, the Annual DR Product
does not require calculation of a Reliability Target and is treated as an unlimited resource in the
RPM auctions.

Section 6: Limited-Availability Resource Constraints Procedures

Welcome to the Limited-Availability Resource Constraints Procedures section of the PJM Manual for ***PJM Resource Adequacy Analysis***. In this section you will find the following information:

- An overview of the procedures PJM uses to compute the Limited-Availability Resource Constraints at both the RTO level and at an LDA level.

- A description of the Base Capacity Demand Resource Constraint Procedures

- A description of the Base Capacity Resource Constraint Procedures

- A description of the Limited-Availability Resource Constraint Procedures at the LDA Level

6.1 Overview

The procedures described below are performed prior to each RPM Base Residual Auction and Incremental Auction. The procedures use the most recent IRM Study model and PJM load forecast model applicable to the Delivery Year (DY) being evaluated. Limited-Availability Resource Constraints are established for both the Base Capacity Demand Resource and the Base Capacity Resource for the RTO and for any LDA that is modeled as a separate area in the RPM auction. The Resource Constraints are posted with the other planning parameters prior to each RPM auction. The procedures are in effect for only the 2018/2019 and 2019/2020 Delivery Years.

6.2 Base Capacity Demand Resource Constraint

Load Model

1. The daily load forecast distributions for the applicable Delivery Year are obtained for all weekdays from the PJM load forecast model. The distributions are based on a range of historical weather scenarios. This results in approximately 260 daily load distributions.

2. The maximum load value from each weather scenario's summer period (June 1 – August 31) is determined. The median of the distribution of all these maximum load values represents the 50/50 forecasted summer RTO peak for the applicable Delivery Year.

3. The daily load distributions from step 1 are per-unitized on the 50/50 peak load value determined in step 2. In other words, the ratio of each weather scenario load to the median forecast peak is calculated. Using the ratio calculated, all weather scenario loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows all the daily load distributions to be shifted up or down by altering the forecasted summer peak load.

Capacity Model

1. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained for all 52 weeks of the applicable Delivery Year. The cumulative capacity probability table represents the distribution of available capacity each week. Available

capacity is defined as generation that is not expected to be on a forced, maintenance or planned outage.

Analysis

1. As described in step 3, the daily load distributions are iteratively shifted to equal the IRM established for the applicable DY.

2. A reference annual LOLE is determined based on the daily load distributions from step 3 and the capacity distributions from step 4. The resulting case is the Base Case.

3. Varying amounts of Base Capacity Demand Resource (expressed as a percent of the unrestricted peak load) are then added to the capacity model. Base Capacity Demand Resource is modeled to be interruptible from June 1 through September 30 while being unavailable for the rest of the DY. Base Capacity Demand Resource is represented as a 100% available resource and is assumed to displace an equal amount of 100% available Capacity Performance Resource for the entire year

4. At each Base Capacity Demand Resource amount, the annual LOLE is determined and the percent increase in risk from the reference annual LOLE is calculated

5. The Base Capacity Demand Resource Constraint is equal to the Base Capacity Demand Resource amount at which the percent increase from the reference LOLE computed in step 6 is 5%. The Base Capacity Demand Resource Constraint in MW is expressed as a percent of the forecasted unrestricted peak.

6.3 Base Capacity Resource Constraint

Load Model

1. The weekly load model from the most recent IRM Study is obtained for all 52 weeks of the applicable Delivery Year. For more details on the load model used in the IRM Study, see Section 3.2.1 in this manual.

Capacity Model

1. The PJMRTO cumulative capacity probability table from the most recent IRM Study is obtained for all 52 weeks of the applicable Delivery Year. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is defined as generation that is not expected to be on a forced, maintenance or planned outage.

2. The available capacity during the peak week of winter is adjusted to reflect winter ratings of thermal and wind units.

Analysis

1. The weekly load distributions are iteratively shifted to equal the IRM established for the applicable DY.

2. A reference annual LOLE is determined based on the weekly load distributions from step 4 and the capacity distributions from steps 2 and 3. The resulting case is the Base Case.

3. The weekly cumulative capacity probability tables are adjusted to reflect the unavailability of the amount of Base Capacity Demand Resource computed in the previous procedure (in other words, the Base Capacity Demand Resource is assumed to have cleared at its full constrained level).

4. Varying amounts of Base Capacity Resource (expressed as a percent of the unrestricted peak load) are then added to the capacity model. Base Capacity Resource is modeled to be unavailable during the peak winter week while being available for the rest of the DY. The Base Capacity Resource is represented as a 100% available resource and is assumed to displace an equal amount of 100% available Capacity Performance Resource for the entire year

5. At each Base Capacity Resource amount, the annual LOLE is determined and the percent increase in risk from the reference annual LOLE is calculated

6. The Base Capacity Resource Constraint is equal to the Base Capacity Resource amount at which the percent increase from the reference LOLE computed in step 5 is 10%, plus the Base Capacity Demand Resource Constraint. The Base Capacity Resource Constraint in MW is expressed as a percent of the forecasted unrestricted peak.

6.4 Limited-Availability Resource Constraints at the LDA Level

The procedure for establishing the Base Capacity Demand Resource Constraint and the Base Capacity Resource Constraint for each of the LDAs that are modeled separately in RPM is identical to the procedure for the RTO detailed above with the following exceptions:

-   In Step 1 of Base Capacity Resource Constraint

    o   The weekly load model for the LDA is derived using the same time period as in the IRM Study's Load Model.

-   In Step 4 of Base Capacity Demand Resource Constraint and Step 2 of Base Capacity Resource Constraint

    o   The LDA's available internal capacity during each week is increased by the Capacity Emergency Transfer Limit (CETL). This is the maximum amount of resources expected to be available to the LDA during a local capacity emergency.

-   In Step 5 of Base Capacity Demand Resource Constraint and Step 4 of Base Capacity Resource Constraint

    o   The daily/weekly load distributions are shifted only once to match the LDA's 50/50 forecasted unrestricted non-coincident peak for the applicable Delivery Year

-   In Step 9 of Base Capacity Demand Resource Constraint and Step 9 of Base Capacity Resource Constraint

    o   The Base Capacity Demand Resource Constraint and the Base Capacity Resource Constraint for an LDA are expressed as a percent of the LDA's forecasted unrestricted coincident peak.

Revision History

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

  o Revisions needed to clean-up outdated language and ensure language follows to current processes

  o 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**.