



Working to Perfect the Flow of Energy

PJM Manual 28:

Operating Agreement Accounting

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Prepared by

Strategic Market Services
Department

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PJM Manual 28: Operating Agreement Accounting

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Harry E. Dessender, General Manager
Market Strategy

Current Revision

Revision ~~43-44~~ (01/20/2010)

- ~~• Revised Transmission Losses Accounting section to reflect the changes to the distribution of Transmission Loss Charges as retroactively approved by FERC (EL08-14)~~
- ~~• Added clarifying item in the Operating Reserve Accounting section related to the Day-ahead pumped storage optimization program~~



Introduction

Welcome to the *PJM Manual for Operating Agreement Accounting*. In this Introduction, you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the 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 www.pjm.com and select “Manuals” under the “Documents” pull-down menu.

About This Manual

The *PJM Manual for Operating Agreement Accounting* is one of a series of manuals within the Accounting and Billing set of manuals. This manual focuses on the accounting for energy with the PJM Energy Market. It establishes the basis for the charges and credits for the purchase and sale of energy and related services.

The *PJM Manual for Operating Agreement Accounting* consists of 18 sections. The sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for this PJM Manual for Operating Agreement Accounting are:

- PJM Members and Transmission Customers
- Other Control Areas
- External auditors, lawyers, and regulators
- PJM settlements staff and audit staff
- PJM customer relations and training staff



References

The references to other documents that provide background or additional detail directly related to the *PJM Manual for Operating Agreement Accounting* are:

- PJM Manual for [Open Access Transmission Tariff Accounting \(M-27\)](#)
- PJM Manual for [Balancing Operations \(M-12\)](#)
- PJM Manual for [Billing \(M-29\)](#)
- PJM Manual for [Scheduling Operations \(M-11\)](#)
- PJM Manual for [Administrative Services for the PJM Interconnection Agreement.\(M-33\)](#)
- Operating Agreement of PJM Interconnection, L.L.C.
- PJM Open Access Transmission Tariff

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.

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
- A section at the end detailing all previous revisions of this PJM manual



Section 1: Market Overview

Welcome to the *Market Overview* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of the PJM Energy Market accounting services (see “*Market Accounting Overview*”).
- A description of PJM Market Settlements Accounting Input Data (see “*Accounting Input Data*”).

1.1 Market Accounting Overview

There are several services within the PJM Energy Market for which PJM calculates charges and credits that are allocated among the PJM Members. PJM provides accounting for the following services that are described in detail in the other sections of this manual.

- *Spot Market Energy* — Energy bought or sold by PJM Members through the PJM Energy Market.
- *Transmission Congestion* — The increased cost of energy delivered when the Transmission System is operating under constrained conditions.
- *Transmission Losses* — Energy requirements in excess of load requirements due to the energy consumed by the electrical impedance characteristics of the Transmission System.
- *Regulation* — The capability of a specific resource with appropriate telecommunications, control, and response capability to increase or decrease its output in response to a regulating control signal (see the PJM Manual for ***Balancing Operations***).
- *Synchronized Reserve* — The capability of a specific resource with appropriate telecommunications, control, and response capability to increase output (or reduce consumption) in response to a synchronized reserve event and/or operate at a point that deviates from economic dispatch (including condensing mode) to provide 10-minute reserve (see the PJM Manual for ***Balancing Operations***).
- *Operating Reserve* — The amounts of generating Capacity scheduled to be available for specified periods of an Operating Day to ensure the reliable operation of PJM.
- *Reactive Services* — The amounts of generation altered by PJM to maintain reactive reliability.
- *Synchronous Condensing* — The instructions to generators to operate in synchronous condensing mode for reasons other than reactive support or synchronized reserve to ensure the reliable operation of PJM.
- *Emergency Energy* — Energy bought from other Control Areas or sold to other Control Areas by PJM due to Emergencies either within PJM or within the other Control Areas.



- *PJM Emergency Load Response* – The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.
- *PJM Economic Load Response* – The Economic Load Response Program is designed to provide incentive to end-use customers or Curtailment Service Providers (“CSP”) to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices (“LMP”) are high.
- *Metering Reconciliation* — Metering errors and corrections that are reconciled at the end of each month by a meter error correction charge adjustment.
- *Inadvertent Interchange* – Differences between hourly net actual energy flows and net scheduled energy flow into or out of the PJM control area.
- *Unscheduled Transmission Service* — Service that PJM Members can provide to or receive from the New York ISO and are credited or charged according to the Operating Agreement.
- *Ramapo PAR Facilities* — Carrying charges collected from PJM Mid-Atlantic Control Zone transmission owners paid to the New York ISO for the Phase Angle Regulators (PARs) at Ramapo and charged according to the Operating Agreement.
- *Financial Transmission Rights Auction* — market participants may purchase/sell FTRs by participating in the Annual and Monthly auctions.
- *Auction Revenue Rights* — ARRAs are the mechanism by which the proceeds from the FTR auctions are allocated.



These services are applicable to the different types of market participation, as shown in Exhibit 1. Each service is further broken down in the billing statement (see the *PJM Manual for Billing*).

	MARKET BUYERS	MARKET SELLERS	TRANSMISSION CUSTOMERS
Spot Market Energy	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Regulation	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Operating Reserves	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Transmission Congestion	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/>
Transmission Losses	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/>
Emergency Energy	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Meter Reconciliation	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Unscheduled Transmission Service	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Capacity Credit Market	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Financial Transmission Rights	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>
Auction Revenue Rights	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>

Exhibit 1: Types of PJM Services

The PJM Energy Market accounting is designed to operate on a balanced basis. That is, the total amount of the charges equals the total amount of the credits; there are no residual funds. With certain exceptions, each of the services also operates on a balanced basis. That is, the charges and credits for a particular service, such as regulation, offset each other exactly. In certain cases, charges in excess of credits, or vice versa, in one service are used to offset the costs of providing another service.

1.2 Accounting Input Data

At the end of each operating hour, PJM collects information regarding actual operations during the hour. This information is recorded either by the PJM dispatchers or by automated systems. The market accounting processes use this information as input data. Other accounting input data is provided from various systems and databases. This information includes data describing PJM Members' installed generating resources, scheduling information for PJM Members' transactions, and Transmission System parameters, such as loss factors determined annually by PJM system planning staff. The market accounting processes use this information as described in the following sections of this manual



Section 2: Locational Marginal Price

Welcome to the *Locational Marginal Price* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- How PJM defines Locational Marginal Price (see “*Definition of Locational Marginal Price*”).
- How PJM calculates Real-Time Locational Marginal Prices (see “*Calculation of Real-Time Locational Marginal Price*”).
- How PJM verifies Real-Time Locational Marginal Prices (see “*PJM Real-Time Locational Marginal Price Verification Procedure*”).
- How LMPs are used and calculated in the PJM Energy Market accounting (see “*Using & Calculating Locational Marginal Prices*”).

2.1 Definition of Locational Marginal Price

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour (\$/MWh). LMP is a pricing approach that addresses Transmission System congestion and loss costs, as well as energy costs. Therefore, each spot market energy customer pays an energy price that includes the full marginal cost of energy of delivering an increment of energy to the purchaser's location.

- When there is transmission congestion in PJM, the PJM dispatcher dispatches one or more of the generating units out of economic merit order to keep transmission flows within limits. There may be multiple large areas, each including many resources that are dispatched to relieve the congestion. The LMP reflects the cost of redispatch for out-of-merit resources and cost of delivering energy to that location.
- LMPs are calculated at all injections, withdrawals, EHV's (nominal voltage of 500 KV and above), Interfaces, and various aggregations of these points.
- LMPs are calculated in both the Real-time Energy Market and Day-ahead Energy Market.
- The LMP calculation calculates the full marginal cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of three separate components of LMP. In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of Locational Marginal Price:
 - **System Energy Price** - is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource.
 - **Congestion Price** - is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation

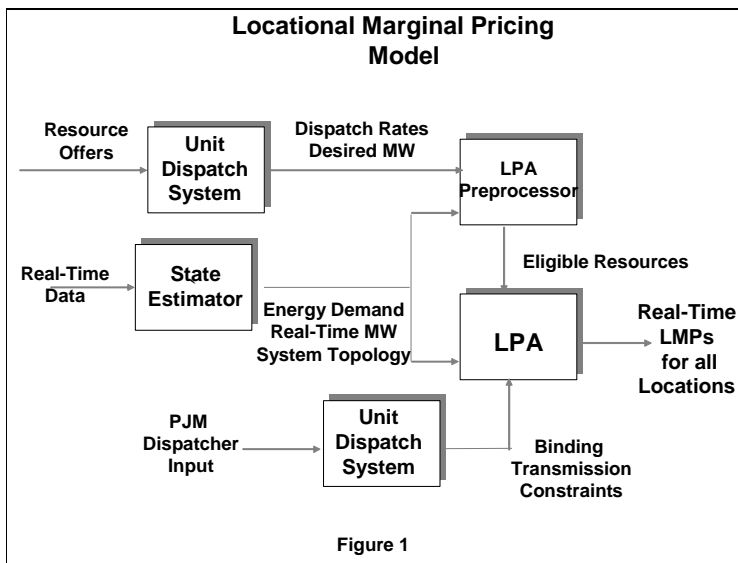
resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings.

- **Loss Price** - is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.
- The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Locational Marginal Price at that bus.

2.2 Calculation of Real-Time Locational Marginal Price

The PJM Real-Time Locational Marginal Price (LMP) calculation process consists of several programming modules that are executed as part of the real-time sequence. The real-time sequence executes every five minutes on the PJM Energy Management System (EMS). A functional diagram of the PJM LMP Model is shown in Figure 1. As indicated in Figure 1, the main modules of the PJM LMP Model are:

- Unit Dispatch System (UDS)
- PJM State Estimator
- LPA Preprocessor
- Locational Pricing Algorithm (LPA)





Each of the PJM LMP modules are described in detail below.

2.3 Unit Dispatch System

The Unit Dispatch System (UDS) is a software tool that provides the PJM dispatchers with the capability to manage changes in load, generation, interchange, and transmission constraints simultaneously on a near real-time basis, by providing recommended dispatch solutions. The UDS evaluates various system conditions to produce a dispatch solution for a user-selected look-ahead time. This allows the operator to simultaneously manage multiple transmission constraints.

The Unit Dispatch System is not a stand-alone system. It is an application that processes data from the markets database and other PJM systems. UDS executes a dispatch solution automatically every five minutes or when executed by the operator. To calculate the solution, UDS looks at online and available resources, resource offer data, forecasted load, scheduled and current interchange, ACE (Area Control Error), as well as various other input parameters.

Real-time data sources include:

- Load forecast data from EMS
- ACE, steam deviation, regulation signal from EMS
- Constraint data - unit sensitivities from EMS
- State Estimator output from EMS
- Outage data from eDART
- Transaction data from EES

The application then produces three cases with each solution solving the Security Constrained Economic Dispatch problem. Each of these solution cases contains:

- A recommended set of zonal dispatch rates
- A list of exceptions to the dispatch rates for constraint control
- Individual resource dispatch rates
- Individual Resource Desired MW level

For the purpose of Real-time LMP, the Individual Resource dispatch rates are the \$/MW value from the resource offer curve corresponding to either the limited or unrestricted desired MW level. The limited desired MW value takes into account unit restrictions such as ramp rate limits, economic minimum, and economic maximum. In contrast, the unrestricted desired MW value ignores ramp rate limits.

UDS gathers transmission constraint information from the EMS and develops its dispatch solution based on using the most economic resources to control a given constraint. The optimization that takes place when the UDS executes ensures that the optimal dispatch solution is reached respecting all binding transmission constraints.

When the operator approves a recommended solution, the zonal dispatch rates and/or individual resource MWs are bridged to the EMS, where they are automatically sent out to resources or local control centers.



In addition to being used for economic dispatch, results of each approved solution are used as input to the Real-Time LMP calculation. When the operator approves a recommended solution, the following data is sent to the Real-Time LMP calculation:

- Individual Resource dispatch rates
- Resource specific Desired MW level (UDS Des MW)
- Binding transmission constraints

2.4 PJM State Estimator

The Real-Time LMP calculation depends upon having a complete and consistent power flow solution as input. This input requirement can be achieved by using a state estimator. The state estimator is a standard power system operations tool whose purpose is to provide a base case power flow solution for input into other computer programs.

The state estimator uses actual operating conditions that exist on the power grid (as described by metered inputs) along with the fundamental power system equations to calculate the remaining flows and conditions that are not metered. Since the state estimator solution provides a complete and consistent model of actual operating conditions based upon observable (metered) input and an underlying mathematical model, it can be used to provide the basis for the Locational Marginal Price calculations.

The inputs to the state estimator are the available (metered) real-time measurements, the current status of equipment (lines, generators, transformers, etc.), and the bus load distribution factors.

This standard industry tool depends upon data redundancy and the underlying physical and mathematical relationships of the power system to provide a solution with less error than the original measurements. Therefore the state estimator can correct "bad data" and calculate missing data in the model to provide a consistent representation of existing network conditions.

The PJM state estimator is run on a thirty-second cycle and can provide the following inputs to the PJM LMP Model, on a five-minute basis:

- AC powerflow solution
- Actual generator MW output
- Bus loads
- Tie line flows
- MW losses by transmission zone
- Actual MW flow on any constrained transmission facility

2.5 Locational Pricing Algorithm (LPA) Preprocessor

Since the Real-Time LMP calculation is based on actual resource output rather than a theoretical optimal dispatch, it is necessary to screen resources to determine if they are eligible to participate in the Real-Time LMP calculation.



The LPA Preprocessor performs this screening function by analyzing the following to determine if a resource is following economic dispatch requests.

- Resource state estimated MWh output (aka Real-Time MWh or SE MW)
- Resource offer price curves
- Economic dispatch rates
- Desired MW level for each resource that was specified by UDS

The program therefore acts as a real-time performance monitoring function for resources that have designated themselves as dispatchable.

Dispatchable resources whose actual MW output is 110% or less than the desired MW level are considered to be following the economic dispatch instructions and are therefore eligible to be passed through to the LPA as eligible resources. This evaluation includes any resources that are specifically requested by the UDS program to operate out of economic merit order dispatch in order to control a transmission constraint. These resources are designated as eligible to set LMP if they are on-line and following the dispatch instruction. When designated, an “eligible to set LMP” flag is set for each resource for each applicable 5-minute interval within an operating hour. The LPA Preprocessor also screens external bilateral transactions that are designated as dispatchable to determine if their offer data is consistent with current dispatch rates and if they are therefore eligible to set LMP.

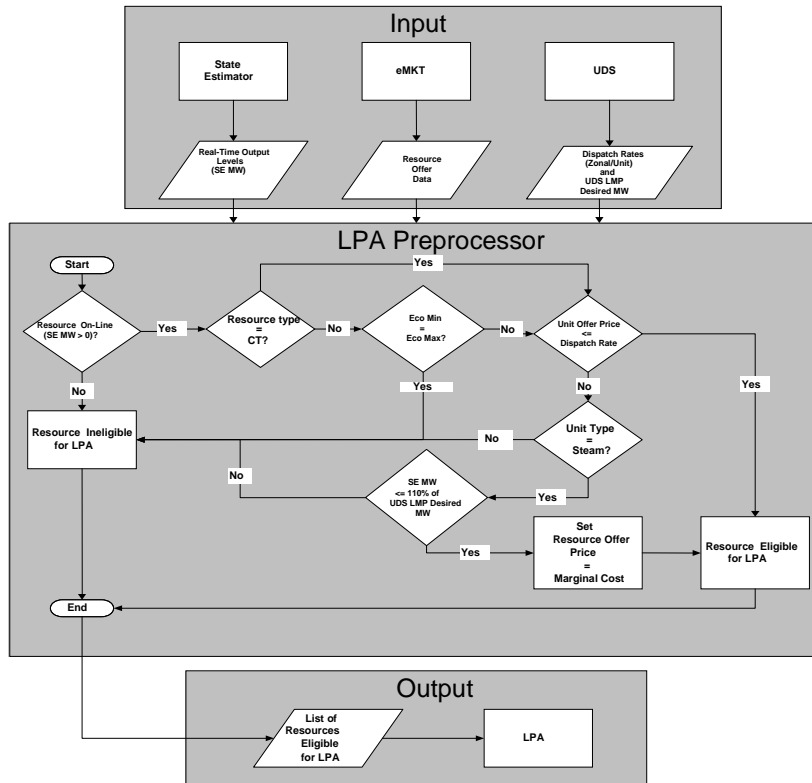
Resources that are not eligible to participate in Real-Time LMP calculations are those that are declared must run or that are not following economic dispatch requests based on the criteria outlined above.

The offer price of eligible resources corresponds to a value derived from their applicable offer curve (or MW schedule for external bilateral transactions). The LPA Preprocessor calculates this Real-Time offer value using the following criteria:

- If the resource’s state estimated MW value is less than or equal to the desired MW value, then the Real-time resource offer value is calculated by comparing the state estimated MW output to the resource’s offer curve.
- If the resource’s state estimated MW value is greater than the desired MW value, then the Real-Time resource offer value is calculated by comparing the desired MW value to the resource’s offer curve.

The eligible resources are introduced to the LPA and are modeled at actual MW output with a small bandwidth to allow for solution tolerance. Resources that are not eligible to participate in Real-Time LMP calculations are modeled as ineligible resources with their MW output fixed at the actual MW value from the state estimator solution.

Figure 2 below shows how the LPA Preprocessor determines the list of eligible units and transactions.





2.6 Locational Pricing Algorithm

The function of the Locational Pricing Algorithm (LPA) is to determine the Real-Time LMP values on a five minute basis. The LPA calculates prices for each of the PJM nodes in the state estimator model and for interface busses used as a proxy for transfers to and from PJM and external control areas. The Real-Time LMPs are defined as the cost to serve the next increment of load at each node bus location for the current system state estimated operating point, taking into account eligible resource real-time offer prices and the buses' location with respect to transmission limitations and incremental system losses.

The LPA is an incremental linear optimization program that is formulated at the current state estimated operating point. The objective is to minimize the cost function subject to the power balance constraint, generation MW bounds, transaction MW bounds, any transmission constraints that currently exist on the system and a normalized distribution of system losses to a network location.

Since the goal of the PJM LMP system is to calculate the Real-time LMP values based on actual system operating conditions, the state estimated powerflow solution is used as a starting point for the incremental linear programming formulation. This powerflow solution is then linearized in order to perform the LMP calculations. As outlined in previous sections, the set of eligible resources is determined by the LPA Preprocessor and is input to the LPA as a set of control variables. The set of eligible resources, P_i , are modeled in the formulation at the state estimated MW amount with a small bandwidth to allow for solution tolerance. The cost coefficients in the objective function for the eligible resources are set equal to the Real-time bid that is calculated by the LPA Preprocessor based on the state estimated MW level and the incremental offer (or bid) curve. These cost coefficients are assumed to have a constant slope.



The PJM incremental linear programming formulation is as follows:

Minimize:

$$Z = \sum C_i(\Delta P_i)$$

Subject to:

$$\sum_{i=1}^n \Delta P_i - Loss = 0 \quad (\text{power balance})$$

$$\sum_{i=1}^n A_{ij} (\Delta P_i - D_i^{Loss} \times Loss) \leq 0 \quad (\text{network constraints})$$

$$\Delta P_i^{\min} \leq \Delta P_i \leq \Delta P_i^{\max} \quad (\text{resource limits})$$

where:

ΔP_i - the change in rate of energy injection (+) or energy consumption (-) in MW for resource i.

~~Loss~~ - ~~total~~ system loss demand (in MW) for reliability monitored facilities¹ and generator step-up (GSU) transformers included in the Marginal Loss calculation² as a function of location-specific injections and withdrawals

ΔP_i^{\max} - the upper MW bound for resource i

ΔP_i^{\min} - the lower MW bound for resource i

i - an index over the set of flexible resources

C_i - the calculated real-time price for resource i

A_{ij} - the sensitivities for resource bus i and active constraint j with respect to the reference bus

D_i^{loss} - normalized distribution of system losses to network location i.

The LMP values at each bus are by-products of the linear programming formulation that is listed above. The LMP value at a particular location is essentially the sum of the system marginal price of generation at the reference bus plus the marginal congestion price at the location associated with the various binding transmission constraints plus the marginal loss price at the location. The marginal values associated with various constraints in the

¹ The list of Reliability Monitored Facilities can be reviewed at <http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx>

² Only GSU transformers of the generating units do not self-provide losses over the GSU transformers are included in the Marginal Loss calculation. A list of such GSU transformers will be provided at the PJM website when the proposed change is implemented.

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optimization problem are called shadow prices. The shadow price of a constraint can be explained as the incremental change in value of the objective function for a unit change in the limit (right hand side) of the constraint. Therefore, an equation for computing LMPs can be expressed in terms of these shadow prices.

The LMP equation can be written as follows:

$$LMP_i = \lambda - \sum [A_{ik} (SP_k)] + \lambda \left(\frac{1}{Pf_i} - 1 \right)$$

where:

LMP_i = the Locational Marginal Price at bus i

λ = the system marginal price of generation at the reference bus

A_{ik} = the sensitivity for bus i on binding constraint k

SP_k = the shadow price of constraint k

Pf_i = the penalty factor for resource i . $Pf_i = \left(1 - \frac{\partial Loss}{\partial P_i} \right)^{-1}$

2.7 PJM Real-Time Locational Marginal Price Verification Procedure

PJM continually monitors the processes that are associated with the calculation of Real-Time LMPs. In the event of a data input failure, program failure, or logging error, corrective actions may be taken to ensure that the resulting Real-Time LMPs are as accurate as is reasonably obtainable.

- Data Input Failures (Stale cost data, stale dispatch rates, stale EMS data) or Program Failures (State Estimator failure, LPA Failure, Constraint logger failure)
 - Data input failures can occur when telecommunication problems exist either on the PJM computer network or on the data lines between PJM and PJM member companies. If failures occur within PJM's network, all possible steps will be taken to recover the original data for use in LMP calculation reruns. In the event of a program failure, an attempt will first be made to correct the reason for the failure and to recalculate LMP values for the affected intervals. If the failure cannot be corrected (due to a data input failure), and the original data cannot be recovered, PJM may utilize data from the best available alternate data sources including, but not limited to, backup systems, dispatcher logs, raw telemetry data, and member company data sources. In the event of a data input or program failure, LMP replacements will be performed as outlined below:
- If the stale data or program failure exists for less than 6 intervals within the same hour then the affected intervals will be replaced with data from the last successful interval.
- If the stale data or program failure exists for more than six intervals within the same hour then:



- If the hour is unconstrained, the hourly LMP will be replaced with the hourly integrated dispatch rate, or
- If the system is constrained, the LMP values will be recalculated using data from the best available sources.
- If the stale data or program failure exists for less than 6 intervals within the same hour but the previous hour had 12 failures then:
 - If the hour is unconstrained, the hourly LMP will be replaced with the hourly integrated dispatch rate, or
 - If the system is constrained, the LMP values will be recalculated using data from the best available sources.
- *Logging Errors (Transmission constraint logging, CT logging)* – The reference for logging times is the transmission dispatcher manual log. In the event of a logging error, LMP replacements will be performed as outlined below:
 - Transmission constraint or CT logs entered (or removed) with a delay of less than four intervals) – No recalculation of LMP is required.
 - Transmission constraint or CT logs entered (or removed) with a delay of four intervals or more) – The constraint and/or CT data will be corrected and LMP values will be recalculated.
 - Transmission constraint or CT logs entered incorrectly - The constraint and/or CT data will be corrected and LMP values will be recalculated.

2.8 Calculation of Ramp Limited Desired MWh

Operating Reserve deviations to generators that are operating at PJM's direction are based on a comparison of their Real-time desired MW with their Real-time MWh. For the purposes of settlement of Operating Reserve charges and credits, a Ramp-Limited Desired MW value will be used to determine whether a unit is following PJM dispatch instructions as well as the actual quantity of deviations that will be calculated when a unit be determined to not be following dispatch instructions.

PJM will calculate a Ramp Limited Desired MW value for units where the economic minimum and economic maximum are at least as far apart in real-time as they are in Day-Ahead.

- Real Time Economic Minimum <= 105% of Day-Ahead Economic Minimum or Day-Ahead Economic Minimum plus 5MW, whichever is greater.
- Real Time Economic Maximum >= 95% Day-Ahead Economic Maximum or Day-Ahead Economic Maximum minus 5MW, whichever is lower.

PJM will determine a unit's Ramp-Limited Desired MW according to the following calculation:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLA}_{\text{time}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$



where the variables are:

- UDStarget = UDS basepoint for the previous UDS case
- AOutput = Unit's output at case solution time
- UDSLAtime = UDS look ahead time
- Case_Eff_time = Time between base point changes
- RL_Desired = Ramp limited desired MW

UDS LMP Desired MWh is calculated by comparing the hourly integrated UDS LMP to the unit's bid curve to determine a corresponding MW value. This value is not ramp-limited.

In the event of technical difficulties where either a) UDS data does not exist or b) there is not a sufficient amount of data to calculate a reasonable Ramp Limited Desired MW value, the UDS LMP Desired MW value will be used.

PJM utilizes the Ramp-Limited Desired MW value to determine whether a unit is following PJM dispatch instructions. PJM will calculate two values, for a generation resource that is operating at PJM's direction:

- the MW off dispatch - is a defined term that is the lesser of the difference between the actual output of a unit in MW and the UDS Basepoint, or the difference between the actual output of a unit in MW and its Ramp-Limited Desired MW.
- % off dispatch.

PJM will use the lesser of the difference between the actual output and the desired dispatch point, or the actual output and Ramp-Limited Desired MW value. The % off dispatch and MW off dispatch will then be calculated as time-weighted averages of the values calculated with each dispatch solution over the course of an hour.

Pool-scheduled and dispatchable self-scheduled resources operating above economic minimum will then be considered to be following dispatch if :

- (a) actual output is between their Ramp-Limited Desired MW value and desired dispatch point,
 - (b) % off dispatch is less than or equal to 10, or
 - (c) hourly integrated Real-time MWh are within five percent (5%) or 5 MW (whichever is greater) of the hourly integrated Ramp-Limited Desired MW.
- Dispatchable pool-scheduled and self-scheduled generation resources that follow dispatch won't be assessed Balancing Operating Reserve deviations, and those that do not follow dispatch will be assessed Balancing Operating Reserve deviations based on $|\text{hourly integrated Real-time MWh} - \text{hourly integrated Ramp Limited Desired MW}|$, pursuant to the rules as defined in PJM Manual M28. The rules provide that Ramp-Limited Desired MW value must be used to determine real-time deviations from day-ahead schedules for generation resources. (See "Operating Reserve" section of PJM Manual M28 for a detailed description of the calculation of generator deviation charges).



2.9 Using and Calculating Locational Marginal Prices

LMPs are used in the PJM Energy Market accounting to calculate charges or credits for many of the market services, including:

- *Spot Market Energy* — LMPs are used to calculate the charges for Spot Market Energy purchases and the credits for Spot Market Energy deliveries. (See “Spot Market Energy Accounting” section of PJM Manual M28 for a detailed description of these calculations).
- *Operating Reserve* — LMPs, along with other components, are used to determine whether providers of Operating Reserve are properly compensated for their costs. (See “Operating Reserve Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Transmission Congestion* — Congestion price components of LMPs are used in the calculation of Transmission Congestion Charges and to determine the value of FTRs used in the calculation of Transmission Congestion Credits. (See “Transmission Congestion Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Transmission Losses* — Loss price components of LMPs are used to determine the charges for transmission losses. (See “Transmission Losses Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Emergency Energy* — LMPs are used to calculate the charges and credits for Emergency purchases and sales between PJM and other Control Areas. (See “Emergency Energy Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *PJM Load Response Programs* — LMPs are used to calculate charges and credits for the PJM Load Response Programs (see “Section 9: PJM Load Response Programs Accounting” of PJM Manual M28 for a detailed description of this calculation).
- *Metering Reconciliation* — Weighted average LMPs are used to calculate monthly meter error correction charges between PJM Members and between Control Areas. (See “Metering Reconciliation Accounting” section of PJM Manual M28 for a detailed description of this calculation).

In general, generators are paid based on the generator bus LMP and loads are charged based on the load bus LMP. Transmission Customers or Energy Market Buyers are charged for congestion on transactions based on the differential in source and sink LMPs. LMPs are calculated on a periodic basis throughout the Operating Day, nominally every five minutes. At the end of each hour, an average of the five-minute LMP values is computed. The resulting hourly LMPs are then used in the PJM Energy Market accounting, as described in the other sections of this manual.

PJM Actions:

- PJM determines which CT units can set LMP. A CT can set LMP if it meets any of the following criteria:



- The CT is on for economic reasons, the CT bid price is less than or equal to the dispatch rate, and the state estimator MW output of the CT is greater than zero.
- The CT is logged on for transmission and a transmission constraint is logged (CTs logged as on for transmission when a constraint is not logged are treated as economic), the CT bid price is less than or equal to the dispatch rate, and the state estimator MW output of the CT is greater than zero.
- PJM determines which steam units can set LMP. A steam unit can set LMP if it meets the following criteria:
 - The steam unit is not on for transmission congestion and the bid price is less than or equal to the dispatch rate, and the state estimator MW value is less than or equal to 110% of the unit's desired MW value.
 - The steam unit is on for transmission congestion and a transmission constraint is logged, the bid price is less than or equal to the dispatch rate, and the state estimator MW value is less than or equal to 110% of the unit's desired MW value.
- PJM determines the pool transactions that can set LMP. A pool transaction can set LMP if the transaction bid price is less than or equal to the Dispatch Rate.



Section 3: Spot Market Energy Accounting

Welcome to the *Spot Market Energy Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- An overview of the spot market accounting (see “*Spot Market Accounting Overview*”).
- How PJM determines spot market net interchange for each PJM Member (see “*Calculating Spot Market Interchange*”).
- How charges for spot market energy are calculated for market buyers and sellers (see “*Interchange Market Buyers’ Charges*”).
- How spot market energy charge reconciliations are calculated (see “*Reconciliation for Spot Market Charges*”).

3.1 Spot Market Accounting Overview

The PJM Energy Market is the regional competitive market that is administered by PJM for the purchase and sale of Spot Market energy. PJM Members buy and sell energy from the spot market based on metered and scheduled use. PJM schedules and dispatches generation on the basis of least-cost, security constrained dispatch and the bids and operating characteristics offered by the sellers into PJM. PJM dispatches generation to meet the PJM Member buyers’ requirements, as well as the requirements for Ancillary Services.

PJM is responsible for administering the Day-ahead and Balancing PJM Energy Markets, including, performing the following accounting-related functions:

- accounting for transactions
- rendering bills to buyers and sellers
- receiving payments from and dispersing payments to buyers and sellers

The Spot Market facilitates the trading of energy by PJM Members. The Spot Market clears hourly at the appropriate day-ahead and real-time System Energy Price component of LMP. PJM calculates a day-ahead and a real-time System Energy Price each hour for the entire PJM RTO, as specified in **Section 2** of this PJM Manual. Energy delivered to the Spot Market is compensated at the System Energy Price for that hour. Energy purchased from the Spot Market is charged at the System Energy Price for that hour.

3.2 Business Rules for eSchedules and eMTR Data Submissions

Unilateral Corrections to eSchedules Load Responsibility Data

- For load responsibility eSchedules data submitted by the LSE (as opposed to the typical EDC submittal), EDCs need more certainty of accurate and final data prior to the PJM eSchedules data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the eSchedules deadline.



- These LSEs must submit their data two hours prior to the established PJM eSchedules data submission deadlines.
- If this does not occur, EDCs shall be allowed to e-mail PJM with the LSE's load responsibility data (with a copy provided to the applicable LSE) so that PJM can enter that EDC-calculated data prior to the eSchedules data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the eSchedules deadline may be resolved via the EDC load reconciliation data submissions.

Unilateral Corrections to eMTR Generation Data

- For generation MWh data submitted by the generation owner (as opposed to the EDC submittal), EDCs need more certainty of accurate and final eMTR data prior to the PJM eSchedules data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the eSchedules deadline.
- If gross data errors in the submitted data are identified by the EDC (and PJM concurs with the findings), EDCs shall be allowed to e-mail PJM with the correct generator data (with a copy provided to the applicable generation owner) so that PJM can enter that data prior to the eMTR data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the eMTR deadline may be resolved via monthly Meter Error Correction data submissions.

3.3 Calculating Spot Market Interchange

Net interchange for PJM Members is the difference between a participant's total energy resources (including both generation and purchased energy) and its energy demand (including both load and energy sale obligations).

For each hour, PJM calculates each market participant's hourly day-ahead and real-time net spot market energy interchange.

Day-ahead net interchange equals the sum of a market participant's demand and decrement bids cleared in the day-ahead market, less any accepted generation and increment offers cleared in the day-ahead market, and is adjusted for all day-ahead energy transactions in which the customer account is involved.

Real-time net interchange consists of a market participant's hourly metered tie line flows (if applicable), less any ownership of metered generation, and is adjusted for all real-time energy transactions (including any load obligations [de-rated for transmission losses] or generation modeled by eSchedule transactions, and including any eSchedule transactions that were priced day-ahead) in which the customer account is involved.

3.4 Transmission Loss De-rating Factors

Because PJM employs a Marginal Loss (ML) methodology, energy market-related settlements need to use load responsibilities de-rated for transmission losses. This is due to the fact that the LMPs include a loss price component. In order to remove all transmission



losses on reliability monitored facilities and GSU transformers included in ML calculation, as represented in PJM's network system model, hourly EDC loss de-rating factors are applied to the total EDC load and to individual LSE load responsibilities. In general, these loss de-rating factors represent total transmission losses divided by total load including losses. (Note that these are different from traditional loss factors which reflect total losses divided by load excluding losses.)

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Each hour, PJM calculates a loss de-rating factor for each EDC that has their tie lines fully metered directly to PJM. For non-PJM Mid-Atlantic EDCs (that do not receive an allocation of the jointly-owned PJM 500 kV transmission system losses), the calculation is as follows:

$$\text{EDC } \textit{total-state-estimated Loss MWh for reliability monitored facilities and GSU transformers included in ML calculation} / \text{EDC total revenue-metered load MWh including all losses}$$

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For PJM Mid-Atlantic EDCs (that do receive an allocation of the jointly-owned PJM 500 kV transmission system losses), the calculation is as follows:

$$\frac{\text{EDC } \textit{total-state-estimated non-500kV Loss MWh for reliability monitored facilities and GSU transformers included in ML calculation} + \text{EDC revenue-metered 500kV Loss Allocation MWh}}{\text{EDC total revenue-metered load MWh including all non-500kV losses} + \text{EDC revenue-metered 500kV Loss Allocation MWh}}$$

These EDC hourly loss de-rating factors are applied to the LSE load responsibility eSchedule MWh quantities (which are inclusive of all losses) that are carved-out of the applicable EDC's total load, as well as applied to any residual load responsibility remaining with the EDCs, as follows:

$$\text{Loss De-rated Load MWh} = (1 - \text{EDC Loss De-rating Factor}) \times \text{eScheduled, or Revenue-Metered, Load Responsibility MWh}$$

3.5 State-estimated vs. Revenue-metered Energy Quantities

Real-time generation MWh are initially determined by the PJM State Estimator, however, they are replaced by revenue meter data, if the equivalent revenue meter values are available via PJM eMTR.

The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distribution Company (EDC) that reports hourly net energy flows from metered tie lines to PJM via eMTR and for which all generators within that EDC's territory report revenue meter data for their hourly net energy delivered via eMTR, the total EDC revenue-metered load is calculated as the sum of the net import energy flows reported by their tie revenue meters plus the net generation reported by the generator revenue meters. The amount of load at each of such EDC's load buses calculated by the PJM State Estimator is then adjusted, in proportion to its share of the total load of that EDC, in order that the total amount of load across all of the EDC's load buses matches its total revenue meter calculated load.

3.6 Spot Market Energy Charges

Market participant customer accounts incur +/- charges for Day-ahead Spot Market Energy based on their day-ahead net interchange. If a market participant's day-ahead net interchange is a net purchase of day-ahead spot market energy in an hour (a positive value), they are charged for purchasing their net interchange for that hour at the hour's day-



ahead System Energy Price. If a market participant's day-ahead net interchange is a net sale of day-ahead spot market energy in an hour (a negative value), they are provided with a negative charge for selling their net interchange for that hour at the hour's day-ahead System Energy Price.

Market participant customer accounts incur +/- charges for Balancing Spot Market Energy based on the deviation between their real-time net interchange and their day-ahead net interchange. Hourly balancing spot market deviations are calculated by subtracting the hour's day-ahead net interchange from the hour's real-time net interchange. If a market participant's balancing spot market deviation is a net purchase of real-time spot market energy in an hour (a positive value), they are charged for purchasing their balancing deviation for that hour at the hour's real-time System Energy Price. If a market participant's balancing spot market deviation is a net sale of real-time spot market energy in an hour (a negative value), they are provided with a negative charge for selling their balancing deviation for that hour at the hour's real-time System Energy Price.

PJM Actions:

- PJM accounting process retrieves the following information:
- each market participant's hourly day-ahead and real-time net interchange (MWh)
- the hourly RTO system-wide System Energy Price (\$/MWh)
- PJM calculates the Day-ahead Spot Market Energy charge (positive or negative) for each hour for each Market Participant as:

$$\text{Day-ahead Spot Market Energy Charge} = (\text{Day-ahead Net Interchange}) * (\text{Day-ahead System Energy Price})$$

- PJM calculates the Balancing Spot Market Energy charge (positive or negative) for each hour for each Market Participant as:

$$\text{Balancing Spot Market Energy Charge} = (\text{Real-time Net Interchange} - \text{Day-ahead Net Interchange}) * (\text{Real-time System Energy Price})$$

3.7 Reconciliation for Spot Market Energy Charges

PJM will calculate reconciled Spot Market Energy charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Spot Market Energy charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the real-time PJM System Energy Price for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Spot Market charges for a month may be either a positive or a negative value.



Section 4: Regulation Accounting

Welcome to the *Regulation Accounting* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of how Regulation is provided and accounted for in the PJM Regulation Markets (see “*Regulation Accounting Overview*”).
- How credits are calculated for providers of Regulation (see “*Regulation Credits*”).
- How charges are calculated for users of Regulation (see “*Regulation Charges*”).
- How regulation charge reconciliations are calculated (see “*Reconciliation for Regulation Charges*”).

4.1 Regulation Accounting Overview

Regulation is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60 cycles per second (60 Hz). PJM commits on-line resources whose output is raised or lowered as necessary to follow moment-to-moment changes in load. Regulation is predominantly achieved using automatic generation control equipment. Regulating resources include both generators and demand side response resources.

PJM operates the Regulation Market where a Regulation Market Clearing Price (RMCP) is determined based on Regulation offers and estimated opportunity costs. PJM assigns the most economically efficient set of regulating resources available in real-time to separately meet the applicable NERC regions’ regulation zone requirements. For more detailed information about how regulating requirements are developed and how Regulation is assigned, see the ***PJM Manual for Balancing Operations (M-12)***. For an overview of the Regulation Market, see the ***PJM Manual for Scheduling Operations (M-11)***.

Each PJM load serving entity has an hourly Regulation obligation equal to their regulation zone real-time load ratio share of the applicable Regulation requirement for the hour, prorated to reflect the total amount of Regulation actually assigned.

A market participant’s Regulation obligation can be satisfied from their own resources capable of providing Regulation, by contractual arrangements with other Market Participants capable of providing Regulation, and/or by purchases of Regulation from the PJM Regulation Market.

Resource owners of self-scheduled Regulation are credited at the hourly RMCP for each MW of Regulation supplied. Resource owners providing Regulation at the direction of PJM are credited for each Regulation MWh at the higher of the hourly RMCP or their Regulation offer price (plus real-time opportunity cost, for generating resources). Regulation buyers are charged the hourly RMCP plus their percentage share of any Regulation provider’s unrecovered costs over and above their RMCP payments.



4.2 Regulation Credits

Each resource supplying Regulation at the direction of PJM is credited at the higher of the hourly Regulation Market Clearing Price (RMCP) or its Regulation offer price (plus real-time opportunity cost, for generating resources). A resource supplying self-scheduled Regulation is credited at the hourly RMCP. Regulation credits for joint-owned generators providing Regulation are allocated to the owners based on their ownership shares.

PJM Actions:

- From the Regulation log, PJM identifies each resource that supplied Regulation (both pool-scheduled and self-scheduled) during an hour.
- PJM calculates the hourly credit for each assigned regulating resource by multiplying each increment of such Regulation in megawatts during the hour by the Regulation Market Clearing Price (RMCP) for that hour.
$$RMCP\ Credit = Regulation\ MW \times RMCP$$
- PJM calculates the lost opportunity costs incurred by each generator providing Regulation at the direction of PJM for the hour. Note that the energy offer referred to below is the generator's incremental energy offer curve that is associated with the price-based or cost-based schedule used in the real-time dispatch of the unit.
- If a generator must reduce its output to provide Regulation, its lost opportunity cost equals the amount of its energy offer at its economically desired level in excess of its energy offer at its Regulation setpoint (biased to reflect the actual Regulation signal) or actual output MWh, as applicable.
- If a generator must increase its output to provide Regulation, its lost opportunity cost equals the amount of its energy offer at its Regulation setpoint (biased to reflect the actual Regulation signal) or actual output MWh, as applicable, in excess of its energy offer at its economically desired level.
- If the LMP is less than the generator's energy offer at economic minimum, the lost opportunity cost will also include the lesser of: (i) the difference between its energy offer at economic minimum and the LMP at its generation bus times its economic minimum; or (ii) the difference between its Regulation setpoint and its economic minimum times the LMP at its generation bus.
- PJM calculates shoulder hours' lost opportunity costs incurred by each generator providing Regulation at the direction of PJM for the preceding and following hour. Note that the energy offer referred to below is the generator's incremental energy offer curve that is associated with the price-based or cost-based schedule used in the real-time dispatch of the unit.
- A generator is eligible for preceding shoulder hour lost opportunity costs when: it is online the hour prior to regulating; the Regulation assignment starts at the top of the hour; it is not regulating during the preceding hour; and the LMP Desired from the prior hour is not already within the regulation hour regulation limits.



- A generator is eligible for following shoulder hour lost opportunity costs when: it is online the hour following regulating; the Regulation assignment ends at the top of the following hour; it is not regulating during the following hour; and the LMP Desired from the following hour is not already within the regulation hour regulation limits.
- In the preceding or following hour of regulation, if a generator must reduce its output, its shoulder hour lost opportunity cost equals the amount of its energy offer at the preceding or following hour economically desired level in excess of its energy offer at its Regulation setpoint at the start or end of the regulating hour.
- In the preceding or following hour of regulation, if a generator must increase its output, its shoulder hour lost opportunity cost equals the amount of its energy offer at its Regulation setpoint at the start or end of the regulating hour in excess of its energy offer at the preceding or following hour economically desired level.
- For each resource providing Regulation at the direction of PJM, the sum of its Regulation offer price (and lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is compared to its RMCP credits.
- If the resource's pool-scheduled Regulation offer price (plus lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is greater than its RMCP credit for that hour, then the resource receives an additional credit equal to the amount that its Regulation offer price (plus lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is in excess of its RMCP credit.

Lost Opportunity Cost Credit = (Regulation Offer + Lost Opportunity Cost, including Shoulder Hours' Lost Opportunity Cost, if applicable) – RMCP Credit, only if quantity is positive

- Note that, if the resource's pool-scheduled Regulation offer price (plus lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is less than its RMCP credit for that hour, the excess revenues received will offset any Balancing Operating Reserve credits received by that generator for that day.
- PJM sums the Regulation credits (both RMCP credits and Lost Opportunity Cost credits) to determine the total hourly credit for each Regulation market participant, taking into account joint-ownership of regulating generators.

4.3 Regulation Charges

Each PJM load serving entity, or other Regulation buyer, is charged at the hourly Regulation Market Clearing Price (RMCP) for the amount of Regulation purchased to meet their hourly obligation. Hourly Regulation obligations equal their real-time load ratio share of the total amount of Regulation assigned by PJM that hour, adjusted for any bilateral Regulation transactions. In addition, net purchasers of Regulation in an hour are also charged a proportionate share of any lost opportunity credits paid to regulating generators for unrecovered costs over and above their RMCP payments (including costs incurred by generators operating for PJM solely for Regulation).



PJM Actions:

- From the Regulation log, PJM sums the total amount of Regulation supplied (both pool-scheduled and self-scheduled) during an hour.
- PJM determines each load serving entity's (LSE's) applicable regulation zone load ratio share based on their real-time load (excluding transmission losses).

$$\text{Load Ratio Share} = \frac{\begin{matrix} \text{Real Time Load} + \text{Retail or Wholesale Load Responsibility} \\ \text{eSchedule MW, if buyer} \\ \text{Retail or Wholesale Load Responsibility} \\ \text{eSchedule MW, if seller} \end{matrix}}{\text{Total PJM Real Time Load}}$$

- PJM calculates each LSE's hourly Regulation obligation by multiplying their applicable regulation zone load ratio share for that hour by the total amount of Regulation supplied in that hour for the applicable regulation zone's market.

$$\text{Regulation Obligation} = \text{Load Ratio Share} * \text{Total Regulation Assigned}$$

- PJM adjusts obligations to reflect bilateral Regulation transactions among Regulation market participants.

$$\text{Adjusted Obligation} = \text{Regulation Obligation} + \text{Regulation MW Purchased} - \text{Regulation MW Sold}$$

- PJM calculates the hourly charge for each Regulation buyer by multiplying their adjusted regulation zone Obligation in megawatts during the hour by the Regulation Market Clearing Price (RMCP) for that hour.

$$\text{RMCP Charge} = \text{Adjusted Obligation} * \text{RMCP}$$

- PJM calculates amount of Regulation each market buyer purchased from the applicable market by subtracting the amount of self-scheduled regulation MW provided by that market buyer from their adjusted obligation for the hour.

$$\text{Net Regulation Purchase} = \text{Adjusted Obligation} - \text{Self Scheduled Regulation MW}$$

- If any lost opportunity or other unrecovered costs due to regulating were credited to Regulation providers, each Regulation market buyer is allocated a share of the hourly costs based on the amount of Regulation they purchased from the market that hour.

$$\text{Lost Opportunity Charge} = \frac{\text{Total Lost Opportunity Costs} * \text{Net Regulation Purchase}}{\text{Total PJM Regulation Purchases}}$$

- PJM sums the Regulation charges (both RMCP charges and Lost Opportunity charges) to determine the total hourly charge for each Regulation market participant.



4.4 Reconciliation for Regulation Charges

PJM will calculate reconciled Regulation charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Regulation charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Regulation billing determinant for that hour. The hourly Regulation charge billing determinant (in \$/MWh) is calculated by dividing the total hourly Regulation charges by the total real-time PJM load (de-rated for transmission losses) for in that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Regulation charges for a month may be either a positive or a negative value.



Section 5: Operating Reserve Accounting

Welcome to the *Operating Reserve Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how Operating Reserve is provided and accounted for in the Day-ahead and Balancing PJM Energy Markets (see “*Operating Reserve Accounting Overview*”).
- How day-ahead and balancing credits are calculated for providers of pool-scheduled Operating Reserve (see “*Credits for Operating Reserve*”).
- How the total pool cost of day-ahead and balancing Operating Reserve, Synchronous Condensing, and Reactive Services are allocated (see “*Charges for Operating Reserve*”).

5.1 Operating Reserve Accounting Overview

Accounting for Operating Reserve is performed on a daily basis. A pool-scheduled resource of a PJM Member is eligible to receive credits for providing Operating Reserve in the day-ahead market and, provided that the resource was available for the entire time specified in its offer data, in the balancing market. The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for specified operating period segments during the day (including any amounts credited for day-ahead scheduling reserve in excess of the day-ahead scheduling reserve offer, any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, and any amounts credited for resources providing reactive services). If the total value is less than the offer amount, the difference is credited to the PJM Member.

Credits are also provided for pool-scheduled energy transactions, for generating units operating as synchronous condensers (not for synchronized reserve nor for reactive services) at the direction of PJM, for cancellation of pool-scheduled resources, for units whose output is suspended or reduced due to a transmission constraint or other reliability reason, for units performing an annual black start test, and for units providing reactive services at the direction of PJM.

The offered price for pool-scheduled resources will be capped for the entire operating day in the event either of the following conditions exists:

- The generation resource is identified in the day-ahead schedule to be dispatched out of economic merit order to control an identified transmission constraint.
- The generation resource is dispatched to provide quick start reserve for reliability.

In the event one of the above conditions exists, the offer prices will be capped at one of the following three levels, as specified in advance by the resource owner:

- The weighted average real-time Locational Marginal Price at the generation bus during all hours over the past six months in which the resource was dispatched in economic merit order above minimum.



- The incremental operating cost of the generation resource as determined in the PJM Cost Development Guideline Manual plus a 10% adder.
- An amount negotiated between PJM and the Market Seller in the event the generation resource cannot recover costs with either of the first two methods above.

The total cost of Day-ahead Operating Reserve for the Operating Day is allocated and charged to PJM Members in proportion to their total cleared day-ahead demand and decrement bids plus their cleared day-ahead exports for that Operating Day. The total cost of Balancing Operating Reserve for the Operating Day is allocated and charged to PJM Members in proportion to their locational real-time deviations from day-ahead schedules and generating resource deviations during that Operating Day, or to PJM Members in proportion to their real-time load plus exports during that Operating day for generator credits provided for reliability. In order to determine the reason why the Operating Reserve credit has been earned so that the charges related can be properly allocated, PJM conducts a Balancing Operating Reserve Cost Analysis (BORCA). PJM also calculates a Regional Balancing Operating Reserve rate for the costs of Operating Reserves that result from actions to control transmission constraints that are solely within pre-defined regions in the RTO. Additional costs of Operating Reserves that result from actions to control transmission constraints that benefit the entire RTO will continue to be allocated equally to deviations across the entire RTO. A detailed description of the Regional Balancing Operating Reserve Cost Analysis (BORCA) analysis can be found in M11. The total cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) for the Operating Day is allocated and charged to PJM Members in proportion to their total load plus their exports during that Operating Day. The total cost of Reactive Services for the Operating Day is allocated and charged to PJM Members in proportion to their total load in the applicable transmission zone.

5.2 Regional Balancing Operating Reserve Cost Analysis (BORCA)

The purpose of the Balancing Operating Reserve Cost Analysis is to separate those Balancing Operating Reserve charges to be allocated to deviations between Day-ahead schedules and Real-time quantities from those that should be allocated to real-time load and exports. The key factor in separating the allocation is the determination of the particular units by which operating reserve credits were earned, and the units for which those credits should be allocated to deviations as opposed to those units for which those credits should be allocated to load and exports. This cost determination will occur in two stages: those units called on during the Reliability Analysis, and those units called on to operate during the Operating Day. In both cases, the proposed changes establish clear, definitive, and objective criteria that will be applied to such units to determine the reason Balancing Operating Reserve credits were earned.

Resources scheduled by PJM during its reliability analysis for an Operating Day, the associated Balancing Operating Reserve charges are allocated based on the reason the resource was scheduled.

- When a resource is scheduled by PJM during its reliability analysis if the resource is committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve Requirement, then in such cases, Balancing



Operating Reserve charges will be allocated to real-time deviations from day-ahead schedules.

- If however, a resource is scheduled by PJM during its reliability analysis not to account for anticipated deviations between day-ahead schedules and real time conditions but instead to provide additional reliability margin, Balancing Operating Reserve charges must be allocated to real-time load plus exports.
- Balancing Operating Reserve credits earned by units called on by PJM to operate during the Operating Day for which the LMP at the unit's bus does not meet or exceed the unit's applicable offer (cost or price) for at least four, five-minute intervals of at least one clock hour during which the unit was running at PJM's direction will be allocated according to ratio share of load plus exports.
- Balancing Operating Reserve credits earned by all other units operating at PJM's direction in real-time will be allocated according to deviations between Day-ahead schedules and Real-time quantities. The logic behind this distinction is that units called on in real-time for which LMP exceeds their offer for a significant number of intervals while they are running are necessary to meet load requirements respecting active transmission constraints.
- Units called on at PJM's direction in real time for which the LMP does not exceed the unit's offer were not needed and were therefore operating in order to ensure reliability is maintained as opposed to account for differences between day-ahead schedules and real-time system conditions.

PJM further collects Balancing Operating Reserve credits that are accrued to resources operating to manage local transmission constraints. In order to appropriately collect the costs of Balancing Operating Reserve for local constraints within the pre-determined regions where the constraints existed, PJM calculates Regional Balancing Operating Reserve adders.

PJM calculates Regional Balancing Operating Reserve adders for the following Regions within the PJM RTO

- Western Region of PJM RTO, comprised of the AEP, APS, ComEd, Duquesne, and Dayton Zones and
- Eastern Region of PJM RTO made of the AEC, BGE, Dominion, PENELEC, PEPSCO, ME, PPL, JCPL, PECO, DPL, PSEG and RE Zones.

Balancing Operating Reserve credits that are accrued to resources operating to control transmission constraints that benefit the entire RTO are charged as an RTO Balancing Operating Reserve rate.

- (See "Operating Reserve Accounting" section of PJM Manual M28 for a detailed description of the calculation of allocation charges).

5.3 Credit for Operating Reserve

Credits for Operating Reserve are calculated for each of the following situations:

- pool-scheduled generating resources (day-ahead and balancing markets)
- pool-scheduled transactions (day-ahead and balancing markets)



- canceled pool-scheduled resources (balancing market)
- resources providing quick start reserve (balancing market)
- resources reduced or suspended due to a transmission constraint or for other reliability purposes (balancing market)
- resources performing annual scheduled black start tests (balancing market)
- synchronous condensing for purposes other than providing synchronized reserve
- resources providing reactive services

5.3.1 Credits for Pool-Scheduled Generating Resources

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled generating resources.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market
 - state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM eMTR (if available)
 - scheduled MWh for eSchedules "Generation" contracts, if applicable
 - generator dispatch rates, UDS basepoint MWh, and ramp-limited desired MWh
 - generator day-ahead and real-time LMPs
- PJM calculates the resource's hourly day-ahead offer amount based on its day-ahead offer data and its cleared day-ahead Scheduled MWh for that hour.
- PJM accounting process applies the startup and hourly no-load bids if the start-up and no-load switch is set in the resource offer data and if the start-up bid is applicable for the MWh and status of the resource.
- Day-ahead credits for startup reflect the appropriate hot, intermediate, or cold state of the resource as it was scheduled in the day-ahead market.
- PJM calculates the resource's hourly day-ahead energy market value as:
$$\text{Scheduled MWh} * \text{Day ahead LMP}$$
- PJM calculates the daily Day-ahead Operating Reserve credits for each resource as follows:
 - Sum hourly day-ahead offer amounts, including applicable no-load and startup costs, for the day
 - Sum hourly day-ahead energy market values for the day



- Day-ahead Operating Reserve credit equals any portion of the resource's total day-ahead offer amount in excess of its total day-ahead market value
- PJM sums the Day-ahead Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.
- PJM determines eligibility for Balancing Operating Reserve credits for each generating resource from dispatcher logs. The following operating guidelines are used in the determination of Operating Reserve credits:
 - Resource must operate according to the on and off times requested by PJM, and units tripping during pool-scheduled periods of operation will retain their eligibility up through the hour in which the unit trips (unless the unit trips before half-past the hour, in which case the hour of the trip will not be eligible).
 - Resources that trip, are requested to restart by PJM, and return to operate as requested, are eligible to receive credits for the latter period of operation.
 - Resources that operate on a different schedule from the schedule that was accepted in the day-ahead market are ineligible for credits.
- PJM determines the resource's hourly Real-time MWh based on its state estimated generator bus MWh or its scheduled MWh via a unit-specific eSchedules "Generation" contract or its revenue meter value from PJM eMTR, as applicable, for that hour.
- PJM determines the resource's hourly Operating Reserve Desired MWh based on its ramp-limited desired MWh or UDS basepoint MWh, when available. If available, UDS basepoint MWh is used when 1.) the UDS basepoint MWh are less than or equal to the ramp-limited desired MWh or 2.) the UDS basepoint MWh is greater than the ramp-limited desired MWh and the resource's Real-time MWh is greater than the ramp-limited desired MWh.
- PJM determines the resource's percent off dispatch as the lesser of the difference between the resource's Real-time MWh and the UDS basepoint MWh or the Real-time MWh and the ramp-limited desired MWh, if available. UDS LMP desired MWh is used to calculate a resource's percent off dispatch when 1.) data is unavailable due to technical difficulties or 2.) a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum 5% or 5MW, whichever is lower.
- If the resource's UDS basepoint MWh and ramp-limited desired MWh are not available or the percent off dispatch is greater than 20%, PJM determines the resource's hourly UDS LMP Desired MWh based on its dispatch rate, applicable schedule's offer data, and minimum and maximum energy limits for that hour. For steam units, the lesser of the day-ahead scheduled and real-time economic minimum limits and the greater of the day-ahead scheduled and real-time economic maximum limits are used. For CTs, operating at PJM direction, the actual real-time output is used as the Operating Reserve Desired MWh value.



- PJM calculates the resource's hourly real-time energy offer amount based on its applicable schedule's offer data and its Real-time MWh for that hour. However, for any hour where the resource's Real-time MWh is greater than 110% of its Operating Reserve Desired MWh, Operating Reserve Desired MWh is used to determine the hourly real-time energy offer amount.
- PJM applies the start-up and hourly no-load bids if the start-up and no-load switch is set in the resource offer data and if the start-up bid is applicable for the MWh and status of the resource.
- If applicable, when a resource is started during the day at the direction of PJM, the resource's real-time offer amount for that day includes its startup costs based on the appropriate hot, intermediate, or cold state of the resource. For resources that start generating for PJM from a condensing state, the applicable startup cost for that resource equals the amount submitted in writing to the PJM Market Settlement Operations Department to be in effect that Operating Day.
- If applicable, the resource's real-time offer amount includes its hourly no-load costs prorated for any hour during which it starts generating or stops generating as follows, using a 10% tolerance:

*If: Real time MWh < 0.9 * Scheduled Minimum MWh,*

Then: Hourly No Load is prorated by (Real time MWh / Scheduled Minimum MWh)

- PJM calculates the resource's hourly balancing energy market value as:
$$(Real\ time\ MWh - Scheduled\ MWh) * Real\ time\ LMP$$
- Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable, will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources).
- PJM calculates the daily Balancing Operating Reserve credits for each generating resource's operating segment as follows:
 - Sum hourly real-time offer amounts and include applicable no-load and startup costs for the segment
 - Sum hourly balancing energy market values for the segment
- For each operating segment, Balancing Operating Reserve credit equals any portion of the resource's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits, plus 4) any Day-Ahead Scheduling Reserve Market revenues in excess of its offer, plus 5) any Synchronized Reserve Market



revenue in excess of its offer plus opportunity cost plus energy use plus startup costs, plus 6) any Reactive Services revenue.

- For any operating day in which PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert, if a generator's priced-based offer results in revenues for "economic" hours to produce an effective offer price of \$1000/MWh or greater, that generator shall not receive any operating reserve credits in accordance with the PJM Operating Agreement sections 3.2.3 (l), (m), and (n). PJM calculates an effective offer price by summing the Operating Reserve credits which would have been applicable absent this exemption, plus the LMP market value provided to the generator during "economic" hours, all divided by the sum of the generation MWh during those "economic" hours. "Economic" hours are defined as: 1) those hours in which the LMP is at or above the generator's offer price; 2) those hours that PJM dispatched the generator in excess of its min run time; and, 3) those hours that a generator with a min run time of less than or equal to 1 hour and more than one available starts per day is operated at the request of PJM.
- PJM sums the Balancing Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.

5.3.2 Credits for Pool-Scheduled Transactions

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled energy sales to the spot market.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher transaction logs
 - day-ahead and real-time external energy sales to spot market
 - hourly transaction bid rate and MW (\$/MWh, MW)
 - day-ahead and real-time LMPs
- PJM calculates the hourly day-ahead offer amount for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the transaction offer price.
- PJM calculates the hourly day-ahead energy market value for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the day-ahead LMP at the sink of the transaction.
- PJM calculates the daily Day-ahead Operating Reserve credits for each transaction as follows:
 - Sum hourly day-ahead offer amounts for the day
 - Sum hourly day-ahead energy market values for the day
 - Day-ahead Operating Reserve credit equals any portion of the transaction's total day-ahead offer amount in excess of its total day-ahead market value



- PJM sums the Day-ahead Operating Reserve transaction credits for each PJM Member.
- PJM calculates the hourly real-time offer amount for each spot market import transaction by multiplying the real-time transaction MWh by the transaction offer price.
- PJM calculates the hourly balancing energy market value for each spot market import transaction by multiplying the real-time hourly deviation from the cleared day-ahead transaction MWh amount by the real-time LMP at the sink of the transaction.
- PJM calculates the daily Balancing Operating Reserve credits for each transaction as follows:
 - Sum hourly real-time offer amounts for the day
 - Sum hourly balancing energy market values for the day
- Balancing Operating Reserve credit equals any portion of the transaction's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits.
- PJM sums the Balancing Operating Reserve transaction credits for each PJM Member.

5.3.3 Credits for Synchronous Condensing

At the end of each Operating Day, PJM calculates the credits due each PJM Member for synchronous condensing for purposes other than providing synchronized reserve or reactive services.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - resource generation data
 - real-time LMPs
- PJM calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.
- PJM calculates each eligible resource's condensing cost for each period by multiplying the duration (in hours) by the hourly cost to condense plus energy use cost as specified in the offer data.
- When a resource is requested to start condensing from an off state, a condensing credit is provided equal to the resource's condensing startup cost as specified in the offer data.



- PJM calculates the daily synchronous condensing cost for each resource by summing all hourly condensing and energy use costs, including applicable startup costs, for the day.
- PJM sums the synchronous condensing credits for all resources for each PJM Member.

5.3.4 Credits for Canceled Pool-Scheduled Resources

At the end of each month, PJM calculates the credits due to each PJM Member for pool-scheduled resources that were canceled before coming on-line.

PJM Actions:

- PJM retrieves the following information:
 - list of canceled resources (dispatcher log)
 - resource startup cost data
 - resource generation data
 - written confirmation of actual costs incurred by participants due to cancellations (to be received within 45 days of date invoice was received by participant for the month in question)
- PJM credits each PJM Member for cancellations based on the actual costs incurred and submitted in writing to the PJM Market Settlement Operations Department. Eligibility is confirmed using resource generation data and dispatcher logs. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer data.
- PJM sums the Balancing Operating Reserve cancellation credits for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.3.5 Credits for Resources providing Quick Start Reserve

At the end of each month, PJM calculates the credits due to each PJM Member for resources providing quick start reserve (under emergency conditions).

PJM Actions:

- PJM retrieves the following information:
 - list of units called on to provide quick start reserve for reliability (dispatcher log)
 - resource offer data
 - resource generation data



- written confirmation of actual costs incurred by participants (to be received within 45 days of date invoice was received by participant for the month in question)
- PJM credits each PJM Member for resources providing quick start reserve based on the actual costs incurred and submitted in writing to the PJM Market Settlement Operations Department. Eligibility is confirmed using resource generation data and dispatcher logs.
- PJM sums the Balancing Operating Reserve quick start resource credits for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.3.6 Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons

At the end of each Operating Day, PJM calculates the credits due to each PJM Member for resources incurring lost opportunity costs associated with following PJM's request to reduce or suspend the output of a generating resource due to a transmission constraint or for other reliability reasons.

Pool-scheduled generators whose output is reduced or suspended and the hourly integrated real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited hourly in an amount equal to: $(\text{Desired MWh} - \text{Actual MWh}) * (\text{Real-time LMP} - \text{Incremental Offer Rate at Actual MWh})$. The Desired MWh used in this calculation is based on the hourly integrated real-time LMP at the generator's bus and adjusted for any regulation or synchronized reserve assignments.

Pool-scheduled combustion turbine units scheduled to produce energy in the day-ahead market, but are not called on by PJM and do not operate in real-time, are credited hourly in an amount equal to the higher of: $(\text{Real-time LMP} - \text{Day-ahead LMP}) * \text{Day-ahead scheduled MWh}$; or $(\text{Real-time LMP} - \text{Incremental Offer Rate at Day-ahead scheduled MWh}) * \text{Day-ahead scheduled MWh}$.

PJM Actions:

- PJM retrieves the following information:
 - list of units and timeframes reduced or suspended for a transmission constraint or other reliability reason (dispatcher logs and Market Operations eligibility data)
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market
 - state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM eMTR (if available)
 - scheduled MWh for eSchedules "Generation" contracts, if applicable
 - generator day-ahead and real-time LMPs



- assigned regulation MWh and regulation bias factors
- assigned synchronized reserve MWh
- PJM sums the Balancing Operating Reserve lost opportunity cost credits for all reduced or suspended generating resources for each PJM Member.

5.3.7 Credits for Resources Performing Annual Scheduled Black Start Tests

At the end of each month, PJM calculates the credits due to each PJM Member for resources performing annual black start tests. Compensation for energy delivered to the transmission system shall be provided for the unit's minimum run time at the higher of the unit's cost-capped offer or real-time LMP plus start-up and no-load for up to two start attempts, if necessary. Compensation for tests where no energy was delivered to the transmission system shall be provided for the unit's start-up costs for up to two start attempts, if necessary.

PJM Actions:

- PJM retrieves the following information:
 - list of units performing annual scheduled black start tests (PJM Performance Compliance Department log)
 - resource cost-capped offer data
 - resource generation data
 - applicable real-time LMP
 - applicable start-up and no-load costs
- PJM sums the Balancing Operating Reserve annual black start test credits for all resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.3.8 Credits for Resources Providing Reactive Services

At the end of each month, PJM calculates the credits due each PJM Member for reactive services. Generators whose active energy output is altered at the request of PJM for the purpose of maintaining reactive reliability within the PJM Region are credited hourly for lost opportunity costs if their output is reduced or suspended and credited in accordance with balancing operating reserve credit calculations if their output is increased.

Generators operating as synchronous condensers for the purpose of maintaining reactive reliability at the request of PJM, are credited for each hour (or partial hour) of condensing an amount equal to the higher of: 1) the Synchronized Reserve Market Clearing Price for the hour multiplied by the amount of synchronized reserve provided (i.e., economic maximum limit of the unit); or 2) the sum of the unit's offered cost to condense, energy use cost, and start-up cost.



PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market
 - state estimator generation MWh
 - state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM eMTR (if available)
 - scheduled MWh for eSchedules “Generation” contracts, if applicable
 - generator day-ahead and real-time LMPs
 - assigned regulation MWh and regulation bias factors
 - assigned synchronized reserve MWh
- PJM sums the reactive services credits for all generating resources for each PJM Member.

5.4 Charges for Operating Reserve

The total cost of providing Operating Reserve for the Operating Day is the sum of the credits provided to PJM Members for supplying the Day-ahead and Balancing Market Operating Reserve. The daily total cost of Day-ahead Operating Reserve is allocated and charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports. The daily total cost of Balancing Operating Reserve is allocated and charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations, or to PJM Members in proportion to their real-time load plus exports for generator credits provided for reliability. The total daily cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) is allocated and charged to PJM Members in proportion to their real-time load (excluding losses) plus exports during that Operating Day. The total daily cost of reactive services is allocated and charged to PJM members serving load in the transmission zone in which the generator providing reactive services resides in proportion to their real-time load (excluding losses) during that Operating Day.

PJM Actions:

- PJM calculates for each Operating Day the Total Cost of Day-ahead Operating Reserve by summing the following credits for all PJM Members:
 - Total Day-ahead Operating Reserve generating resource credits (\$)
 - Total Day-ahead Operating Reserve transaction credits (\$)
- PJM calculates for each Operating Day the Day-ahead Operating Reserve charges by allocating the total cost of Day-ahead Operating Reserve to each PJM Member based on their daily share of cleared day-ahead demand and decrement bids plus cleared day-ahead exports.



- PJM calculates for each Operating Day the Total Regional Cost of Balancing Operating Reserve to be charged for reliability by summing the total Balancing Operating Reserve resource credits for reliability (\$) for each region and for all PJM Members
- PJM calculates for each Operating Day the Balancing Operating Reserve charges for reliability by allocating the total cost of Balancing Operating Reserve for reliability on a regional basis to each PJM Member based on their daily share of the sum of their load plus exports in each region (RTO, East, and West). West region is defined as transmission zones AEP, AP, ComEd, DUQ, and Dayton, and East region is defined as transmission zones AE, BGE, DOM, Penelec, PEPCO, Meted, PPL, JCPL, PECO, Delmarva, PSEG, and Rockland. RTO region includes the East and West region and exports that are at interfaces or hubs not completely contained in either the East or West region.
- PJM calculates for each Operating Day the Total Cost of Balancing Operating Reserve to be charged to deviations by summing the following credits for all PJM Members:
 - Total Regional Balancing Operating Reserve generating resource credits for deviations (\$) Total Balancing Operating Reserve demand resource credits (\$)
 - Total Balancing Operating Reserve transaction credits (\$)
 - Total Balancing Operating Reserve cancellation credits (\$)
 - Total Balancing Operating Reserve quick start resource credits (\$)
 - Total Balancing Operating Reserve reduction/suspension credits (\$)
 - Total Balancing Operating Reserve annual black start test credits (\$)
- PJM calculates for each Operating Day the total generating resource deviations as the sum of hourly deviations for generating resources that are not following dispatch as follows:
 - Each pool-scheduled or dispatchable self-scheduled generator not following PJM dispatch due to its actual output not being between its ramp-limited Desired MWh and UDS Basepoint MWh, and its % off dispatch is > 10%, will be assessed deviations as Real-time MWh – ramp-limited desired MWh. If the % off dispatch is > 20%, deviations will be assessed as Real-time MWh – UDS LMP Desired MWh (as determined in the Credits for Pool-Scheduled Generating Resources section of this manual).
 - For each self-scheduled generating resource with an economic maximum limit less than or equal to 110% of the economic minimum limit or not dispatched by PJM above its economic minimum, unless the resource is lowering its output in accordance with PJM direction in response to a minimum generation emergency event (or declaration) will be assessed deviations as Real-time MWh – Day-ahead Schedule MWh.
 - Each unit that has tripped or is scheduled Day-ahead and does not run in Real-time will be assessed deviations as Real-time MWh – Day-ahead scheduled MWh



- Each unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will be assessed deviations as Real-time MWh – UDS LMP Desired MWh
- Each unit that is not dispatchable in both the Day-ahead and Real-time market will be assessed deviations as Real-time MWh – Day-ahead scheduled MWh. Units that choose to participate in the Day-ahead pumped storage optimization program are considered not dispatchable in the Day-ahead market.
- Each unit where the real-time economic minimum is greater than its Day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum by 5% or 5MW, whichever is lower, and UDS LMP Desired MWh for the hours is either below the real-time economic minimum or above the real-time economic maximum, will be assessed deviations as Real-time MWh – UDS LMP Desired MWh
- Deviations are not calculated if 1.) the absolute value of the hourly deviation MWh is less than 5 MWh or 2.) the absolute value of the deviation MWh ratio to applicable day-ahead scheduled MWh or desired MWh is less than or equal to 5%
- Hours during which a generator is assigned by PJM for: Regulation; or, assigned by PJM for Synchronized Reserve (and actual MWh are less than day-ahead scheduled MWh) are omitted from this calculation.
- Resource deviations for units located at a “single bus” will be able to offset one another. A “single bus” will be any unit located at the same site and that has the identical electrical impacts on the transmission system. Unit parameters do not have to be identical for the units’ deviation MWh to offset one another. Units at a “single bus” must be contained in the same customer account.
- PJM calculates for each Operating Day the withdrawal deviations as the sum of the following hourly real-time deviations from day-ahead values for each customer account:
 - Absolute Value of (cleared day-ahead demand bid MWh + cleared day-ahead decrement bid MWh + day-ahead sale transaction MWh – real-time load de-rated for transmission losses – real-time sale transaction MWh)
 - Withdrawal deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations. Further netting will also occur for any hubs and interfaces fully contained within a given zone.
 - Dynamically scheduled export transactions are omitted from this calculation.
- PJM calculates for each Operating Day the injection deviations as the sum of the following hourly real-time deviations from day-ahead values for each customer account:
 - Absolute Value of (cleared day-ahead increment offer MWh + day-ahead purchase transaction MWh – real-time purchase transaction MWh)



- Injection deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations. Further zonal netting will also occur for any hubs and interfaces fully contained within a given zone.
- Resource, withdrawal, and injection deviations that occur within a single zone (including applicable hubs and interfaces) will be associated with a particular PJM region (East or West).
- Resource, withdrawal, and injection deviations that occur for hubs and interfaces not fully contained within a single zone will be associated with the RTO region.
- PJM calculates for each Operating Day the Balancing Operating Reserve charges to deviations by allocating the total cost of Balancing Operating Reserve for deviations on a regional basis to each customer account based on their daily share of the sum of the total hourly deviations in each region (RTO, East, and West).
- A PJM Member's deviations in the RTO region include deviations at hubs and interfaces that are not completely contained in either the East or West region as well as deviations in either the East or West region.
- PJM calculates for each Operating Day the Balancing Operating Reserve charges for reliability by allocating the total cost of Balancing Operating Reserve for reliability on a regional basis to each PJM Member based on their daily share of the sum of their load plus exports in each region (RTO, East, and West).
- A PJM Member's load plus exports in the RTO region include exports at hubs and interfaces that are not completely contained in either the East or West region as well as load plus exports in either the East or West region.
- Any Operating Reserve charges attributable to generators operated on behalf of transmission owners for local constraints, or on behalf of generation owners for special unit constraints, are directly assessed to the applicable requesting party.
- PJM calculates for each Operating Day the synchronous condensing charges by allocating a pro-rata share of the total cost of synchronous condensing payments to PJM exports (excluding dynamically scheduled exports) with the remaining costs separately allocated based on PJM Region real-time load (excluding losses) ratio shares.
- PJM calculates for each Operating Day the total cost of reactive services for the purpose of maintaining reactive reliability. The cost of reactive services are allocated and charged to each market participant based on real-time load (excluding losses) ratio shares in the transmission zone(s) in which the reactive services were provided.

5.5 Reconciliation for Operating Reserve Charges

PJM will calculate reconciled Operating Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules



(in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Operating Reserve charge for Reliability reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the region (RTO, East, and West) by the Operating Reserve charge for Reliability billing determinants for that region and day. The daily Operating Reserve charge for Reliability billing determinant (in \$/MWh) for each region is calculated by dividing the total Balancing Operating Reserve charges for Reliability in that region by the total real-time load (de-rated for transmission losses) and real-time exports in that region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for Reliability for a month may be either a positive or a negative value.

PJM calculates the Reactive Services charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the transmission zone by the Reactive Services billing determinants for that zone and day. The daily Reactive Services billing determinant (in \$/MWh) for each transmission zone is calculated by dividing the total Reactive Services charge in that transmission zone by the total real-time load (de-rated for transmission losses) in that transmission zone for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for reactive services for a month may be either a positive or a negative value.

PJM calculates the Synchronous Condensing charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the PJM Region by the Synchronous Condensing billing determinants for that day. The daily Synchronous Condensing billing determinant (in \$/MWh) for the PJM Region is calculated by dividing the total Synchronous Condensing charges in the PJM Region by the total real-time load (de-rated for transmission losses) and real-time exports in the PJM Region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for synchronous condensing for a month may be either a positive or a negative value.



Section 6: Synchronized Reserve Accounting

Welcome to the *Synchronized Reserve Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how Synchronized Reserve are provided and accounted for in the PJM Energy Markets (see “*Synchronized Reserve Accounting Overview*”).
- How credits are calculated for providers of Synchronized Reserve (see “*Credits for Synchronized Reserve*”).
- How the total cost of Synchronized Reserve is allocated (see “*Charges for Synchronized Reserve*”).
- How Synchronized Reserve charge reconciliations are calculated (see “*Reconciliation for Synchronized Reserve Charges*”).

6.1 Synchronized Reserve Accounting Overview

Accounting for Synchronized Reserve is performed on an hourly basis. Synchronized Reserve shall be supplied from resources located within the metered boundaries of PJM. Resources participating in the reserve market are divided into two tiers. Tier 1 is comprised of all those resources on-line following economic dispatch and able to ramp up from their current output in response to a synchronized event. Tier 2 consists of the additional resources that are synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional synchronized reserve not available from Tier 1 resources. Synchronized Reserve resources include generators and demand side response resources.

The total PJM Synchronized Reserve Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid in accordance with the applicable NERC Council standards.

Tier 1 synchronized reserve credits are awarded to all resource owners whose resources increased output or decreased consumption in response to a synchronized reserve event (with the exception of those resources that were assigned Tier 2 synchronized reserve). Tier 2 synchronized reserve credits are awarded to all resource owners that have either self-scheduled synchronized reserve or sold synchronized reserve into the market.

Tier 1 synchronized reserve credits are equal to the integrated increase in MWh output or decrease in MWh of consumption from each resource over the length of a synchronized reserve event times the synchronized energy premium less the hourly integrated LMP. The synchronized energy premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus \$50/MWh

The synchronized reserve offer price for Tier 2 resources will be capped at a maximum value of the unit's O&M cost (as determined by the Cost Development Task Force) plus \$7.50/MWh.

If a unit is called on by PJM for the sole purpose of providing synchronized reserve, the unit is guaranteed recovery of all costs including start-up, no-load and minimum energy costs.



Resources that are assigned regulation when a synchronized reserve event is initiated will be compensated based on the amount of response provided beyond their regulation commitment, as well as for any response in excess of their regulation high limit or economic maximum (whichever is lower).

Each PJM Member LSE incurs a synchronized reserve obligation based on their hourly real-time load ratio share and applicable synchronized reserve zone's requirements during that hour. During hours when the Synchronized Reserve Clearing Price is the same throughout the PJM Region, an LSE's synchronized reserve obligation is equal to its real-time load ratio share times the amount of synchronized reserve assigned for the entire PJM Region. During hours when congestion causes the Synchronized Reserve Clearing Price to separate, each LSE's synchronized reserve obligation is equal to its real-time load ratio share within its synchronized reserve zone and the amount of synchronized reserve assigned in that synchronized reserve zone.

Participants may fulfill their synchronized reserve obligations by: owning Tier 1 resources from which PJM obtains synchronized reserve, self-scheduling owned Tier 2 resources, entering bilateral arrangements with other PJM market participants or purchasing synchronized reserve from the PJM synchronized reserve market.

6.2 Credits for Synchronized Reserve

At the end of each hour, PJM calculates the credits due each PJM Member for Synchronized Reserve.

PJM Actions:

- PJM retrieves the following information:
 - Synchronized Reserve Ramp rate for Tier 1 resources
 - Synchronized Reserve maximum for Tier 1 resources
 - Synchronized Reserve availability for Tier 2 resources
 - Synchronized Reserve offer quantity for Tier 2 resources (MW)
 - Synchronized Reserve offer price for Tier 2 resources (\$/MWh)
 - Energy use for condensing Tier 2 resources
 - Condense-to-generate startup cost
 - Synchronized Reserve bilateral transactions
 - 5-minute interval LMP data
 - Total PJM synchronized reserve requirement as determined in whole MWh for each hour of the operating day
- PJM calculates the hourly Synchronized Reserve credits for each Tier 1 resource as follows:
 - These credits are equal to the integrated increase in MW generator output (or decrease in MW consumption for demand side response resources) from each resource over the length of a synchronized reserve event times the



synchronized energy premium less the hourly integrated LMP. The synchronized energy premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus \$50/MWh. For demand side response resources when LMP is less than \$75, credits are based on a rate equal to the synchronized energy premium less the hourly integrated LMP and the applicable demand response retail rate.

- PJM calculates the hourly Synchronized Reserve credits for each Tier 2 resource as follows:
 - These credits are awarded to resource owners that have either self-scheduled synchronized reserve or sold synchronized reserve into the market.
 - Synchronized reserve credits for resources self-scheduled to provide synchronized reserve equal the Tier 2 clearing price times the resource's self-scheduled synchronized reserve capability.
 - Synchronized reserve credits for units that offered synchronized reserve into the market and were selected to provide synchronized reserve are the higher of: the Tier 2 clearing price times the resource's assigned synchronized reserve capability or the resource's synchronized reserve offer times its assigned synchronized reserve capability (plus opportunity cost, energy use costs, and startup costs incurred, for generators), as applicable.

6.3 Charges for Synchronized Reserve

The total cost of providing Synchronized Reserve for each hour is the sum of the credits provided to PJM Members for supplying Synchronized Reserve in that hour. The hourly cost of Tier 1 and Tier 2 Synchronized Reserve is allocated separately and charged to PJM Members.

PJM Actions:

- PJM calculates for each hour the Total Cost of Synchronized Reserve by summing the following credits for all PJM Members:
 - Total Tier 1 credits for Synchronized Reserve (\$)
 - Total Tier 2 credits for Synchronized Reserve (\$)
- PJM calculates for each hour each participants synchronized reserve obligation as determined by applying the real-time load ratio share (adjusted for load responsibility) in the applicable synchronized reserve zone to the total synchronized reserve assigned for that hour and then adding bilateral sales and subtracting bilateral purchases. Synchronized reserve charges are then determined for both the amount of Tier 1 applied to each participant's obligation and the amount of Tier 2 each participant purchased from the market.
- PJM calculates for each hour the Tier 1 charges by allocating the total cost of Tier 1 credits to each PJM Member based on their ratio share of Tier 1 synchronized reserve allocated to obligation. Note that Tier 1 charges will only exist if a synchronized reserve event occurs during a given hour.



- PJM calculates for each hour the Tier 2 charges as the appropriate hourly Tier 2 clearing price times the MW of Tier 2 self-scheduled toward the participant's obligation plus that which is purchased from the market, plus the participant's share of any unrecovered costs incurred by assigned Tier 2 resources over and above the Tier 2 clearing price, plus the participant's share of any unrecovered costs incurred by those units PJM committed for the sole purpose of providing synchronized reserve, plus the participant's share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour.

6.4 Reconciliation for Synchronized Reserve Charges

PJM will calculate reconciled Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Synchronized Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Synchronized Reserve billing determinants for that hour. The hourly Synchronized Reserve charge billing determinants (in \$/MWh) for each synchronized reserve zone and control area is calculated by dividing the total hourly Synchronized Reserve charges in that synchronized reserve zone by the total PJM real-time load (de-rated for transmission losses) in that synchronized reserve zone for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Synchronized Reserve charges for a month may be either a positive or a negative value.



Section 7: Transmission Congestion Accounting

Welcome to the *Transmission Congestion Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A general description of how charges and credits are calculated when the transmission system is scheduled or operated under constrained conditions (see “*Transmission Congestion Accounting Overview*”).
- How Transmission Congestion Charges are calculated (see “*Transmission Congestion Charges*”).
- How Transmission Congestion Credits are calculated (see “*Transmission Congestion Credits*”).

7.1 Transmission Congestion Accounting Overview

When the Transmission System is scheduled day-ahead or operating real-time under constrained conditions, PJM calculates Congestion Charges for each PJM Member. The basis for the Congestion Charge is the applicable day-ahead or real-time congestion price component of LMPs. PJM calculates day-ahead and real-time locational Congestion Prices each constrained hour, as specified in **Section 2** of this PJM Manual. Every PJM Member is charged for the cost of congestion on the Transmission System, based on the difference between the congestion price at the location on the Transmission System where the PJM Member injects energy and the congestion price at the location where the PJM Member withdraws energy.

The following calculations are performed:

- Day-ahead and Balancing Transmission Congestion Charges (implicit and explicit) for each PJM Member are calculated.
- FTR Target Allocations are determined and totaled for each FTR holder for each hour.
- The Total PJM Congestion Charges for the hour are calculated and allocated to FTR holders as Transmission Congestion Credits based on FTR Target Allocations.
- At the end of each month, any Excess Congestion Charges are distributed as additional Transmission Congestion Credits to FTR holders with Congestion Credit Deficiencies in that month or in previous months of the current planning period.
- Any remaining Congestion Credit Deficiencies (for ARRS and FTRs) remaining at the end of the planning period are satisfied by a reallocation of congestion credits that were provided in previous months of the planning period such that all months of the planning period are equal in their resulting deficiency percentages.
- Any Excess Congestion Charges that remain unallocated at the end of the planning period are used to satisfy any ARR deficiencies that may exist.



- Any Excess Congestion Charges that remain unallocated at the end of the planning period after the distribution to deficient ARR holders are allocated proportionately to FTR holders with net positive FTR target allocations for that planning period.

7.2 Transmission Congestion Charges

Transmission Congestion Charges are made up of two types:

- *Implicit* — Implicit Congestion Charges are the congestion charges associated with the congestion price differentials between the PJM Member's generation and scheduled purchases, netted out against its load (excluding losses) and scheduled sales.
- *Explicit* — Explicit Congestion Charges are the congestion charges associated with the congestion price differential from the scheduled source and sink of a transaction. The Transmission Customer pays the Congestion Charges for external transactions. The buyer pays the explicit Congestion Charges for internal transactions.

Transmission Congestion Charges can be both positive and negative.

7.2.1 Implicit Transmission Congestion Charges

Implicit Transmission Congestion Charges are the congestion charges for moving energy injections to energy withdrawals across a constrained system. They are derived by calculating an hourly Net Congestion Bill for each market participant's customer account.

The Net Congestion Bill value represents a PJM Member's total congestion obligation during a constraint, including both physical and scheduled energy. It is the difference between a PJM Member's total withdrawal congestion payment and its total injection congestion revenue. There are two primary components to the Day-ahead Net Congestion Bill.

- *Day-Ahead Injection Credits* — Day-ahead injection credits are calculated for all cleared generation and increment offers and day-ahead energy purchase transactions. Day-ahead injection credits are calculated at the generator bus congestion price, increment offer congestion price, or the congestion price at the sink of the purchase transaction, as applicable.
- *Day-Ahead Withdrawal Charges* — Day-ahead withdrawal charges are calculated for all cleared demand and decrement bids and day-ahead energy sale transactions. Day-ahead withdrawal charges are calculated at the load bus congestion price, decrement bid congestion price, or the congestion price at the source of the sale transaction, as applicable.

Each PJM Member's hourly day-ahead implicit congestion charges (positive or negative) is that hour's day-ahead net congestion bill, which equals their day-ahead withdrawal charges minus their day-ahead injection credits for that hour.

There are two primary components to the Balancing Net Congestion Bill.

- *Balancing Injection Credits* — Balancing injection credits are calculated for all deviations between a PJM Member's real-time generation and energy purchase



transactions and their day-ahead generation, increment, and energy purchase transactions. Balancing injection credits are calculated for each bus at which a real-time deviation from its day-ahead scheduled injection exists using the congestion price at that bus.

- **Balancing Withdrawal Charges** — Balancing withdrawal charges are calculated for all deviations between a PJM Member's real-time load (de-rated for transmission losses) and energy sale transactions and their day-ahead demand, decrement, and energy sale transactions. Balancing withdrawal charges are calculated for each bus at which a real-time deviation from its day-ahead scheduled withdrawal exists using the congestion price at that bus.

Each PJM Member's hourly balancing implicit congestion charges (positive or negative) is that hour's balancing net congestion bill, which equals their balancing withdrawal charges minus their balancing injection credits for that hour.

PJM Actions:

- PJM retrieves the following information:
 - demand and decrement bids cleared day-ahead (MWh)
 - generation schedules and increment offers cleared day-ahead (MWh)
 - each PJM Member's percentage of joint owned units (% ownership)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly state estimator MWh for each load bus (trued up to match revenue meter data from eMTR, if available)
 - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from eMTR, if available)
 - hourly day-ahead and real-time Congestion Prices (\$/MWh)
- PJM calculates the day-ahead withdrawal charges for each PJM Member for each of their day-ahead demand, decrement, and sale transactions as follows:

*Day-ahead withdrawal Charge = Day-ahead Demand MWh * Day-ahead Load Bus Congestion Price*

OR

*Decrement Transaction MWh * Day-ahead Congestion Price*

OR

*Day-ahead Sale Transaction MWh * Source Day-ahead Congestion Price*

- PJM calculates day-ahead injection credits for each PJM Member for each of their day-ahead generation, increment, and purchase transactions as follows:

*Day-ahead Injection Credit = Day-ahead Generation MWh * % Ownership * Day-ahead Gen Bus Congestion Price*

OR

*Increment Transaction MWh * Day-ahead Congestion Price*

OR



*Day-ahead Purchase Transaction MWh * sink Day-ahead Congestion Price*

- PJM calculates each PJM Member's hourly Day-ahead Net Congestion Bill as the sum of their day-ahead withdrawal charges minus the sum of their day-ahead injection credits.
- PJM calculates each PJM Member's hourly Day-ahead Implicit Congestion Charge as:

Day-ahead Implicit Congestion Charge = Day-ahead Net Congestion Bill

Note: Day-ahead implicit congestion charges are only calculated for market participants whose day-ahead spot market interchange includes actual or scheduled sources or sinks that reflect different congestion prices.

- PJM calculates the hourly balancing withdrawal charges for each PJM Member for each bus as follows:

*Balancing Withdrawal Charge = (Real-time loss de-rated Load MWh + Real-time Sale Transaction MWh – Day-ahead Demand MWh – Decrement Transaction MWh – Day-ahead Sale Transaction MWh) * Real-Time Bus Congestion Price*

- PJM calculates hourly balancing injection credits for each PJM Member for each bus as follows:

*Balancing Injection Credit = (Real-time Generation MWh * % Ownership + Real-time Purchase Transaction MWh – Day-ahead Generation MWh * % Ownership – Increment Transaction MWh – Day-ahead Purchase Transaction MWh) * Real-Time Bus Congestion Price*

- PJM calculates each PJM Member's hourly Balancing Net Congestion Bill as the sum of their balancing withdrawal charges minus the sum of their balancing injection credits.
- PJM calculates each PJM Member's hourly Balancing Implicit Congestion Charge as:

Balancing Implicit Congestion Charge = Balancing Net Congestion Bill

Note: Balancing implicit congestion charges are only calculated for market participants whose real-time spot market interchange includes actual or scheduled sources or sinks that reflect different congestion prices.

7.2.2 Explicit Transmission Congestion Charges

Explicit Transmission Congestion Charges are the congestion charges for moving energy across the Transmission System during a constraint. Explicit congestion charges equal the difference between the source and sink Congestion Prices of a transaction. (Explicit congestion charges are not included in the Net Congestion Bill calculations.)

- *Internal Purchases* — For internal purchases, the Explicit Congestion Charges are calculated based on the differences in Congestion Prices between their sink



buses and source buses. The buyer pays the Explicit Congestion Charges associated with an internal transaction.

- *Import & Export Transactions* — For point-to-point and network secondary transmission customers, the Explicit Congestion Charges are calculated based on the difference between the sink Congestion Price and the source Congestion Price. The Transmission Customer pays the explicit Congestion Charges associated with an import or export transaction.

PJM Actions:

- PJM retrieves the following information:
 - transmission service reservations (MW, period, and source/sink)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly day-ahead and real-time Congestion Prices (\$/MWh)
- PJM calculates the hourly Day-ahead Explicit Congestion Charge for each transaction as:

$$\text{Day-ahead Explicit Congestion Charge} = \text{Day-ahead Transaction MWh} * (\text{Sink Day-ahead Congestion Price} - \text{Source Day-ahead Congestion Price})$$

- PJM calculates the hourly Balancing Explicit Congestion Charge for each transaction as:

$$\text{Balancing Explicit Congestion Charge} = (\text{Real-time Transaction MWh} - \text{Day-ahead Transaction MWh}) * (\text{Sink Real-time Congestion Price} - \text{Source Real-time Congestion Price})$$

7.3 Reconciliation for Transmission Congestion Charges

PJM will calculate reconciled Transmission Congestion charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Transmission Congestion charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the real-time Congestion Price at the aggregate sink bus associated with the eSchedules contract for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Congestion charges for a month may be either a positive or a negative value.

7.4 Transmission Congestion Credits

Each market participant who holds Financial Transmission Rights receives Transmission Congestion Credits, which is a share of the total Day-ahead and Balancing Congestion Charges collected for each constrained hour. Each FTR holder's Transmission Congestion Credits are calculated based upon the Financial Transmission Rights (FTRs) it holds.



7.4.1 FTRs and FTR Target Allocations

An FTR is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the Transmission System is congested and differences in day-ahead Congestion Prices result. The purpose of an FTR is to protect the holder from increased energy costs due to transmission congestion. Each FTR is defined from a point of receipt to a point of delivery. For each hour in which congestion exists on the day-ahead Transmission System between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Total PJM Congestion Charges collected from the Market Participants. An FTR's value, therefore, is related to Transmission Congestion Charges. (See the *PJM Manual for Financial Transmission Rights* for more information.)

FTR Target Allocations are the amounts of credit each FTR holder should receive in each constrained hour due to the value of its FTRs. The FTR Target Allocation is calculated for each FTR in each hour by multiplying the MW value of the FTR times the sink Day-ahead Congestion Price minus the source Day-ahead Congestion Price. The total FTR Target Allocation for each FTR holder is the sum of the FTR Target Allocations for all FTRs that it holds. A market participant's net FTR Target Allocation for an hour may be either a positive or a negative value.

7.4.2 Total PJM Congestion Charges

The Total PJM Congestion Charges are the sum of the Day-ahead and Balancing Congestion Charges for all PJM Members, adjusted for the value of day-ahead and balancing congestion revenues due to inadvertent interchange, losses, and the MISO joint operating agreement coordination, minus the negatively valued FTR Target Allocations. The Congestion Charges paid in the Spot Market are the total Spot Market purchase payments minus the total Spot Market sale revenues.

PJM Actions:

- PJM calculates the hourly Total PJM Congestion Charges by summing the following:
 - day-ahead and balancing implicit congestion charges (\$)
 - day-ahead and balancing explicit congestion charges (\$)
 - inadvertent interchange congestion value (\$)
 - transmission losses congestion value (\$)
 - MISO joint operating agreement congestion value (\$)
- And then subtracting:
 - the total of all market participants' FTR Target Allocations where the net total FTR Target Allocation for that customer in the hour is a negative value (\$)



7.4.3 Hourly Allocation of Total PJM Congestion Charges

Total PJM Congestion Charges (including the net difference in interchange and negative Target Allocations) are allocated back to FTR holders based on their positive FTR Target Allocations. Market participants with negative FTR Target Allocations will always receive 100% of their FTR Target Allocations as negative Transmission Congestion Credits. The inclusion of these negative credits in the calculation of Total PJM Congestion Charges effectively increases the amount that is available to be allocated as credits to the FTR holders with positive FTR Target Allocations.

If the Total PJM Congestion Charges for an hour are greater than the total positive FTR Target Allocations, then there will be funds remaining in the hour after the distribution of Transmission Congestion Credits. These funds are called Excess Congestion Charges. Sometimes the calculation of Total PJM Congestion Charges for an hour can result in a negative value. When this occurs, no positive Transmission Congestion Credits would be awarded, and the Total PJM Congestion Charges for the hour would be treated as negative excess congestion charges. The hourly Excess Congestion Charges and the hourly negative Total PJM Congestion Charges are accumulated for the month to be distributed in a second allocation at the end of the month.

PJM Actions:

- PJM accounting process retrieves the following information:
 - hourly Total PJM Congestion Charge (\$)
 - each market participant's hourly FTR Target Allocations (\$)
- PJM accounting process calculates the total positive FTR Target Allocation by summing the following values:
 - sum of all market participants' FTR Target Allocations where the net total FTR Target Allocation for that customer in the hour is a positive value
- If the Total PJM Congestion Charge is a positive value that is greater than or equal to the total positive FTR Target Allocation for the hour, the Transmission Congestion Credits for each FTR holder is equal to its FTR Target Allocations and the Congestion Credit Deficiency for each FTR holder is zero. The Excess Congestion Charge is equal to the Total PJM Congestion Charge minus the Total positive FTR Target Allocations.
- If the Total PJM Congestion Charge is a positive value that is less than the total positive FTR Target Allocation for the hour, then the Transmission Congestion Credit for each market participant is equal to that market participant's FTR Target Allocation multiplied by the Total PJM Congestion Charge and divided by the Total PJM positive FTR Target Allocations if the market participant's FTR Target Allocation is a positive value, and is equal to 100% of the market participant's FTR Target Allocation if the market participant's FTR Target Allocation is a negative value. Each market participant's hourly Congestion Credit Deficiency is calculated as its FTR Target Allocation minus its hourly Transmission Congestion Credit.



- If the Total PJM Congestion Charge is a negative value, then the Transmission Congestion Credit for each market participant is equal to 100% of that market participant's FTR Target Allocation if the Transmission Customer's FTR Target Allocation is a negative value, and is equal to \$0.00 if the market participant's FTR Target Allocation is a positive value. Each market participant's hourly Congestion Credit Deficiency is equal to its FTR Target Allocation if the FTR Target Allocation is a positive value.

7.4.4 Monthly Allocation of Excess Congestion Charges

The objectives of the monthly Excess Congestion Charge distribution are to cover any deficiency in Transmission Congestion Credits received by each FTR holder when compared to its FTR Target Allocations, and to distribute any remaining excess at the end of the planning period first to ARR holders in proportion to ARR deficiencies and then to Network and Firm Transmission Customers. The monthly allocation is performed in five stages.

- *Stage One* — If Unscheduled Transmission Service revenues were received during the month, these charges would be allocated as additional Transmission Congestion Credits to FTR holders in proportion to, but not greater than, the total of the Congestion Credit Deficiencies in the hour to which the Unscheduled Transmission Service charge applied. Congestion Credit Deficiencies for the hour are then recalculated as a result of this allocation. Any remaining Unscheduled Transmission Service charge that cannot be allocated in the applicable hour is added to the Excess Congestion Charge for that hour. Likewise, any revenues paid to or received from MISO for JOA market-to-market congestion relief measures are also applied to the applicable hours' congestion revenues.

PJM calculates the monthly total Excess Congestion Charge by summing the Excess Congestion Charge for each hour of the month and subtracting the Total Congestion Charge for each hour of the month in which the Total Congestion Charge was negative. PJM then distributes the monthly Total Excess Congestion Charge plus any net annual or monthly FTR Auction revenues in excess of ARR Target Allocations for that month as additional Transmission Congestion Credits to each FTR holder in proportion to, but not greater than, the sum of the hourly Congestion Credit Deficiencies in that month. If the monthly total Excess Congestion Charge is a negative value, no additional Transmission Congestion Credits can be allocated, and the negative monthly total Excess Congestion Charge would be allocated as a positive charge to Day-Ahead Operating Reserve.

PJM calculates the final monthly Congestion Credit Deficiency for each FTR holder as the difference between the sum of the Transmission Customer's total FTR Target Allocations for the month minus the sum of all Transmission Congestion Credits distributed either hourly or monthly to that FTR holder.

- *Stage Two* — If there is any monthly total Excess Congestion Charge remaining after the stage one distribution, PJM distributes that remaining excess as additional Transmission Congestion Credits to each FTR holder in proportion to, but not greater than, the final monthly Congestion Credit Deficiencies from previous months of that PJM planning period (June 1 to May 31). The final



monthly Congestion Credit Deficiencies for each FTR holder in each month are then updated to reflect the additional Transmission Congestion Credits received.

- *Stage Three* — If any monthly total Excess Congestion Charge remains after the stage two distribution, that remaining excess is carried forward to be allocated to FTR holders with monthly Congestion Credit Deficiencies in future months of the PJM planning period.
- *Stage Four* — At the end of the PJM planning period, PJM distributes any Excess Congestion Charges remaining after the stage three distribution to ARR holders in proportion to any ARR deficiency that may exist over such period.
- *Stage Five* — At the end of the PJM planning period, any Excess Congestion Charges remaining after the stage four distribution are allocated proportionately to FTR holders with net positive FTR target allocations for that planning period.

7.5 Reassignment of Financial Transmission Rights (FTRs)

A transitional FTR Allocation will be conducted for new zone load being added as a result of new market integration. This transitional allocation of FTRs will cover the period of time between the implementation of the new zone added and the next Annual ARR Allocation in which the new member elects to participate. The new member, at their election, will have until the second Annual FTR Auction after they join PJM to participate in the Annual FTR Auction.

For a transitional period, Network and Firm Transmission Customers that take service that sinks in new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into the PJM interchange energy market. The election of a direct FTR Allocation shall be made prior to the commencement of each Annual FTR Auction.

Network and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights may receive allocations of Auction Revenue Rights. Network and Firm Transmission Customers in new PJM zones must choose to receive either an FTR Allocation or an ARR Allocation. A Network or Firm Transmission Customer cannot choose to receive both an FTR Allocation and an ARR Allocation.

FTRs allocated for the transition period will be reassigned on a proportional basis within a transmission zone or load aggregation zone as load switches between LSEs within the transition period. The reassignment of FTRs is an automatic process, which is conducted by PJM on a daily basis (or as frequently as necessary). An LSE that loses load will lose a pro-rata share of their FTRs in proportion to the amount of load lost.

The total set of FTRs lost by LSEs losing load in a transmission zone or load aggregation zone will be reallocated to LSEs gaining load in the zone or load aggregation zone in proportion to each LSEs MW load gain relative to the total load shifted in the zone or load aggregation zone.



Section 8: Transmission Losses Accounting

Welcome to the *Transmission Losses Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- How transmission losses are accounted for (see “*Transmission Losses Accounting Overview*”).
- How market participants are charged for losses (see “*Transmission Loss Charges*”).
- How PJM market participants receive credits for the collected loss charges (see “*Transmission Loss Credits*”).
- How transmission loss charge reconciliations are calculated (see “*Reconciliation for Transmission Loss Charges*”).
- How transmission loss credit reconciliations are calculated (see “*Reconciliation for Transmission Loss Credits*”).

8.1 Transmission Losses Accounting Overview

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines, and other transmission facilities. Only the losses incurred on facilities included in the PJM network model and, therefore, reflected in the PJM State Estimator are included in the PJM settlements for transmission losses.

PJM calculates Transmission Loss Charges for each PJM Member. The basis for the Loss Charge is the applicable day-ahead or real-time loss price component of LMPs. PJM calculates day-ahead and real-time locational Loss Prices each hour, as specified in **Section 2** of this PJM Manual. Every PJM Member is charged for the cost of losses on the Transmission System, based on the difference between the loss price at the location on the Transmission System where the PJM Member injects energy and the loss price at the location where the PJM Member withdraws energy.

The following calculations are performed:

- Day-ahead and Balancing Transmission Loss Charges (implicit and explicit) for each PJM Member are calculated.
- The Total PJM Loss Charges for the hour are calculated and allocated as Transmission Loss Credits based on load (excluding losses) plus export plus Up-To Congestion transaction ratio shares, where exports and Up-To Congestion transactions are only those that pay for transmission service.

8.2 Transmission Loss Charges

Transmission Loss Charges are made up of two types:

- *Implicit* — Implicit Loss Charges are the loss charges associated with the loss price differentials between the PJM Member’s generation and scheduled purchases, netted out against its load (excluding losses) and scheduled sales.



- *Explicit* — Explicit Loss Charges are the loss charges associated with the loss price differential from the scheduled source and sink of a transaction. The Transmission Customer pays the Loss Charges for external transactions. The buyer pays the explicit Loss Charges for internal transactions.

Transmission Loss Charges can be both positive and negative.

8.2.1 Implicit Transmission Loss Charges

Implicit Transmission Loss Charges are the loss charges for moving energy injections to energy withdrawals across the system. They are derived by calculating an hourly Net Loss Bill for each market participant's customer account.

The Net Loss Bill value represents a PJM Member's total loss obligation, including both physical and scheduled energy. It is the difference between a PJM Member's total withdrawal loss payment and its total injection loss revenue. There are two primary components to the Day-ahead Net Loss Bill.

- *Day-Ahead Injection Credits* — Day-ahead injection credits are calculated for all cleared generation and increment offers and day-ahead energy purchase transactions. Day-ahead injection credits are calculated at the generator bus loss price, increment offer loss price, or the loss price at the sink of the purchase transaction, as applicable.
- *Day-Ahead Withdrawal Charges* — Day-ahead withdrawal charges are calculated for all cleared demand and decrement bids and day-ahead energy sale transactions. Day-ahead withdrawal charges are calculated at the load bus loss price, decrement bid loss price, or the loss price at the source of the sale transaction, as applicable.

Each PJM Member's hourly day-ahead implicit loss charges (positive or negative) is that hour's day-ahead net loss bill, which equals their day-ahead withdrawal charges minus their day-ahead injection credits for that hour.

There are two primary components to the Balancing Net Loss Bill.

- *Balancing Injection Credits* — Balancing injection credits are calculated for all deviations between a PJM Member's real-time generation and energy purchase transactions and their day-ahead generation, increment, and energy purchase transactions. Balancing injection credits are calculated for each bus at which a real-time deviation from its day-ahead scheduled injection exists using the loss price at that bus.
- *Balancing Withdrawal Charges* — Balancing withdrawal charges are calculated for all deviations between a PJM Member's real-time load (de-rated for transmission losses) and energy sale transactions and their day-ahead demand, decrement, and energy sale transactions. Balancing withdrawal charges are calculated for each bus at which a real-time deviation from its day-ahead scheduled withdrawal exists using the loss price at that bus.

Each PJM Member's hourly balancing implicit loss charges (positive or negative) is that hour's balancing net loss bill, which equals their balancing withdrawal charges minus their balancing injection credits for that hour.



PJM Actions:

- PJM retrieves the following information:
 - demand and decrement bids cleared day-ahead (MWh)
 - generation schedules and increment offers cleared day-ahead (MWh)
 - each PJM Member's percentage of joint owned units (% ownership)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly state estimator MWh for each load bus (trued up to match revenue meter data from eMTR, if available)
 - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from eMTR, if available)
 - hourly day-ahead and real-time Loss Prices (\$/MWh)

- PJM calculates the day-ahead withdrawal charges for each PJM Member for each of their day-ahead demand, decrement, and sale transactions as follows:

$$\text{Day-ahead withdrawal Charge} = \text{Day-ahead Demand MWh} * \text{Day-ahead Load Bus Loss Price}$$

OR

$$\text{Decrement Transaction MWh} * \text{Day-ahead Loss Price}$$

OR

$$\text{Day-ahead Sale Transaction MWh} * \text{Source Day-ahead Loss Price}$$

- PJM calculates day-ahead injection credits for each PJM Member for each of their day-ahead generation, increment, and purchase transactions as follows:

$$\text{Day-ahead Injection Credit} = \text{Day-ahead Generation MWh} * \% \text{ Ownership} * \text{Day-ahead Gen Bus Loss Price}$$

OR

$$\text{Increment Transaction MWh} * \text{Day-ahead Loss Price}$$

OR

$$\text{Day-ahead Purchase Transaction MWh} * \text{sink Day-ahead Loss Price}$$

- PJM calculates each PJM Member's hourly Day-ahead Net Loss Bill as the sum of their day-ahead withdrawal charges minus the sum of their day-ahead injection credits.
- PJM calculates each PJM Member's hourly Day-ahead Implicit Loss Charge as:

$$\text{Day-ahead Implicit Loss Charge} = \text{Day-ahead Net Loss Bill}$$

8.2.2 Explicit Transmission Loss Charges

Explicit Transmission Loss Charges are the loss charges for moving energy across the Transmission System. Explicit loss charges equal the difference between the source and sink Loss Prices of a transaction. (Explicit loss charges are not included in the Net Loss Bill calculations.)



- *Internal Purchases* — For internal purchases, the Explicit Loss Charges are calculated based on the differences in Loss Prices between their sink buses and source buses. The buyer pays the Explicit Loss Charges associated with an internal transaction.
- *Import & Export Transactions* — For point-to-point and network secondary transmission customers, the Explicit Loss Charges are calculated based on the difference between the sink Loss Price and the source Loss Price. The Transmission Customer pays the explicit Loss Charges associated with an import or export transaction.

PJM Actions:

- PJM retrieves the following information:
 - transmission service reservations (MW, period, and source/sink)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly day-ahead and real-time Loss Prices (\$/MWh)
- PJM calculates the hourly Day-ahead Explicit Loss Charge for each transaction as:

$$\text{Day-ahead Explicit Loss Charge} = \text{Day-ahead Transaction MWh} * (\text{Sink Day-ahead Loss Price} - \text{Source Day-ahead Loss Price})$$

- PJM calculates the hourly Balancing Explicit Loss Charge for each transaction as:

$$\text{Balancing Explicit Loss Charge} = (\text{Real-time Transaction MWh} - \text{Day-ahead Transaction MWh}) * (\text{Sink Real-time Loss Price} - \text{Source Real-time Loss Price})$$

8.3 Reconciliation for Transmission Loss Charges

PJM will calculate reconciled Transmission Loss charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Transmission Loss charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the real-time Loss Price at the aggregate sink bus associated with the eSchedules contract for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Loss charges for a month may be either a positive or a negative value.

8.4 Transmission Loss Credits

The total amount of both day-ahead and balancing hourly transmission losses charges, adjusted for the value of day-ahead and balancing spot market losses and loss revenues due to inadvertent interchange is allocated among the PJM market participants in proportion



to their real-time load (de-rated for transmission losses) plus their real-time PJM exports (that pay for transmission service) plus their Up-To Congestion transactions (that pay for transmission service) as a percentage of the total PJM load (excluding losses), exports, and Up-To Congestion transactions.

PJM Actions:

- PJM accounting process retrieves the following information:
 - hourly real-time load (excluding losses) for each LSE (MWh)
 - hourly real-time PJM export schedules for each market participant (MWh)
 - hourly day-ahead Up-To Congestion transactions for each market participant (MWh)
 - hourly export and Up-To Congestion transaction links to transmission service reservations
 - transmission service reservations (MW, period, type, and source/sink)
 - each market participant's day-ahead and balancing loss charges (\$)
 - spot market loss value (\$)
 - inadvertent interchange loss value (\$)
- PJM accounting process calculates the total hourly transmission loss charges by summing the day-ahead and balancing loss charges for each market participant plus the spot market value of losses, including an adjustment for the inadvertent interchange loss value.
- PJM accounting process calculates the hourly real-time load (excluding losses) plus export plus Up-To Congestion transaction ratio of each market participant.
- PJM includes only Up-To Congestion transaction MWh that pay for transmission service. PJM compares the Up-To Congestion transaction MWh to the linked transmission service reservation capacity MW for the hour. The hourly Up-To Congestion Transaction MWh used in this calculation is capped at the hourly reservation capacity amount.
- PJM includes only export transaction MWh that pay for transmission service. PJM compares the export transaction MWh to the linked transmission reservation capacity MW for the hour (recognizing ramping and time zone shifts) to ensure that the export transaction MWh do not exceed the linked transmission service capacity MW.
- PJM accounting process allocates the total hourly loss charges as hourly transmission loss credits for each market participant based on their hourly real-time load (excluding losses) plus export plus Up-To Congestion transaction ratio share.

8.5 Reconciliation for Transmission Loss Credits

PJM will calculate reconciled Transmission Loss credits for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings that were based



on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.

PJM calculates the Transmission Loss credit reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Transmission Loss Credit billing determinant for that hour. The hourly Transmission Loss Credit billing determinants (in \$/MWh) are calculated by dividing the total day-ahead and balancing transmission loss revenues for an hour by the total PJM real-time load (de-rated for transmission losses) and exports (that pay for transmission service) and Up-To Congestion transactions (that pay for transmission service) in that hour. These credit reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Loss credits for a month may be either a positive or a negative value.



Section 9: Emergency Energy Accounting

Welcome to the *Emergency Energy Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of the types of Emergency energy transactions and how they are accounted for (see “*Emergency Energy Accounting Overview*”).
- How Emergency energy purchases from other Control Areas are accounted for (see “*Emergency Energy Purchases by PJM*”).
- How Emergency energy sales to other Control Areas are accounted for (see “*Emergency Energy Sales by PJM*”).
- How Minimum Generation Emergency purchases from other Control Areas are accounted for (see “*Minimum Generation Emergency Purchases by PJM*”).
- How Minimum Generation Emergency sales to other Control Areas are accounted for (see “*Minimum Generation Emergency Sales by PJM*”).

9.1 Emergency Energy Accounting Overview

PJM may purchase energy from outside PJM as needed to alleviate or end an Emergency, and may sell energy to another Control Area as requested during Emergency conditions in that Control Area. Emergencies may be reserve deficiencies or Minimum Generation (low load) Emergencies.

Emergency energy sales to other Control Areas are priced at 150% of the real-time LMP at the bus or busses at the border of PJM at which the energy is delivered.

Minimum Generation Emergency energy sales to other Control Areas are priced at a mutually agreed upon price not to exceed the real-time LMP at the bus or busses at the border of PJM at which the energy is delivered.

9.2 Emergency Energy Purchases by PJM

The net cost in excess of real-time LMPs of Emergency energy purchased is allocated to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.

If generator reductions are requested by PJM for reliability during hours of Emergency energy purchases, the reduced MWh are used to reduce that PJM Market Participants' charge allocation.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy purchase transactions (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)



- hourly list of integrated real-time bus LMPs (\$)
- PJM's designated interface points with adjacent Control Areas
- PJM calculates the total charges to be allocated among PJM Market Participants for each Emergency energy purchase as:

*Emergency Energy Purchase (MWh) **

(Emergency Energy Purchase Price – Real-Time Interface LMP)

- PJM allocates the total hourly charge for Emergency energy purchases to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.
- A billing adjustment is calculated, as applicable, to exempt any MWh of generator reductions requested by PJM for reliability during any hours of Emergency energy purchases.

9.3 Emergency Energy Sales by PJM

The net revenues in excess of real-time LMPs of Emergency energy sales is credited to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales, plus any energy sales from within PJM to entities outside of PJM that have been curtailed by PJM during the Emergency.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy sales (\$, MWh)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly integrated real-time bus LMPs (\$)
 - PJM interface points with adjacent Control Areas
 - External sales that are curtailed by PJM during Emergency energy sales
- PJM calculates the total credits to be allocated among PJM Market Participants for each Emergency energy sale as:

*Emergency Energy Sale (MWh) * (Emergency Energy Sale Price – Real-Time Interface LMP)*

- PJM allocates the total hourly credit for Emergency energy sales among PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales, plus any energy sales from within PJM to entities outside of PJM that have been curtailed by PJM during the Emergency.



9.4 Minimum Generation Emergency Purchases by PJM

The net cost of Minimum Generation Emergency energy purchased is allocated to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy minimum purchases (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly integrated real-time LMPs (\$)
 - PJM interface points with adjacent control areas
- PJM calculates the total charges to be allocated among PJM Market Participants for each Minimum Generation Emergency energy purchase as:

$$\text{Minimum Generation Emergency Energy Purchase (MWh)} * (\text{Emergency Energy Purchase Price} - \text{Real-Time Interface LMP})$$

- PJM allocates the total hourly charge for Minimum Generation Emergency purchases to PJM Market Participants in proportion to their real-time deviation from the net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

9.5 Minimum Generation Emergency Sales by PJM

The net revenues in connection with Minimum Generation Emergency energy sales to other Control Areas are credited to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy minimum sales (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly integrated real-time bus LMPs (\$)
 - PJM interface points with adjacent Control Areas
- PJM calculates the total credits to be allocated among PJM Market Participants for each Minimum Generation Emergency energy sale as:

$$\text{Minimum Generation Emergency Energy Sale (MWh)} *$$



(Emergency Energy Sale Price – Real-Time Interface LMP)

- PJM allocates the total hourly credit for Minimum Generation Emergency energy sales among PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.



Section 10: PJM Load Response Programs Accounting

Welcome to the *PJM Load Response Programs Accounting* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- An overview of PJM Load Response Programs (see “*PJM Load Response Programs Overview*”).
- A description of the accounting procedure for the PJM Load Response Programs (see “*PJM Load Response Programs Accounting Procedures*”).

10.1 PJM Load Response Programs Overview

The PJM Load Response Programs are designed to provide an incentive to end-use customers or curtailment service providers (“CSP”) to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices (“LMP”) are high or when an emergency event occurs. PJM offers two different types of Load Response Programs, the Emergency Load Response Program and the Economic Load Response Program.

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.

The Economic Load Response Program is designed to provide incentive to end-use customers or curtailment service providers (“CSP”) to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices (“LMP”) are high.

10.2 PJM Load Response Programs Accounting Procedures

10.2.1 Emergency Load Response Program

Under the Emergency Load Response Program, payment for reducing load is based on the actual kWh relief provided plus an adjustment for losses. PJM pays the appropriate zonal or aggregate Locational Marginal Price (LMP) to the PJM Member that nominates the load. Payment will be equal to the measured reduction adjusted for losses times the appropriate zonal Locational Marginal Price (LMP). If, however, the sum of the hourly energy payments to a participant dispatched by PJM is not greater than or equal to the value of the standing offer price for actual, achieved reductions, then the CSP will be made whole up to the value of the standing offer for the actual, achieved reductions.

The measured reduction of both Energy Only and Full Emergency Load Response Program participants can be either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction. The reduction of the Full Emergency Load Response participant, for purposes of capacity credit, will be the Guaranteed Load Drop or the reduction committed to achieve the Firm Service Level as calculated according to the ALM formula. The reduction of the Full Emergency Load Response Participant that nominates Direct Load Control will be calculated as provided in the Load Data Systems Manual for purposes of both energy payment and capacity credit.



Full Emergency Load Response participants that fail to provide a load reduction dispatched by PJM shall be assessed the ALM Deficiency Charge. The ALM Deficiency Charge shall equal the lesser of the Compliance Deficiency Value X the Daily Capacity Deficiency Rate X 365/10, or the Compliance Deficiency Value X two (2) times the Annual Value of the Capacity Credit divided by a factor of 5. The Annual Value of the Capacity Credit shall equal the weighted average of the clearing prices for the three (3) planning period capacity credit markets run prior to the beginning of the Planning Period.

During Emergency conditions, costs for Emergency purchases in excess of LMP are allocated to PJM Market Participants in proportion to their increase in net purchases from the PJM energy market during the hour in the real-time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under the Emergency Load Response Program are allocated to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's load reduction meter data
 - EDC loss de-rating factors
 - loss factor
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly list of integrated real-time LMPs (\$)
- PJM calculates the total credits for each PJM Market Participant in the Emergency Load Response Program as:

*(Actual kWh relief provided de-rated for transmission losses + an adjustment for losses) **

(Appropriate real-time zonal LMP or aggregate LMP)

- PJM allocates the total hourly charge for the Emergency Load Response Program to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.

10.2.2 Economic Load Response Program

Under the Economic Load Response Program, Market Participants have the option to submit load response bids in the day-ahead market or may chose to commit to a reduction of load they draw from the system during times of high prices and receive payments based on real-time LMP for the reductions.

Day-Ahead Operations:

PJM will accept demand reduction bids from an end-use customer or its representative CSP for a specific MW curtailment (in minimum increments of .1 MW or 100 kW). The demand



reduction bid will include the day-ahead LMP above which the end-use customer would not consume, and could also include shut-down costs and/or the number of contiguous hours for which the load reduction must be committed.

Reimbursement for reducing load is based on the reductions of MWh committed in the day-ahead market. An end-use customer or representative CSP that submits a load reduction bid day-ahead that is accepted by PJM when the day-ahead LMP is less than \$75/MWh will be paid by PJM the day-ahead LMP less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are those charges the participant would have otherwise paid the LSE absent the load reduction. PJM shall recover LMP less an amount equal to the applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced.

In all cases, the applicable zonal or aggregate LMP is used as appropriate for the individual end-use customer.

An end-use customer or representative CSP that submits a load reduction bid day-ahead that is accepted by PJM when the day-ahead LMP is greater than or equal to \$75/MWh will be paid by PJM the day-ahead LMP. PJM shall recover LMP less an amount equal to the applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to generation and transmission charges, if any, will be recovered from all cleared day-ahead demand bids within the zone in which the load that was reduced. If the total amount of recoverable charges reflecting the generation and transmission charges for the entire program exceeds \$17.5 million in a year, thereafter participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP.

Total payments to end-use customers or their representative CSP for accepted day-ahead Economic Load Response bids will not be less than the total value of the load response bid, included any submitted shut-down costs. Any shortfall will be made up through normal, day-ahead operating reserve.

End-use customers or their representative CSP that have load reductions committed in the day-ahead market that cannot demonstrate hourly performance in real-time equal to at least that of the day-ahead commitment will be charged real-time LMP for the amount of the shortfall, plus any associated balancing operating reserve charges. LSEs that otherwise would have load that was reduced shall receive any associated operating reserve credits plus, if real-time LMP is higher than day-ahead LMP during the shortfall, the difference between day-ahead and real-time LMP times the shortfall.

End-use customers or their representative CSP that have load reductions committed in the day-ahead market that have hourly performance in real-time greater than that of the day-ahead commitment will be credited for the additional load response according to the Real-Time Economic Load accounting process.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's cleared day-ahead scheduled load reduction quantities
 - each PJM Market Participant's actual metered reduction



- o EDC loss de-rating factors
- o each PJM Market Participant's cleared day-ahead demand bids
- o associated shut-down costs
- o hourly list of integrated day-ahead LMPs (\$)
- o retail rate (generation and transmission)
- If the day-ahead LMP is less than \$75/MWh, PJM shall recover day-ahead LMP less an amount equal to the applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced as:
 - Cleared Day-ahead MWh load reduction * (Day-ahead LMP – retail rate)*
- Payment will be made by PJM to the end-use customer or its representative (CSP) as:
 - Cleared Day-ahead MWh load reduction * (Day-ahead LMP – retail rate)*
- If the day-ahead LMP is greater than or equal to \$75/MWh, PJM shall recover an amount equal to the applicable generation and transmission charges from all LSE's with cleared day-ahead demand bids in the zone of the load reduction. PJM shall recover the remaining amount, LMP less an amount equal to the generation and transmission charges from the LSE that otherwise would have the load that was reduced as:

LSE that otherwise would have the load that was reduced:

$$\text{Cleared Day-ahead MWh load reduction} * (\text{Day-ahead LMP} - \text{retail rate})$$

All LSE's in the zone of the load reduction:

$$(\text{Generation and transmission charges}) * \left[\frac{\text{Participant's total cleared day-ahead demand bid in zone}}{\text{Total cleared day-ahead demand bids in zone}} \right]$$

Payment will be made by PJM to the end-use customer or its representative (CSP) as:

$$\text{Cleared Day-Ahead MWh load reduction} * \text{Day-ahead LMP}$$

- If the total amount of recoverable charges reflecting the generation and transmission charges for the entire program exceeds \$17.5 million in a year, thereafter participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP.

LSE that otherwise would have the load that was reduced:

$$\text{Cleared Day-ahead MWh load reduction} * \text{Day-ahead LMP}$$

Payment will be made by PJM to the end-use customer or its representative (CSP) as:



*Cleared Day-ahead MWh load reduction * Day-ahead LMP*

- End-use customers or their representatives (LSEs/CSPs) that have load reductions committed in the day-ahead market that cannot demonstrate hourly performance in real-time equal to at least that of the day-ahead commitment will be charged real-time LMP for the amount of the shortfall, plus any associated balancing operating reserve charges. LSEs that otherwise would have load that was reduced shall receive any associated operating reserve credits plus, if real-time LMP is higher than day-ahead LMP during the shortfall, the difference between day-ahead and real-time LMP times the shortfall:

LSE that otherwise would have the load that was reduced:

$$\text{Real-Time Charge} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times (\text{RT LMP} - \text{DA LMP}) + (\text{Actual MWh relief provided} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MAX}(0, (\text{RT LMP} - \text{MIN}(\text{DA LMP}, \text{Retail Rate})))$$

All LSE's in the zone of the load reduction when DA LMP \geq 75:

$$\text{Real-Time Charge} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MIN}(\text{Retail Rate}, \text{RT LMP})$$

Payment will be made by PJM to the end-use customer or its representative (LSE/CSP) when DA LMP $<$ 75 as:

$$\text{Real-Time Credit} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MAX}(0, (\text{RT LMP} - \text{MIN}(\text{DA LMP}, \text{Retail Rate})))$$

Payment will be made by PJM to the end-use customer or its representative (LSE/CSP) when DA LMP \geq 75 as:

$$\text{Real-Time Credit} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MAX}(0, \text{RT LMP})$$

- End-use customers or their representative CSP that have load reductions committed in the day-ahead market that have hourly performance in real-time greater than that of the day-ahead commitment will be credited for the additional load response according to the Real-Time Economic Load accounting process:

LSE that otherwise would have the load that was reduced:

$$\text{Real-Time Charge} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MAX}(0, (\text{RT LMP} - \text{Retail Rate}))$$

All LSE's in the zone of the load reduction when RT LMP \geq 75:

$$\text{Real-Time Charge} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MIN}(\text{Retail Rate}, \text{RT LMP})$$

Payment will be made by PJM to the end-use customer or its representative (LSE/CSP) when RT LMP $<$ 75 as:

$$\text{Real-Time Credit} = (\text{Actual MWh relief provided de-rated for transmission losses} - \text{DA Cleared Reduction MWh} + \text{an adjustment for losses}) \times \text{MAX}(0, (\text{RT LMP} - \text{Retail Rate}))$$



Payment will be made by PJM to the end-use customer or its representative (LSE/CSP) when RT LMP \geq 75 as:

Real-Time Credit = (Actual MWh relief provided de-rated for transmission losses - DA Cleared Reduction MWh + an adjustment for losses) X MAX(0, (RT LMP))

Real-Time Operations:

Reimbursement for reducing load is based on the actual kWh relief provided in excess of committed day-ahead load reductions plus an adjustment for losses. If the real-time LMP is less than \$75/MWh, the end-use customer or representative CSP will be paid by PJM the real-time LMP less an amount equal to the applicable generation and transmission charges. If the real-time LMP is greater than or equal to \$75/MWh, the end-use customer or representative CSP will be paid by PJM the real-time LMP. In cases where load response is dispatched by PJM, the total payment to end-use customers or their representative CSP will not be less than the total value of the load response bid, including any submitted shut-down costs. Any shortfall will be made up through normal, balancing operating reserve. In all cases, the applicable zonal or aggregate LMP issued as appropriate for the individual end-use customer. PJM shall recover LMP less an amount equal to the applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to generation and transmission charges, if any, will be recovered from all load within the zone in which the load that was reduced.

When PJM has dispatched in real time the load reduction of an end-use customer that pays for the delivery of energy according to the hourly value of the real-time LMP, then PJM shall pay the CSP the difference between the actual savings achieved by the load reduction based on zonal LMP and the total value of the load response bid, if the savings achieved are less than the total value of the load response bid.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's day-ahead scheduled load reduction quantities
 - each PJM Market Participant's actual metered reduction de-rated for transmission losses
 - associated shut-down costs
 - loss factor
 - hourly list of integrated real-time LMPs (\$)
 - retail rate (generation and transmission)
- If the real-time LMP is less than \$75/MWh, PJM shall recover real-time LMP less an amount equal to the applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced:

(Actual MWh relief provided de-rated for transmission losses + an adjustment for losses) x (Real-Time LMP – Retail Rate)



Payment will be made by PJM to the end-use customer or its representative (/CSP) as:

*Actual MWh relief provided de-rated for transmission losses * (Real-Time LMP – retail rate)*

- If the real-time LMP is greater than or equal to \$75/MWh, PJM shall recover an amount equal to the applicable generation and transmission charges from all LSE's in the zone of the load reduction. PJM shall recover the remaining amount, LMP less an amount equal to the generation and transmission charges from the LSE that otherwise would have the load that was reduced:

LSE that otherwise would have the load that was reduced:

*(Actual MWh relief provided de-rated for transmission losses + an adjustment for losses) * (Real time LMP – retail rate)*

All LSE's in the zone of the load reduction:

$$(Generation\ and\ Transmission\ on\ charges) * \left[\frac{Participant's\ Real\ time\ Load\ (excluding\ losses)\ in\ zone}{Total\ Real\ time\ load\ (excluding\ losses)\ in\ zone} \right]$$

Payment will be made by PJM to the end-use customer or its representative (LSE/CSP) as:

*Actual MWh relief provided de-rated for transmission losses * Real – Time LMP*



Section 11: Metering Reconciliation Accounting

Welcome to the *Metering Reconciliation Accounting* section of the PJM Manual for **Operating Agreement Accounting**. In this section, you will find the following information:

- How metering errors and corrections are reconciled and corrected (see “*Meter Correction Billing*”).

11.1 Meter Error Correction Billing

Metering errors and corrections are reconciled at the end of each month by a meter correction charge. The monthly meter error correction charge (plus/minus) is determined by the product of the positive or negative deviation in energy amounts times the load weighted average real-time LMP for all load buses in the PJM Region, as applicable for tie meter corrections, or times the generation weighted average real-time LMP for individual generation buses for generator meter corrections.

Meter error data is submitted to PJM via eMTR no later than noon on the third PJM business day after the end of the billing cycle applicable to the meter correction.

A PJM Member may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter is limited to bills for transactions occurring in the most recent annual accounting period of the billing PJM Member in which the meter error occurred and the prior annual accounting period. Billing cycle accounting for PJM Mid-Atlantic 500 kV transmission losses is adjusted to account for errors in meters on those 500 kV Transmission Facilities.

11.1.1 Meter Corrections between PJM Members

If a PJM Member or PJM discovers a meter error affecting an interchange of energy with another PJM Member(s) and makes the error known to the other PJM Member(s) prior to the completion by PJM of the accounting for the interchange, and if the PJM Members are willing to adjust hourly tie readings to compensate for the error, an adjustment in tie readings may be made by the PJM Members in order to correct for the meter error, provided corrected information is provided to PJM in accordance with PJM's accounting deadlines. No such adjustment may be made if PJM has completed the accounting for the Operating Day in which the interchange occurred. If this is not practical, the error is accounted for by a correction at the end of the billing cycle.

11.1.2 Meter Corrections between Control Areas

An error in metered interchange between a PJM Member and an entity in another Control Area is corrected by adjusting the hourly meter readings. If this is not practical, the error is accounted for by a correction at the end of the billing cycle. The PJM Member with ties to such other Control Area experiencing the error accounts for the full amount of the discrepancy and an appropriate debit or credit is applied proportionately among all LSEs based on load (de-rated for transmission losses). PJM adjusts the actual interchange



between PJM and the other Control Area to maintain a proper record of inadvertent energy flow.

PJM Actions:

- PJM receives meter correction data from the fully metered PJM Members.
- PJM verifies and reconciles the meter correction data to ensure data consistency.
- PJM allocates PJM Mid-Atlantic 500 kV meter corrections to all fully metered PJM Mid-Atlantic EDCs in proportion to their monthly PJM Mid-Atlantic real-time load (excluding losses), and allocates external tie line meter corrections to all PJM RTO LSEs in proportion to their monthly PJM RTO real-time load (excluding losses).
- PJM calculates a monthly load weighted-average real-time LMP for the PJM RTO and generation weighted-average real-time LMPs.
- PJM calculates meter error correction charges or credits for each EDC, LSE, or generator, as follows:

$$\text{Meter Correction Charge (+/-)} = (\text{Tie Meter Correction MWh} * \text{PJM Monthly Load Weighted-Average LMP}) + (\text{Generation Meter Correction MWh} * \text{Applicable Monthly Generation Weighted-Average LMP})$$

- The following table shows the market participants that receive +/- meter correction charges based on the various types of meters that require corrections.

Type of Tie Meter Correction	Mid-Atlantic 500kv?	Impacted Participant(s)	Impacted Participant(s)
PJM Internal Tie	Yes	Applicable EDC	PJM Mid-Atlantic EDCs
	No	Applicable EDC	Applicable EDC
PJM External Tie	Yes	PJM Mid-Atlantic EDCs	All PJM LSEs
	No	Applicable EDC	All PJM LSEs
Generator Tie	Yes	Generator	PJM Mid-Atlantic EDCs
	No	Generator	Applicable EDC



Section 12: Station Power Accounting

Welcome to the *Station Power Accounting* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of the accounting procedure for Station Power billing adjustments (see “*Station Power Accounting Procedure*”).

12.1 Station Power Accounting Procedure

In accordance with the June 28, 2001 FERC order regarding PJM’s treatment of generator station power (Docket No. ER01-1936, effective July 1, 2001), PJM performs monthly netting of hourly generator output and station power consumption to determine if the following billing adjustments are required:

- Adjustment to Spot Market Energy billing (for third-party supply of station power)
- Adjustment to Non-firm Point-to-point Transmission Service billing (for remote self-supply of station power)

The hourly net generation MWh quantities that are used in PJM energy market settlements (excluding energy consumed for pumping at pumped storage hydro facilities and for synchronous condensing) are netted over the calendar month for each generator and for each generation owner. Any billing adjustments required for generators or generation owners with net negative totals are calculated and included in the subsequent month’s billing cycle.

Generation MWh values are retrieved from the PJM eMTR system for generators that report revenue meter data to PJM eMTR. Monthly MWh data for generators not represented in PJM eMTR must be reported to PJM by the generation owners, or by the applicable PJM Members on their behalf, by the 15th calendar day of the following month.

If a superseding arrangement for the treatment station power exists between a generation owner and the applicable electric distribution company (EDC) in whose service territory the generator resides, then hourly net station power consumption (i.e., negative net generation MWh) is not reported to PJM for settlements purposes. In this case, compensation for station power consumption is handled bilaterally between the EDCs and generation owners and PJM billing adjustments for station power are not applicable.

12.1.1 Third-Party Supply

For each individual business entity with ownership rights to one or more generators (or joint-owned shares of generators) in PJM, their net generation MWh are netted for the month to determine if a third-party retail purchase of station power occurred. If a generation owner’s monthly net generation MWh is negative, then that third-party supply of net station power consumption is allocated to their generators that were off-line during the month based on a rank order methodology.

Starting with the generator with the most negative net MWh for the month, the entity’s net MWh quantity is allocated (in 0.001 MWh increments) across all hours in the month where that generator had net negative MWh. If additional net negative MWh remains for the



generation owner after being allocated to the first generator, the remaining MWh are allocated to each generator with net negative MWh based on the magnitude of the generators' net MWh (from highest to lowest) until it is all allocated.

A PJM billing adjustment will shift the financial responsibility for the wholesale value of the third-party sale of station power consumption from the generation owner to the appropriate EDC. The allocated MWh are priced at the applicable generator's hourly LMP and accumulated for the month to determine the spot market energy billing adjustment. The billing adjustment is a credit to the generation owner's billing account and a charge to the applicable EDC's billing account. The MWh allocations will be provided to the EDC and may be included in PJM's retail load reconciliation process, if desired, to facilitate the retail billing process between the EDC and the generation owner (or its designated PJM network customer).

12.1.2 Remote Self-Supply

For each generating unit (or for multiple generating units with station power requirements metered at a common source) or joint-owned share of a generating unit, the generation MWh are netted for the month to determine if station power was remotely self-supplied. If a generator's monthly net generation MWh is negative (excluding that which was determined to be supplied by a third party), then PJM non-firm point-to-point transmission service charges are determined by multiplying the net negative MWh quantity by the current discounted rate of \$0.67/MWh. Through PJM billing adjustments, the non-firm charges are assessed to the generation owner's billing account and allocated as credits to all firm point-to-point and network integration transmission customers in accordance with the PJM Open Access Transmission Tariff section 27a in proportion to their demand charges for that month.



Section 13: Unscheduled Transmission Service Accounting

Welcome to the *Unscheduled Transmission Service Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of the accounting procedure for Unscheduled Transmission Service (see “*Unscheduled Transmission Service Accounting Procedure*”).

13.1 Unscheduled Transmission Service Accounting Procedure

When PJM provides Unscheduled Transmission Service to the NYISO, the compensation received is allocated with the monthly excess congestion credit allocations. When PJM receives Unscheduled Transmission Service from the NYISO, the charges due NYISO are netted against any credits received by PJM.



Section 14: Ramapo PAR Facilities Accounting

Welcome to the *Ramapo PAR Facilities Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of the accounting procedure for Ramapo PAR facilities accounting (see “*Ramapo PAR Facilities Accounting Procedure*”).

14.1 Ramapo PAR Facilities Accounting Procedure

The PJM East Transmission Owners have entered into a facility agreement with the New York ISO for the installation and operation of phase angle regulating (PAR) facilities at Ramapo. Each PJM Mid-Atlantic transmission owner pays to the NYISO its share of the carrying charges in proportion to their Transmission Revenue Requirements in effect at the time when such charges are incurred. NYISO then pays Consolidated Edison the total revenues for the Ramapo PAR.



Section 15: Capacity Credit Market Accounting

Section 15 has been removed permanently for the implementation of the Reliability Pricing Model.



Section 16: Financial Transmission Rights Auctions Settlement

Welcome to the *Financial Transmission Rights Auctions Settlement* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- An overview of the Financial Transmission Rights (FTR) Auctions settlement (see “*FTR Auctions Settlement Overview*”).
- How charges for FTR Auction transactions are calculated for FTR Auction buyers (see “*FTR Auction Buyers’ Charges*”).
- How credits for FTR Auction transactions are calculated for FTR Auction sellers (see “*FTR Auction Sellers’ Credits*”).
- How FTR Auction revenues are allocated (see “*Allocation of FTR Auction Revenues*”).

16.1 FTR Auctions Settlement Overview

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR auctions. Market participants may purchase/sell FTRs by participating in the Long-term, Annual, and Monthly FTR auctions. The Long-term and Annual FTR auctions offer for sale the entire transmission entitlement that is available on the PJM system on a long-term basis. The Monthly FTR Auctions provide a method of auctioning the residual FTR capability that remains on the PJM Transmission System after the Annual auction is conducted. The Annual FTR auction is a multi-round auction consisting of four rounds. FTRs that are purchased in one round may be offered for sale in subsequent rounds of the Annual auction. The Monthly auctions allow FTR market participants an opportunity to offer for sale any FTRs that they currently hold and to buy the residual FTR capability that remains on the PJM Transmission System after the Annual auction is conducted. PJM conducts the monthly auctions once a month. FTRs can be in the form of an option or an obligation. For discussion purposes, FTR obligations and FTR options will be referred to as FTRs, unless otherwise noted. Each FTR acquired in the Annual FTR Auction entitles the holder to credits of Transmission Congestion Charges for one calendar year. Each FTR acquired in the monthly auctions entitles the holder to credits of Transmission Congestion Charges for one calendar month. Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the FTR auctions are allocated. An ARR holder may “self-schedule” an FTR obligation into the Annual FTR auction as a “price-taker” auction buy bid. The “self-scheduled” FTR must have exactly the same source and sink points as the ARR. This feature may only be used in Round 1 of the Annual FTR auction and must be for a 24-hour FTR obligation product.

PJM is responsible for administering the PJM FTR Auctions; including performing the following settlement functions:

- settlement of awarded auction FTRs
- allocation of FTR Auction revenues to ARR holders
- rendering bills to buyers and sellers



- receiving payments from and dispersing payments to buyers and sellers

The FTR Auctions also facilitate the trading of FTRs by PJM Members. Winning bidders pay market price for FTRs acquired in the auctions; FTR sellers are paid market price for the FTRs they surrender to PJM. The winning quotes are determined by the set of simultaneously feasible FTRs with the highest total auction value, as determined by the bids of the buyers and taking into account the reservation prices of the sellers. PJM will calculate the clearing prices for all FTR obligations at all buses, regardless of whether they are bought or sold in the auctions. PJM will calculate the clearing prices for all FTR options for all valid option paths, regardless of whether they are bought or sold in the auctions. All auction revenues, net of payments to entities selling FTRs into the auctions, are allocated among ARR holders. Additional details on the FTR Auctions can be found in the PJM Manual for **Financial Transmission Rights (M-06)**, Section, 5: FTR Auctions. Additional details on ARRs can be found in the PJM Manual for **Financial Transmission Rights (M-06)**, Section, 2: Auction Revenue Rights Overview.

16.2 FTR Auction Buyers' Charges

PJM Market buyers are charged for FTR Auction purchases based on the FTR awarded (in 0.1 MW increments) and the market clearing price. PJM calculates a market clearing price for each FTR based on the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. The market clearing price for all FTRs is the difference between prices at specified pairs of receipt and delivery points as determined by the auctions. The market clearing price for an FTR obligation can be computed directly from the nodal clearing prices and can be a negative value. The market clearing price for an FTR option is a function of the shadow price of each binding constraint and cannot be computed directly from nodal prices. The market clearing price of an FTR option can never be a negative value. The FTR Auction charge is the product of the Market Buyer's FTR purchase and the market clearing price.

PJM Actions:

- PJM prepares a list of FTR Auction buyers.
- PJM accounting process retrieves the following information:
 - each participant's daily FTR Auction purchases (MW)
 - each FTR market clearing price (\$/MW)
- PJM accounting process calculates the monthly FTR Auction charge for each FTR as follows:

*FTR Auction Charge = FTR Purchased (MW) * Market Clearing Price*

- PJM accounting process sums the FTR auction charges for each FTR Auction participant to calculate the participant's total monthly FTR Auction charge.

16.3 FTR Auction Sellers' Credits

PJM Market sellers are credited for FTR Auction sales based on the FTR awarded (in 0.1 MW increments) and the market clearing price. PJM calculates a market clearing price for each FTR based on the set of simultaneously feasible FTRs with the highest net total



auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. The market clearing price for all FTRs is the difference between prices at specified pairs of receipt and delivery points as determined by the auctions. The market clearing price for an FTR obligation can be computed directly from the nodal clearing prices and can be a negative value. The market clearing price for an FTR option is a function of the shadow price of each binding constraint and cannot be computed directly from nodal prices. The market clearing price of an FTR option can never be a negative value. The FTR Auction credit is the product of the Market Seller's FTR sales and the market clearing price.

PJM Actions:

- PJM prepares a list of FTR Auction sellers.
- PJM accounting process retrieves the following information:
 - each participant's FTR Auction sales (MW)
 - each FTR market clearing price (\$/MW)
- PJM accounting process calculates the monthly FTR Auction credit for each FTR as follows:

$$\text{FTR Auction Credit} = \text{FTR Sold (MW)} * \text{Market Clearing Price}$$

- PJM accounting process sums the FTR auction credits for each FTR Auction participant to calculate the participant's total monthly FTR Auction credit.

16.4 Allocation of FTR Auction Revenues

All auction revenues, net of payments to entities selling FTRs into the auctions, are allocated among ARR holders as ARR credits. The amount of credit that each ARR holder should receive is based on the economic value or Target Allocation of the ARR. ARR Target Allocations will be based on the FTR obligation clearing prices from each round of the Annual FTR auction. The ARR Target Allocation can be positive or negative and as such, an ARR can be either a financial benefit or a liability to the holder.

PJM Actions:

- PJM prepares a list of ARR holders.
- PJM accounting process retrieves the following information:
 - ARR Target Allocation LMP based on the nodal clearing prices for each round of the Annual FTR auction
- PJM accounting process calculates the FTR auction allocation of revenue credits to ARR holders as follows:

$$\text{ARR Target Allocation} = (\text{ARR MW}/\# \text{ of rounds}) * (\text{LMP}_{\text{Delivery}} - \text{LMP}_{\text{Receipt}})$$

- PJM accounting process allocates the FTR auction allocation of revenue credits to ARR holders for a month as follows:
 - Each day, the total of all daily ARR Target Allocations are compared to the total net revenues of the applicable Monthly FTR auction (divided by the



- number of days in the month) plus the total net revenues of the Annual FTR auction (divided by the number of days in planning period).
- If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then total ARR credits equal total ARR Target Allocations.
 - If excess Annual and Monthly FTR Auction revenues remain after this allocation, or if no deficiencies exist, all remaining FTR auction revenue is treated as excess congestion charges and is distributed starting with Stage One as described in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.
 - If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference between ARR Target Allocations and ARR credits are called ARR deficiencies. The ARR deficiencies may be funded by Annual Excess Congestion Charges starting with Stage Four as explained in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.



Section 17: Auction Revenue Rights Settlements

Welcome to the *Auction Revenue Rights Settlements* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- An overview of the Auction Revenue Rights (ARR) settlements (see “*ARR Settlements Overview*”).
- How daily Reassignment of ARRs occurs as load changes within a zone within the planning period (see “*Daily Reassignment of ARRs as load changes*”).
- How Annual and Monthly FTR Auction revenues are allocated (see “*Allocation of Annual and Monthly FTR Auction Revenues*”).

17.1 ARR Settlements Overview

Auction Revenue Rights are financial entitlements allocated annually to PJM Network Integration and Firm Point-to-Point Transmission Service customers that entitle the holder to receive an allocation of the net revenues from the PJM Annual and Monthly FTR Auctions. ARRs can be acquired by three mechanisms: 1) Annual ARR allocation where ARRs requested by customers are allocated on an annual basis; 2) Daily reassignment of ARRs whereby ARRs that were allocated for the planning period will be reassigned on a proportional basis within a zone as load shifts between LSEs within the planning period; and 3) Firm Point-to-Point Transmission Service customers have the option to request ARRs consistent with their transmission reservation. Firm Point-to-Point Transmission Service ARR requests will have the same duration as the transmission service, which may be one year, one month, one week or one day.

Network Integration Transmission Service ARRs are requested via PJM eCapacity. Firm Point-to-Point Transmission Service ARRs are requested via OASIS. ARRs awarded must be simultaneously feasible to ensure that Annual and Monthly FTR Auction revenues are adequate to cover the economic value of all ARRs.

Each holder of an ARR will be entitled to revenues from the Annual and Monthly FTR Auctions based on the economic value of the ARR. The ARR economic value or ARR Target Allocation is equal to the ARR MW amount divided by the number of rounds in the Annual FTR Auction times the price difference from the ARR sink point to the ARR source point. The LMP values used in the above calculation for settlements for annual ARRs will be based on the nodal clearing prices for FTR obligations from each round of the Annual FTR auction.

The ARR Target Allocation can be a benefit or a liability. The hourly economic value of an ARR is positive (a benefit) when the nodal LMP at the sink point (point of delivery) is higher than the nodal LMP at the source point (point of receipt). The hourly economic value of an ARR is negative (a liability) when the nodal LMP at the source point (point of receipt) is higher than the nodal LMP at the sink point (point of delivery).

Transmission customers with negative ARR Target Allocations will always receive 100% of their ARR Target Allocations as negative ARR Credits. The inclusion of these negative credits effectively increases the amount that is available to be allocated as credits to the transmission customers with positive ARR Target Allocations.



If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations, then total ARR credits equal total ARR Target Allocations. If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations, then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference between ARR Target Allocations and ARR credits are called ARR deficiencies. Settlements for the Annual and Monthly FTR Auctions and the corresponding ARRs will be performed on a monthly basis.

Within the planning period, as load changes from one LSE to another within a transmission zone, a proportionate share of the ARRs defined to sink into that zone are reassigned from the old LSE to the new LSE. The reassignment of ARRs is an automatic process that is conducted on a daily basis. ARRs are only reassigned from those LSEs that have lost load in a zone and have a net positive economic ARR position in that zone. An LSE that loses load will lose ARR MWs in proportion to the amount of load lost and this same proportion will reduce each individual ARR assigned to the LSE.

Each holder of an annual ARR can convert the ARR into an FTR by “self-scheduling” the FTR into the first round of the Annual FTR auction on the exact same path as the ARR or the holder may retain the allocated ARR and receive the associated allocation of revenues from the Annual and Monthly FTR auctions.

PJM is responsible for performing the following settlement functions:

- settlement of awarded ARRs
- reassignment of ARRs
- allocation of Annual FTR Auction revenues
- allocation of Monthly FTR Auction revenues
- rendering bills to buyers and sellers
- receiving payments from and dispersing payments to buyers and sellers

17.2 Daily Reassignment of ARRs as load changes

Within the planning period, as load changes from one LSE to another within a transmission zone, a proportionate share of the ARRs defined to sink into that zone are reassigned from the old LSE to the new LSE. The reassignment of ARRs is an automatic process that is conducted on a daily basis. ARRs are only reassigned from those LSEs that have lost load in a zone and have a net positive economic ARR position in that zone. An LSE that loses load will lose ARR MWs in proportion to the amount of load lost and this same proportion will reduce each individual ARR assigned to the LSE.

PJM Actions:

On a daily basis, ARRs are reassigned using the following procedure:

- PJM compares each LSEs Network Service Peak Load in a zone to the Network Service Peak Load of the previous day.



- PJM analyzes each LSEs net economic ARR position. For each LSE losing load and having a net positive economic ARR position for that zone, the percentage of load lost for each LSE is determined. Each ARR, owned by the LSE losing load and having a net positive economic ARR position, is reduced by the percentage of load lost.
- PJM assigns that total set of forfeited ARRs to LSEs gaining load in the zone based on a percentage of the MW load gain divided by the total MWs of load shifting in the zone.

17.3 Allocation of Annual and Monthly FTR Auction Revenues

All Annual and Monthly FTR auction revenues are allocated to holders of ARRs on a proportional basis as ARR credits.

PJM Actions:

- PJM prepares a list of ARR holders.
- PJM accounting process retrieves the following information:
 - ARR target allocation LMP based on the nodal clearing prices for each round of the Annual FTR auction
- PJM accounting process calculates the FTR auction allocation of revenue credits to ARR holders as follows:

$$\text{ARR Target Allocation} = (\text{ARR MW} / \# \text{ of rounds}) * (\text{LMP}_{\text{Delivery}} - \text{LMP}_{\text{Receipt}})$$

- PJM accounting process allocates the net FTR auction allocation of revenue credits to ARR holders for a month as follows:
 - Each day, the total of all daily ARR Target Allocations are compared to the total net revenues of the applicable Monthly FTR auction (divided by the number of days in the month) plus the total net revenues of the Annual FTR auction (divided by the number of days in planning period).
 - If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then total ARR credits equal total ARR Target Allocations.
 - If excess Annual and Monthly FTR Auction revenues remain after this allocation, all remaining FTR auction revenue is treated as excess congestion credits and is distributed starting with Stage One as described in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.
 - If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference between ARR Target Allocations and ARR credits is called



ARR deficiencies. The ARR deficiencies may be funded by Annual Excess Congestion Charges starting with Stage Four as explained in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.



Section 18: Inadvertent Interchange Accounting

Welcome to the *Billing* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of the accounting procedures for determining PJM inadvertent interchange charge allocations (see *"Inadvertent Interchange Billing"*).

18.1 Inadvertent Interchange Billing

- Inadvertent Interchange is the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. This MWh quantity may be a positive or negative value in any given hour and is priced at the PJM load weighted-average LMP for the hour. The value of this energy is allocated to all market participants based on real-time load (excluding losses) ratio shares in the PJM Region. This results in positive or negative Inadvertent Energy charges for each hour.

PJM Actions:

- PJM calculates the hourly inadvertent interchange MWh
- PJM calculates the hourly load weighted-average real-time LMP for the PJM RTO
- PJM calculates the hourly value of inadvertent interchange by multiplying the inadvertent interchange MWh by the PJM load weighted-average LMP
- PJM allocates PJM Inadvertent Interchange charges (+/-) to all PJM market participants in proportion to their hourly real-time load (excluding losses) ratio share
- Reconciliation for Inadvertent Interchange Charges
- PJM will calculate reconciled Inadvertent Interchange charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past months' billings that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules contract.
- PJM calculates the Inadvertent Interchange charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the PJM system-wide system energy price (in \$/MWh) for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Inadvertent Interchange charges for a month may be either a positive or a negative value.



Section 19: Billing

Welcome to the *Billing* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A summary of the billing process for the PJM Operating Agreement Accounting (see “*Billing Process Overview*”).

19.1 Billing Process Overview

A single billing statement is issued by PJM monthly to each PJM customer account, detailing all charges and credits for the month that apply to that customer under the PJM Operating Agreement and the PJM Open Access Transmission Tariff. The billing statement presents a net amount due from the customer or due to the customer. Weekly billing statements are also issued for certain line items. The ***PJM Manual for Billing (M-29)*** describes the billing process in detail.

The Operating Agreement related billing statement line items that are described in this manual are as follows.

- Day-ahead and Balancing Spot Market Energy (charges)
- Synchronized Reserve (charges/credits)
- Day-ahead Scheduling Reserve (charges/credits)
- Regulation (charges/credits)
- Transmission Congestion (day-ahead and balancing charges/credits)
- Transmission Losses (day-ahead and balancing charges/credits)
- Day-ahead and Balancing Operating Reserve (charges/credits)
- Synchronous Condensing (charges/credits)
- Reactive Services (charges/credits)
- Emergency Energy (charges/credits)
- Meter Correction (charges)
- Inadvertent Interchange (charges)
- Unscheduled Transmission Service (charges)
- Ramapo PAR Facilities (charges/credits)
- RPM-related (charges/credits)
- Financial Transmission Rights Auction (charges/credits)
- Auction Revenue Rights (credits)
- Reconciliation for Spot Market Energy (charges)
- Reconciliation for Transmission Congestion (charges)



- Reconciliation for Transmission Losses (charges/credits)
- Reconciliation for Regulation (charges)
- Reconciliation for Synchronized Reserve (charges)
- Reconciliation for Inadvertent Interchange (charges)
- Reconciliation for Day-ahead Scheduling Reserve (charges)

The ***PJM Manual for Open Access Transmission Tariff Accounting (M-27)*** describes the Tariff-related line items of the billing statement in detail.



Revision History

Revision 43 (01/20/2010)

- Revised Transmission Losses Accounting section to reflect the changes to the distribution of Transmission Loss Charges as retroactively approved by FERC (EL08-14).
- Added clarifying item in the Operating Reserve Accounting section related to the Day-ahead pumped storage optimization program

Revision 42 (07/31/2009)

- Revised Operating Reserve Accounting section to reflect Balancing Operating Reserve construct change as approved by FERC (ER08-1569)
- Add several new load reconciliation charge descriptions that were recently implemented.
- Revised Regulation Accounting section to allow for the recovery of lost opportunity costs incurred by generating market buyers and market sellers during the hour preceding the initial regulating hour and the hour following the final regulation hour as approved by FERC (ER09-789)

Revision 41 (11/01/2008)

- Cleaned up to better align with new settlement system

Revision 40 (6/1/2008)

- Section 7: Revised to reflect new allocation method for any end-of-planning period excess congestion revenues

Revision 39 (1/01/2008)

- Added business rules for eSchedules and eMTR Data Submissions

Revision 38 (06/01/2007)

- Revisions were made to reflect the implementation of Marginal Losses and for general clean-up.

Revision 37 (03/07/2007)

- Section 2: Revised to add a section titled "Calculation of Real-Time Locational Marginal Price"

Revision 36 (01/01/2007)

- Section 5: Clarified the hourly Operating Reserve deviation charge eligibility for generators not following PJM dispatch signals.



- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual

Revision 35 (09/26/06)

- Section 4: Clarified the generator energy offer data used by PJM for Regulation lost opportunity cost credit calculations.
- Section 5: Clarified the hourly Operating Reserve credit eligibility for when a generator trips.

Revision 34 (08/28/06)

- Exhibit 1: Updated to include the new Manual 30: Alternative Collateral Program.
- Section 5: Modified rules to clarify the determination of a resource's hourly Desired MWh and no-load compensation values.
- Section 10: Modified section for revised rules for Demand Response Participation.

Revision 33 (05/01/06)

- Change to Section 4: Regulation Accounting. Add demand side response regulation charges and credits.
- Change to Section 6: Spinning Reserve Accounting. Rename spinning reserve market to synchronized reserve market and add demand side response synchronized reserve charges and credits.
- Revisions were also made to globally change "spinning" to "synchronized."

Revision 32 (03/01/06)

- Change to Section 5: Operating Reserve Agreement Accounting, "Charges for Operating Reserves". Revised to remove requirement that self-scheduled generator deviation exemptions must be requested in writing.
 - Revisions were made on the following page: 44.

Revision 31 (11/01/05)

- Cleanup changes to clarify the single Regulation market and to clarify Operating Reserves charges.

Revision 30 (08/01/05)

- Cleanup changes to clarify the single Regulation market and to clarify Operating Reserves charges.



- Changes to Section 5: Operating Reserve Agreement Accounting, “Credits for Pool-Scheduled Generating Resources”. Revised to include clarification on the elimination of credits during Maximum Emergency operating days.
- Changes to Section 5: Operating Reserve Agreement Accounting, “Charges for Operating Reserves”, Part 6. Revised to enable generating units that trip to retain Operating Reserve eligibility for period of time the unit was running for PJM.
- Changes to Section 5: Operating Reserve Agreement Accounting, “Credits for Pool Scheduled Generating Resources”, Part 4a. Revised to exempt from Balancing Operating Reserve deviation charges, generators that are self-scheduled but have a dispatchable range when following PJM dispatch above minimum.

Revision 29 (05/20/05)

- Minor changes including mention of MISO JOA market-to-market revenues in Congestion Credit section and clarifications to Operating Reserves charge and credit calculations.

Revision 28 (05/05/05)

- Charges for Operating Reserves - revised part 4A.
- Meter Correction Billing – corrected meter error data submittal timeframe.

Revision 27 (10/01/04)

- Revised to reflect the integration of AEP/Dayton.

Revision 26 (05/01/04)

- Revised to reflect the integration of ComEd.

Revision 25 (04/23/04)

- Revised Section 5: Operating Reserves Accounting to include credits to generators that adjust active power output at PJM's direction for the purpose of maintaining reactive reliability (Reactive Services). Expanded and clarified provisions regarding lost opportunity cost compensation to generators that are reduced or suspended by PJM due to a transmission constraint or for other reliability purposes. Also clarified the provisions for exempting balancing operating reserves charges and for including energy use costs in synchronous condensing credits.
- Revised Section 7: Transmission Congestion Accounting to reflect the transitional Financial Transmission Rights (FTR) Allocation and FTR reassignment process that will be conducted for new zone load being added as a result of market growth.



- Revised Section 7: Transmission Congestion Accounting to adjust the allocation period for excess congestion revenues from a calendar year basis to a PJM planning period basis.

Revision 24 (07/01/03)

- Revised Section 5: Operating Reserves Accounting to reflect the credits for resources performing an annual scheduled Black Start test.
- Revised Section 7: Transmission Congestion Accounting Overview to reflect the updated allocation procedures for Transmission Congestion Credits.
- Revised Section 16: Financial Transmission Rights Auctions Settlement to reflect the PJM Annual and Monthly FTR Auctions settlement.
- Added Section 17: Auction Revenue Rights Settlements.

Revision 23 (02/01/03)

- Revised Section 11: Meter Reconciliation Accounting to reflect the updated meter error data submission requirement.

Revision 22 (12/01/02)

- Revised Section 5: Operating Reserves. Revision coincides with the inclusion of the Spinning Reserve Section.
- Added new Section 6: Spinning Reserve Accounting. All remaining sections re-numbered respectively.

Revision 21 (10/01/02)

- Added new Section 9: PJM Load Response Programs Accounting.
- All remaining sections re-numbered respectively.

Revision 20 (06/01/02)

- Revised to reflect the new Emergency Energy allocation procedures.
- Revision 19 (04/01/02)
- Revised to reflect the changes to incorporate the PJM West Region and Rockland Electric Company.

Revision 18 (07/01/01)

- Added new Section 10: Station Power Accounting.
- Renumbered Sections 10 through 14 to 11 through 15 respectively.

Revision 17 (06/01/01)

- Revised to reflect the implementation of the PJM eMTR System.



Revision 16 (05/17/01)

- Revisions have been made to Section 6: Transmission Congestion Accounting. Revised to include additional detail to further clarify excess congestion allocation procedures.

Revision 15 (12/01/00)

- This revision contains the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for **Definitions and Abbreviations (M-35)**.

Revision 14 (06/01/00)

- Section 5: Operating Reserves Accounting
- Revised subsection "Credits for Pool-Scheduled Generating Resources." Corrected to remove the description of a credit adjustment during Max Emergency conditions.

Revision 13 (06/01/00)

- All Sections updated to reflect Two Settlement implementation of a Day-Ahead Energy Market and the new Regulation Market.

Revision 12 (01/03/00)

- Section 5: Operating Reserves Accounting was updated to reflect a short run solution (effective 01/01/00) to correct for a market design flaw related to bidding constraints.

Revision 11 (09/23/99)

- Section 5: Operating Reserves Accounting was updated to reflect the FERC approval of the application of operating reserves charges on all export transactions and approval of the new opt out procedures (dynamic scheduling) for those that want to opt out of spot market backup.

Revision 10 (08/02/99)

- Section 2: Locational Marginal Price was expanded to include a new sub-section containing information on PJM's Locational Marginal Price verification procedure.

Revision 09 (06/01/99)

- Added new Section 13: Fixed Transmission Rights Auction Settlements.
- Billing section re-numbered as Section 14.

Revision 08 (04/01/99)

- Section 03: Spot Market Energy Accounting
 - Addition of Reconciliation Billing.



- Section 4: Regulation Accounting
 - Addition of Reconciliation Billing.
- Section 5: Operating Reserves Accounting
 - Addition of Reconciliation Billing and updated Market-based Pricing in the calculation of Operating Reserves credits.
- Section 7: Transmission Losses Accounting
 - Addition of Reconciliation Billing.

Revision 07 (01/01/99)

- Section 03: Spot Market Energy Accounting
 - 5% penalty for self-scheduled resources no longer in effect. Elimination of Non-Delivery Charges.
- Section 12: Capacity Credit Market Accounting
 - New section which replaces Emergency Reliability Service Accounting

Revision 06 (12/07/98)

- Section 06: Transmission Congestion Accounting
 - Modifications were made to “Transmission Congestion Charges.” A note, explaining calculation of implicit congestion charges when a radial transmission limitation exists, was also added to “Transmission Congestion Charges.”

Revision 05 (10/13/98)

- Section 05: Operating Reserves Accounting
 - Modifications made to “Charges for Operating Reserves” reflecting all Market Participants having the opportunity to buy and sell power in the Spot Market on an hourly basis.

Revision 04 (07/01/98)

- Section 01: Market Overview
 - Corrections made to “Market Accounting Overview.”
- Section 03: Spot Market Energy Accounting
 - Corrections made to “PJM Actions” of “Interchange Seller’s Credits.”
- Section 05: Operating Reserves Accounting
 - Corrections made to “PJM Actions” of “Credits for Canceled Pool-Scheduled Resources” under “Credits for Operating Reserves.”
 - Corrections made to “PJM Actions” of “Credits for Pool-Scheduled Aggregate Resources” under “Credits for Operating Reserves.”



- Corrections made to “PJM Actions” of “Cost of Operating Reserves.”
- Corrections made to “PJM Actions” of “Charges for Operating Reserves.”
- Section 13: Billing
- Corrections made to “Billing Process Overview.”

Revision 03 (06/15/98)

- Section 03: Spot Market Energy Accounting
 - Corrections made to Non-Delivery Charges formulas.
- Section 08: Emergency Energy Accounting
 - Corrections made to Emergency Energy Purchases by PJM and Minimum Generation Emergency Purchases by PJM formulas.

Revision 02 (05/01/98)

- All sections revised for change from “Market Clearing Price” to “Locational Marginal Price.”
- Deleted Attachments B, C, and D.

Revision 01 (01/06/98)

- Section 4: Regulation Accounting
 - Added “(6) PJM calculates the Average Cost of Regulation dispatched by PJM from all Generating Market Buyers and Market Sellers supplying excess Regulation at the direction of PJM” under “Regulation Credits.”
 - Added “(7) If according to the Regulation log, PJM is deficient of its Control Area Regulation requirement for the hour, additional credits (*Total PJM Regulation MW Deficiency * Average Cost of Regulation*) are allocated to Market Buyers and Market Sellers based on their percentage of total Regulation supplied’ under “Regulation Credits.”
 - Deleted “(2) PJM calculates the average cost of Regulation dispatched by PJM from all Generating Market Buyers and Market Sellers supplying excess Regulation at the direction of PJM” under “Regulation Charges.”
 - Added “(4) If according to the Regulation log, PJM is deficient of its Control Area Regulation requirement for the hour, additional charges for any remaining regulating deficiency (not satisfied by self-scheduled, allocated pool-scheduled, or allocated self-scheduled excess regulation) are assessed to Internal Market Buyers and Market Sellers, that are also Internal Market Buyers, at the Average Cost of Regulation” under “Regulation Charges.”

Revision 00 (09/02/97)

This revision is the preliminary draft of the PJM Manual for **Operating Agreement Accounting**