Working to Perfect the Flow of Energy

PJM Manual 19:

Load Forecasting and Analysis

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Prepared by

Capacity Adequacy Planning

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Approval

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Thomas A. Falin, Manager

Capacity Adequacy Planning Department

Current Revision

Revision 13 (06/01/2008)

A new Exhibit 1 was added, presenting definitions of variables used in the load forecast model. Other exhibits were re-numbered.

Exhibit 2 was revised to reflect a new weather station assignment for the DAY zone.

Section 4: Removed note from Weather Normalization Procedure description (the process is finalized).

Attachment A: Revised to reflect that the guidelines apply to both capacity- and energy-related load drop estimates.

Introduction

Welcome to the ***PJM Manual for Load Forecasting and 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 the PJM Office of the Interconnection for the operation, planning, and accounting requirements of the PJM RTO 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
- Miscellaneous

For a complete list of all PJM Manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The ***PJM Manual for Load Forecasting and Analysis*** is one of a series of manuals within the Reserve group of manuals. This manual focuses on load-related topics. This manual describes the data input requirements, the processing performed on the data, computer programs involved in processing the data, and the reports that are produced. It then describes processes used to analyze load data and produce a long-term planning forecast.

The ***PJM Manual for Load Forecasting and Analysis*** consists of four sections. These sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for the ***PJM Manual for Load Forecasting and Analysis*** are:

Electric Distribution Company (EDC) planners — The EDC planners are responsible for supplying historical load data in the required format, for using coincident peaks to allocate normalized peaks, and for input data verification.

Load Serving Entity (LSE) planners — LSEs use allocated peaks and the Load Management systems to determine their capacity obligations.

PJM staff — PJM is responsible for the calculation of hourly PJM loads, normalizing PJM seasonal peaks, forecasting RTO and zonal peaks for capacity obligations, compiling the PJM Load Forecast Report, and administering Load Management. This information is used in calculating the capacity obligations.

Planning Committee members — The Planning Committee is responsible for the stakeholder review of the peak forecasts and techniques for their determination.

Reliability Assurance Agreement Signatories — The Markets Reliability Committee is involved in the review of rules, methods and parameters associated with Load Forecasting and Analysis.

References

There are several references to other documents that provide background or additional detail. The ***PJM Manual for Load Forecasting and Analysis*** does not replace any information in these reference documents. The following documents are the primary source of specific requirements and implementation details:

- eMTR documentation
- PJM Load Forecast Report
- PJM Manual for Emergency Operations (M-13)
- Reliability Assurance Agreement
- Behind-the-Meter Generation Business Rules (in Manual M-14D)
- Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.
- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of this PJM manual.

Section 1: Overview

Welcome to the *Overview* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the Load Forecasting and Analysis (see "Overview of Load Forecasting and Analysis")

Overview of Load Forecasting and Analysis

Load Forecasting and Analysis utilizes the PJM eMTR load data, Load Management, PJM Load Forecast Model, and Weather Normalization and Peak Allocation.

PJM Hourly Load Data — After-the-fact hourly load data are entered by EDCs and used by PJM for deriving seasonal load profiles, weather normalization factors, 1CP zonal load contributions for Network Service billing, charts contained in the PJM Load Forecast Report, and the Monthly Operations Report.

PJM Load Forecast Model — PJM staff produces an independent forecast of monthly and seasonal peak load and load management, for each PJM zone, region, the RTO, and selected combinations of zones. The PJM Load Forecast Report includes tables and charts presenting the results.

Weather Normalization and Peak Allocation — PJM uses approved techniques for weather-normalizing historical summer and winter zonal peaks, and determining RTO unrestricted coincident peaks.

Section 2: PJM Hourly Load Data

Welcome to the *PJM Hourly Load Data* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the historic hourly load data file (see "Load Data Overview")
- Guidelines for reporting load data to PJM (see "Load Data Reporting Business Rules")

Load Data Overview

Official historic hourly load data for each EDC with revenue-metered tie data reported to PJM is collected via the eMTR application. For EDCs submitting all internal generation, eMTR will calculate a revenue-quality load based on submitted tie and generation meter values. EDCs may accept these values as their reported hourly service territory load, with the option to input data directly through the application's user interface or via uploaded XML files. The entered data are available through eMTR screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into eMTR, refer to the information posted on the PJM Website (under "eTools", select "eMTR.")]

Load Data Definitions

Actual Net Metered Interchange: The sum of allocated tie metered values to which the EDC is a party.

Total Internal Generation: The sum of all meter values for non-500kV generators electrically located in the EDC's zone. For PJM Western and Southern regions, 500kV generation will be counted as part of internal generation.

Allocated Mid-Atlantic 500kV Losses: Participant's share of total PJM Mid-Atlantic 500kV losses

Calculated Load = Actual Net Metered Interchange + Total Internal Generation + Allocated 500kV Losses.

Load Data Reporting Business Rules

As established by the PJM Planning Committee, the following guidelines govern the reporting of load data into the PJM eMTR application:

Data Reporting Responsibility: It will be the responsibility of each PJM electric distribution company (EDC) with fully-metered tie flows to report hourly load data for its metered area(s), regardless of which entity is responsible for serving end-use customers.

For all entities using network transmission service, it will be the responsibility of the signatory to the Network Integration Transmission Service Agreement to ensure that hourly load data are reported to PJM for its customers via PJM eSchedules.

For Curtailment Service Providers (CSPs) Active Load Management credit, it will be their responsibility to provide estimates of load management impacts, hourly by PJM zone, whether the interruption was initiated by PJM or the LSE.

Data Specifications: Load data supplied to eMTR will reflect each entity's total impact to the system, and will therefore need to properly account for system losses and flows. PJM will adjust loads for their assigned share of Extra High Voltage losses. LSEs providing load management impact estimates will adjust loads for system losses. Data are accepted in eMTR in 0.001 MWh increments.

Reporting Schedule: The data for each day should initially be entered within the following ten calendar days, except during peak periods, when the data must be entered daily. PJM contacts EDCs when daily reporting is needed.

Edits to load data should be made by the tenth calendar day of the following month.

PJM will adjust submitted load data, as necessary, to reflect additional load that is determined by PJM after-the-fact, resulting from third-party supply of generator station power requirements.

Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 13 of the Reliability Assurance Agreement and the PJM West Reliability Assurance Agreement.

EDC/LSE Actions:

- *Enter Hourly Load Data* — PJM EDCs submit hourly load values into eMTR, as required. Load management impacts must be delivered to PJM in accordance with schedules established by PJM with input from the Load Analysis Subcommittee (*See Section 5 and Attachment A*).

- *Edit the Data as necessary* — All hourly load value changes for a given month must be entered and edited by the 10th of the following month.

- *Notify the OI of All Changes* — Without this notification, PJM can only determine that changes have been made but cannot readily identify specific changes which were made.

PJM Actions:

- *Allocate Extra High Voltage Losses:* — 500kV losses in the PJM Mid-Atlantic region are calculated as the total 500kV system energy injections minus withdrawals. Hourly 500kV losses are allocated to each PJM Mid-Atlantic EDC with revenue metered tie flows reported to eMTR, in proportion to their real-time load ratio share.

- *Distribute Reports:* — By the 10th of each month, PJM makes reports of load data from the previous month available to the EDCs. This data includes a summary Daily Load Report for each day of the month, showing daily peak loads and the monthly energy total for each LSE and for the PJM RTO. A monthly summary report also is provided.

- *Post Zonal Data:* — PJM will publish zonal load data in an electronic format on a monthly basis.

- *Data Usage:* — PJM uses the hourly load data for operational analysis, for calculating seasonal load factors, developing weather normalization curves, for allocating the PJM weather normalized seasonal peaks, and for preparing various charts and tables in the PJM Load Forecast Report.

Section 3: PJM Load Forecast Model

Welcome to the *PJM Load Forecast Model* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the PJM Load Forecast Model (see "Forecast Model Overview").
- A description of the methodology used to produce the PJM forecast (see "Development of the Forecast").
- A description of the forecast review and approval process (see "Review and Approval the Forecast").

Forecast Model Overview

The PJM Load Forecast Model produces 15-year monthly forecasts of unrestricted peaks assuming normal weather for each PJM zone and the RTO. The model uses anticipated economic growth and weather conditions to estimate growth in peak load. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. The forecast is produced by PJM and released prior to each Planning Period, typically in January.

Development of the Forecast

The PJM Load Forecast employs econometric multiple regression models to estimate daily peak load for each PJM zone (the non-coincident peak), and the zone's contribution to the daily RTO peak (the coincident peak). Definitions of each model variable are presented in Exhibit 1. The variables included are:

Dependent Variable - Load:

For the non-coincident models, zonal hourly metered load data are supplemented with estimated load drops provided by EDCs and LSEs (as outlined in Attachment A) to obtain unrestricted hourly load. The maximum value for each day is used in the regressions. For the coincident models, the zone's contribution to the daily RTO unrestricted peak load is used in the regressions.

Calendar Effects:

Days of the week, month of the year, holidays, minutes of daylight, and Daylight Savings Time impacts are included in the model using binary variables. Holiday seasonal lighting load is reflected using a trend variable.

Weather Data:

Weather is included in the models using different variables for heating, cooling and shoulder seasons. For the heating season (December, January and February), the Winter Weather Parameter is defined as:

If WIND > 10 mph,

$$WWP = DB - (0.5 * (WIND - 10))$$

If WIND ≤ 10 mph,

$$WWP = DB$$

Where: WIND = Wind velocity, in miles per hour;

WWP = Wind speed adjusted dry bulb temperature;

DB = Dry bulb temperature (^oF).

For the cooling season (June, July and August), Temperature-Humidity Index (THI) is used as the weather variable:

If DB ≥ 78,

$$THI = DB - 0.55 * (1 - HUM) * (DB - 58)$$

If DB < 78,

$$THI = DB$$

Where: THI = Temperature humidity index;

DB = Dry bulb temperature (^oF);

HUM = Relative Humidity (where 100% = 1).

For shoulder months (March, April, May, September, October and November), the average daily dry bulb temperature serves as the weather variable.

Additionally, measures of heating and cooling degree days are included. These readings are divided into separate morning, afternoon, evening, and night effects, as well as weekends. They are also lagged over three days. Weather data for each PJM zone is calculated according to the mapping presented in Exhibit 2.

Economic Drivers:

Measures of economic and demographic activity are included in the forecast models, representing total U.S., state, or metropolitan areas, depending upon their predictive value. Economic drivers for states and metropolitan areas are assigned to each PJM zone according to the mapping presented in Exhibit 3. Models for each PJM zone share the same general specification.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. From this distribution, the median values are used to shape the monthly profile within each season.

The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

RTO and Coincident Forecasts

To obtain the RTO peak forecast, the solution for each of the zonal coincident peak (CP) models are summed by day and weather scenario to obtain the RTO peak for the day. By weather scenario, the maximum daily RTO value for the season is found. For the RTO, a distribution of the seasonal RTO peak vs. weather scenario is developed. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

To determine the final zonal RTO-coincident peak (CP) forecasts, a methodology similar to the process for deriving zonal NCPs is applied. By weather scenario, the maximum daily CP load for a zone over the summer season is found. For each zone a distribution of zonal CP vs. weather scenario is developed. From this distribution the median value is selected. The median zonal CPs are summed and this sum is then used to apportion the forecasted RTO peak to produce the final zonal CP forecasts.

Load Management and Behind-the-Meter Generation

PJM incorporates estimates of load management and behind-the-meter generation to supplement the base, unrestricted forecast. PJM receives input from affected EDCs and LSEs to develop its estimates.

[Note: More information on behind-the-meter generation can be found in the Behind-the-Meter Generation Business Rules in the PJM Manual for Generator Operational Requirements (M-14D) posted on PJM.com.]

Non-Zone Peak Forecast

For use in the Reliability Pricing Model (RPM), PJM staff develops summer peak forecasts of the recognized non-zone loads. These forecasts are produced separately from the PJM Load Forecast Model, and utilize methods appropriate for each situation. Non-zone forecasted loads are added to the associated PJM zone for RPM purposes only.

Energy Forecast

For use in reporting requirements of FERC and NERC, PJM staff develops 15-year monthly forecasts of unrestricted energy assuming normal weather for each PJM zone and the RTO. These forecasts are produced using the same model specification and processing method as the peak model with the exception that the dependent variable is daily energy consumption instead of daily peak load.

Dependent Variable – Net Energy For Load:

Zonal hourly metered load data are supplemented with estimated load drops provided by EDCs and LSEs (as outlined in Attachment A) to obtain unrestricted hourly load. The sum of hourly load values for each day is used in the regressions.

Review and Approval of the Forecast

The PJM Load Forecast is reviewed by the Load Analysis Subcommittee, and presented to the Planning Committee for endorsement. Final approval is received from the PJM Board of Managers.

A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee.

Calendar Data

Day of week

Variable Name	Type or Formula	Description
Monday	Binary	Day of the Week
Tuesday	Binary	Day of the Week
Wednesday	Binary	Day of the Week
Thursday	Binary	Day of the Week
Friday	Binary	Day of the Week
Saturday	Binary	Day of the Week

Holiday

MartinLutherKingDay	Fuzzy	MLK Day Holiday
PresidentsDay	Fuzzy	President's Day Holiday
GoodFriday	Binary	Good Friday Religious Holiday
MemorialDay	Fuzzy	Memorial Day Holiday
July4th	Fuzzy	Independence Day and surrounding days
LaborDay	Fuzzy	Labor Day Holiday
Thanksgiving	Binary	Thanksgiving Holiday
FridayAfterThanksgiving	Fuzzy	Friday After Thanksgiving Holiday
XMasWkB4	Fuzzy	Week Before Christmas
ChristmasEve	Fuzzy	Christmas Eve (value depends on day of week)
ChristmasDay	Binary	Christmas Day
XMasWk	Fuzzy	Week after Christmas Holiday
NewYearsEve	Fuzzy	New Years Eve(value depends on day of week)
NewYearsDay	Binary	New Years Day Holiday
XMasLights	Trend	Christmas Lights/Retail Operations Trend

Month

January	Binary	Month of the Year
February	Binary	Month of the Year
March	Binary	Month of the Year
April	Binary	Month of the Year
May	Binary	Month of the Year
June	Binary	Month of the Year
July	Binary	Month of the Year
August	Binary	Month of the Year
September	Binary	Month of the Year
October	Binary	Month of the Year
November	Binary	Month of the Year

Notes:
Binary – A variable which has a value of 1 for the indicated characteristic, otherwise the value is 0.
Fuzzy – A variable which has a conditional value for the indicated characteristic, otherwise the value is 0.
Trend - A variable which has a value with increasing then decreasing value for the indicated characteristic, otherwise the value is 0.

Weather Data

Variable Name	Type or Formula	Description
NightHDD	Max(50 - NightWWP[1],0)	Night heating degree days
MornHDD	Max(55 - MornWWP[2],0)	Morning heating degree days
AfterHDD	Max(62 - AftWWP[3],0)	Afternoon heating degree days
EvenHDD	Max(55 - EvenWWP[4],0)	Evening heating degree days
NightCDD	Max(NightTHI[5] - 60,0)	Night cooling degree days
MornCDD	Max(MornTHI[6] - 65,0)	Morning cooling degree days
AfterCDD	Max(AftTHI[7]- 72,0)	Afternoon cooling degree days
EvenCDD	Max(EvenTHI[8]- 65,0)	Evening time cooling degree days
WkEndCDD	WkEnd[9] * CDD[10]	Weekend cooling degree days
WkEndHDD	WkEnd[9] * HDD[11]	Weekend heating degree days
ColdWind	Min(Max(60 - AftTHI[7],0) /20,1) * AvgWind[12]	Wind speed index on cold days
HotWind	Min(Max(AftTHI[7] - 60,0) /15,1) * AvgWind[12]	Wind speed index on hot days
LagHDD	IF (month ≤ 5 or month ≥ 10) THEN .75 * Lag(HDD[11], 1) + .25 * Lag(HDD, 2) ELSE 0	Lagged heating degree days
LagCDD	IF (month ≥ 6 & month ≤ 9) THEN .75 * Lag(CDD[10], 1)+.25*Lag(CDD,2) ELSE 0	Lagged cooling degree days
FuzzyHum	Min(Max(AvgTmp[13]- 60,0) /15,1) * AvgHum[14]	Humidity index, triggered at 60 degrees

Intermediate Calculations:

1 NightWWP	Average of WWP for hours ending 1 through 6	
2 MornWWP	Average of WWP for hours ending 7 through 12	
3 AftWWP	Average of WWP for hours ending 13 through 18	
4 EvenWWP	Average of WWP for hours ending 19 through 24	
5 NightTHI	Average of THI for hours ending 1 through 6	
6 MornTHI	Average of THI for hours ending 7 through 12	
7 AftTHI	Average of THI for hours ending 13 through 18	
8 EvenTHI	Average of THI for hours ending 19 through 24	
9 WkEnd	Weekend Binary	
10 CDD	Max(AvgTmp-65,0)	Cooling degree days
11 HDD	Max(60 - AvgTmp,0)	Heating degree days
12 AvgWind	24 hour average wind speed	
13 AvgTmp	24 hour average temperature (Fahrenheit)	
14 AvgHum	24 hour average humidity (percent)	

Seasonal Weather Variables

S_THI	IF (month ≥ 6 & month ≤ 9) THEN MaxTHI[15] ELSE 0	For cooling months, use MaxTHI
W_WWP	IF (month ≤ 2 or month = 12) THEN MinWWP[16] ELSE 0	For heating months, use MinWWP
SH_AvgTmp	IF (month = 3, 4, 5, 10 or 11) THEN AvgTmp[13] ELSE 0	For shoulder months, use AvgTemp

Intermediate Calculations:

15 MaxTHI Maximum THI over 24 hours

16 MaxWWP Maximum WWP over 24 hours

Economic Data

Variable Name	Type or Formula	Description
DailyGMP	Convstock(GMP_ZONE)	Gross Metropolitan Product quarterly values converted to daily

Economic/Weather Data

GMP_HDD	HDD[11] * DailyGMP	Heating Degree Days interacted with GMP
GMP_CDD	CDD[10] * DailyGMP	Cooling Degree Days interacted with GMP

Solar Data

DLSav_EPA2005	Binary	Daylight Savings Time conversion
MinutesDaylight	Minutes	Minutes of daylight at local airport

Exhibit 1: Model Variable Definitions

Weather Station	Airport Name	Zone	Weight
ACY	Atlantic City International	AE	1
CMH	Columbus Port Columbus International	AEP	0.5
CRW	Charleston Yeager	AEP	0.5
IAD	Washington Dulles	APS	0.3
PIT	Pittsburgh International	APS	0.7
BWI	Baltimore Washington International	BGE	1
ORD	Chicago O'Hare International	COMED	1
DAY	Cox-Dayton International	DAY	1
PIT	Pittsburgh International	DLCo	1
IAD	Washington Dulles	DOM	0.3333
ORF	Norfolk International	DOM	0.3333
RIC	Richmond International	DOM	0.3334
PHL	Philadelphia International	DPL	1
EWR	Newark International	JCPL	0.75
ACY	Atlantic City International	JCPL	0.25
PHL	Philadelphia International	METED	0.5
ABE	Allentown Lehigh Valley International	METED	0.5
PHL	Philadelphia International	PECO	1
ERI	Erie International	PENLC	0.5
IPT	Williamsport Regional	PENLC	0.5
DCA	Washington Reagan National	PEPCO	1
ABE	Allentown Lehigh Valley International	PL	0.6
IPT	Williamsport Regional	PL	0.4
EWR	Newark International	PS	1
EWR	Newark International	RECO	1
AVP	Wilkes-Barre Scranton International	UGI	1

Exhibit 2: Assignment of Weather Stations to Zones

Zone	State(s)	Metro Area Name(s)
AE	NJ	Atlantic City NJ
AEP	OH, WV, VA, IN	Fort Wayne IN, South Bend IN, Kalamazoo MI, Canton OH, Columbus OH, Roanoke VA, Charleston WV
APS	PA, OH, WV	Hagerstown MD, Morgantown WV
BGE	MD	Baltimore MD
COMED	IL	Chicago IL
DAY	OH	Dayton OH
DLCO	PA	Pittsburgh PA
DOM	VA	Richmond VA, Virginia Beach VA, Roanoke VA
DPL	DE	Dover DE, Wilmington DE, Salisbury MD
JCPL	NJ	Camden NJ, Edison NJ, Trenton NJ
METED	PA	Allentown/Bethlehem/Easton PA, Reading PA, York PA, Lebanon PA
PECO	PA	Philadelphia PA
PENLC	PA	Erie PA, Altoona PA, Johnstown PA
PEPCO	MD	Washington D.C.
PL	PA	Allentown/Bethlehem/Easton PA, Scranton Wilkes-Barre PA, Harrisburg PA, Lancaster PA, Williamsport PA
PS	NJ	Camden NJ, Edison NJ, Trenton NJ, Newark NJ
RECO	NJ	Newark NJ
UGI	PA	Scranton Wilkes-Barre PA

Exhibit 3: Assignment of Metropolitan Areas and States to Zones

Section 4: Weather Normalization and Coincident Peaks

Welcome to the *Weather Normalization and Coincident Peaks* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the weather normalization process (see "Weather Normalization Overview").
- A description of the weather normalization procedure (see "Weather Normalization Procedure").
- A description of the identification and calculation of PJM unrestricted coincident peaks (see "Peak Load Allocation (5CP)").

Weather Normalization Overview

PJM performs load studies on summer and winter loads, according to the procedures described below. The Load Analysis Subcommittee reviews the normalizations, and either adopts the resulting values, or Members may challenge the results as anomalous. In the latter situation, alternate analysis will be conducted, until a consensus is reached. After the review process is completed, the endorsement of the Planning Committee is requested, with final approval given by the Board of Managers. The weather normalized (W/N) peaks are then used by EDCs to determine capacity peak load shares for wholesale and retail customers.

Weather Normalization Procedure

The standard PJM weather normalization procedure consists of utilizing the PJM Load Forecast Model as described in Section 3 above. After each season, each zonal/RTO NCP and CP model is re-estimated, adding the most recent historical load and weather data [note: economic data are not updated]. Then, the Monte Carlo process is run, including historical weather through the just-completed season. From the resulting distribution of results, the median value is selected as the weather normalized seasonal peak. These peaks are then adjusted, as described above in Section 3, to align the zones with the RTO.

Normalized Peak Appeal Process

Results of the weather-normalization analysis will be reviewed by LAS members. Members will have an opportunity at that point to trigger the following appeal process if, in their judgment, the results of the standard method described above appear inaccurate:

- Any LAS member may request review of any zone's normalized peak, though the primary responsibility resides with the member from the zone in question.
- A request for review will be followed by further analysis, conducted by PJM and LAS members, to identify and quantify the inaccuracy in the weather-normalization of the zone.
- LAS will conduct peer review of all supplemental analysis, and seek a (supermajority) consensus before the issue is presented to the Planning Committee.

- If an adjustment needs to be made to a zonal W/N peak, LAS will forward the proposed zonal W/N peak to the Planning Committee, along with the results of the standard analysis.

The appeals process is designed to address the rare significant miscalculation of a zone's load, and is not intended as a method to "fine tune" the results of the standard method.

EDC/LSE Actions:

- Enter hourly load data into eMTR, as described in Section 2 of this manual.
- Submit Load Management, Emergency and loss of load load drop estimates, as described in Section 5 of this manual.
- Participate in review of seasonal load studies, through the Load Analysis Subcommittee.

PJM Actions:

- Obtain weather observations
- Produce voltage reduction load drop estimates, as described in Attachment A of this manual.
- Weather-normalize the zonal RTO-coincident winter and summer peak loads. Provide recommendation to PJM Planning Committee, by its October meeting, to accept the results of the standard normalization procedure, or to use the alternate methodology.
- If necessary, produce analysis to establish alternate estimate of zonal W/N CP Load.

Peak Load Allocation (5CP)

Zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ the customer's shares of RTO actual peaks. The resulting Peak Load Contributions are then used in the determination of capacity obligations.

PJM establishes and publishes information, referred to as the 5CP, to aid EDCs in the calculation of Peak Load Contributions (also known as "tickets"). For each summer:

- Hourly metered load and load drop estimate data are gathered for the period June 1 through September 30
- RTO unrestricted loads are created by adding load drop estimates to metered load
- From the unrestricted values, the five highest RTO unrestricted daily peaks (5CP) are identified

5CP data are typically released in mid-October.

Attachment A: Load Drop Estimate Guidelines

General

Curtailment Service Providers receiving Demand Resource or Interruptible Load for Reliability credit or offering load reduction into the Emergency option of the Demand-Side Response program are responsible for estimating hourly impacts from load management events, and for reporting them to PJM and the host EDC. Estimates must be produced and communicated for all events (whether PJM- or LSE-initiated), whenever they occur in the year. Estimates must be presented for each Contractually Interruptible customer and each Direct Load Control signal. Estimates must be communicated subsequent to each season in accordance with announced deadlines.

EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

Load drop estimates will be used to construct unrestricted loads used in the PJM Load Forecast Model, normalization of PJM seasonal peaks, and to calculate the unrestricted peak load contributions used in formulating capacity obligations. Additionally, load drop estimates are used in the settlements process of the PJM Demand Side Response program and for compliance review of PJM-initiated Load Management events.

Direct Load Control

The estimated load drop for a DLC program is based on the average impact per customer participating in the program (adjusted for losses), and the amount of time the transmission signal was sent. For each hour of a curtailment event (either capacity- or energy-related), the following calculation must be evaluated:

*DLC Load Drop = # of Active Customers * Per Participant Impact (MW) * Loss Factor * Transmission Signal Ratio*

where, # of Active Customers = the number of participants involved on the day of the interruption;

Per Participant Impact = the PJM-approved impact from a load research study;

Loss Factor = the applicable factor to equate the meter-level impact to a generator-level impact;

Transmission Signal Ratio = the percentage of the hour that the signal was operated (100%=1.0).

Contractually Interruptible

The estimated load drop for Firm Service Level and Guaranteed Load Drop customers is based on the comparison of the customer's metered load during the intervention versus an estimate of what the load would have been without an intervention, adjusted for losses. Alternately, generator data may be used, if the load drop was achieved via backup

generation. For each hour of a curtailment event (either capacity- or energy-related), the following calculation must be evaluated:

*CI Load Drop = (Comparison Load (MW) – Metered Load (MW)) * Loss Factor*

OR

*CI Load Drop = Generation (MW) * Loss Factor*

where, Comparison Load = an estimate of the participant's load in absence of an interruption;

Metered Load = the participant's hourly integrated load;

Loss Factor = the applicable factor to equate the meter-level impact to a generator-level impact;

Generation = the hourly integrated output from a generator used to provide Guaranteed Load Drop.

Due to the differing nature of Firm Service Level and Guaranteed Load Drop programs, and the load profiles of the customers involved, several options are available to estimate comparison loads. **The method used should result in the best possible estimate of what load level would have occurred in the absence of a curtailment event**:

Comparable Day: The customer's actual hourly loads on a non-interruption day judged to be similar in other respects to the interruption day. These loads may be adjusted for differences in weather conditions. Or, an average of the customer's actual hourly loads on peak days;

Same Day (Before/After Event): The customer's actual loads on the same day of the interruption, from the hours surrounding the event. This option is appropriate for high load factor customers with no weather sensitivity;

Load Profile: The Customer's estimated hourly load from an unrestricted load profile approved for use in retail balancing and settlements;

Customer Baseline: The Customer's baseline calculation used to calculate load drops for the PJM Demand Response program;

Regression Analysis: The customer's estimated hourly loads from a regression analysis of the customer's actual loads versus weather. This option is appropriate for customers with significant weather sensitivity.

Missing Data

If the methods outlined above for Contractually Interruptible customers can not be utilized due to missing hourly load data, estimates of actual loads during the event may be substituted. Methods of estimation can vary, but **the method chosen should be done as to provide the best approximation of actual loads**. A possible estimation method is based upon previous performance: the customer's actual hourly loads or generation output

on a previous event day, judged to be similar in other respects to the event day for which load data are missing. These loads may be adjusted for differences in weather conditions.

Whenever missing data are estimated, a written explanation of which data are estimated and the method employed must accompany the load drop estimates.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Direct Load Control Load Research Guidelines

The intention of these guidelines is to ensure that the estimated per-participant impacts of Direct Load Control program reliably represent the amount of load shed, on average, for active program participants.

Curtailment Service Providers with Direct Load Control programs which employ a radio signal may elect to either submit a load research study supporting base per-participant impacts for their program, or utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report. Providers utilizing other technology must submit a load research study. All Providers must submit switch operability studies once every five years.

Requirements for Provider-Submitted Studies

Study Design

DLC load research studies will be designed to achieve a minimum accuracy of 90% Confidence with 20% error.

Study Detail

Load research studies submitted must present estimated per-participant impacts in a matrix which details average impacts on non-holiday weekdays by hour, for the hours ending 13:00 through 20:00 (PJM Eastern Region) or 8:00 through 21:00 (PJM Western Region), and by weather condition (over a range of local conditions under which it can reasonably be expected that the program will be implemented). Separate matrices must be estimated:

By program (and/or cycling scheme);

By PJM zone.

Switch Operability Rate

In addition to base per-participant impacts, studies submitted to PJM must also include the average switch operability rate, reflecting the percentage of all active switches which both receive the control signal and operate. The switch operability rate must be supplied with the original base impact study, and then updated every five years. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%.

Utilizing the Deemed Savings Estimates

[Note: The "Deemed Savings Estimates" study report is available on the PJM.com website.]

Eligibility

Load Management Providers with Direct Load Control programs which employ a radio signal may elect to utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report.

Base Impact Value

Base impacts for air conditioning programs will be established utilizing the aggregate values detailed in Appendix F of the Deemed Savings Estimates report. The Provider must supply the applicable duty cycle strategy (percentage of each hour the unit is interrupted) and an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak). The Provider may opt to customize the base impact by supplying a research study which stratifies its program by A/C usage or connected A/C load. In this case, base impacts will be drawn from the aggregate results presented in Appendix G or H, as appropriate.

Base impacts for water heating programs will be established utilizing the aggregate values detailed in Appendix J. The Provider must supply an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak)

EDCs with base impacts presented in the Deemed Savings report (BGE, JCPL, and PSEG) may elect to use those impacts.

Switch Operability Rate

All Providers utilizing the modeled base per-participant impacts must submit to PJM a switch operability rate study, reflecting the percentage of all active switches which both receive the control signal and operate. This study must be designed to achieve a minimum accuracy of 90% Confidence with 10% error. Any Provider without a switch operability study, or with one older than five years will be given a switch operability rate of 50%.

Revision History

Revision 12 (06/01/2007)

Removed Section 3 and moved content to Manual 18.

Removed Section 7 and moved content to Manual 18.

Revision 11 (06/01/07)

This extensive revision incorporates changes to Load Data Systems due to the implementation of the Reliability Pricing Model (RPM). Sections on Active Load Management and Qualified Interruptible Load have been replaced with a new Load Management section. The Zonal Scaling Factor section reflects a revised calculation. The Load Forecast Model section has been updated for enhancements made to the model specification as well as revised coincident peak forecast method. The Weather Normalization section was revised to reflect that seasonal peaks are now normalized using the load forecast model.

Revision 10 (06/01/06)

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 3—Revised to reflect changes in the handling of outlier observations in weather normalization of seasonal peaks.
- Section 4—Revised to incorporate the addition of the Full Emergency option of Load Response.
- Updated the penalties/rewards section under Compliance.

Revision 09 (01/01/06)

This revision includes a complete revision to Section 6 to detail the PJM-produced load forecast which will be used for capacity and system planning purposes. The previous Section 3 (PJM Load Forecast Report) has been removed since Member input is no longer required for its production.

Revision 08 (06/01/05)

Updated Exhibit 1 to include new PJM Manuals.

This revision includes changes to Section 3 to reflect reporting requirements for sub-Zones. Section 4 was completely revised to reflect a new weather normalization method and revised basis for calculating 5CPs. Section 8 has been modified to reflect revised release dates for Zonal Scaling Factors.

Revision 07 (07/01/04)

This revision includes changes to Section 2, to reflect that 500kV generation will be treated differently in the PJM Western and Southern regions than the Mid-Atlantic Region. Section 4 was revised to reflect that peak load allocation will be impacted for market integration. Section 5 has been modified to reflect that the Active Load Management program has been fully incorporated into the eCapacity application.

Revision 06 (10/01/03)

This revision incorporates a new presentation format. Substantive changes were made to Section 4, to reflect changes in peak normalization procedures. Section 5 and Attachment B were revised to reflect the change in load research requirements for cycling programs to a five year cycle. The previous Section 6 (Forecast Peak Period Load) has been deleted. The section on Qualified Interruptible Load now reflects that it is the same as Active Load Management. New sections have been added for the PJM Entity Forecast and Zonal Scaling Factors. Attachment A includes an additional load drop estimate technique, Customer Baseline. Throughout the document, changes were made to reflect the new committee structure, and the Board of Managers enhanced authority.

Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM.*"

Changed all references from "the PJM OI" to "PJM."

Renamed Exhibits to consecutive numbering.

Reformatted to new PJM formatting standard.

Renumbered pages to consecutive numbering.

Revision 05 (01/01/03)

This revision contains changes to Section 2, which was revised to reflect that hourly load data are reported through the new eMTR application. Section 5 was revised to clarify wording on existing Active Load Management rules and procedures.

Revision 04 (06/01/02)

This revision contains changes to Section 3, which was revised to reflect a new reporting format for the PJM Load Forecast Report. Section 7 was revised to incorporate firm level customers into the Qualified Interruptible Load program.

Revision 03 (01/01/02)

This revision incorporates changes resulting from the addition of PJM West into the Interconnection. Section 4 was revised to add a description of the peak normalization process for PJM West. Sections 6 (Qualified Interruptible Load) and 7 (Forecast Period Peak Load) were added.

Revision 02 (10/01/00)

This revision contains changes to Section 4 to include a clarification of the weather normalization overview, and revises the summer season weather normalization to reflect the newly adopted PJM summer weather parameter. Also, the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for *Definitions and Abbreviations (M-35)*. Attachments B, C, and D have been renamed A, B, and C respectively. Also, changes to the 'new' Attachment A: ALM Load Drop Estimate Guidelines (previously listed as Attachment B) have been in effect since 6/01/00; however, they are now being addressed in this revision.

Revision 01 (06/01/00)

This revision contains changes to Sections 3, 4, and 5, to reflect the influence of retail choice, including the creation of a peak allocation, revamped Active Load Management rules and procedures, and revamped PJM Load Forecast Report. Also, it details a revised weather normalization procedure.

Revision 00 (07/15/97)

This revision is the complete draft of the PJM Manual for Load Data Systems.