PJM Manual 28:

Operating Agreement Accounting

Revision: 86

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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:

- Energy Market
- Regional Transmission Planning Process
- Transmission
- Reserve
- Accounting and Billing
- Administration

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

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 within the PJM Markets. 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 22 sections. The sections are listed in the table of contents beginning on page 2.

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)*

Introduction

- PJM Manual for *Balancing Operations (M-12)*
- PJM Manual for *Billing (M-29)*
- PJM Manual for *Energy & Ancillary Services Market Operations (M-11)*
- 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 PJM Manual.

- Spot Market Energy — Energy bought or sold by Market Participants 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 (PJM Manual 12: Balancing Operations).
- Synchronized Reserve – The capability of a specific on-line 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 (PJM Manual 12: Balancing Operations).
- Non-Synchronized Reserve – The capability of a specific off-line~~non-emergency~~ generation resource with appropriate telecommunications, control, and response capability to increase output from an offline state in response to a non-synchronized reserve event to provide 10-minute reserve (~~see the~~ PJM Manual 12:~~for~~ Balancing Operations).
- Secondary Reserve – The capability of a specific on-line or off-line resource with appropriate telecommunications, control, and response capability to increase output (or reduce consumption) when directed and/or operate at a point that deviates from economic dispatch (including condensing mode) to provide reserves within a response between 10 – 30 minutes (PJM Manual 12: 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 ("FTRs") Auction — Market Participants may purchase/ sell FTRs by participating in the Annual and Monthly auctions.
- Auction Revenue Rights ("ARRs") — ARRs 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 (PJM Manual 29:*Billing*).

	MARKET BUYERS	MARKET SELLERS	TRANSMISSION CUSTOMERS
Spot Market Energy	x	x	
Regulation	x	x	
Operating Reserves	x	x	
Transmission Congestion	x	x	x
Transmission Losses	x	x	x
Emergency Energy	x	x	

	MARKET BUYERS	MARKET SELLERS	TRANSMISSION CUSTOMERS
Meter Reconciliation	x	x	
Unscheduled Transmission Service	x	x	
Capacity Credit Market	x	x	
Financial Transmission Rights	x	x	x
Auction Revenue Rights	x	x	x

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 PJM Manual.

Section 1A: Revenue Data for Settlements

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

- A description of settlement interval data for the Day-ahead and Real-time Energy Markets.
- An overview of how revenue data submitted by Market Participants is used in the settlement calculations further described in this PJM Manual.

1A.1 Business Rules for Revenue Data for Settlements

PJM settles the Day-ahead Energy Market on an hourly basis and the Real-time Energy Market on a five-minute basis. To reflect these two distinct timeframes, PJM refers to the term "Dayahead Settlement Interval" throughout this PJM Manual to mean the interval used to settle Day-ahead transactions, which shall be every one clock hour. In addition, PJM refers to the term "Real-time Settlement Interval" throughout this PJM Manual to mean the interval used to settle real-time transactions, which shall be every five minutes.

Revenue Data for Settlements are real-time energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.

- Generator MW data can be submitted by a Market Participant into Power Meter as either five-minute revenue meter data or hourly revenue meter data. The business rules for electing to submit five minute revenue meter data are specified in Section 3 of this PJM Manual.
- Revenue Data for Settlements for generation resources submitting five-minute revenue meter data is the submitted value for each Real-Time Settlement Interval (five minute interval).
- Once a Market Participant submits five minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five minute basis and cannot switch to hourly revenue meter data submissions. If ownership of a resource is transferred between Market Participants and prior to the transfer the resource is submitting five minute revenue meter data, the new owner of the resource must continue to provide revenue meter data on a five minute basis.
- Revenue Data for Settlements for generation resources submitting hourly revenue meter data shall be determined by the following process:
  o For each five minute interval, PJM calculates a time-weighted telemetry MW value and a State Estimator MW value.
    - A time-weighted telemetry MW value is determined based on the prorated time duration that a telemetry MW value is effective over each five minute interval.

$$\text{Time−weighted Telemetry MW value} = \sum_{i=1}^{n} \left(\text{Telemetry MW}_i * \frac{\text{Time Duration}^i}{5\text{ Minutes}} \right)$$

Where n = number of telemetry values in a five minute interval

- For each hour of the Operating Day, PJM calculates an hourly-integrated telemetry MWh value using the time-weighted telemetry MW values for each of the five minute intervals in the hour

Hourly Integrated Telemetry $MW^h = \sum_{i=1}^{n}$ Time$-$weighted Telemetry MWValue$_i \div 12$

Where n = number of Real-time Settlement Intervals in an hour

- Time-weighted State Estimator MW value is determined based on the prorated time duration that a State Estimator MW value is effective over each five minute interval

Time$-$weighted SE MW value$=\sum_{i n=1}$SE MW$_i$ * Time5 Minutes Duration$i$)

Where n = number of SE values in a five minute interval

- For each hour of the Operating Day, PJM calculates an hourly-integrated State Estimator MWh value using the time-weighted State Estimator MW values for each of the five minute intervals in the hour

Hourly Integrated State Estimator $MWh = \sum_{i=1}^{n}$ Time$-$weighted State Estimator MW Value$_i \div 12$

Where n = number of Real-time Settlement Intervals in an hour

- To determine whether time-weighted Telemetry or time-weighted State Estimator MW values is used to calculate the Revenue Data for Settlements for each five minute interval in an hour, PJM selects the lesser of:
  - o the absolute value difference between the Hourly Revenue Meter MWh and the Hourly Integrated Telemetry MWh and o the absolute value difference between the Hourly Revenue Meter MWh and the Hourly Integrated State Estimator MWh

C= lesser of (A and B)

Where A = |Hourly Revenue Meter MWh – Hourly Integrated Telemetry MWh |

B = |Hourly Revenue Meter MWh - Hourly Integrated State Estimator MWh|

- If A and B are equal, the time-weighted Telemetry MW values are used to calculate the Revenue Data for Settlements for each five minute interval in an hour.
- A tolerance check is performed to ensure the selected time-weighted MW values are within a tolerance for settlement accuracy.
  - o If the time-weighted Telemetry MW values are used to calculate the Revenue Data from Settlements, then the following check is performed:
    - − If the absolute value of the difference between the Hourly Integrated Telemetry MWh and the Hourly Revenue Meter MWh value is greater than 20 percent and greater than 10 MWh, then the Revenue Data for Settlements for each of the Real-time Settlement Intervals of the hour will be flat-profiled and set equal to the Hourly Revenue Meter MWh.

$$\frac{|Hourly\ Integrated\ Telemetry\ MWh - Hourly\ Revenue\ Meter\ MWh|}{Hourly\ Revenue\ Meter\ MWh} > 20\%$$

AND

$$|Hourly\ Integrated\ Telemetry\ MWh - Hourly\ Revenue\ Meter\ MWh| > 10\ MWh$$

- If the time-weighted State Estimator MW values are used to calculate the Revenue Data from Settlements, then the following check is performed:
  - o If the absolute value of the difference between the Hourly Integrated State Estimator MWh and the Hourly Revenue Meter MWh value is greater than 20 percent and greater than 10 MWh, then the Revenue Data for Settlements for each of the Realtime Settlement Intervals of the hour will be flat-profiled and set equal to the Hourly Revenue Meter MWh.

$$\left| \frac{\text{Hourly Integrated State Estimator Telemetry MW}h - \text{Hourly Revenue Meter MW}h}{\text{Hourly Revenue Meter MW}h} \right| > 20\%$$

AND

$$\left| \text{Hourly Integrated State Estimator MW}h - \text{Hourly Revenue Meter MW}h \right| > 10 \text{ MW}h$$

- The Revenue Data for Settlements for each five minute interval in an hour is calculated as follows:.

If C is equal to A, then

$$\text{Revenue Data for Settlements} = \text{Time-weighted Telemetry MW} \\ + \left(\text{Hourly Revenue Meter MW}h - \text{Hourly Integrated Telemetry MW}h \right) \\ *12* \left(\frac{\text{Time-weighted Telemetry MW}}{\sum_{i=1}^{n} \text{Time-weighted Telemetry MW Value}_i} \right)$$

Where n = number of Real-time Settlement Intervals in an hour

If C is equal to B, then

$$\text{Revenue Data for Settlements} = \text{Time-weighted State Estimator MW} \\ + \left(\text{Hourly Revenue Meter MW}h - \text{Hourly Integrated State Estimator MW}h \right) \\ *12* \left(\frac{\text{Time-weighted State Estimator MW}}{\sum_{i=1}^{n} \text{Time-weighted State Estimator MW Value}_i} \right)$$

Where n = number of Real-time Settlement Intervals in an hour

- If a Market Participant is unable to provide telemetry for a generating resource, the Revenue Data for Settlements for each of the five minute intervals of the hour is equal to the hourly revenue meter MWh value.
- For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is equal to the MW value for the five minute intervals that the energy transaction is dispatched or scheduled.
- For Demand Resources, Revenue Data for Settlements is equal to the revenue meter MW data submitted by the Market Participant for the five minute intervals that the resource is dispatched. A Demand Resource can submit either hourly or five minute load reduction data.
- For load, the Revenue Data for Settlements for each of the five minute intervals of the hour is equal to the hourly submitted MWh 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 plus opportunity cost,~~ any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, any amounts credited for non-synchronized reserve in excess of the opportunity cost, any amounts credited for secondary reserve in excess of the opportunity cost ~~and~~, any amounts credited for resources providing reactive services and any amounts attributed to the Market Revenue Neutrality Offset). 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 dispatchable economic load reduction resources, 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, for units providing reactive services at the direction of PJM, and for pool-scheduled and dispatchable self-scheduled resources eligible for dispatch differential lost opportunity cost credits. Nuclear Units are excluded from eligibility for Operating Reserve credits except in cases where PJM requests that nuclear units reduce output at PJM's direction or where a physical problem at a nuclear unit requires a risk premium and that risk premium is submitted to and accepted by the MMU. Other specific circumstances will be evaluated on a case-by-case basis by PJM and MMU.

Market power mitigation and offer capping rules are detailed in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.6.1.

The total cost of Day-ahead Operating Reserve for the Operating Day, excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control, is allocated and charged to PJM Members in proportion to their total cleared day-ahead demand, decrement bids, and up-to congestion transactions at the sink end of the transaction plus their cleared day-ahead exports for that Operating Day. The total cost of Balancing Operating Reserve for the Operating Day, excluding the total cost associated with scheduling units for Black Start service or testing of Black Start units, 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 Manual 11: Energy & Ancillary Services Market Operations. 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. The total cost of Day-ahead Operating Reserve for the Operating Day for resources scheduled to provide Reactive Services or transfer interface control because the resource is known or expected to be needed to maintain system reliability in a zone(s) is allocated and charged to PJM Members in proportion to their total real-time load in the applicable transmission zone(s). The total cost of Operating Reserves for resources providing Black Start service or testing of Black Start units is allocated to Network and Point-toPoint Transmission Customers based on their monthly transmission use on a megawatt basis. Additional details on this allocation can be found in PJM Manual 27: Open Access Transmission Tariff Accounting, Section 7.

5.2 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)
- synchronous condensing for purposes other than providing synchronized reserve or Reactive Services (balancing market)
- canceled pool-scheduled resources (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)

- resources scheduled to provide Black Start service (day-ahead and balancing market)
- synchronous condensing for purposes other than providing synchronized reserve
- resources providing Reactive Services, including synchronous condensing to main reactive reliability
- pool-scheduled and dispatchable self-scheduled resources eligible for dispatch differential lost opportunity cost credits (balancing market)
- dispatchable economic load reduction resources that follow dispatch (day-ahead and balancing markets). See Section 11 for details on Load Response Operating Reserves Credits and Charges.

5.2.1 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: o   dispatcher generation scheduling and operations logs o   resource offer data
  - − the resource's Final Offer, which is the offer on which the resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day
  - − the resource's Committed Offer. For pool scheduled resources, the Committed Offer is the offer on which the resource was scheduled by the Office of the Interconnection for a particular clock hour of the Operating Day. For selfscheduled resources, the Committed Offer is either the offer on which the Market Seller has elected to schedule the resource or the applicable offer based on a) any offer price capping or b) parameter limited schedule restrictions for the a particular clock hour of the Operating Day.
  - o   hourly scheduled MWh for generation offers cleared in day-ahead market o   five minute revenue meter generation MW values from PJM Power Meter if available o   Five minute state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual
  - o   hourly scheduled MWh for InSchedule "Generation" contracts, if applicable o five minute interval generator dispatch rates, UDS basepoint MW, and ramp-limited desired MW
  - o   generator hourly day-ahead LMPs o   five minute real-time LMPs
- PJM calculates the resource's hourly day-ahead offer amount based on its day-ahead Committed Offer 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:

*Scheduled MWh * Day ahead LMP*

- PJM calculates the daily Day-ahead Operating Reserve credits for each resource as follows:
  o Sum hourly day-ahead offer amounts, including applicable no-load and startup costs, for the day
  o Sum hourly day-ahead energy market values for the day
  o Day-ahead Operating Reserve credit equals any portion of the resource's total dayahead offer amount in excess of its total day-ahead market value
  o Day-ahead Operating Reserve credits can be further adjusted by the Day-ahead Operating Reserve Offset as described below to remove any commitment costs, including start-up and no-load costs that are credited through Balancing Operating Reserve credits. For each Operating Day, PJM calculates for each resource, hourly Day-ahead Operating Reserve and a Balancing Operating Reserve Targets. These hourly targets are summed to obtain a Day-ahead Operating Reserve Target and a Balancing Operating Reserve Target for each Operating Day.
- The Day-ahead Operating Reserve Target is calculated as follows:

Day-ahead Operating Reserve Target = (Start-up costs + No-load and Energy Offer Costs) – Day-ahead Revenues

- The No-load and Energy Offer Costs are equal to the sum of the day-ahead no-load and energy offer costs over the Real-time Settlement Intervals that coincide with day-ahead settlement intervals that the resource was scheduled to provide energy. The hourly day-ahead no-load and energy offer costs are divided by twelve to calculate the cost for each Real-time Settlement Interval.
- The Day-ahead Revenues are equal to the sum of the day-ahead scheduled MWh multiplied by the hourly day-ahead LMP at the resource bus divided by twelve for each Real-time Settlement Interval that coincides with a Day-ahead Settlement Interval that the resource was scheduled to provide energy.
- The Balancing Operating Reserve Target is calculated as follows:

Balancing Operating Reserve Target = Resource Costs – (Real-Time Energy Revenue + Reserve Revenue)

- The Resource Costs are equal to the sum of the start-up, no-load and energy offer costs for all Real-time Settlement Intervals that coincide with day-ahead settlement intervals that the resource was scheduled to provide energy.
- The Real-Time Energy Revenue is equal to the five minute revenue data for settlement MW value multiplied by the five minute real-time LMP at the generator's bus summed over the applicable Real-time Settlement Intervals.
- The Reserve Revenue is equal to the sum of the revenues above cost for Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, Secondary Reserves, the Market Revenue Neutrality Offsets for those same products and Reactive Services make whole credits over the applicable Real-time Settlement Intervals.
- The Day-ahead Operating Reserve credits are adjusted by the following offset:

Day-ahead Operating Reserve Offset = Max (Day-ahead Operating Reserve Target – Balancing Operating Reserve Target, 0)

- 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:
  - o 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 five minute interval in which the unit trips.
  - o Resources that trip or fail to start are required to notify PJM per the Synchronization and Disconnection procedures in PJM Manual 14D: Generator Operational Requirements.
  - o 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 trip or failed to start, are requested to restart by PJM for reliability, and operate as requested, are eligible for additional startup costs.
- PJM determines the resource's five minute Real-time MW as described in Section 1A of this PJM Manual.
- Generation resources that are scheduled in the Day-ahead Market are financially responsible for selling their output in real-time. Section 3.2.3(f-1)(ii) of the PJM OATT details provisions for lost opportunity credits for those Flexible Resources that were scheduled in the Day-ahead Market but are not called on by PJM to run in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons). Flexible Resources eligible to be called on in real-time must have a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less for PJM to accurately assess the economic value of the unit and are therefore the only units eligible for these provisions. Any resource scheduled in the Day-ahead Market with a startup plus notification time of greater than 2 hours and a minimum run time of greater than 2 hours should assume that they are committed by PJM in real-time for the duration of the Day-ahead commitment and are therefore only eligible for the aforementioned make whole provisions if PJM denies the commitment of that unit in real-time for either a transmission constraint or reliability.
- If a generation owner calls PJM to bring on a Flexible Resource per its Day-ahead schedule and PJM does not permit the unit to operate in real-time either for reliability or a transmission constraint, it may receive lost opportunity costs as described in section 3.2.3(f-1)(ii) of the OATT as it was not permitted to run by PJM in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons).
- If a Flexible Resource is committed in the Day-ahead Market with a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less at the time of the Day-ahead commitment and then extends its startup plus notification time to more

than 2 hours or its minimum run time to more than 2 hours, it will not be eligible to receive the aforementioned lost opportunity cost provisions in section 3.2.3(f-1)(ii) of the PJM Tariff.

• PJM determines the resource's five minute interval Operating Reserve Desired MW based on its ramp-limited desired MW or UDS basepoint MW, when available. If available, UDS basepoint MW is used when 1.) the UDS basepoint MW are less than or equal to the ramp-limited desired MW or 2.) the UDS basepoint MW is greater than the ramp-limited desired MW and the resource's Real-time MW is greater than the ramp-limited desired MW.

• PJM determines the resource's percent off dispatch for each five minute interval as the lesser of the difference between the resource's Real-time MW and the UDS basepoint MW or the Real-time MW and the ramp-limited desired MW, if available. UDS LMP desired MW 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 MW and ramp-limited desired MW are not available or the percent off dispatch is greater than 20%, PJM determines the resource's five minute interval UDS LMP Desired MW based on its dispatch rate, applicable schedule's offer data, where the applicable schedule's offer is the Final Offer and minimum and maximum energy limits for that five minute interval. 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 Combustion Turbine units, operating at PJM direction, the actual five minute interval real-time output is used as the Operating Reserve Desired MW value.

• PJM calculates the resource's five minute interval real-time energy offer amount based on its applicable schedule's offer data, where the applicable schedule's offer is lesser of the Committed Offer and the Final Offer, and its Real-time MW for that five minute interval. However, for any five minute interval where the resource's Real-time MW is greater than 110% of its Operating Reserve Desired MW, Operating Reserve Desired MW is used to determine the five minute interval real-time energy offer amount.

• PJM applies the startup and hourly no-load bids if the startup and no-load switch is set in the resource offer data and if the startup bid is applicable for the 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.

• PJM calculates the resource's balancing energy market value for each five minute interval in an hour as:

[(Real time MW** – Day-ahead Scheduled MW) * five minute RT LMP] /12
Where the Real-time MW is the greater of [Real-time MW or the lesser of
(greater of (Real-time Dispatch Desired MW and Original Scheduled Desired MW Using
the Committed Offer) and Day-ahead Scheduled MW] and the Day-ahead Scheduled
MW is a flat-profile of the hourly scheduled MWh across each of the five minute intervals
of the hour

**If a resource is committed in the Day-ahead market and increases the cost offer in real-time
resulting in a reduction in Real-time MW from the DA Scheduled MW and is not the result of a
PJM dispatch direction (including regulation, synchronized reserves, non-synchronized
reserves, secondary reserves, reactive services, or reductions due to transmission constraints
or reliability concerns), the maximum of the Real-time MW and greater of the Real-time
Dispatch Desired MW and the original Scheduled Desired MW using the Committed Offer
(capped at the Day-ahead Scheduled MW) will be used in the balancing energy market value
calculation, otherwise Real time MW are used.

- 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 and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment for Demand Resources) and made whole separately for the block of real-time five minute settlement intervals it is operated at PJM's direction in excess of the greater of the day-ahead schedule and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment 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 and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment for Demand Resources).
- PJM calculates the daily Balancing Operating Reserve credits for each generating resource's operating segment as follows:
  o Sum five minute interval real-time offer amounts and include applicable no-load costs divided by twelve and startup costs for the segment
  o Sum five minute interval 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 opportunity cost, plus 5~~4) any Synchronized Reserve Market revenue in excess of its offer plus opportunity cost plus energy use plus startup costs, plus ~~6~~5) any NonSynchronized Reserve Market revenue in excess of its opportunity costs, plus 6) any Secondary Reserve Market revenue in excess of its opportunity costs, plus 7) the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve ~~7~~, plus 8) any Reactive Services ~~revenue~~make whole credit.

  o Synchronized Reserve, Non-Synchronized Reserve, ~~and the real-time five minute interval share of the Day-ahead Scheduling~~and Secondary Reserve ~~credits~~revenue above costs and the Market Revenue Neutrality Offsets are netted against the

Operating Reserve credit in the corresponding five minute interval in which ~~those credits~~they were accrued.

- o A resource that operates outside of its unit-specific parameters is not eligible to receive Balancing Operating Reserve credits nor be made whole when operating to those parameters when not dispatched by PJM unless the resource owner can justify to PJM that the operation outside of the unit-specific parameters was the result of an actual system constraint.

- For any Operating Day in which PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert, or schedules units based on the anticipation of a Max Generation Emergency or Maximum Generation Emergency Alert, if a generator's priced-based offer results in revenues for applicable "economic" five minute intervals to produce an effective offer price greater than or equal to $1000/MWh and is greater than a Market Seller's lowest available and applicable cost-based offer, that generator shall not receive any operating reserve credits in accordance with the PJM Operating Agreement sections 3.2.3 (l), (m), and (n).

  - o For the Real-time market, PJM calculates an effective offer price by summing the Operating Reserve credits which would have been applicable absent this exemption, plus the real-time LMP market value provided to the generator during "economic" five minute intervals, all divided by the sum of the generation MW during those "economic" five minute intervals. "Economic" five minute intervals are defined as: 1) those five minute intervals in which the real-time LMP is at or above the generator's offer price; 2) those five minute intervals that PJM dispatched the generator in excess of its min run time and the generator's offer price is above the real-time LMP; and, 3) those five minute intervals 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.

5.2.2 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:
  - o dispatcher transaction logs
  - o day-ahead and real-time external energy sales to spot market o hourly transaction bid rate and MW ($/MWh, MW) o 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:
  o Sum hourly day-ahead offer amounts for the day
  o Sum hourly day-ahead energy market values for the day
  o 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 for each five minute interval the real-time offer amount for each spot market import transaction by multiplying the real-time transaction MW by the transaction offer price divided by twelve.
- PJM calculates for each five minute interval the balancing energy market value for each spot market import transaction by multiplying the real-time five minute interval deviation from the cleared day-ahead transaction MW amount by the real-time LMP at the sink of the transaction divided by twelve.
- PJM calculates the daily Balancing Operating Reserve credits for each transaction as follows:
  o Sum the five minute interval real-time offer amounts for the day
  o Sum the five minute interval 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.

5.2.3 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: o dispatcher generation scheduling and operations logs o resource offer data o resource generation data o 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 five minute intervals) by the hourly cost to condense plus energy use cost divided by twelve 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 five minute interval condensing and energy use costs, including applicable startup costs, for the day.
- PJM calculates the unit-specific lost opportunity cost credits on a five minute interval for providing synchronous condensing for purposes other than providing synchronized reserve or Reactive Services.
- Five Minute Lost Opportunity Cost Credit = [(Five Minute RT LMP – Offer at Five Minute LMP Desired MW) * (Five Minute LMP Desired MW – Max (Five Minute Unit MW, 0))] / 12 only if quantity is positive.
- PJM sums the synchronous condensing credits for all resources for each PJM Member.

5.2.4 Credits for Canceled Pool-Scheduled Resources

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

PJM Actions

- PJM retrieves the following information:
    - o list of canceled resources (dispatcher log)
    - o resource startup cost data
    - o resource generation data
    - o 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 fee is defined as the actual costs incurred, that are typically included in Start-up Costs, when PJM cancels a pool-scheduled generation resource's start and the resource has not yet reached the point after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero., Cancellation Fees shall be capped at the appropriate Start-up Cost for the resource as specified in its offer data.
- PJM sums the Balancing Operating Reserve cancellation fees for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.2.5 Reserved for Future Use

5.2.6 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. A generating resource that is reduced to honor a stability limitation is not

eligible for lost opportunity cost credits for the MWh reduction associated with honoring the stability limit.

5.2.6.1 Pool-Scheduled Generators

Pool-scheduled generators whose output is reduced or suspended and the five minute real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

*[(Lost Opportunity Cost (LOC)) Deviation * (Five Minute Real-time LMP at generator bus) – Total Opportunity Cost Offer] / 12*

- The LOC Deviation is the difference between the generating resource's Desired MW output using the Final Offer based on the five minute real-time LMP at the generator's bus and the generating resources actual output. The Desired MW output is adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.

- Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the LOC Deviation where the applicable offer curve is the greater of the Committed Offer or the Final Offer for each hour of the Operating Day.

5.2.6.2 Self-Scheduled Generators

Self-scheduled generators whose output is reduced or suspended and the five minute real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

*[(LOC Deviation * Five Minute Real-time LMP at the generator bus) – Total Lost Opportunity Cost] / 12*

- The LOC Deviation is the difference between the generating resource's Desired MW output using the applicable real-time offer based on the five minute real-time LMP at the generator bus and the generating resource's actual output. The Desired MW output is adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.

- The Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the LOC Deviation as determined below:
  - o For a self-scheduled generator operating on a cost-based offer, the applicable offer curve is the greater of the originally submitted cost-based offer or the cost-based offer that the generator was dispatched.

      o For a self-scheduled generator operating on a market-based offer, the applicable offer is determined by the following process:
- If there is only one available cost-based offer:
  - Step 1: Select the greater of cost-based Day-ahead offer and the updated cost-based Real-time offer.
  - Step 2: Compare the offer from Step 1 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.
- If there are multiple cost-based offers available,
  - Step 1: For each available cost-based offer, select the greater of the Dayahead offer and the updated Real-time offer.
  - Step 2: Compare the cost-based offers from Step 1 and select the lesser of all the cost-based offers.
  - Step 3: Compare the cost-based offer from Step 2 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.

5.2.6.3 Flexible Resources

Pool-scheduled Flexible Resources that are scheduled to produce energy in the day-ahead market, but are not called on by PJM and do not operate in the corresponding five minute real-time interval, are credited for each five minute interval in an amount equal to the higher of the:

[(Real-time LMP – Day-ahead LMP) * Day-ahead scheduled MW] / 12;
Or

[(Day-ahead committed MWh* Real-time LMP) – (Total Lost Opportunity Cost Offer including no-load costs)] / 12 + (the start-up costs/number of contiguous hours scheduled in the Day-ahead Energy Market)

- The Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the Day-ahead committed MW where the applicable offer curve is the greater of the Committed Offer or the last Real-time Offer submitted for the offer that the generating resource was committed in the Day-ahead Energy Market for each hour of the Operating Day.
- In the case where a Flexible Resource operates in real-time following PJM dispatch and at least one five minute interval of real-time operation coincides with the any of the hours of the day-ahead commitment, the start-up costs will be excluded from the calculation.

Flexible Resources that submit a Real-time offer greater than their resource's Committed Offer in the Day-ahead energy market are not eligible to received Lost Opportunity Cost Credits.

5.2.6.4 Wind Generators

Pool-scheduled or self-scheduled wind generators whose output is reduced or suspended at the request of the Office of the Interconnection and the five minute real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

[(LOC Deviation * Real-time LMP at the generator bus) – Total Lost Opportunity Cost Offer] / 12

- The LOC Deviation is the difference between the wind generator's scheduled output which is the lesser of the PJM forecasted output or the Desired MW using the Final Offer based on the five minute real-time LMP at the generator bus and wind generator's actual output. The Desired MW is also limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.
- The Total Lost Opportunity Cost Offer for pool-scheduled and self-scheduled wind generators is determined in the same manner as described in this section for poolscheduled and self-scheduled generators respectively.
- Pool-scheduled or self-scheduled wind generators are only eligible for the above referenced credit if they:
  o Operated the resource according to PJM Manual and Tariff requirements for wind resources (PJM Manual 14D: Generator Operational Requirements)
  o Have SCADA capability to transmit and receive instructions from PJM

If PJM experiences a technical issue (e.g. computer system failure or disruption or failure of communications equipment) resulting in an erroneous forecast, PJM and the Market Participant will determine a mutually agreeable settlement value. Recommendations for reconciliation include but are not limited to:

- Using the forecast values as determined by PJM wind forecasting tool from before and after the technical issue to determine forecast value during the issue
- Using the forecast value as determined by PJM wind forecasting tool from before the technical issue for the first half of the duration of the technical issue and forecast value from after the technical issue for the latter half of the duration of the technical issue • Using Market Seller's forecast value during the technical issue

PJM Actions
- PJM retrieves the following information:
  o list of units and timeframes reduced or suspended for a transmission constraint or other reliability reason (dispatcher logs and Market Operations eligibility data)
  o resource offer data
  o hourly scheduled MWh for generation offers cleared in day-ahead market o   five minute revenue meter generation MW values from PJM Power Meter if available o five minute state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual
  o hourly scheduled MWh for InSchedule "Generation" contracts, if applicable o generator hourly day-ahead LMPs o five minute real-time LMPs
  o assigned regulation MW, performance scores and marginal benefit factors o assigned synchronized reserve MW
  o five minute wind forecast from PJM's wind forecasting tool o   maximum facility output MW from Interconnection Service Agreements

- PJM sums the Balancing Operating Reserve lost opportunity cost credits for all reduced or suspended generating resources for each PJM Member.

5.2.7 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:
  o   list of units performing annual scheduled black start tests (PJM Performance Compliance Department log) o resource cost-capped offer data o
         resource generation data o   applicable real-time LMP o   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.

5.2.8 Credits for Resources Providing Reactive Services

At the end of each month, PJM credits each PJM Member for Reactive Services that are provided during the month. Generators whose active energy output is increased at the request of PJM for the purpose of maintaining reactive reliability within the PJM Region and the five minute real-time LMP at the generator bus is lower than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

$$[(Real\text{-}time\ MW - Desired\ MW) * (Offer - Five\ Minute\ real\text{-}time\ LMP\ at\ the\ generator\ bus)] / 12$$

Only if the difference between the Offer and the Five Minute real-time LMP at the generator bus is positive

- Desired MW is the MW amount of the generator using the Final Offer based on the five minute real-time LMP at the generator bus. The Desired MW is adjusted for any effective regulation or synchronized reserve assignments and capped at the stability limit in effect.
- Offer is the cost for the generator using the lesser of the Final Offer or Committed Offer at the increased MW level.

In addition, these generators are also credited for lost opportunity costs if the five minute real-time LMP at the generator's bus is higher than its offer corresponding to the level of output requested by PJM. Pool-scheduled generators are credited in the same manner as described in Section 5.2.6.1, and self-scheduled generators are credited in the same manner as described in Section 5.2.6.2.

Generators operating as synchronous condensers for the purpose of maintaining reactive reliability at the request of PJM, are credited for each five minute interval of condensing an amount equal to the higher of: 1) the real-time Synchronized Reserve Market Clearing Price

for the five minute interval divided by 12 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, start-up cost, and the unit-specific lost opportunity cost of the resource supplying the increment of Synchronized Reserve divided by 12.

PJM Actions

- PJM retrieves the following information:
  - o   dispatcher generation scheduling and operations logs
  - o   resource offer data
  - o   hourly scheduled MWh for generation offers cleared in day-ahead market
  - o   state estimator generation MWh
  - o   five minute revenue meter generation MW values from PJM Power Meter, if available o state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual)
  - o   hourly scheduled MWh for InSchedule "Generation" contracts, if applicable
  - o   generator hourly day-ahead LMPs o   five minute real-time LMPs
  - o   assigned regulation MW, performance scores and marginal benefit factors
  - o   assigned synchronized reserve MW
  - o   maximum facility output MW from Interconnection Service Agreements
- PJM sums the reactive services credits for all generating resources for each PJM Member.

5.2.9 Dispatch Differential Lost Opportunity Cost Credits

As noted in Manual 11, a pricing run calculates the Locational Marginal Prices distinct from the security-constrained economic dispatch of the system. This results in the need for a lost opportunity cost credit to ensure that resources dispatched down in the security-constrained economic dispatch continue to follow PJM's dispatch instructions to address the inflexibility of Fast-Start resources.

Only pool-scheduled or dispatchable self-scheduled resources that are dispatched for energy only by PJM are eligible for Dispatch Differential Lost Opportunity Cost credits.

Pool-scheduled and dispatchable self-scheduled resources that are 1) dispatched by PJM to provide regulation or ancillary services in the real-time market; or 2) manually dispatched by PJM due to a transmission constraint or for other reliability reasons are not eligible to receive Dispatch Differential Lost Opportunity Cost credits.

Dispatch Differential Lost Opportunity Cost credits are only calculated in the balancing energy market.

PJM calculates the Dispatch Differential Lost Opportunity Cost credits for an eligible resource for each five minute real-time settlement interval as the positive difference between the revenue above cost for the pricing run and the revenue above cost for the dispatch run.

PJM Actions

- PJM retrieves the following information:
  - o   dispatcher generation scheduling and operations logs ofive minute interval generator dispatch MW values

- o resource offer data - the resource's Final Offer, which is the offer on which the resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day
- o five minute revenue meter generation MW values from PJM Power Meter, if available
- o state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual)
- o five minute real-time LMPs

The revenue above cost for the pricing run is calculated for each five minute settlement interval as follows:

Pricing Run Revenue Above Cost = (Resource Expected MW Output * Five Minute real-time LMP at the resource bus) – Real-time Market Offer

- The Resource Expected MW Output is the Desired MW (capped at the stability limit in effect) value of the resource based on the Final Offer at the five minute real-time LMP at the resource bus.
- The Real-time Market Offer is the five minute interval offer integrated under the Final Offer for the Resource Expected MW Output.

The revenue above cost for the dispatch run is calculated for each five-minute settlement interval as follows:

Dispatch Run Revenue Above Cost = Max(Five Minute Dispatch MW * Five Minute real-time LMP at the resource bus, Five Minute Revenue Data for Settlements MW * Five Minute realtime LMP at the resource bus) – Min(Cost of the Five Minute Dispatch MW, Cost of Five Minute Revenue Data for Settlement MW)

- The Five Minute Dispatch MW is the MW setpoint for a resource as determined in the security-constrained economic dispatch run.
- The Cost of the Five Minute Dispatch MW is the five minute interval offer integrated under the Final Offer for the Five Minute Dispatch MW.
- The Cost of the Five Minute Revenue Data for Settlements MW is the five minute interval offer integrated under the Final Offer for the Five Minute Revenue Data for Settlements
  MW.

Dispatch Differential Lost Opportunity Cost Credit = Max(Pricing Run Revenue Above Cost – Dispatch Revenue Above Cost, 0)

- PJM sums the Dispatch Differential Lost Opportunity Cost credits for all generating resources for each PJM Member for each hour of the Operating Day.

5.3 Charges for Operating Reserve

The total cost of providing Operating Reserve for the Operating Day is the sum of the credits provided to PJM Market Participant for supplying the Day-ahead and Balancing Market Operating Reserve except those Operating Reserve credits associated with the scheduling of units for Black Start service or testing of Black Start Units, Reactive Services or transfer interface. Credits associated with Black Start service or testing of Black Start Units, Reactive

Service or transfer interface control are charged separate of Day-ahead Operating Reserves and Balancing Operating Reserves.

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.

5.3.1 Day-ahead Operating Reserves

The daily total cost of Day-ahead Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is determined only for the RTO region, allocated and charged to PJM Market Participants in proportion to their cleared day-ahead demand, decrement bids, and up-to congestion transactions at the sink end of the transaction plus their cleared day-ahead exports. Charge allocations for Black Start Service are described in Section 5.3.4 of this PJM Manual and for Reactive Services are described in Section 5.3.5 of this PJM Manual.

PJM Actions

- PJM retrieves the following information for Day-ahead Operating Reserve Charges:
    - Cleared Day-ahead demand (MWh)
    - Cleared Day-ahead decrement bid (MWh)
    - Cleared Day-ahead exports (MWh)
    - Cleared Day-ahead up-to congestion transactions (MWh)
    - Total Day-ahead Operating Reserve generating resource credits ($)
    - Total Day-ahead Operating Reserve transaction credit ($)
- PJM calculates the Day-ahead Operating Reserve Charge as the Market Participant's ratio share of the total Day-ahead Operating Reserve credits as follows:
    - Day-ahead Operating Reserve Charge = Total Day-ahead Operating Credits * ((Cleared Day-ahead demand + decrement bids + up-to congestion transactions + exports) / (Total cleared Day-ahead demand + decrement bids + exports)
    - Total Day-ahead Operating Credits = Total Day-ahead Operating Reserve generating resource credits + Total Day-ahead Operating Reserve transaction credits

5.3.2 Balancing Operating Reserves

The daily total cost of Balancing Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service is determined for each region (RTO, East and West) which is allocated and charged to PJM Market Participants depending if the Balancing Operating Reserve credits are deemed for reliability or deviations.

The regions are defined as follows:

- RTO region = the East and West regions plus exports that are at the interfaces or hubs not completely contained in either the East or West region
- East region = transmission zones AEC, BGE, Dominion, DPL, JCPL, MW, PECO, Penelec, PEPCO, PPL, PSEG and RE

- West region = transmission zones AEP, APS, ATSI, ComEd, DEOK, DUQ, DAY, EKPC and OVEC

PJM determine if Balancing Operating Reserve credits should be charged to the East region or West region, instead of the RTO region, when the resource is needed for a transmission constraint that occur on transmission lines equal to or less than 345 kV.

5.3.2.1 Balancing Operating Reserves for Reliability Charge

PJM calculates for each Operating Day the total Regional Cost of Balancing Operating Reserve to be charged for reliability for each region and for all PJM Market Participants excluding those credits associated with the scheduling of units for Black Start service or testing of Black Start units. PJM allocates these total costs for reliability to each PJM Market Participant based on their daily share of the sum of their Real-time load plus Real-time exports in each region (RTO, East, West).

PJM Actions

- PJM retrieves the following information for Balancing Operating Reserve charges for reliability by region:
  - o Real-time load
  - o Real-time exports
  - o Total Balancing Operating Reserve resource credits for reliability ($)
- PJM calculates the Balancing Operating Reserve charge for reliability as the Market Participant's Real-time load plus exports share of the total Balancing Operating Reserve credits for reliability by region as follows:
  - o *Balancing Operating Reserve for Reliability Charge (by region) = Total Balancing Operating Reserve Credits for Reliability * (Real-time load = Real-time exports)*

5.3.2.2 Balancing operating Reserves for Deviation Charge

PJM calculates for each Operating Day the total cost of Balancing Operating Reserve to be charged for deviations for each region and for all PJM Market Participants excluding those credits associated with the scheduling of units for Black Start service or testing of Black Start units. PJM allocates these total costs for deviations to each PJM Market Participant based on their daily share of the sum of their 5-minute interval deviations associated with generating resources, withdrawals and injections in each region (RTO, East, West).

PJM Actions

- PJM retrieves the following information for Balancing Operating Reserve charges for deviation by region:
  - o Total Regional Balancing Operating Reserve generating resource credits for deviations ($)
  - o Total Balancing Operating Reserve demand resource credits ($)
  - o Total Balancing Operating Reserve transaction credits ($)
  - o Total Balancing Operating Reserve cancellation fees ($)
  - o Total Balancing Operating Reserve quick start resource credits ($)
  - o Total Balancing Operating Reserve reduction/suspension credits ($)

- PJM calculates the Balancing Operating Reserve charge for deviations as the Market Participant's total deviations share of the total Balancing Operating Reserve credits for deviation by region as follows:
  o *Balancing Operating Reserve for Deviations Charge (by region) = Total Balancing Operating Reserve Credit for Deviations * total MW deviations*
  o *Total MW deviations = determined for each Market Participant as further described in Sections 5.3.2.3, 5.3.2.4 and 5.3.2.5 of this PJM Manual*

5.3.2.3 Deviation Calculations for Generating Resources

- PJM calculates for each hour of the Operating Day the individual generating resource deviations as the sum of the absolute value of the five minute interval deviations in the hour divided by 12 for generating resources that are not following dispatch for each five minute interval as follows:
  o Each pool-scheduled or dispatchable self-scheduled generator not following PJM dispatch due to its actual output not being between its ramp-limited Desired MW and UDS Basepoint MW, and its % off dispatch is > 10%, will be assessed deviations as Real-time MW – ramp-limited desired MW. If the % off dispatch is > 20%, deviations will be assessed as Real-time MW – UDS LMP Desired MW (as determined in the Credits for Pool-Scheduled Generating Resources section of this manual).
  o 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 MW – Day-ahead Schedule MW.
  o Each unit that has tripped or is scheduled Day-ahead and does not run in Real-time will be assessed deviations as Real-time MW – Day-ahead scheduled MW
  o Each unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will be assessed deviations as Real-time MW – UDS LMP Desired MW
  o Each unit that is not dispatchable in both the Day-ahead and Real-time market will be assessed deviations as Real-time MW – Day-ahead scheduled MW. Units that choose to participate in the Day-ahead pumped storage optimization program are considered not dispatchable in the Day-ahead market.
  o 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 MW 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 MW – UDS LMP Desired MW
  o Deviations are not calculated if the absolute value of the deviation MW ratio to applicable day-ahead scheduled MW or desired MW is less than or equal to 5%

- Five minute intervals during which a generator is assigned by PJM for: Regulation; assigned by PJM for Synchronized Reserve and reduced from its economic dispatch base point (and actual MW are less than day-ahead scheduled MW), assigned by PJM for Non-Synchronized Reserve (and actual MW are less than the day-ahead scheduled MW) or assigned by PJM for Secondary Reserve and reduced from its economic base point (and actual MW are less than the day-ahead scheduled MW), or Tier 1 resources that respond to a Synchronized Reserve Event are omitted from this calculation.
- Resource five minute interval 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 ("supplier netting"). Unit parameters do not have to be identical for the units' deviation MW to offset one another. Units at a "single bus" must be contained in the same customer account.
- If the hourly sum of the absolute value of the five minute interval deviations for a generating resource divided by 12 for an hour is less than 5 MWh, then the generating resource is not assessed a Balancing Operating Reserve deviation for that hour.

5.3.2.4 Deviation Calculations for Withdrawals
- PJM calculates for each hour of the Operating Day the withdrawal deviations as the sum of the five minute interval real-time deviations from day-ahead values for each customer account as follows:
  - Absolute Value of (cleared day-ahead demand bid MW + cleared day-ahead decrement bid MW + cleared up-to congestion transaction MW at the sink end of the transaction + day-ahead sale transaction MW – real-time load de-rated for transmission losses including the impact of load reconciliation MW – real-time sale transaction MW) divided by 12
  - 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 aggregates fully contained within a given zone. o Dynamically scheduled export transactions are omitted from this calculation.
  - Positive demand deviations (real-time withdrawal MWs less than day-ahead withdrawal MWs) will not be included in the total withdrawal deviation by location during five minute intervals in which an Primary Reserve or Synchronized Reserve shortage in real-time occurs or when PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

5.3.2.5 Deviation Calculation for Injections
- PJM calculates for each hour of the Operating Day the injection deviations as the sum of the five minute interval real-time deviations from day-ahead values for each customer account as follows:
  - Absolute Value of (cleared day-ahead increment offer MW + day-ahead purchase transaction MW – real-time purchase transaction MW) divided by 12

o   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 aggregates fully contained within a given zone.

5.3.3 Synchronous Condenser

The total daily cost of synchronous condenser payments (other than that for synchronized reserve or Reactive Services) is allocated and charged to PJM Market Participants in proportion to their Load Ratio Share during that Operating Day.

5.3.4 Black Start

The total monthly cost of Operating Reserves for resource providing Black Start service or testing of Black Start units is allocated to Network and Point-to-Point Transmission Customers based on their monthly transmission use on a megawatt basis. Additional details on this allocation can be found in PJM Manual 27: Open Access Transmission Tariff Accounting, Section 7.

5.3.5 Reactive Services

The total daily cost for resource scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a zone(s) sums the costs from both Day-ahead and Balancing. This total daily cots are allocated and charged to reach market Participant based on their Load Ratio Share in the applicable transmission zone(s).

5.3.6 Dispatch Differential Lost Opportunity Cost

The total hourly cost of the Dispatch Differential Lost Opportunity Cost credits are allocated and charged to PJM Market Participants on an RTO wide basis in proportion to their real-time load (excluding losses and Direct Charging Energy) plus exports during that Operating Day.

5.4 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 monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule 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, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

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, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

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, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

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

Synchronized Reserve shall be supplied from resources located within the metered boundaries of PJM that are on-line and able to provide additional MWs within 10 minutes or less. Resources participating in the Synchronized 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 reserve 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 ResourcesEconomic Load Response Participants.

The total PJM Synchronized Reserve Requirement is defined as the amount of 10-minute reserve that must be synchronized to the grid in accordance with the applicable NERC Council standards. Additional details on the Primary and Synchronized Reserve requirements can be found in PJM Manual 13: Emergency Operations.

Tier 1 Synchronized Reserve credits are awarded to all resources in both the Day-ahead and Real-time Synchronized Reserve Markets based on pool-scheduled and self-scheduled MW assignment and RT MW output. 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 1 Synchronized Reserve resources are also compensated when the Non-Synchronized Reserve Market Clear Price is non-zero. Tier 2 Synchronized Reserve credits are awarded to all resource owners that have assigned self-scheduled or pool-scheduled Synchronized Reserve.

The Synchronized Reserve offer price for Tier 2 resources is capped at a maximum value of the unit's Operating and Maintenance cost (as determined by the Cost Development Task Force) plus $7.50/MWh.the expected value of the penalty for failing to provide Synchronized Reserve as described and calculated in PJM Manual 15: Cost Development Guidelines

Pool-scheduled Ggenerator resources assigned synchronized reserve in Synchronous Condensing mode and which respond to a Synchronized Reserve Event on-line and providing Tier 2 are made eligible for make-whole payments to recover applicable start-up, no-load and minimum energy costs in the Balancing Operating Reserve billing line item. Demand ResourcesEconomic Load Response Participant resources that respond to a Synchronized Reserve Eevent , and are eligible for make-whole payments to recover shutdown cost and are made-whole in the Operating Reserve for Load Response billing line item.

Resources that are assigned regulation when a Synchronized Reserve event is initiated are 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). Additional details can be found in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 4.82.11.

Each Market Participant that is a Load Serving Entity (LSE) or synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Ssynchronized Rreserve Ooobligation based on their Load Ratio Share and applicable reserve zone's location's requirements during that hour. During hours when the Synchronized Reserve Market Clearing Price (SRMCP) is the same throughout the entire RTO reserve zone, an LSE's Synchronized Reserve Ooobligation is equal to its Load Ratio Share of the RTO reserve zone times the amount of Ssynchronized Rreserve assigned for all Real-time Settlement Intervals five minute intervals for the entire RTO Rreserve zone. During hours when congestion causes the SRMCP is different between the RTO Reserve zone and the Reserve sub-zone,to separate, each an LSE's Synchronized Reserve Ooobligation will be calculated based on their load in the active sub-zone and/or the portion of the RTO Reserve Zone outside of the active sub-zone (the "non sub-zone"). The LSE's active sub-zone Synchronized Reserve Obligation is equal to its Load Ratio Share within that active sub-zone within its reserve zone or sub-zone and times the amount of Synchronized Reserve assigned (pool/self-scheduled) in that reserve zone oractive sub-zone. The LSE's Synchronized Reserve Obligation in the non sub-zone is equal to its Load Ratio Share in the non sub-zone times the amount of Synchronized Reserve assigned (pool/self-scheduled) in the non sub-zone portion of the RTO.

Participants may fulfill their Synchronized Reserve obligations by owning Tier 1 resources from which PJM obtains Synchronized Reserve, entering bilateral arrangements with other PJM Market Participants, or purchasing Synchronized Reserve from the PJM Synchronized Reserve Market.

6.2 Credits for Synchronized Reserve

Synchronized Reserve credits are paid in both Day-ahead and Real-time Synchronized Reserve Markets to Market Participants that supply their resource to PJM as pool-scheduled or self-scheduled. PJM sums the Synchronized Reserve credits (both Synchronized Reserve

~~Clearing Price credits and Synchronized Reserve Lost Opportunity Cost credits) to determine the total hourly credit for each Synchronized Reserve market participant.~~ The credits for the Day-ahead and Real-time Synchronized Reserve Markets appear on the billing statement as two separate billing line items:

- Day-ahead Synchronized Reserve Credits = Sum(Day-ahead Synchronized Reserve Market Clearing Price Credits) for the days in the billing period
- Balancing Synchronized Reserve Credits = Sum(Balancing Synchronized Reserve Market Clearing Price Credits – Synchronized Reserve Shortfall Charges + Synchronized Reserve Lost Opportunity Cost Credits) for the days in the billing period

Synchronized Reserve credits for jointly-owned generators supplying Synchronized Reserves are allocated to the owners based on their ownership share.

6.2.1 Day-ahead Synchronized Reserve Market Clearing Price Credit

Day-ahead Synchronized Reserve Market Clearing Price credits are paid to a pool-scheduled or self-scheduled resource that is assigned Synchronized Reserve MWs within the Day-ahead Market to satisfy the 30-minute Reserve Requirement, Primary Reserve Requirement and/or Synchronized Reserve Requirement.

PJM Actions
- PJM retrieves the following information for Day-ahead Synchronized Reserve Market Clearing Price credit:
  o Day-ahead Synchronized Reserve assignments (pool/self-scheduled) (MWh)
  o Day-ahead Synchronized Reserve Market Clearing Price (DA SRMCP) ($/MWh)
- PJM calculates for each hour the Day-ahead Synchronized Reserve Market Clearing Price credit for each eligible resource by multiplying the Day-ahead Synchronized Reserve MWs assigned by the DA SRMCP.
  o Day-ahead Synchronized Reserve Market Clearing Price Credit = Day-ahead Synchronized Reserve MW * DA SRMCP

~~Synchronized Reserve credits are paid to Tier 1 resources and Tier resources. Since Tier 1 resources are online units following economic dispatch and Tier 2 resources offer and must be cleared through the Synchronized Reserve Market, there are different compensation methodologies. Lost opportunity cost credits are descried in Section 6.2.2 of this PJM Manual.~~

~~**PJM Actions**~~
- ~~PJM retrieves the following information for the Tier 1 Synchronized Reserve Clearing Price credit:~~
  o ~~Synchronized Reserve Ramp rate for Tier 1 resources~~ o ~~Synchronized Reserve maximum for Tier 1 resources~~ o ~~5 minute MW response~~ o ~~Synchronized energy premium price~~
  o ~~Total PJM Synchronized Reserve requirement as determined in whole MW for each five minute interval of the operating day~~

- o Synchronized Reserve Market Clearing Price (SRMCP) ($/MWh) o Non-Synchronized Reserve Market Clearing Price (NSRMCP) ($/MWh)
- PJM calculates the five minute interval Synchronized Reserve credits for each Tier 1 resource for when the five minute intervals NSRMCP is zero for the same reserve zone or sub-zone that a Tier 1 resource is located, Tier 1 Synchronized Reserve credits are equal to the increase in MW generator output (or decrease in MW consumption for demand side response resources) from each resource for each five minute interval during the length of a Synchronized Reserve event multiplied by the synchronized energy premium divided by 12. The synchronized energy premium is $50/MWh.
  - o *Tier 1 Synchronized Reserve Credit = Five Minute MW Response * $50/MWh / 12*
- PJM calculates the five minute interval Synchronized Reserve credit for each Tier 1 resource for when the five minute intervals NSRMCP is non-zero for the applicable reserve zone or subzone, Tier 1 synchronized reserve credits are equal to the applicable reserve zone or sub-zone Synchronized Reserve Market Clearing Price multiplied by the lesser of the increase in MW output or decrease in MW of consumption from each resource for each five minute interval during the length of a synchronized reserve event and the estimated Tier 1 the resource could have provided. During five minute intervals when no synchronized reserve event occurs in the applicable reserve zone or sub-zone, the Tier 1 resource will be compensated using the estimated Tier 1 amount for only those resources that can reliably provide Synchronized Reserve service per the rules in Manual 11: Energy & Ancillary Services Market Operations, Section 4.2.1.
  - o *Tier 1 Synchronized Reserve Credit = (Lesser of Five Minute Actual Response OR Five Minute Estimated Tier 1 Response) * SRMCP / 12*
- PJM retrieves the following information for the Tier 2 Synchronized Reserve Clearing Price credit:
  - o Synchronized Reserve availability o Synchronized Reserve assigned quantity (MW) o Synchronized Reserve offer price o Synchronized Reserve bilateral transactions o Energy use for condensing resource o Condense startup cost o 5-minute interval LMP data
  - o Total PJM Synchronized Reserve requirement
  - o Synchronized Reserve Market Clearing Price (SRMCP) ($/MWh)
- PJM calculates the five minute interval Synchronized Reserve Clearing Price credits for both pool-scheduled and self-scheduled Tier 2 resource to equal the five minute SRMCP divided by 12 times the resource's five minute Synchronized Reserve capability less any shortfall for the five minute interval due to failure to provide assigned capability during a Synchronized Reserve event.
  - o *Tier 2 Synchronized Reserve Credit = (SRMCP / 12) * (Assigned Synchronized Reserve MW – Synchronized Reserve MW Shortfall)*

6.2.2 Balancing Synchronized Reserve Market Clearing Price Credit

Balancing Synchronized Reserve Market Clearing Price credits are paid to a pool-scheduled or self-scheduled resource that is assigned Synchronized Reserve within the Real-time Market to satisfy the 30-minute Reserve Requirement, Primary Reserve Requirement and/or Synchronized Reserve Requirement.

PJM Actions

- PJM retrieves the following information for Balancing Synchronized Reserve Market Clearing Price credit:
    - Real-time Synchronized Reserve assignments (pool/self-scheduled) (MWh)
    - Economic Maximum MW
    - Real-time Synchronized Reserve Maximum MW
    - Real-time MW output
    - Day-ahead Synchronized Reserve assignments (pool/self-scheduled) (MWh)
    - Real-time Synchronized Reserve Market Clearing Price (RT SRMCP) ($/MWh)
    - Synchronized Reserve Shortfall MW
- PJM calculates for each Real-time Settlement Interval the Balancing Synchronized Reserve Market Clearing Price credit for each eligible resource by taking the difference between the *capped* Real-time Synchronized Reserve assignment and Day-ahead Synchronized Reserve assignment and multiplying it by the RT SRMCP, then dividing the product by 12.
    - Balancing Synchronized Reserve Market Clearing Price Credit = ((Capped Real-time Synchronized Reserve Assignment – Day-ahead Synchronized Reserve Assignment) * RT SRMCP) / 12
    - Capped Real-time Synchronized Reserve Assignment =
        - If no Synchronized Reserve Event occurs = Minimum (Real-time Synchronized Reserve Assignment MW, (Minimum (Economic Maximum MW, Real-time Synchronized Reserve Maximum MW)) – Real-time MW Output)
        - If a Synchronized Reserve Event occurs = Real-time Synchronized Reserve Assignment MW
- Synchronized Reserve Shortfall Charge = If a pool-scheduled or self-scheduled generation resource or Economic Load Response Participant resource fails to provide the Capped Real-time Synchronized Reserve Assignment during a Synchronized Reserve Event, then the resource will be assessed a Synchronized Reserve Shortfall Charge equal to the product of the RT SRMCP and the lesser of the amount of the MW shortfall during the event or Capped Real-time Synchronized Reserve Assignment MW. The calculation of the MW shortfall is further described in Manual 11, Section 4. This Shortfall Charge will apply to each Real-Time Settlement Interval the resource was assigned or self-scheduled for real-time Synchronized Reserve in the Operating Day on which the event occurred. This charge is netted against any Balancing Synchronized

Reserve Market Clearing Price Credits the resource received in the calculation of the Balancing Synchronized Reserve Market Credit billing line item.

6.2.23 Synchronized Reserve Lost Opportunity Cost Credit

PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit for pool-scheduled Tier 2 resources if the Synchronized Reserve Lost Opportunity Cost (excluding any reduction for a stability limit) is greater than the total SRMCP Credits (Day-ahead and Balancing) received through the Synchronized Reserve Market for the resource for the each Real-time Settlement Interval. five minute interval. If the resulting amount is negative, then the credit is $0.

PJM Actions

- PJM retrieves the following information for the Synchronized Reserve Lost Opportunity Cost credit:
  o Day-ahead Synchronized Reserve Offer Amount ($)
  o Real-time Synchronized Reserve Offer Amount ($)
  o Economic Maximum MW
  o Real-time Synchronized Reserve Maximum MW
  o Real-time MW usage
  o Day-ahead MW usage
  o Day-ahead Synchronized Reserve assignments (MWh)
  o Real-time Synchronized Reserve assignments (MWh)
  o Day-ahead Synchronized Reserve Market Clearing Price Credit ($/MWh)
  o Balancing Synchronized Reserve Market Clearing Price Credit ($/MWh)
  o Market Revenue Neutrality Offset ($) (as determined and calculated in Section 15 of this PJM Manual)
  o Synchronized Reserve Opportunity Cost Credits Owed ($) (as determined and calculated in Section 15 of this PJM Manual)
- For each Real-time Settlement Interval, PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit for a resource if the costs associated with that resource are greater than the credits received by the resource.
  o Synchronized Reserve Lost Opportunity Cost Credit = Max(Synchronized Reserve Cost – Synchronized Reserve Credit, 0)
- PJM calculates the cost side of the Synchronized Reserve Lost Opportunity Cost Credit equation as follows:
  o Synchronized Reserve Cost = (Day-ahead Synchronized Reserve Offer Amount + Real-time Synchronized Reserve Offer Amount + Day-ahead Synchronized Reserve Opportunity Cost + Real-time Synchronized Reserve Opportunity Cost) / 12
    ▪ Day-ahead Synchronized Reserve Offer Amount = Day-ahead Synchronized Reserve Offer Price * Day-ahead Synchronized Reserve assignment
    ▪ Real-time Synchronized Reserve Offer Amount = Real-time Synchronized Reserve Offer Price * Max(Capped Real-time Synchronized Reserve

Assignment (as determined and calculated in Section 6.2.2 of the PJM Manual) – Day-ahead Synchronized Reserve assignment), 0).

- Day-ahead Synchronized Reserve Opportunity Cost will equal (A * B) - C:
  - A = DA LMP at the generation bus or applicable Economic Load Response Participant resource pricing point

  - B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load
  - C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.
  - For the following resource types, the Day-ahead Synchronized Reserve Opportunity Cost is calculated as follows:
    - Resources committed to provide synchronized reserves in synchronous condensing mode = (Day-ahead energy usage to provide Synchronous Condensing * DA LMP at the generation bus) + (Day-ahead Condense Start-up costs / Number of Hours assigned Synchronized Reserve)
  - Economic Load Response Participants resource = $0
- Real-time Synchronized Reserve Opportunity Cost will equal (A * B) – C:
  - A = RT LMP at the generation bus or applicable Economic Load Response Participant resource pricing point
  - B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy
  - C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation

resource's expected output level if it had been dispatched in economic merit order to provide energy.

- For the following resource types, the Real-time Synchronized Reserve Opportunity Cost is calculated as follows:
  - Resources providing synchronized reserves in synchronous condensing mode = ((Real-time energy usage to provide Synchronous Condensing – Day-ahead energy usage to provide Synchronous Condensing) * RT LMP at the generation bus) + any additional condense start-up costs in excess of Day-ahead Condense Start-up costs
  - Hydro unit (spill mode) = (RT LMP at the generation bus * (Real-time Synchronized Reserve assignment – Day-ahead Synchronized Reserve assignment)
  - Hydro unit (non-spill mode with day-ahead energy commitment > 0) = (RT LMP at the generation bus - average RT LMP at the generation bus for the appropriate on peak / off peak period) * (Real-time Synchronized Reserve assignment – Day-ahead Synchronized Reserve assignment). If the average RT LMP value is higher than the RT LMP at the generator bus, then the Real-time Synchronized Reserve Opportunity Cost will equal zero.
    - o Where the "on peak" is defined as 0700 – 2259 and "off-peak" is defined as 0000 – 0659, 2300-2359, excluding those hours during which all available units at the hydro plant were operating
  - Hydro unit (non-spill mode with no day-ahead energy commitment > 0) = $0
- PJM calculates the credit side of the Synchronized Reserve Lost Opportunity Cost Credit equation as follows:
  - o Synchronized Reserve Credit = (Day-ahead Synchronized Reserve Market Clearing Price Credit /12) + (Market Revenue Neutrality Offset + Synchronized Reserve Opportunity Cost Credit Owed + Balancing Synchronized Reserve Market Clearing Price Credit – Synchronized Reserve Shortfall Charge)
    - ▪ Day-ahead Synchronized Reserve Market Clearing Price Credit = as determined and calculated in Section 6.2.1 of the PJM Manual
    - ▪ Market Revenue Neutrality Offset = as determined and calculated in Section 15 of this PJM Manual
    - ▪ Synchronized Reserve Opportunity Cost Credit Owed = as determined and calculated in Section 15 of this PJM Manual
    - ▪ Balancing Synchronized Reserve Market Clearing Price Credit = as determined and calculated in Section 6.2.2 of the PJM Manual
    - ▪ Synchronized Reserve Shortfall Charge = as determined and calculated in Section 6.2.2 of this PJM Manual

Real-time LMP

Energy use (only used for condensing units)

Applicable offer curves

Synchronized Reserve Market Clearing Price (SRMCP) credit

PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit if the lost opportunity cost is greater than the Synchronized Reserve Market Clearing Price credit for the resource for the five minute interval.

Synchronized Reserve Lost Opportunity Cost Credit = (Synchronized Lost Opportunity Cost / 12) – SRMCP Credit

*Synchronized Lost Opportunity Cost = (Energy Use * 5-minute real-time LMP) + (MW deviation * (5-minute real-time LMP – Offer Price))*

Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time LMP at the hydro unit bus for the appropriate on peak (0700 – 2259) or off-peak (0000 – 0659, 2300-2359) period, excluding those hours during which all available units at the hydro plant were operating.

If a hydro unit is in spill, the lost opportunity cost for each five minute interval is equal to (i) the Synchronized Reserve assigned MW multiplied by (ii) the real-time five minute LMP at the generator bus.

If a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost for each five minute interval is equal to (i) the Synchronized Reserve assigned MW multiplied by (ii) the difference between the real-time five minute LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average realtime LMP value is higher than the real-time five minute LMP at the generator bus, the lost opportunity cost will be zero.

If a hydro unit is not committed day-ahead, the lost opportunity cost is equal to zero.

6.3 Charges for Synchronized Reserve

The total cost of providing Synchronized Reserve for each hour is the sum of the five minute credits provided to PJM Members for supplying Synchronized Reserve in that hour. The cost of Tier 1 and Tier 2 Synchronized Reserve is allocated separately and charged to PJM Members. PJM allocates the cost of the total Day-ahead and Balancing Synchronized Reserve credits paid to resources providing Synchronized Reserve as charges to Market Participants with a Synchronized Reserve Obligation in the RTO zone, active sub-zone or non sub-zone as described in section 6.1 of this PJM Manual. PJM calculates charges for the RTO Reserve Zone when there is no price separation between the RTO Reserve Zone and the active sub-zone, and calculates charges for the active sub-zone and non sub-zone portions of the RTO, rather than for the RTO Reserve Zone, when there is price separation.

Each Market Participant that is a Load Serving Entity (LSE) or synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Synchronized Reserve Obligation based on their

Load Ratio Share and applicable reserve zone's or reserve sub-zone's requirements during that hour. A Load Serving Entity (LSE) whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 does not have a Synchronized Reserve Obligation.

PJM separately allocates the charges associated with Synchronized Reserve Market Clearing Price Credits and Synchronized Reserve Load Opportunity Cost Credits and ~~appear~~includes them on the billing statement as one billing line item:
- Synchronized Reserve Charge = Synchronized Reserve Market Clearing Price Charge + Synchronized Reserve Lost Opportunity Cost Charge + Synchronized Reserve Retroactive Penalty Charge

6.3.1 Synchronized Reserve Market Clearing Price Charge

~~Each Market Participant that is a Load Serving Entity (LSE) or synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Synchronized Reserve Obligation based on their Load Ratio Share and applicable reserve zone's requirements during that hour. A Load Serving Entity (LSE) whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 do not have a Synchronized Reserve Obligation.~~ **PJM Actions**
- PJM retrieves the following information for the Synchronized Reserve Market Clearing Price Charge
  o Market Participant's Load Ratio Share (MWh)
  o Bilateral Synchronized Reserve transactions (sales and purchases) (MWh)
  o Total PJM Real-time Synchronized Reserve assigned (pool and self-scheduled) (MWh)
  o Day-ahead Synchronized Reserve Market Clearing Price Credits ($)
  o Balancing Synchronized Reserve Market Clearing Price Credits ($)
- PJM calculates each Market Participant's hourly Synchronized Reserve Market Clearing Price charges by RTO zone or active sub-zone and non sub-zone in which the load is located by multiplying the Total Synchronized Reserve Market Clearing Price Credits in that location times the Market Participant's Synchronized Reserve Obligation Share in that location.
  o Synchronized Reserve Market Clearing Price Charges = Total Synchronized Reserve Market Clearing Price Credits * Synchronized Reserve Obligation Share
- PJM calculates for each hour the Total Synchronized Reserve Market Clearing Price Credits in the applicable location.
  o Total Synchronized Reserve Market Clearing Price Credits = Day-ahead Synchronized Reserve Market Clearing Price Credits + Balancing Synchronized Reserve Market Clearing Price Credits – Synchronized Reserve Shortfall Charge
- PJM calculates each Market Participant's hourly Synchronized Reserve Obligation Share by RTO zone or active sub-zone and non sub-zone based on their Load Ratio

Share in that location, adjusted by bilateral Synchronized Reserve sales and purchases.

o   Synchronized Reserve Obligation Share = ((Load Ratio Share * Total PJM Real-time Synchronized Reserve assigned) – Synchronized Reserve MW Purchased + Synchronized Reserve MW Sold) / Total PJM Real-time Synchronized Reserve assigned

: o   Synchronized Reserve bilateral transactions

Total PJM Synchronized Reserve assigned by reserve zone and sub-zone o   Total Synchronized Reserve shortfall (MWh) by reserve zone and sub-zone

PJM calculates the Synchronized Reserve Tier 1 charges for each Market Participant for the applicable zone or subzone by multiply the total Tier 1 credits by the Tier 1 Allocation to Obligation ratio for that hour

*Tier 1 Charges = Total Tier 1 Credit * (Tier 1 Allocation to Obligation / Total Tier 1 Allocation to Obligation) o   Tier 1 Allocation to Obligation = Lesser of (Remaining Bilateral Adjusted Obligation or Obligation Ratio Share of Excess Tier 1) + Lesser of (Adjusted Synchronized Reserve Obligation or Tier 1 Estimate MWh) o   Remaining Bilateral Adjusted Obligation = Adjusted Synchronized Reserve Obligation – Tier 1 Estimate MWh o   Obligation Ratio Share of Excess Tier 1 = Total Tier 1 Excess * (Remaining Bilateral Adjusted Obligation / Total Remaining Bilateral Adjusted Obligation) o   Adjusted Synchronized Reserve Obligation = Synchronized Reserve Obligation + Bilateral Synchronized Reserve Sales – Bilateral Synchronized Reserve Purchases o   Synchronized Reserve Obligation = (Total Tier 1 Estimated and Tier 2 Assigned) * Market Participant Load / Total Load)*

PJM calculates the Synchronized Reserve Tier 2 charges for each Market Participant for the applicable zone or subzone by the appropriate hourly Tier 2 Synchronized Reserve credits times the Market Participant's ratio share of Synchronized Reserve adjusted obligation MW, less any Tier 1 Synchronized Reserve applied to obligation.

*Tier 2 Charges = (above Obligation Tier 1 Adjustment / Total PJM Above Obligation Tier 1 Adjustment) * Total PJM Synchronized reserve Tier 2 Credits o   Above Obligation Tier 1 Adjustment = Adjusted Synchronized Reserve Obligation – Tier 1 Allocation to Obligation o   If the hourly-integrated SRMCP is equal for all the sub-zones within a reserve zone, the Total PJM Synchronized Reserve Tier 2 Credits in the reserve zone are allocated based on a Market Participant's above obligation ration share in the reserve zone.*

If the hourly-integrated SRMCP is different for the sub-zones within a reserve zone, the Total PJM Synchronized Reserve Tier 2 Credits in the sub-zone are allocated based on a Market Participant's above obligation ration share in the sub-zone.

6.3.2 Synchronized Reserve Lost Opportunity Cost Charge

PJM Actions

- PJM retrieves the following information for Synchronized Reserve Lost Opportunity Cost Charge:
  - o   Market Participant's Load Ratio Share (MWh)

- o   Bilateral Synchronized Reserve transactions (sales and purchases) (MWh)
- o   Total PJM Real-time Synchronized Reserve assigned (MWh)
- o   Self-scheduled Synchronized Reserve (MWh)
- o   Total PJM self-scheduled Synchronized Reserve (MWh)
- o   Total PJM Synchronized Lost Opportunity Cost Credits

• PJM calculates each Market Participant's hourly Synchronized Reserve Lost Opportunity Cost Charges by RTO zone or active sub-zone and non sub-zone by multiplying the Total PJM Synchronized Lost Opportunity Cost Credits in that location times the Market Participant's Synchronized Reserve Purchase ratio share in that location.

- o   Synchronized Reserve Lost Opportunity Cost Charge = Total PJM Synchronized Lost Opportunity Cost Credits * Synchronized Reserve Purchase ratio share

• PJM calculates each Market Participant's hourly Synchronized Reserve Purchases by RTO zone active or sub-zone and non sub-zone based on their Load Ratio Share in the location, adjusted by bilateral Synchronized Reserve sales and purchases minus Synchronized Reserve self-schedule MWs.

- o   Synchronized Reserve Purchases = ((Load Ratio Share * Total PJM Real-time Synchronized Reserve assigned)) – Synchronized Reserve MW Purchased + Synchronized Reserve MW Sold – Synchronized Reserve Self-Scheduled MW)) / (Total PJM Real-time Synchronized Reserve assigned – Total PJM self-scheduled Synchronized Reserve used to satisfy a Synchronized Reserve Obligation)

- ~~The amount of unrecovered costs allocated to each Market Participant is determined based on each Market Participant's ratio share of Tier 2 Synchronized Reserve purchased from the market. A Market Participant's purchases equals their Synchronized Reserve obligation MW less any Tier 1 Synchronized Reserve applied to obligation, less any self-scheduled Tier 2 MW.~~
  - o   *~~Synchronized Reserve Lost Opportunity Cost Charge Cleared = Total Lost Opportunity Cost Credits * (Synchronized Reserve Purchase / Total PJM Synchronized Reserve Purchases)~~* o   *~~Synchronized Reserve Purchase = (Above Obligation Tier 1 Adjustment – Tier 2 Self Scheduled MWh)~~*
- ~~The cost of Tier 2 resources assigned by PJM during the operating hour in addition to that which resulted from the Tier 2 clearing process due to reduced availability of Tier 1 Synchronized Reserve are allocated to those entities for which less Tier 1 was available during the hour that was estimated prior to the hour (Tier 1 Lost MW), in proportion to the reduction in Tier 1 availability. If there are no entities with a reduction in Tier 1 availability, the cost of these resources assigned during the hour is allocated based on a participant's purchases from the market.~~
  - o   *~~Synchronized Reserve Lost Opportunity Cost Charge Added = Total Lost Opportunity Cost Credit Added * (Tier 1 Lost MW / Total Tier 1 Lost MW)~~*

- A Market Participant is also charged a share of any unrecovered costs incurred by assigned Tier 2 pool-schedule resources, including those Tier 2 resources assigned in addition to that which was estimated prior to a given hour, over and above those Tier 2 resources clearing price credits.

6.3.3 Synchronized Reserve ~~Tier 2~~ Retroactive Penalty Charge

~~Tier 2~~ Rresources that fail to provide assigned ~~Tier 2 capability~~Synchronized Reserve during a Synchronized Reserve Event incur a retroactive ~~obligation to refund at SRMCP the amount of the shortfall for the five minute interval measured in MW for all of the five minute intervals the resource was assigned over the immediate past interval,~~ penalty charge. This retroactive penalty charge is determined by multiplying the retroactive penalty MWs times the RT SRMCP for all Real-time Settlement Intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a duration immediately preceding the Synchronized Reserve Event.

- Retroactive Penalty Charge for resources with a shortfall = Retroactive Penalty MW * RT SRMCP / 12
    - o Retroactive Penalty MWs = Min (Synchronized Reserve Shortfall Charge MW, Capped Real-time Synchronized Reserve assignment (as determined and calculated in Section 6.2.2 of the PJM Manual)
    - o T~~the~~ duration ~~of which~~ is equal to the lesser of the average number of days between E~~e~~vents ~~as determined by the annual review of the last 2 years,~~ or the number of days since the resource last failed to respond with its PJM-assigned or self-scheduled Synchronized Reserve amount in response to a S~~s~~ynchronized R~~r~~eserve E~~e~~vent.
    - o The average number of days between Events is determined by the annual review of the last two (2) years.
- Retroactive Penalty Charge for LSEs without a Synchronized Reserve shortfall = Total PJM Retroactive Penalty Charges * -1 * Synch Reserve Obligation Ratio Share excluding the obligations of those receiving a Retroactive Penalty Charge for a performance shortfall.
- Market Participants that own multiple resources assigned or self-scheduled to provide ~~Tier 2~~ Synchronized Reserve are permitted to demonstrate aggregate response, such that any resource that responds greater than their assignment (pool or self-scheduled) can be used to offset any resource that responds less than their assignment ~~or self-schedule~~ of ~~Tier 2~~ Synchronized Reserve during a Synchronized Reserve Event.
- The Market Participant's aggregate response does not affect how an individual resource is credited for ~~Tier 2~~ Synchronized Reserve it provides as described above, but is used to determine what the Market Participant owes in retroactive penalty~~refund~~ charges for each resource that was assigned ~~or self-scheduled~~ to provide ~~Tier 2~~ Synchronized Reserve and responded less than their assignment or self-schedule of ~~Tier 2~~ Synchronized Reserve.
    - o *Tier 2 Retroactive Penalty Charge = Resource Retroactive Shortfall MW * SRMCP / 12* o *Resource Retroactive Shortfall MW = Resource Shortfall MW –*

> *((Resource Shortfall MW / Participant's Total Shortfall MW) * Participant's Total Over Response MW)*
> • If there are multiple Synchronized Events during a day, the maximum Retroactive Penalty MWs, per resource, for the day is used to determine what the Market Participant owes in Retroactive Penalty Charges.
> • If the Retroactive Shortfall MW value per the above equation is less than 0 MW, the Retroactive Shortfall MW is equal to 0 MW.

> **Note:**
> If there are multiple Synchronized Reserve Events during a day, the maximum Resource Retroactive Shortfall MWh for the day is used to determine what the Market Participant owes in refund charges.

The retroactive penalty charges calculated above are allocated based on a Market Participant's ratio share of the Synchronized Reserve obligation MW ~~less any Tier 1 Synchronized Reserve applied to obligation o~~in the five minute intervals of the Synchronized Reserve event for the ~~subzone or Reserve Zone~~location for which the Synchronized Reserve event occurred. If the event spans multiple hours, the retroactive penalty charges are prorated hourly based on the duration of the E~~e~~vent within each hour. Market Participants that incur a retroactive penalty charge and also have an applicable Synchronized Reserve obligation during the hours(s) of the Synchronized Reserve Event are not included in the allocation of such penalties. Additional details on verification and non-performance can be found in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 4.

6.4 Reconciliation for Synchronized Reserve Charges

PJM calculates reconciled Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that are based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule 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 location (R~~r~~eserve ~~zone~~ Zone ~~and~~ or active sub-zone and non sub-zone) is calculated by dividing the total hourly Synchronized Reserve charges in that ~~reserve zone or sub-zone~~location by the total PJM real-time load (de-rated for transmission losses) in that ~~reserve zone or sub-zone~~location 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, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

Section 7: Non-Synchronized Reserve Accounting

Welcome to the Non-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 Non-Synchronized Reserve are provided and accounted for in the PJM Energy Markets (see "*Non*-Synchronized Reserve Accounting Overview").
- How credits are calculated for providers of Non-Synchronized Reserve (see "Credits for Non-Synchronized Reserve").
- How the total cost of Non-Synchronized Reserve is allocated (see "Charges for NonSynchronized Reserve").
- How Non-Synchronized Reserve charge reconciliations are calculated (see "Reconciliation for Non-Synchronized Reserve Charges").

7.1 Non-Synchronized Reserve Accounting Overview

Non-Synchronized Reserve shall be supplied from non-emergency generation resources located within the metered boundaries of PJM that are off-line and available to provide energyfully convert their reserve capability into energy in 10 minutes or less. Non-Synchronized Reserve can be provided by non-emergency generation resources that can fully convert their reserve capability into energy in 10-minutes from an offline state. PJM determines the amount of Nnon-Ssynchronized Rreserves on each resource.

There is no explicit requirement for Non-Synchronized Reserve. PJM must maintain a total quantity of 10-minute reserve (Primary Reserve) and Synchronized Reserve on the system at all times. Primary Reserves are comprised of Synchronized and Non-Synchronized Reserve. PJM maintains a total Primary Reserve requirement such that a required portion of that Primary Reserve is provided by Synchronized Reserve. The remainder between the Primary Reserve requirement and Synchronized Reserve requirement may be supplied by either additional Synchronized Reserve or Non-Synchronized Reserve, whichever is more economic. Additional details on the Primary and Synchronized Reserve requirements can be found in PJM Manual 13: Emergency Operations.

Non-Synchronized Reserve credits are awarded to resources in both the Day-ahead and Real-time Markets that are assigned to provide Non-Synchronized Reserves by PJM.

Each PJM Market Participant that is a Load Serving Entity (LSE) or a non-synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Nnon-Ssynchronized Rreserve Oobligation based on their Load Ratio Share and applicable reserve zone'slocation's requirement Non-Synchronized Reserve assigned for all Real-time Settlement Intervals (five minute) during that hour. During hours when the Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the same throughout the entire RTO reserve zone, an LSE's Non-Synchronized Reserve Obligation is equal to its Load Ratio Share of the RTO Reserve Zone times the amount of Non-Synchronized Reserve assigned for all Real-time Settlement Intervals for the RTOentire Rreserve zone. During hours when congestion causes the Non-

Synchronized Reserve Market Clearing Price (NSRMCP) to separate is different between the RTO Reserve zone and the Reserve sub-zone, an each LSE's Non-Synchronized Reserve Obligation will be calculated based on their load in active sub-zone and/or the portion of the RTO Reserve zone outside of the active sub-zone (the "non sub-zone"). The LSE's active sub-zone Non-Synchronized Reserve Obligation is equal to its Load Ratio Share within that active sub-zone times within its reserve zone or sub-zone and the amount of Non-Synchronized Reserve assigned in that active reserve zone or sub-zone. The LSE's Synchronized Reserve Obligation in the non sub-zone is equal to its Load Ratio Share in the non sub-zone times the amount of Non-Synchronized Reserve assigned in the non sub-zone portion of the RTO.

Participants may fulfill their Non-Synchronized Reserve Obligations by entering bilateral arrangements with other PJM Market Participants or purchasing Nnon-Ssynchronized Rreserve from the PJM Non-Synchronized Reserve Market.

7.2 Credits for Non-Synchronized Reserve

Non-Synchronized Reserve credits are paid in both Day-ahead and Real-time Non-Synchronized Reserve Markets to Market Participants that supply their resource to are assigned to provide Non-Synchronized Reserves by PJM. PJM sums the Non- Synchronized Reserve credits (both Non-Synchronized Reserve Clearing Price credits and Non-Synchronized Reserve Lost Opportunity Cost credits) to determine the total hourly credit for each Non-Synchronized Reserve market participant. The credits for the Day-ahead and Real-time Non-Synchronized Reserve Markets appear on the billing statement as two separate billing line items:

- Day-ahead Non-Synchronized Reserve Credits = Sum(Day-ahead Non-Synchronized Reserve Market Clearing Price Credits) for the days in the billing period
- Balancing Non-Synchronized Reserve Credits = Sum(Balancing Non-Synchronized Reserve Market Clearing Price Credits + Non-Synchronized Reserve Lost Opportunity Cost Credits) for the days in the billing period

Non-Synchronized Reserve credits for jointly- owned generators that supply Non-Synchronized Reserves are allocated to the owners based on their ownership shares.

7.2.1 Day-ahead Non-Synchronized Reserve Market Clearing Price Credit

Day-ahead Non-Synchronized Reserve Market Clearing Price credits are paid to a generation resource that are dispatched is assigned Non-Synchronized Reserve MWs within the Day-ahead Market to meet satisfy the 30-minute Reserve Requirement and/or Primary Reserve Requirement.

Synchronized Reserve requirement. Lost opportunity cost credits are described in Section 7.2.2 of this PJM Manual.

PJM Actions

- PJM retrieves the following information for Day-ahead Non-Synchronized Reserve Market Clearing Price credit:
  o Day-ahead Non-Synchronized Reserve assignments (MWh)
  o Non-Synchronized Reserve shortfall (MWh)
  o Day-ahead Non-Synchronized Reserve Market Clearing Price (DA NSRMCP) ($/MWh)
- PJM calculates the Non-Synchronized Reserve MW supplied as the Non-Synchronized Reserve assigned MWs less the amount of Non-Synchronized Reserve MWs the resource failed to provide in response to a Non-Synchronized Reserve event (NonSynchronized Reserve shortfall) for the five minute interval.
  o Non-Synchronized Reserve MW = Non- Synchronized Reserve Assignments - NonSynchronized Reserve shortfall
- PJM calculates for each hour the Day-ahead Non-Synchronized Reserve Market Clearing Price (NSRMCP) credit for each eligible resource and for each five minute interval by multiplying the Day-ahead Non-Synchronized Reserve MWs supplied assigned by the Day-ahead Non-Synchronized Reserve Clearing Price ($/MWh) divided by 12.
  o Day-ahead Non-Synchronized Reserve Market Clearing Price Credit = Day-ahead Non-Synchronized Reserve Assignment MW * (NSRMCP / 12)Day-ahead Non-Synchronized Market Clearing Price DA NSRMCP

7.2.2 Balancing Non-Synchronized Reserve Market Clearing Price Credit

Balancing Non-Synchronized Reserve Market Clearing Price credits are paid to a generation resource that is assigned Non-Synchronized Reserve within the Real-time Market to satisfy the 30-minute Reserve Requirement and/or Primary Reserve Requirement.

PJM Actions

- PJM retrieves the following information for the Balancing Non-Synchronized Reserve Market Clearing Price credit:
  o Real-time Non-Synchronized Reserve assignments (MWh)
  o Day-ahead Non-Synchronized Reserve assignments (MWh)
  o Real-time Non-Synchronized Reserve Market Clearing Price (RT NSRMCP) ($/MWh)
- PJM calculates for each Real-time Settlement Interval the Balancing Non-Synchronized Reserve Market Clearing Price credit for each eligible resource by taking the difference between the Real-time and Day-ahead Non-Synchronized Reserve assignments and multiplying it by the RT NSRMCP, then dividing the product by 12.
  o Balancing Non-Synchronized Reserve Market Clearing Price Credit = ((Real-time Non-Synchronized Reserve Assignment – Day-ahead Non-Synchronized Reserve Assignment) * RT NSRMCP) / 12

7.2.~~2~~3 Non-Synchronized Reserve Lost Opportunity Cost Credit

PJM calculates the ~~Lost opportunity cost credit for N~~non-~~S~~synchronized Reserve Lost Opportunity Cost Credit for pool-scheduled resources if the Non-Synchronized Reserve Lost Opportunity Cost is greater than the total NSRMCP Credits (Day-ahead and Balancing) received through the Non-Synchronized Reserve Market for each Real-time Settlement Interval. ~~are calculated for each hour. If the resulting amount is positive, then the lost opportunity cost credits are allocated, however, I~~if the resulting amount is negative, then the credit is $0.

PJM Actions
- PJM retrieves the following information for Non-Synchronized Reserve Lost Opportunity Cost credit~~.~~:
  - o ~~Real-time LMP~~
  - o ~~LMP Desired MW~~
  - o ~~Offer at LMP Desired~~
    - o Day-ahead Non-Synchronized Reserve Market Clearing Price ~~(NSRMCP)~~ Credit
    - o Balancing Non-Synchronized Reserve Market Clearing Price Credit
    - o Market Revenue Neutrality Offset (as determined and calculated in Section 15 of this PJM Manual)
    - o Non-Synchronized Reserve Opportunity Cost Credits owed (as determined and calculated in Section 15 of this PJM Manual)
- For each Real-time Settlement Interval, PJM calculates a Non-Synchronized Reserve Lost Opportunity Cost Credit ~~if the lost opportunity cost is greater than the Non-Synchronized Reserve Market Clearing Price Credit~~ for the resource ~~for the five minute interval~~ if the costs associated with that resource are greater than the credits received by the resource.
    - o Non-Synchronized Reserve Lost Opportunity Cost Credit = Max(Non-Synchronized Reserve Cost – Non-Synchronized Reserve Credit, 0)
- PJM calculates the cost side of the Non-Synchronized Reserve Lost Opportunity Cost Credit equation as $0. Non-Synchronized Reserves has no offer, nor an opportunity cost for MW committed as reserves rather than energy.
- PJM calculates the credit side of the Non-Synchronized Reserve Lost Opportunity Cost Credit equation as follows:
    - o Non-Synchronized Reserve Credit = (Day-ahead Non-Synchronized Reserve Market Clearing Price Credit /12) + (Market Revenue Neutrality Offset + Non-Synchronized Opportunity Cost Credit Owed + Balancing Non-Synchronized Reserve Market Clearing Price Credit)
    - o Day-ahead Non-Synchronized Reserve Market Clearing Price Credit = as determined and calculated in Section 7.2.1 of the PJM Manual
    - o Market Revenue Neutrality Offset = as determined and calculated in Section 15 of this PJM Manual

o Non-Synchronized Opportunity Cost Credit Owed = as determined and calculated in Section 15 of this PJM Manual

o Balancing Non-Synchronized Reserve Market Clearing Price Credit = as determined and calculated in Section 7.2.2 of the PJM Manual

o ~~Non-Synchronized Reserve Lost Opportunity Cost Credit = (Non-Synchronized Reserve Lost Opportunity Cost / 12) – NSRMCP Credit~~

o ~~Non-Synchronized Reserve Lost Opportunity Cost = (5-minute LMP Desired MWh * 5-minute RT LMP) – 5-minute LMP Desired Offer~~

- ~~Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time LMP at the hydro unit bus for the appropriate on peak (0700 - 2259) or off-peak (0000 – 0659, 2300 2359) period, excluding those hours during which all available units at the hydro plant were operating.~~
- ~~If a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost for each five minute interval is equal to (i) the Non-Synchronized Reserve assigned MW multiplied by (ii) the difference between the real-time five minute LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average real-time LMP value is higher than the real-time five minute LMP at the generator bus, the lost opportunity cost is zero.~~
- ~~If a hydro unit is not committed day-ahead, the lost opportunity cost is equal to zero.~~

7.3 Charges for Non-Synchronized Reserve

PJM allocates the cost of the total Day-ahead and Balancing Non-Synchronized Reserve credits paid to resources providing Non-Synchronized Reserve as charges to Market Participants with a Non-Synchronized Reserve Obligation in the RTO zone, active sub-zone or non sub-sone as described in section 7.1 of this PJM Manual. PJM calculates charges for the RTO Reserve Zone when there is no price separation between the RTO Reserve Zone and the active sub-zone, and calculates charges for the active sub-zone and non sub-zone portions of the RTO, rather than for the RTO Reserve Zone, when there is price separation.

Each PJM Market Participant that is a Load Serving Entity (LSE) or non-synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Non-Synchronized Reserve Obligation based on their Load Ratio Share and applicable reserve zone's ~~Non-Synchronized Reserve assigned during that hour~~requirements during that hour. A Load Serving Entity (LSE) whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 does not have a Non-Synchronized Reserve Obligation.

PJM separately allocates the charges associated with Non-Synchronized Reserve Market Clearing Price Credits and Non-Synchronized Reserve Load Opportunity Cost Credits and ~~appear~~includes them on the billing statement as one billing line item:

- Non-Synchronized Reserve Charge = Non-Synchronized Reserve Market Clearing Price Charge + Non-Synchronized Reserve Lost Opportunity Cost Charge

PJM sums the Non-Synchronized charges (both Non-Synchronized Reserve Market Clearing Price Charges and Non-Synchronized Lost Opportunity Cost Charge) to determine the total hourly charge for each Market Participant.

7.3.1 Non-Synchronized Reserve Market Clearing Price Charge
PJM Actions
- PJM retrieves the following information for Non-Synchronized Reserve Market Clearing Price Charge:
  - Market Participant's Load Ratio Share (MWh)
  - Bilateral Non-Synchronized Reserve transactions (sales and purchases) (MWh)
  - Total PJM Real-time Non-Synchronized Reserve assigned (MWh)
  - Total Non-Synchronized Reserve shortfall (MWh)
  - Total Day-ahead Non-Synchronized Reserve Market Clearing Price (NSRMCP) Credits ($)
  - Balancing Non-Synchronized Reserve Market Clearing Price Credits ($)
- PJM calculates each Market Participant's hourly Non-Synchronized Reserve Market Clearing Price charges by RTO zone or active sub-zone and non sub-zone in which the load is located by multiplying the Total Non-Synchronized Reserve Market Clearing Price Credits in that location times the Market Participant's Non-Synchronized Reserve Obligation Share in that location.
  - Non-Synchronized Reserve Market Clearing Price Charges = Total Non-Synchronized Reserve Market Clearing Price Credits * Non-Synchronized Reserve Obligation Share
- PJM calculates for each hour the Total Non-Synchronized Reserve Market Clearing Price Credits in the applicable location.
  - Total Non-Synchronized Reserve Market Clearing Price Credits = Day-ahead Non-Synchronized Reserve Market Clearing Price Credits + Balancing Non-Synchronized Reserve Market Clearing Price Credits
- PJM calculates each Market Participant's hourly Non-Synchronized Reserve Obligation Share by RTO zone or active sub-zone and non sub-zone in the applicable reserve zone or sub-zone based on their Load Ratio Share in that location, adjusted by bilateral Non-Synchronized Reserve sales and purchases.
  - Non-Synchronized Reserve Obligation Share = ((Load Ratio Share * Total PJM Non-Synchronized Reserve assigned) – Non-Synchronized Reserve MW Purchased + Non-Synchronized Reserve MW Sold) / Total PJM Real-time Non-Synchronized Reserve assigned
    Adjusted Non-Synchronized Reserve Obligation / Total PJM Adjusted Obligation

~~Adjusted Non-Synchronized Reserve Obligation = Non-Synchronized Reserve Obligation – Non-Synchronized Reserve MW Purchased + Non-Synchronized Reserve MW Sold~~

~~Non-Synchronized Reserve Obligation = Load Ratio Share * Total Non-Synchronized Reserve Provided~~

- ~~PJM calculates for each hour the Non-Synchronized Reserve charges by multiplying the appropriate Total Non-Synchronized Reserve Market Clearing Price Credits times the appropriate Market Participant's Non-Synchronized Reserve Obligation Share.~~
    - ~~Non-Synchronized Reserve Charges = Total Non-Synchronized Reserve Market Clearing Price Credits * Non-Synchronized Reserve Obligation Share~~
- ~~If the hourly-integrated Non-Synchronized Reserve Market Clearing Price is equal for all the sub-zones within a reserve zone, the Total Non-Synchronized Reserve Clearing Price Credits in the reserve zone is allocated based on a Market Participant's obligation ratio share in the reserve zone.~~
- ~~If the hourly-integrated Non-Synchronized Reserve Market Clearing Price is different for the sub-zones within a reserve zone, the Total Non-Synchronized Reserve Clearing Price Credits in the sub-zone is allocated based on a Market Participant's obligation ratio share in the sub-zone.~~

7.3.2 Non-Synchronized Lost Opportunity Cost Charge

PJM Actions

- PJM retrieves the following information for Non-Synchronized Reserve Lost Opportunity Cost Charge:
    - Market Participant's Load Ratio Share (MWh)
    - Bilateral Non-Synchronized Reserve transactions (sales and purchases) (MWh)
    - Total PJM Real-time Non-Synchronized Reserve assigned
    - Total PJM Non-Synchronized Lost Opportunity Cost Credits

• PJM calculates each Market Participant's hourly Non-Synchronized Reserve Lost Opportunity Cost Charges by RTO zone or active sub-zone and non sub-zone by multiplying the Total PJM Non-Synchronized Lost Opportunity Cost Credits in that location times the Non-Synchronized Reserve Purchases ratio share in that location.

- Non-Synchronized Reserve Lost Opportunity Cost Charge = Total PJM Non-Synchronized Lost Opportunity Cost Credits * Non-Synchronized Reserve Purchases ratio share

• PJM calculates each Market Participant's hourly Non-Synchronized Reserve Purchases by RTO zone or active sub-zone and non sub-zone based on their Load Ratio Share in that location, adjusted by bilateral Non-Synchronized Reserve sales and purchases .

- Non-Synchronized Reserve Purchases = (((Load Ratio Share * Total PJM Real-time Non-Synchronized Reserve assigned) – Non-Synchronized Reserve MW Purchased + Non-Synchronized Reserve MW Sold)) / Total PJM Real-time Non-Synchronized Reserve assigned

PJM allocates for each hour the Non-Synchronized Reserve Lost Opportunity Cost Charges based on each Market Participant's ratio share of Non-Synchronized Reserve purchased from the market. A participant's purchases from the market equals their non-synchronized reserve obligation.

     o   *Non-Synchronized Reserve Lost Opportunity Cost Charge = Total Lost Opportunity Cost Credits * (Market Participant's Non-Synchronized Reserve Purchase / Total PJM Non-Synchronized Reserve Purchases)*

7.4 Reconciliation for Non-Synchronized Reserve Charges

PJM will calculate reconciled Non-Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Non-Synchronized Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Non-Synchronized Reserve billing determinants for that hour. The hourly Non-Synchronized Reserve charge billing determinant (in $/MWh) for each location (Reserve Zone or active sub-zone and non sub-zone) ~~reserve zone and sub-zone~~ is calculated by dividing the total hourly Non-Synchronized Reserve charges in that ~~reserve zone or sub-zone~~location by the total PJM real-time load (derated for transmission losses) in that ~~reserve zone or sub-zone~~location for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Non-Synchronized Reserve charges for a month may be either a positive or a negative value and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

Section 15: Market Revenue Neutrality Offset~~Ramapo PAR Facilities~~ Accounting

Welcome to the Market Revenue Neutrality Offset~~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~~how Market Revenue Neutrality Offset and Opportunity Cost Credit Owed are used within the Reserve Market ~~Ramapo PAR facilities~~ accounting (see "Market Revenue Neutrality Offset Overview~~Ramapo PAR Facilities Accounting Procedure~~").
- A description of the calculation procedure for Market Revenue Neutrality Offset (see "Market Revenue Neutrality Offset").
- A description of the calculation procedure for Opportunity Cost Credit Owed (see "Opportunity Cost Credit Owed").

15.1 Market Revenue Neutrality Offset Overview ~~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.~~

A resource's energy and reserve assignments can differ between the day-ahead and real-time markets. To the extent a resource's assignment in one market is increased in real-time (as compared to day-ahead), its assignment in another market may need to be decreased in order to ensure the resource's capability is not exceeded. This generally leads to balancing settlements with additional revenue earned in the market where the assignment was increased and decreased revenue in the market where the assignment was decreased (in the form of a buy back from the day-ahead position). The cost of the buy back from the day-ahead reserve position is included in the Lost Opportunity Cost Credit calculation for each reserve market.

However, the amount of Lost Opportunity Cost Credit paid to cover this buy back can be reduced by two values: the Market Revenue Neutrality Offset or the Lost Opportunity Cost Credit Owed.

The Market Revenue Neutrality Offset calculation recognizes any additional profit (revenue above cost) earned in the market(s) with the increased real-time assignment(s) and uses that additional profit to offset any cost incurred from buying back its day-ahead reserve assignments in the markets where the assignment was decreased in real-time. The Market Revenue Neutrality Offset reduces the Lost Opportunity Cost Credit for each reserve market so that a resource is not made whole for costs that were recovered via another market. In the event the

additional profit exceeds the additional costs created by this shift in assignments, the Market Revenue Neutrality Offset is capped at the amount of those costs.

In order to be eligible to recover any opportunity cost incurred from the buy back from the day-ahead assignment in a reserve market, a resource cannot act in a manner that results in the resource's real-time reserve assignment being less than its day-ahead assignment. If a resource's own actions cause the need to buy back from the day-ahead reserve assignment, the cost attributable to that buy back is captured as Lost Opportunity Cost Owed, which is an offset in the Lost Opportunity Cost Credit calculation that reduces the amount otherwise owed to the resource.

15.2 Market Revenue Neutrality Offset

Market Revenue Neutrality Offset is calculated for each Real-time Settlement Interval, if eligible. Each resources assigned reserves in the day-ahead market is eligible for the Market Revenue Neutrality Offset, unless any of the following apply:

- The resource's real-time reserve assignment (Synchronized, Non-Synchronized, and/or Secondary) decreases due to the resource being self-scheduled to provide energy, another reserve product or Regulation;
- The resource reduces its flexibility in real-time such that it no longer qualifies for that reserve product in real-time;
- The resource's Final Offer is less than its Committed Offer for energy
- The resource trips offline or otherwise becomes unavailable in real-time;
- The resource does not follow the dispatch direction provided as described in Section 5.2.1 and Section 11.2.2 of this PJM Manual
- The resource fails to come online and reach Economic Minimum output within 30 minutes (Secondary Reserve only)
- The resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve market (Synchronized Reserve only)

PJM determines a Market Revenue Neutrality Offset for the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets. When a resource is assigned in the multiple reserve markets and/or the energy market for the same Real-time Settlement Interval, the additional profits earned in each market are summed together and then allocated back out to each reserve market based on that market's ratio share of the total costs across all reserve markets due to buying back from the day-ahead assignments.

As example, a resource is assigned both Synchronized Reserve and Secondary Reserve MWs in the Day-ahead Market, however, in real-time, PJM shifts the assignment of those MWs to the Energy Market. PJM will determine the increase in profit earned in the energy market and allocate it to the Synchronized Reserve and Secondary Reserve markets using the ratio share of cost of the buy back for the given market to the total cost of the buy back in both the Synchronized Reserve and Secondary Reserve markets.

The first step in the Market Revenue Neutrality Offset calculation is to calculate the additional profit a Market Participant earned across all energy and/or reserve markets where the resource had an increase in its real-time assignment as compared to day-ahead. This is referred to as the Total Value from Increases portion of the Market Revenue Neutrality Offset calculation.

- Total Value from Increases = Sum(Value from Energy Market + Value from Synchronized Reserve Market + Value from Non-Synchronized Reserve Market + Value from Secondary Reserve Market)
    - Value from Energy Market = ((RT Energy MW – DA Energy MW) * RT LMP) – Incremental energy offer ($) for the increased energy MW (i.e., area under the offer curve)
    - Value from Synchronized Reserve Market = MIN(any Synchronized Reserve Market revenue in excess of its offer plus opportunity costs, Balancing revenue above cost due to the increased Synchronized Reserve assignment)
    - Value from Non-Synchronized Reserve Market = MIN(any Non-Synchronized Reserve Market revenue in excess of its offer plus opportunity costs, Balancing revenue above cost due to the increased Non-Synchronized Reserve assignment)
    - Value from Secondary Reserve Market = MIN(any Secondary Reserve Market revenue in excess of its offer plus opportunity costs, Balancing revenue above cost due to the increased Secondary Reserve assignment)

The second step in the calculation is to calculate the additional lost opportunity cost the resource incurred in the reserve markets where it had a decrease in its real-time assignment as compared to its day-ahead assignment. This is referred to as the LOC Credit Due to Reduction portion of the Market Revenue Neutrality calculation.

- LOC Credit Due to Reduction for Synchronized Reserve = MIN ((Day-ahead Synchronized Reserve Offer Amount + Day-ahead Synchronized Reserve Opportunity Cost – Day-ahead Synchronized Reserve Market Clearing Price Credit – Balancing Synchronized Reserve Market Clearing Price Credit), ABS(Balancing Synchronized Reserve Market Clearing Price Credit))
- LOC Credit Due to Reduction for Non-Synchronized Reserve = MIN ((Day-ahead Non-Synchronized Reserve Market Clearing Price Credit – Balancing Non-Synchronized Reserve Market Clearing Price Credit), ABS(Balancing Non-Synchronized Reserve Market Clearing Price Credit))
- LOC Credit Due to Reduction for Secondary Reserve = MIN ((Day-ahead Secondary Reserve Opportunity Cost – Day-ahead Secondary Reserve Market Clearing Price Credit – Balancing Secondary Reserve Market Clearing Price Credit), ABS(Balancing Secondary Reserve Market Clearing Price Credit))

The third step is to allocate the Market Revenue Neutrality Offset value to each reserve market where the resource had a decrease in the real-time assignment using the ratio share of the

resource's LOC Credits Due to Reduction in all reserve markets. This is the value that then offsets the Lost Opportunity Cost Credit paid to the resource in that reserve market.

- Market Revenue Neutrality Offset for a given reserve market = Min (Total Value from Increases * LOC Credit Due to Reduction in the given reserve market / Sum(resource's LOC Credits Due to Reduction in all reserve markets), LOC Credit Due to Reduction in the given reserve market)

15.3 Opportunity Cost Credit Owed

Opportunity Cost Credit Owed is calculated for each Real-time Settlement Interval where a resource's real-time reserve assignment in a given market was decreased from its day-ahead reserve assignment in that market, and where the resource is not eligible for the Market Revenue Neutrality Offset as described in section 15.2 above.

- Opportunity Cost Credit Owed Due to Reduction for Synchronized Reserve = LOC Credit Due to Reduction for Synchronized Reserve as calculated in Section 15.2 of this PJM Manual
- Opportunity Cost Credit Owed Due to Reduction for Non-Synchronized Reserve = LOC Credit Due to Reduction for Non-Synchronized Reserve as calculated in Section 15.2 of this PJM Manual
- Opportunity Cost Credit Owed Due to Reduction for Secondary Reserve = LOC Credit Due to Reduction for Secondary Reserve as calculated in Section 15.2 of this PJM Manual

Section 19: Secondary ~~Day-ahead Scheduling~~ Reserve Accounting

Welcome to the Secondary ~~Day-ahead Scheduling~~ Reserve Accounting section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how ~~Day-ahead Scheduling~~Secondary Reserves are provided and accounted for in the PJM Energy Markets (see "Secondary~~Day-ahead Scheduling~~ Reserve Accounting Overview").
- How credits are calculated for providers of ~~Day-ahead Scheduling~~Secondary Reserve (see "Credits for ~~Day-ahead Scheduling~~Secondary Reserve").
- How the total cost of ~~Day-ahead Scheduling~~Secondary Reserve is allocated (see "Charges for ~~Day-ahead Scheduling~~Secondary Reserve").
- How ~~Day-ahead Scheduling~~Secondary Reserve charge reconciliations are calculated (see "Reconciliation for ~~Day-ahead Scheduling~~Secondary Reserve Charges").

19.1 Secondary Reserve Accounting Overview

Secondary Reserve shall be supplied from resources located within the metered boundaries of PJM that are on-line or off-line and able to provide response within 10 and 30 minutes. Secondary Reserve resources include generators and Economic Load Response Participants.

The total PJM 30-minute Reserve Requirement is defined as the amount of reserves to be supplied from Synchronized and Non-Synchronized resource, available within 30-minutes. Additional details on the 30-minute Reserve requirements can be found in the PJM Manual 13: Emergency Operations

Secondary Reserve credits are awarded to resources in both the Day-ahead and Real-time Markets based on assignment and RT MW output. The Secondary Reserve offer price for a resource is $0.

Each Market Participant that is a Load Serving Entity (LSE) or secondary buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Secondary Reserve Obligation based on their Load Ratio Share and applicable reserve location's requirements during that hour. During hours when the Secondary Reserve Market Clearing Price (SecRMCP) is the same throughout the entire RTO reserve zone, an LSE's Secondary Reserve Obligation is equal to its Load Ratio Share of the RTO reserve zone times the amount of Secondary Reserve assigned for all Real-time Settlement Intervals for the RTO Reserve zone. During hours when the SecCRMCP is different between the RTO Reserve zone and the Reserve sub-zone, an LSE's Secondary Reserve Obligation will be calculated based on their load in active sub-zone and/or the portion of the RTO Reserve Zone outside of the active sub-zone (the "non sub-zone"). The LSE's active sub-zone Secondary Reserve Obligation is equal to its Load Ratio Share within that active sub-zonetimes the amount of Secondary Reserve assigned in that active sub-zone. The LSE's Secondary Reserve Obligation in the non sub-zone is equal to its Load Ratio Share in the non

sub-zone times the amount of Secondary Reserve assigned in the non sub-zone portion of the RTO.

Participants may fulfill their Secondary Reserve obligations by entering bilateral arrangements with other PJM Market Participants, or purchasing Secondary Reserve from the PJM Secondary Reserve Market.

19.2 Credits for Secondary Reserve

Secondary Reserve credits are paid in both Day-ahead and Real-time Secondary Reserve Markets to Market Participants that supply their resource to PJM. The credits for the Day-ahead and Real-time Secondary Reserve Markets appear on the billing statement as two separate billing line items:

- Day-ahead Secondary Reserve Credits = Sum(Day-ahead Secondary Reserve Market Clearing Price Credits) for the days in the billing period
- Balancing Secondary Reserve Credits = Sum(Balancing Secondary Reserve Market Clearing Price Credits + Secondary Reserve Lost Opportunity Cost Credits) for the days in the billing period

Secondary Reserve credits for jointly-owned generators supplying Secondary Reserves are allocated to the owners based on their ownership share.

19.2.1 Day-ahead Secondary Reserve Market Clearing Price Credit

Day-ahead Secondary Reserve Market Clearing Price credits are paid to a resource that is assigned Secondary Reserve MWs by PJM within the Day-ahead Market to satisfy the 30-minute Reserve Requirement.

PJM Actions

- PJM retrieves the following information for Day-ahead Secondary Reserve Market Clearing Price credit:
  - o Day-ahead Secondary Reserve assignments (MWh)
  - o Day-ahead Secondary Reserve Market Clearing Price (DA SecRMCP) ($/MWh)
- PJM calculates for each hour the Day-ahead Secondary Reserve Market Clearing Price credit for each eligible resource by multiplying the Day-ahead Secondary Reserve MWs assigned by the Day-ahead Secondary Reserve Market Clearing Price.
  - o Day-ahead Secondary Reserve Market Clearing Price Credit = Day-ahead Secondary Reserve MW * DA SecRMCP

19.2.2 Balancing Secondary Reserve Market Clearing Price Credit

Balancing Secondary Reserve Market Clearing Price credits are paid to a resource that is assigned Secondary Reserve within the Real-time Market to satisfy the 30-minute Reserve Requirement.

PJM Actions
- PJM retrieves the following information for Balancing Secondary Reserve Market Clearing Price credit:
  - Real-time Secondary Reserve assignments (MWh)
  - Economic Maximum MW
  - Real-time Secondary Reserve Maximum MW
  - Real-time MW output
  - Day-ahead Secondary Reserve assignments (MWh)
  - Real-time Synchronized Reserve assignments (MWh)
  - Real-time Secondary Reserve Market Clearing Price (RT SecRMCP) ($/MWh)
  - Secondary Reserve Shortfall MW
- PJM calculates for each Real-time Settlement Interval the Balancing Secondary Reserve Market Clearing Price credit for each eligible resource by taking the difference between the *capped* Real-time Secondary Reserve assignment and Day-ahead Secondary Reserve assignments and multiplying it by the RT SecRMCP, then dividing the product by 12.
  - Balancing Secondary Reserve Market Clearing Price Credit = ((Capped Real-time Secondary Reserve Assignment – Day-ahead Secondary Reserve Assignment – Secondary Reserve Shortfall MW) * RT SecRMCP) / 12
  - Capped Real-time Secondary Reserve Assignment = Minimum (Real-time Secondary Reserve MW, (Minimum (Economic Maximum MW, Real-time Secondary Reserve Maximum MW) – Real-time MW Output – Real-time Synchronized Reserve MW)
  - Secondary Reserve Shortfall MW =
    - fFor a real-time offline generation resource that does not reach Economic Minimum output within 30 minutes as instructed by PJM., Secondary Reserve Shortfall MW = will have its Capped Real-time Secondary Reserve assignment set to zero for all intervals associated with the Real-time Secondary Reserve assignment and the last interval the resource was online, but not prior to the start of that Operating Day. This will be reflected in settlements as a Secondary Reserve Shortfall MW. This shortfall MW will be applied to all prior intervals in which the resource was assigned to provide real-time Secondary Reserve starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online.
    - Secondary Reserve Shortfall MW For a A real-time Economic Load Response that does not reduce by at least the Economic Minimum within 30 minutes as instructed by PJM, Secondary Reserve Shortfall MW = will have its Capped Real-time Secondary Reserve assignment. set to zero for all intervals associated with the Real-time Secondary Reserve assignment and the last interval the resource reduced, but not prior to the start of that Operating Day. This will be reflected in settlements as a

~~Secondary Reserve Shortfall MW.~~ This shortfall MW will be applied to all prior intervals in which the resource was assigned to provide real-time Secondary Reserve starting at the later of (A) the last interval the resource reduced load at PJM's instruction or (B) the beginning of that Operating Day, through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day.

19.2.3 Secondary Reserve Lost Opportunity Cost Credit

PJM calculates a Secondary Reserve Lost Opportunity Cost Credit for pool-scheduled resources if the Secondary Reserve Lost Opportunity Cost (excluding any reduction for a stability limit) is greater than the total SecRMCP Credits (Day-ahead and Balancing) received through the Secondary Reserve Market for each Real-time Settlement Interval. If the resulting amount is negative, then the credit is $0.

PJM Actions
- PJM retrieves the following information for the Secondary Reserve Lost Opportunity Cost credit:
  o Day-ahead Secondary Reserve Market Clearing Price Credit ($/MWh)
  o Balancing Secondary Reserve Market Clearing Price Credit ($/MWh)
  o Market Revenue Neutrality Offset ($) (as determined and calculated in Section 15 of this PJM Manual)
  o Secondary Reserve Opportunity Cost Credits Owed ($) (as determined and calculated in Section 15 of this PJM Manual)
- For each Real-time Settlement Interval, PJM calculates a Secondary Reserve Lost Opportunity Cost Credit for a resource if the costs associated with that resource are greater than the credits received by the resource.
  o Secondary Reserve Lost Opportunity Cost Credit = Max (Secondary Reserve Cost – Secondary Reserve Credit, 0)
- PJM calculates the cost side of the Secondary Reserve Lost Opportunity Cost Credit equation as follows:
  o Secondary Reserve Cost = (Day-ahead Secondary Reserve Opportunity Cost + Real-time Secondary Opportunity Cost) / 12
    ▪ Day-ahead Secondary Reserve Opportunity Cost will equal (A * B) - C:
      • A = DA LMP at the generation bus or applicable Economic Load Response Participant resource pricing point
      • B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment

- C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment
- For the following resource types, the Day-ahead Secondary Reserve Opportunity Cost is calculated as follows:
  - Resources committed to provide secondary reserves in synchronous condensing mode = (Day-ahead energy usage to provide Synchronous Condensing * DA LMP at the generation bus) + (Day-ahead Condense Start-up costs / Number of Hours assigned Secondary Reserve)
- Real-time Secondary Reserve Opportunity Cost will equal (A * B) – C:
  - A = RT LMP at the generation bus or applicable Economic Load Response Participant resource pricing point
  - B = The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment
  - C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment
  - For the following resource types, the Real-time Secondary Reserve Opportunity Cost is calculated as follows:
    - Resources providing secondary reserves in synchronous condensing mode without a Real-time Synchronized Reserve assignment = ((Real-time energy usage to provide Synchronous Condensing – Day-ahead energy usage to provide Synchronous Condensing) * RT LMP at the generation bus) + any additional condense start-up costs in excess of Day-ahead Condense Start-up costs

- Resources providing secondary reserves in synchronous condensing mode with a Real-time Synchronized Reserve assignment = $0
- Hydro unit (providing secondary reserve in spill mode) = (RT LMP at the generation bus * (Real-time Secondary Reserve assignment – Day-ahead Secondary Reserve assignment)
- Hydro unit (non-spill mode with day-ahead energy commitment > 0) = (RT LMP at the generation bus - average RT LMP at the generation bus for the appropriate on peak / off peak period) * (Real-time Secondary Reserve assignment – Day-ahead Secondary Reserve assignment). If the average RT LMP value is higher than the RT LMP at the generator bus, then the Real-time Secondary Synchronized Reserve Opportunity Cost will equal zero.
- Where the "on peak" is defined as 0700 – 2259 and "off-peak" is defined as 0000 – 0659, 2300-2359, excluding those hours during which all available units at the hydro plant were operating
- Hydro unit (non-spill mode with no day-ahead energy commitment > 0) = $0

- PJM calculates the credit side of the Secondary Reserve Lost Opportunity Cost Credit equation as follows:
  o Secondary Reserve Credit = (Day-ahead Secondary Reserve Market Clearing Price Credit / 12) + (Market Revenue Neutrality Offset + Secondary Reserve Opportunity Cost Credit Owed + Balancing Secondary Reserve Market Clearing Price Credit – Secondary Reserve Shortfall Charge)
    - Day-ahead Secondary Reserve Market Clearing Price Credit = as determined and calculated in Section 19.2.1 of the PJM Manual
    - Market Revenue Neutrality Offset = as determined and calculated in Section 15 of this PJM Manual
    - Secondary Reserve Opportunity Cost Credit Owed = as determined and calculated in Section 15 of this PJM Manual
    - Balancing Secondary Reserve Market Clearing Price Credit = as determined and calculated in Section 19.2.2 of the PJM Manual
    - Secondary Reserve Shortfall Charge = as determined and calculated in Section 19.2.2 of this PJM Manual

19.3 Charges for Secondary Reserve

PJM allocates the cost of the total Day-ahead and Balancing Secondary Reserve credits paid to resources providing Secondary Reserve as charges to Market Participants with a Secondary Reserve Obligation in the RTO zone, active sub-zone or non sub-zone as described in section 6.1 of this PJM Manual. PJM calculates charges for the RTO Reserve Zone when there is no price separation between the RTO Reserve Zone and the active sub-zone, and calculates charges for the active sub-zone and non sub-zone portions of the RTO, rather than for the RTO Reserve Zone, when there is price separation.

Each Market Participant that is a Load Serving Entity (LSE) or secondary buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Secondary Reserve Obligation based on their Load Ratio Share and applicable reserve zone's or reserve sub-zone's requirements during that hour. A Load Serving Entity (LSE) whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 does not have a Secondary Reserve Obligation.

PJM separately allocates the charges associated with Secondary Reserve Market Clearing Price Credits less any Secondary Reserve Shortfall Charges and Secondary Reserve Lost Opportunity Cost Credits and includes them on the billing statement as one billing line item:

- Secondary Reserve Charge = Secondary Reserve Market Clearing Price Charge + Secondary Reserve Lost Opportunity Cost Charge

19.3.1 Secondary Reserve Market Clearing Price Charge
PJM Actions
- PJM retrieves the following information for the Secondary Reserve Market Clearing Price Charge
  - Market Participant's Load Ratio Share (MWh)
  - Bilateral Secondary Reserve transactions (sales and purchases) (MWh)
  - Total PJM Real-time Secondary Reserve assigned (MWh)
  - Day-ahead Secondary Reserve Market Clearing Price Credits ($)
  - Balancing Secondary Reserve Market Clearing Price Credits ($)
- PJM calculates for each hour the Secondary Reserve Market Clearing Price charges by RTO zone or active sub-zone and non sub-zone in which the load is located by multiplying the Total Secondary Reserve Market Clearing Price Credits in that location times the Market Participant's Secondary Reserve Obligation Share in that location.
  - Secondary Reserve Market Clearing Price Charges = Total Secondary Reserve Market Clearing Price Credits * Secondary Reserve Obligation Share
- PJM calculates for each hour the Total Secondary Reserve Market Clearing Price Credits in the applicable location.
  - Total Secondary Reserve Market Clearing Price Credits = Day-ahead Secondary Reserve Market Clearing Price Credits + Balancing Secondary Reserve Market Clearing Price Credits
- PJM calculates each Market Participant's hourly Secondary Reserve Obligation Share by RTO zone or active sub-zone and non sub-zone based on their Load Ratio Share in that location, adjusted by bilateral Secondary Reserve sales and purchases.
  - Secondary Reserve Obligation Share = ((Load Ratio Share * Total PJM Real-time Secondary Reserve assigned) – Secondary Reserve MW Purchased + Secondary Reserve MW Sold) / Total PJM Real-time Secondary Reserve assigned

19.3.2 Secondary Reserve Lost Opportunity Cost Charge

PJM Actions

- PJM retrieves the following information for Secondary Reserve Lost Opportunity Cost Charge:
  - Market Participant's Load Ratio Share (MWh)
  - Bilateral Secondary Reserve transactions (sales and purchases) (MWh)
  - Total PJM Real-time Secondary Reserve assigned (MWh)
  - Total PJM Secondary Lost Opportunity Cost Credits
- PJM calculates each Market Participant's hourly Secondary Reserve Lost Opportunity Cost Charges by RTO zone or active sub-zone and non sub-zone by multiplying the Total PJM Secondary Lost Opportunity Cost Credits in that location times the Secondary Reserve Purchases ratio share in that location.
  - Secondary Reserve Lost Opportunity Cost Charge = Total PJM Secondary Reserve Lost Opportunity Cost Credits * Secondary Reserve Purchases ratio share
- PJM calculates each Market Participant's hourly Secondary Reserve Purchases by RTO zone or active sub-zone and non sub-zone based on their Load Ratio Share in that location, adjusted by bilateral Secondary Reserve sales and purchases.
  - Secondary Reserve Purchases = ((Load Ratio Share * Total PJM Real-time Secondary Reserve assigned) – Secondary Reserve MW Purchased + Secondary Reserve MW Sold) / Total PJM Real-time Secondary Reserve assigned

19.4 Reconciliation for Secondary Reserve Charges

PJM will calculate reconciled Secondary Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Secondary Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Secondary Reserve billing determinant for that hour. The hourly Secondary Reserve charge billing determinant (in $/MWh) for each location (Reserve Zone or active sub-zone and non sub-zone) is calculated by dividing the total hourly Secondary Reserve charges in that location by the total PJM real-time load (de-rated for transmission losses) in that location for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Secondary Reserve charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

19.1 Day-ahead Scheduling Reserve Accounting Overview

The Day-ahead Scheduling Reserve Market is a construct for a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System. The Day-ahead Scheduling [30-Minute] Reserve Market is an offer-based market that will clear existing reserve requirements on a day-ahead, forward basis.

The Day-ahead Scheduling Reserve Market is designed to create an explicit value for an additional ancillary service in the PJM Markets, on a short-term basis. A Day-ahead Scheduling [30-Minute] Reserve Market can provide a pricing method and price signals that can encourage generation and Demand Resources to provide Day-ahead Scheduling Reserves (DASR) and to encourage new resources to be deployed with the capability to provide such services. Operational conditions may occur that result in PJM increasing the Day-ahead Scheduling Reserve requirement on an hourly basis, as specified in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 11.2.1.

The Day-ahead Scheduling Reserve Market is designed to interact with the current PJM Operating Reserve construct. While a clearing market for Day-ahead Scheduling [30-Minute] Reserves may reduce out-of-market payments to generators in the form of Operating Reserve credits, it will not eliminate them, and the remaining Operating Reserve costs will continue to be allocated.

19.2 Credits for Day-ahead Scheduling Reserve

Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule and meets the eligibility is credited the scheduled MW at the Day-ahead Scheduling Reserve clearing price. If the resource's Day-ahead Scheduling Reserve offer price (plus opportunity costs, if applicable) is less than its Day-ahead Scheduling Reserve credit for that hour, the excess revenues received will offset any Balancing Operating Reserve credits received by that resource for that hour. Day-ahead Scheduling Reserve credits for joint-owned generators are allocated to the owners based on their ownership shares.

PJM Actions

- PJM retrieves the following information for Day-ahead Scheduling Reserve credits:
  o Day-ahead scheduled minimum and scheduled economic maximum o Real-time economic minimum and economic maximum o Real-time availability
  o Resource offer data – startup time and notification time (including real-time hourly updates)
  o Real-time generation MWh and demand resource MWh o Day-ahead Scheduling Reserve award quantity (MW) o Day-ahead Scheduling Reserve clearing price ($/MWh) o Day-ahead Scheduling Reserve offer price ($/MWh) o Day-ahead Scheduling Reserve opportunity cost
- PJM determines the eligibility to receive Day-ahead Scheduling Reserve credits as follows:
  o For resources with a start time plus notification time of greater than 30 minutes, the resource is required to be online and operating at PJM's direction during the hour of the award with a real-time dispatchable range (Economic Max – Economic Min) at least as great as the day-ahead dispatchable range (Economic Max – Scheduled Min). A

- resource does not have a real-time dispatchable range if the real-time fixed gen flag is enabled for the hour of the award.
    - o For resources with a start time plus notification time of less than or equal to 30 minutes, the resource would be required to be available to the PJM operator for dispatch during the hours of the award and start within 30 minutes if dispatched by PJM.
    - o If a unit with a Day-ahead Scheduling Reserve award for any hour in the day is requested to start in an hour that it did not receive a Day-ahead Scheduling Reserve award, the unit must start within 30 minutes in order to receive the award for the day.
    - o For Demand Resources, measurement is the difference between the Demand Resource's MW consumption at the time a resource is requested by PJM dispatch to reduce and its MW consumption after 30 minutes of the request. In order to allow for small fluctuations and possible telemetry delays, Demand Resources consumption at the start of the event is defined as the greatest telemetered consumption between one (1) minute prior to and one (1) minute following the issuance of the dispatch instruction. Similarly, a Demand Resource's consumption thirty minutes after the dispatcher request is defined as the lowest consumption measured between twenty nine (29) and thirty (31) minutes after the start of the request.
    - o Hydro resources are required to be available to the PJM operator for dispatch during the hours of the award.
- PJM calculates hourly Day-ahead Scheduling Reserve credits for each eligible generator and Demand Resource as follows:
    - o Day-ahead Scheduling Reserve Credit = Day-ahead cleared Day-ahead Scheduling Reserve MW * Day-ahead Scheduling Reserve Clearing Price

19.3 Charges for Day-ahead Scheduling Reserve

Each Market Participant is charged an hourly obligation share of Day-ahead Scheduling Reserve credits in proportion to the Base Day-ahead Scheduling Reserve Obligation Share and Ratio Share of Demand Difference.

PJM Actions

- PJM retrieves the following information for Day-ahead Scheduling Reserve charges:
    - o Market Participant's Load Ratio Share o Day-ahead Scheduling Reserve credits o Cleared Day-ahead Scheduling Reserve
    - o Resource offer data – startup time and notification time (including real-time hourly updates)
    - o Real-time generation MWh and demand resource MWh o Day-ahead Scheduling Reserve award quantity (MW) o Day-ahead Scheduling Reserve clearing price ($/MWh) o Day-ahead Scheduling Reserve offer price ($/MWh) o Day-ahead Scheduling Reserve bilateral transactions
- PJM determines the MW requirement share associated with Base Day-ahead Scheduling Reserves as follows:
    - o *Total Base Day-ahead Scheduling Reserve Eligible MW = Total DASR Eligible MW * Base Requirement Share o Base Requirement Share = Base Day-ahead Scheduling Reserve Requirement MW /*
        (Base Day-ahead Scheduling Reserve Requirement MW + Additional Day-ahead

Scheduling Reserve Requirement MW) o *Base Day-ahead Scheduling Reserve Requirement MW = the requirement defined in PJM Manual 13: Emergency Operations, Section 2, plus any additional reserves scheduled to account for operational uncertainty*
- o *Additional Day-ahead Scheduling Reserve Requirement MW = MAX(Forecast RT load (MWh) – Adjusted Fixed Demand (MWh), 0) as defined in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 11*
- PJM determines each Market Participant's Base Day-ahead Scheduling Reserve Obligation Share based on the Load Ration Share as follows:
  - o *Base Day-ahead Scheduling Reserve Obligation Share = Adjusted Base Dayahead Scheduling Reserve Obligation / Total Base Day-ahead Scheduling Reserve Adjusted Obligation* o *Adjusted Base Day-ahead Scheduling Reserve Obligation = Base Day-ahead*

    Scheduling Reserve Obligation – Day-ahead Scheduling Reserve MW purchased = Day-ahead Scheduling Reserve MW sold
  - o *Base Day-ahead Scheduling Reserve Obligation = Load Ratio Share * Total Base Day-ahead Scheduling Reserve Eligible MW*
- PJM calculates the Base Day-ahead Scheduling Reserve Charge for each market Participant as follows:
  - o *Base Day-ahead Scheduling Reserve Charge = Base Day-ahead Scheduling Reserve credits * Base Day-ahead Scheduling Reserve Obligation Share* o *Base Day-ahead Scheduling Reserve credits = Base Requirement Share * Dayahead Scheduling Reserve credit*
- PJM calculates the Additional Day-ahead Scheduling reserve Charge for each market Participant that are net purchasers in the Day-ahead Energy Market. Additional Dayahead Scheduling Reserves are scheduled in response to RTO-wide Hot or Cold Weather Alerts or other reasons for conservative operations.
  - o *Additional Day-ahead Scheduling Reserve Charge = Additional Day-ahead Scheduling Reserve credits * Ratio Share of Demand Difference* o *Additional Day-ahead Scheduling Reserve credits = Additional Requirement Share * Day-ahead Scheduling Reserve credits* o *Ratio Share of demand Difference = Demand Difference (MWh) / Total Hourly Demand Difference (MWh)* o *Additional Requirement Share = 1 – Base Requirement Share*
  - o *Demand Difference (MWh) = MAX(Real-time load MWh including the impact of load reconciliation MWh – MAX(Day-ahead fixed demand MWh + cleared price sensitive demand MWh + cleared decrement MWh – cleared increment MWh), 0, 0)*

19.4 Reconciliation for Day-ahead Scheduling Reserve Charges

PJM will calculate reconciled Day-ahead Scheduling Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by

~~March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.~~

~~PJM calculates the Day-ahead Scheduling Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Day-ahead Scheduling Reserve billing determinant for that hour. The hourly Base Day-ahead Scheduling Reserve charge billing determinant (in $/MWh) is calculated by dividing the total hourly Base Day-ahead Scheduling Reserve 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 Base Day-ahead Scheduling Reserve charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.~~

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Section 20: 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").

20.1 Billing Process Overview

A single billing statement is issued by PJM monthly to each PJM Market Participant account, detailing all charges and credits for the month that applies 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 Market Participant or due to the Market Participant. Weekly billing statements are also issued for certain line items, as described in PJM Manual 29: Billing. The Operating Agreement related billing statement line items that are described in this PJM Manual are as follows:

- Day-ahead and Balancing Spot Market Energy (charges)
- Synchronized Reserve (charges/credits)
- Non-Synchronized Reserve (charges/credits)
- Secondary 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 Non-Synchronized Reserve (charges)
- Reconciliation for Secondary Reserve (charges)
- Reconciliation for Inadvertent Interchange (charges)
   Reconciliation for Day-ahead Scheduling Reserve (charges)