

PJM Manual 28:

Operating Agreement Accounting

Revision: ~~8950~~

Effective Date: November 1, 2022

Prepared by
Market Settlements Development Department

PJM © 2022





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 \(M-27\)](#)



- 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



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 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, 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 poolscheduled 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-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.

5.2 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 self-scheduled 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:

$$\text{Scheduled MWh} * \text{Day ahead LMP}$$

- 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 day-ahead 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:

$$\text{Day-ahead Operating Reserve Target} = (\text{Start-up costs} + \text{No-load and Energy Offer Costs}) - \text{Day-ahead Revenues}$$

- 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:

$$\text{Balancing Operating Reserve Target} = \text{Resource Costs} - (\text{Real-Time Energy Revenue} + \text{Reserve Revenue})$$



- 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 revenues above cost for Synchronized Reserves, Non-Synchronized Reserves, Secondary Reserves, minus the Market Revenue Neutrality Offset for those same products, plus the 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:
 - 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.
 - 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.
 - 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.
- 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:

$$[(\text{Real time MW}^{**} - \text{Day-ahead Scheduled MW}) * \text{five minute RT LMP}] / 12$$

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 Synchronized Reserve Market revenue in excess of its offer plus opportunity cost plus energy use plus startup costs, plus 5) any Non-Synchronized Reserve Market revenue in excess of its opportunity costs, plus 6) any Secondary Reserve Market revenue in excess of its opportunity costs, ~~plus-minus~~ 7) the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, plus 8) any Reactive Services make whole credit.
 - o Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve revenue above costs and the Market Revenue Neutrality Offsets are netted against the Operating Reserve credit in the corresponding five minute interval in which 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 \$1,000/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 = $[(\text{Five Minute RT LMP} - \text{Offer at Five Minute LMP Desired MW}) * (\text{Five Minute LMP Desired MW} - \text{Max (Five Minute Unit MW, 0)})] / 12$ 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:

$$\frac{[(\text{Lost Opportunity Cost (LOC)}) \text{ Deviation} * (\text{Five Minute Real-time LMP at generator bus}) - \text{Total Opportunity Cost Offer}] / 12}$$

- 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:

$$\frac{[(\text{LOC Deviation} * \text{Five Minute Real-time LMP at the generator bus}) - \text{Total Lost Opportunity Cost}] / 12}$$

- 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 Day-ahead 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:

$$[(\text{Real-time LMP} - \text{Day-ahead LMP}) * \text{Day-ahead scheduled MW}] / 12;$$

Or

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



- 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 abovereferenced 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:

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

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 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"



- o 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 of five 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 real-time 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:
 - o Cleared Day-ahead demand (MWh) o Cleared Day-ahead decrement bid (MWh) o Cleared Day-ahead exports (MWh)
 - o Cleared Day-ahead up-to congestion transactions (MWh) o Total Day-ahead Operating Reserve generating resource credits (\$) o 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:
 - o *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))*
 - o *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 / 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:
 - 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).
 - 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.
 - 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
 - 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
 - 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.
 - 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
 - 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 schedule MW), or 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:
 - o 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
 - o 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.
 - o 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:
 - o 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 costs are allocated and charged to each 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. Synchronized Reserve resources include generators and Economic 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 the PJM Manual 13: Emergency Operations.

Synchronized Reserve credits are awarded to 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.

The Synchronized Reserve offer price for resources is capped at the expected value of the penalty for failing to provide Synchronized Reserve as described and calculated in the PJM Manual 15: Cost Development Guidelines.

Pool-scheduled generator resources assigned synchronized reserve in Synchronous Condensing mode and which respond to a Synchronized Reserve Event 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. Economic Load Response Participant resources that respond to a Synchronized Reserve Event 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 4.8.



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 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 Obligation is equal to its Load Ratio Share of the RTO Reserve zone times the amount of Synchronized Reserve assigned for all Real-time Settlement Intervals for the RTO reserve zone. During hours when the SRMCP is different between the RTO reserve zone and Reserve sub-zone an LSE's Synchronized Reserve Obligation 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 times the amount of Synchronized Reserve assigned (pool-self-scheduled) in that active 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 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. 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

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:
 - o Real-time Synchronized Reserve assignments (pool/self-scheduled) (MWh)
 - o Economic Maximum MW
 - o Real-time Synchronized Reserve Maximum MW
 - o Real-time MW output
 - o Day-ahead Synchronized Reserve assignments (pool/self-scheduled) (MWh)
 - o Real-time Synchronized Reserve Market Clearing Price (RT SRMCP) (\$/MWh)
 - o 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.
 - o Balancing Synchronized Reserve Market Clearing Price Credit = $((\text{Capped Realtime Synchronized Reserve Assignment} - \text{Day-ahead Synchronized Reserve Assignment}) * \text{RT SRMCP}) / 12$
 - o Capped Real-time Synchronized Reserve Assignment =
 - If no Synchronized Reserve Event occurs = Minimum (Real-time Synchronized Reserve Assignment MW, $\text{Max}(\text{Minimum (Economic Maximum MW, Real-time Synchronized Reserve Maximum MW)} - \text{Real-time MW Output}, 0)$)



- 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.

6.2.3 Synchronized Reserve Lost Opportunity Cost Credit

PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit for pool-scheduled 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 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 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 $\text{Synchronized Reserve Lost Opportunity Cost Credit} = \text{Max}(\text{Synchronized Reserve Cost} - \text{Synchronized Reserve Credit}, 0)$
- PJM calculates the cost side of the Synchronized Reserve Lost Opportunity Cost Credit equation as follows:
 - o $\text{Synchronized Reserve Cost} = (\text{Day-ahead Synchronized Reserve Offer Amount} + \text{Real-time Synchronized Reserve Offer Amount} + \text{Day-ahead Synchronized Reserve Opportunity Cost} + \text{Real-time Synchronized Reserves Opportunity Cost}) / 12$
- 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 in the dispatch run
 - 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 in the dispatch run.
 - 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 Startup costs / Number of Hours assigned Synchronized Reserve)



- Economic Load Response Participants resources that do not have a day-ahead commitment to provide energy in the same hour = \$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 in the pricing run.
 - 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 in the pricing run.
- For the following resource types, the Real-time Synchronized Reserve Opportunity Cost is calculated as follows:
 - o Resources providing synchronized reserves in synchronous condensing mode = $((\text{Real-time energy usage to provide Synchronous Condensing} - \text{Day-ahead energy usage to provide Synchronous Condensing}) * \text{RT LMP at the generation bus}) + \text{any additional condense start-up costs in excess of Day-ahead Condense Start-up costs}$
 - o Hydro unit (spill mode) = $(\text{RT LMP at the generation bus} * (\text{Real-time Synchronized Reserve assignment} - \text{Day-ahead Synchronized Reserve assignment}))$
 - o Hydro unit (non-spill mode with day-ahead energy commitment > 0) = $(\text{RT LMP at the generation bus} - \text{average RT LMP at the generation bus for the appropriate on peak / off peak period}) * (\text{Real-time Synchronized Reserve assignment} - \text{Day-ahead Synchronized Reserve assignment})$. 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



- o Hydro unit (non-spill mode with no day-ahead energy commitment > 0) = \$0
- o Economic Load Response Participant resources = \$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

6.3 Charges for Synchronized Reserve

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 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 Clearing Price Charge

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 $\text{Synchronized Reserve Market Clearing Price Charges} = \text{Total Synchronized Reserve Market Clearing Price Credits} * \text{Synchronized Reserve Obligation Share}$
- PJM calculates for each hour the Total Synchronized Reserve Market Clearing Price Credits in the applicable location.
 - o $\text{Total Synchronized Reserve Market Clearing Price Credits} = \text{Day-ahead Synchronized Reserve Market Clearing Price Credits} + \text{Balancing Synchronized Reserve Market Clearing Price Credits} - \text{Synchronized Reserve Shortfall Charge}$
- 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 $\text{Synchronized Reserve Obligation Share} = ((\text{Load Ratio Share} * \text{Total PJM Realtime Synchronized Reserve assigned}) - \text{Synchronized Reserve MW Purchased} + \text{Synchronized Reserve MW Sold}) / \text{Total PJM Real-time Synchronized Reserve assigned}$

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)

6.3.3 Synchronized Reserve Retroactive Penalty Charge

Resources that fail to provide assigned Synchronized Reserve during a Synchronized Reserve Event incur a retroactive 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 The duration is equal to the lesser of the average number of days between Events 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 Synchronized Reserve Event.
 - 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 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 of Synchronized Reserve during a Synchronized Reserve Event.
- The Market Participant's aggregate response does not affect how an individual resource is credited for Synchronized Reserve it provides as described above, but is used to determine what the Market Participant owes in retroactive penalty charges for each resource that was assigned to provide Synchronized Reserve and responded less than their assignment or self-schedule of Synchronized Reserve.
- 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.

The retroactive penalty charges calculated above are allocated based on a Market Participant's ratio share of the Synchronized Reserve obligation MW in the five minute intervals of the Synchronized Reserve Event for the 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 Event 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 (Reserve Zone or active sub-zone and non sub-zone) is calculated by dividing the total hourly Synchronized 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 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 generation resources located within the metered boundaries of PJM that are off-line and available to fully convert their reserve capability into energy in 10 minutes or less. PJM determines the amount of non-synchronized reserves 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 Realtime 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 Non-Synchronized Reserve Obligation based on their Load Ratio Share and applicable location’s requirement 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 RTO Reserve zone. During hours when the NSRMCP is different between the RTO Reserve zone and the Reserve sub-zone, an 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 the amount of



Non-Synchronized Reserve assigned in that active 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 non-synchronized reserve 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 NonSynchronized Reserve Markets to Market Participants that are assigned to provide Non-Synchronized Reserves by PJM. The credits for the Day-ahead and Real-time NonSynchronized 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 is assigned Non-Synchronized Reserve MWs within the Day-ahead Market to satisfy the 30-minute Reserve Requirement and/or Primary Reserve Requirement. **PJM Actions**

- PJM retrieves the following information for Day-ahead Non-Synchronized Reserve Market Clearing Price credit:
 - Day-ahead Non-Synchronized Reserve assignments (MWh)
 - Day-ahead Non-Synchronized Reserve Market Clearing Price (DA NSRMCP) (\$/MWh)
- PJM calculates for each hour the Day-ahead Non-Synchronized Reserve Market Clearing Price credit for each eligible resource by multiplying the Day-ahead NonSynchronized Reserve MWs assigned by the Day-ahead Non-Synchronized Reserve Clearing Price.
 - Day-ahead Non-Synchronized Reserve Market Clearing Price Credit = Day-ahead Non-Synchronized Reserve Assignment * 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 $\text{Balancing Non-Synchronized Reserve Market Clearing Price Credit} = ((\text{Real-time Non-Synchronized Reserve Assignment} - \text{Day-ahead Non-Synchronized Reserve Assignment}) * \text{RT NSRMCP}) / 12$

7.2.3 Non-Synchronized Reserve Lost Opportunity Cost Credit

PJM calculates the Non-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. 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 Day-ahead Non-Synchronized Reserve Market Clearing Price 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 for the resource if the costs associated with that resource are greater than the credits received by the resource.
 - o $\text{Non-Synchronized Reserve Lost Opportunity Cost Credit} = \text{Max}(\text{Non-Synchronized Reserve Cost} - \text{Non-Synchronized Reserve Credit}, 0)$
- 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

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-zone 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 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 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

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:
 - o Market Participant's Load Ratio Share (MWh)
 - o Bilateral Non-Synchronized Reserve transactions (sales and purchases) (MWh)
 - o Total PJM Real-time Non-Synchronized Reserve assigned (MWh)



- o Day-ahead Non-Synchronized Reserve Market Clearing Price Credits (\$)
- o 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.
 - o 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.
 - o Total Non-Synchronized Reserve Market Clearing Price Credits = Day-ahead NonSynchronized 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 based on their Load Ratio Share in that location, adjusted by bilateral Non-Synchronized Reserve sales and purchases.
 - o 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

7.3.2 Non-Synchronized Lost Opportunity Cost Charge

PJM Actions

- PJM retrieves the following information for Non-Synchronized Reserve Lost Opportunity Cost Charge:
 - o Market Participant's Load Ratio Share (MWh)
 - o Bilateral Non-Synchronized Reserve transactions (sales and purchases) (MWh)
 - o Total PJM Real-time Non-Synchronized Reserve assigned
 - o 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.
 - o Non-Synchronized Reserve Lost Opportunity Cost Charge = Total PJM NonSynchronized 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 .
 - o
$$\text{Non-Synchronized Reserve Purchases} = \frac{((\text{Load Ratio Share} * \text{Total PJM Real-time Non-Synchronized Reserve assigned}) - \text{Non-Synchronized Reserve MW Purchased} + \text{Non-Synchronized Reserve MW Sold})}{\text{Total PJM Real-time Synchronized Reserve assigned}}$$

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) is calculated by dividing the total hourly Non-Synchronized 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 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 Accounting

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

- A description of how Market Revenue Neutrality Offset and Opportunity Cost Credit Owed are used within the Reserve Market accounting (see “Market Revenue Neutrality Offset Overview”).
- 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

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 caused by the reduction in assignment 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 resource 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)



- o 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)
- o 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)
- o 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)
- o 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 (MAX(0, (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 Due to Reduction), ABS(Balancing Synchronized Reserve Market Clearing Price Credit Due to Reduction))
 - o Balancing Synchronized Reserve Market Clearing Price Credit Due to Reduction = (Real-time Synchronized Reserve Assignment – Day-ahead Synchronized Reserve Assignment) * RT SRMCP) / 12
- LOC Credit Due to Reduction for Non-Synchronized Reserve = MIN (MAX(0, (Day-ahead NonSynchronized Reserve Market Clearing Price Credit – Balancing Non-Synchronized Reserve Market Clearing Price Credit Due to Reduction), ABS(Balancing Non-Synchronized Reserve Market Clearing Price Credit Due to Reduction))
 - o Balancing Non-Synchronized Reserve Market Clearing Price Credit Due to Reduction = (Real-time Non-Synchronized Reserve Assignment – Day-ahead Non-Synchronized Reserve Assignment) * RT NSRMCP) / 12
- LOC Credit Due to Reduction for Secondary Reserve = MIN (Max(0, (Day-ahead Secondary Reserve Opportunity Cost – Day-ahead Secondary Reserve Market Clearing Price Credit – Balancing Secondary Reserve Market Clearing Price Credit Due to Reduction), ABS(Balancing Secondary Reserve Market Clearing Price Credit Due to Reduction))
 - o Balancing Secondary Reserve Market Clearing Price Credit Due to Reduction = (Real-time Secondary Reserve Assignment – Day-ahead Secondary Reserve Assignment) * RT SecRMCP) / 12

Commented [A1]: Added subsequent to first read. Floor the inner part of this equation at 0 so that the end result cannot be negative.

Commented [A2]: Added subsequent to first read. Floor the inner part of this equation at 0 so that the end result cannot be negative.

Commented [A3]: Added subsequent to first read. Floor the inner part of this equation at 0 so that the end result cannot be negative.



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 = $\text{Min}(\text{Total Value from Increases} * \text{LOC Credit Due to Reduction in the given reserve market} / \text{Sum}(\text{resource's LOC Credits Due to Reduction in all reserve markets}), \text{LOC Credit Due to Reduction in the given reserve market})$

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 Reserve Accounting

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

- A description of how Secondary Reserves are provided and accounted for in the PJM Energy Markets (see “*Secondary Reserve Accounting Overview*”).
- How credits are calculated for providers of Secondary Reserve (see “Credits for *Secondary Reserve*”).
- How the total cost of Secondary Reserve is allocated (see “Charges for *Secondary Reserve*”).
- How Secondary Reserve charge reconciliations are calculated (see “Reconciliation for *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 30minute Reserve Requirement.

PJM Actions

- PJM retrieves the following information for Day-ahead Secondary Reserve Market Clearing Price credit:
 - Day-ahead Secondary Reserve assignments (MWh)
 - 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.
 - 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



- o Day-ahead Secondary Reserve assignments (MWh)
- o Real-time Synchronized Reserve assignments (MWh)
- o Real-time Secondary Reserve Market Clearing Price (RT SecRMCP) (\$/MWh)
- o 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.
 - o 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
 - o Capped Real-time Secondary Reserve Assignment = Minimum (Real-time Secondary Reserve MW, $\text{Max}(\text{Minimum (Economic Maximum MW, Real-time Secondary Reserve Maximum MW)} - \text{Real-time MW Output} - \text{Real-time Synchronized Reserve MW}, 0)$)
 - o Secondary Reserve Shortfall MW =
 - For a real-time offline generation resource that does not reach Economic Minimum output within 30 minutes as instructed by PJM. Secondary Reserve Shortfall MW = Capped Real-time Secondary Reserve assignment. 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.
 - For 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 = Capped Real-time Secondary Reserve assignment. 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 $(A * B) - C$:
 - o A = DA LMP at the generation bus or applicable Economic Load Response Participant resource pricing point
 - o 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 in the dispatch run less any Day-ahead Synchronized Reserve Market assignment
 - o 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 in the dispatch run less any Day-ahead Synchronized Reserve Market assignment
 - o 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 without a Day-ahead Synchronized Reserve assignment = (Day-ahead energy usage to provide Synchronous Condensing * DA LMP at the generation bus) + (Day-ahead Condense Startup costs / Number of Hours assigned Secondary Reserve)



- Resources providing secondary reserves in synchronous condensing mode with a Day-ahead Synchronized Reserve assignment = \$0
- Resources committed to provide secondary reserves in offline mode = \$0
- Economic Load Response Participant resources that do not have a day-ahead commitment to provide energy in the same hour = \$0

Commented [A4]: Added subsequent to the first read. This provides the counterpoint for the revision made in the bullet above.

- Real-time Secondary Reserve Opportunity Cost will equal $(A * B) - C$:
 - o A = RT LMP at the generation bus or applicable Economic Load Response Participant resource pricing point
 - o 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 in the pricing run less any Real-time Synchronized Reserve Market assignment
 - o 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 in the pricing run less any Real-time Synchronized Reserve Market assignment
 - o 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 = $((\text{Real-time energy usage to provide Synchronous Condensing} - \text{Day-ahead energy usage to provide Synchronous Condensing}) * \text{RT LMP at the generation bus}) + \text{any additional condense start-up costs in excess of Day-ahead Condense Startup costs}$
 - Resources providing secondary reserves in synchronous condensing mode with a Real-time Synchronized Reserve assignment = \$0
 - Resources with a Real-time Secondary Reserve assignment in offline mode = \$0
 - Hydro unit (providing secondary reserve in spill mode) = $(\text{RT LMP at the generation bus} * (\text{Real-time Secondary Reserve assignment} - \text{Day-ahead Secondary Reserve assignment}))$



- 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 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
- **Economic Load Response Participant resources = \$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)
 - 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

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
 - o Market Participant's Load Ratio Share (MWh)
 - o Bilateral Secondary Reserve transactions (sales and purchases) (MWh) o Total PJM Real-time Secondary Reserve assigned (MWh) o Day-ahead Secondary Reserve Market Clearing Price Credits (\$) o 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.
 - o 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.
 - o 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.
 - o 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:
 - o Market Participant's Load Ratio Share (MWh)
 - o Bilateral Secondary Reserve transactions (sales and purchases) (MWh) o Total PJM Real-time Secondary Reserve assigned (MWh) o 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.
 - o $\text{Secondary Reserve Lost Opportunity Cost Charge} = \text{Total PJM Secondary Lost Opportunity Cost Credits} * \text{Secondary Reserve Purchases ratio share}$
- 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.
 - o $\text{Secondary Reserve Purchases} = ((\text{Load Ratio Share} * \text{Total PJM Real-time Secondary Reserve assigned}) - \text{Secondary Reserve MW Purchased} + \text{Secondary Reserve MW Sold}) / \text{Total PJM Real-time Secondary Reserve assigned}$

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 (derated 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.





Revision History

Revision 88 (10/01/2022):

- Conforming changes associated with ER19-1486 (Reserve Price Formation)
- Section 1: updated service accounting definitions
- Section 5
 - o Section 5.1: Added inclusion of Secondary Reserve and Market Revenue Neutrality Offset into different Operating Reserve calculations and Added language regarding Nuclear Units eligibility for Operating Reserve credits from Manual 11
 - o Section 5.2: Added inclusion of Secondary Reserve and Market Revenue Neutrality Offset into different Operating Reserve calculations
 - o Section 5.3: Clarify generator deviation calculation with the inclusion of Secondary Reserves
- Section 6
 - o Overall clean-up for Tier I and Tier II language
 - o Section 6.1: Clarification of how the Obligation is calculated between RTO zone and Sub-Zone
 - o Section 6.2: Renamed and reworded for Day-ahead and Balancing Synchronized Reserve Market Clearing Price Credit; added 6.2.3 for Synchronized Reserve Lost Opportunity Cost Credit
 - o Section 6.3: Added more details for the new charge calculations of Clearing Price and LOC; Re-word Retroactive Penalty Charge section for organization
 - o Section 6.4: added clarification regarding the billing determinants per Reserve and Sub-zone
- Section 7: Updated all sections to reflect all associated calculations for credits and charges
 - o Section 7.1: Clarification of how the Obligation is calculated between RTO zone and Sub-Zone
 - o Section 7.2: Renamed and reworded for Day-ahead and Balancing NonSynchronized Reserve Market Clearing Price Credit; added 7.2.3 for Non-Synchronized Reserve Lost Opportunity Cost Credit
 - o Section 7.3: Added more details for the new charge calculations of Clearing Price and LOC



- o Section 7.4: added clarification regarding the billing determinants per Reserve and Sub-zone
- Section 15: was used for Ramapo PAR Facilities but now re-used for Market Revenue Neutrality Offset associated calculations. Ramapo PAR Facilities did not go away with ER19-1486. The PAR calculation moved into the Market-Market calculation
- Section 19: was used for Day-ahead Scheduling Reserves (DASR), but ER19-1486 removed this product. Re-used for new Secondary Reserves and all associated calculations for credits and charges.
- Section 20: updated Billing Line Item names

Revision 87 (07/27/2022):

- Conforming language associated with FERC Order ER20-1590 in Section 11 associated with Load Management Test and Retesting for an energy settlement.

Revision 86 (06/01/2022):

- Conforming changes to support the FERC Order (ER21-1802) for Stability Limits
 - o Section 4.2.2.2
 - Added clarification language that the Desired MW output will consider the stability limits
 - o Sections 5.2.6; 5.2.6.1; 5.2.6.2 and 5.2.6.4
 - Added clarification language that lost opportunity cost credits are not paid for the MWs associated with a stability limit reduction
 - Added clarification language on how the Desired MW output will consider the stability in effect
 - o Sections 5.2.8 and 5.2.9
 - Added clarification language that the Desired MW output will consider the stability limits
 - o Section 6.2.2
 - Added clarification language that the Desired MW output will consider the stability limits

Revision 85 (09/01/2021):

- Conforming changes to support the FERC Order (ER19-2722) for Fast-Start Pricing
 - o Sections 5.1, 5.2: added reference to Dispatch Differential Lost Opportunity Cost credits
 - o Section 5.2.1: Describe the offset to Day-ahead Operating Reserve credits to account for double counting of commitment costs
 - o Section 5.2.9: new section to describe the settlement calculations for resources that are eligible to receive Dispatch Differential Lost Opportunity Cost credits



- o Section 5.3.6: new section to describe the allocation of Dispatch Differential Lost Opportunity Cost credits as charges to market participants based on ratio share of real-time load plus exports
- Periodic Review to address:
 - o Updated/correct terminology
 - o Section 2: added 2.2 and 2.3; removed language regarding specific rules associated with CPLE, DUKE and NCMPA1 due to termination in 2020
 - o Section 3: added 3.10
 - o Section 4: added 4.2.1, 4.2.2, 4.2.2.1, 4.2.2.2, 4.3.1 and 4.3.2
 - o Section 5.2.1: changed 'Flexible Resources' back to 'Combustion Turbine units' due to being inadvertently changed during Intra-day Offer (IDO) implementation
 - o Section 5: added 5.3.1, 5.3.2, 5.3.2.1, 5.3.2.2, 5.3.2.3, 5.3.2.4, 5.3.2.5, 5.3.3, 5.3.4 and 5.3.5
 - o Section 6: added 6.2.1, 6.2.2, 6.3.1, 6.3.2 and 6.3.3
 - o Section 7: added 7.2.1, 7.2.2, 7.3.1 and 7.3.2
 - o Section 19: reorganized language

Revision 85 (06/01/2021):

- Updates for compliance with FERC Docket No. ER19-2722
 - o Section 5.1, 5.2, 5.3 – descriptions and calculations for generator credits
 - o 5.2.9 – new section to describe dispatch differential lost opportunity cost credits

Administrative Change: (02/04/2021, Approved by Rebecca Stadelmeyer):

- Updated manual ownership from Ray Fernandez to Rebecca Stadelmeyer

Revision 84 (12/17/2020):

- Updates for compliance with EL14-37, Allocation of uplift to up-to congestion transactions
 - o Section 5.1, 5.3 – Add the sink end of cleared up-to congestion transactions to be allocated Day-ahead Operating Reserve charges.
 - o Section 5.3 – Add the sink end of cleared up-to congestion transactions to the withdrawal deviation calculation for Operating Reserves.

Revision 83 (12/03/2019):

- Updates for compliance with FERC Order 841, Electric Storage Participation in Markets Operated by RTOs and ISOs, Docket No. RM 16-23-000
 - o Section 13.1 – Note that Direct Charging Energy is not Station Power and end-use charging for an electric vehicle is end-use load.
 - o Added Section 22 – Energy Storage Resource Charging Energy



- Section 22.1 provides an overview of Energy Storage Resource Charging Energy
- Section 22.2 describes the various charges related to Direct Charging Energy
- Section 22.3 describes charges for Load Serving Charging Energy
- Section 22.4 provides various methods to differentiate Direct Charging Energy from Load Serving Charging Energy for an Energy Storage Resource
- Section 22.5 describes monthly reconciliation for Direct Charging Energy and Load Serving Charging Energy

Revision 82 (07/25/2019):

- Periodic Review updated to address:
 - o Section 3.4 – Add process to handle condition when state-estimator loss MWh is unavailable
 - o Section 5.2.5 – Remove entire section as Quick Start Reserve is obsolete o
Section 5.2.8 – Update to describe Reactive Operating Reserve as being credited hourly
 - o Section 19.3 - Provide consistency on terms used for Day Ahead Scheduling Reserve settlement o

Correct various typos

Revision 81 (10/25/2018):

- Modified Section 5.2.1 for consistency with PJM OATT
- Added Section 21 to describe settlements related to Pseudo Tie Overlapping Congestion
- Modified Section 8.4.5 to include the Real-time Pseudo Tie Balancing Congestion refund as a component of the Total Balancing Congestion Charges

Revision 80 (06/01/2018):

- Modified Section 8.4.4 to account for shift in excess congestion credits from FTR Holders to ARR Holders

Revision 79 (04/01/2018):

- Updated Sections 1A.1 and 11.2 for five minute settlements changes per FERC Compliance Order issued on February 21, 2018
- Removed the reference to Manual 33 from the Introduction section

Revision 78 (04/01/2018):

- Added New Section 1.A.1 – Description of Revenue Data for five minute settlements
- Updated Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13 for implementation of five minute settlements



Revision 77 (11/01/2017):

- Revised Section 5: Operating Reserve Accounting to reflect Intra-Day Offer changes as approved by FERC (ER-16-382-000).



Revised Section 12: Meter Reconciliation Accounting to include pseudo-tie generator and dynamic schedule imports and exports and define the applicable rate as well as the impacted market participants.

Revision 76 (06/01/2017):

- Revised Section 8 :Transmission Congestion Accounting Overview to reflect Balancing Congestion changes as approved by FERC (ER16-121)

Revision 75 (11/18/2016):

- Updated Section 3.5 to provide a description of a fully metered EDC.

Revision 74 (07/01/2016):

- Cover to Cover Periodic review clarifying changes to better describe existing rules and processes.

Revision 73 (03/31/2016):

- Revision to Section 5.2.4 and 5.3 effective 03/31/16 to provide clarification language and establish consistency with M-11 and M-15 regarding cancellation fees.

Revision 72 (12/17/2015):

- Revision to Section 5.2.1 effective 12/14/2015 for offer cap language conforming to changes related to FERC Docket No. ER16-76-000.

Revision 71 (06/01/2015):

- Effective 6/1/2015, changes to section 5 to include the impact of load reconciliation MWh in the settlement of balancing operating reserve deviation charges and section 12 to include the extension for submitting monthly meter error corrections.

Revision 70 (04/01/2015):

- Added revisions to section 19 to account for additional day-ahead scheduling reserves scheduled in response to hot or cold weather alerts or escalating emergency conditions

Revision 69 (04/01/2015):

- Removal of revisions to section 5.2.1 Credits for Pool-Scheduled Generating Resources effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.
- Administrative change updated references from eSchedule to InSchedule.

Revision 68 (01/16/2015):

- Revisions to section 5.2.1 Credits for Pool-Scheduled Generating Resources effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.



Revision 67 (01/01/2015):

- Effective 1/1/2015, changes to Sections 10 and 11 to include the impact of load reconciliation MWh in the settlement of Emergency Energy and Emergency Load Response.

Revision 66 (10/30/2014):

- Effective 10/30/2014, changes to Section 6 to compensate resources based on tier 1 estimates only when those resources can be relied upon to provide Tier 1 Synchronized Reserve per the rules in Manual 11.

Revision 65 (04/24/2014):

- Effective, 4/24/2014 changes to Section 6 to incorporate the Manual 11 aggregate response business rule for the purpose of calculating Synchronized Reserve Market retroactive penalty charges.
- Effective 5/29/2014, revisions resulting from the Settlements Formulation Review project and other clean-up items.
- Regulation Credits (Sections 4.2) – Inclusion of regulation set point definition, percentage of hour calculation, and descriptions of regulation shoulder hour calculation scenarios.
- Operating Reserve Credits (Section 5.2) – Clarified eligibility rules for resources that trip or fail to start and added reference to Manual 14D notification procedures. Clarified balancing value calculation when units operate at a lower value in Real-time than their Day-ahead commitment.
- Load Response Accounting (Section 11) – Added definition of Actual MWh relief and corrected units.
- Day-ahead Scheduling Reserve Accounting (Section 19) – clarified that resources do not have a dispatchable range if the real-time fixed gen flag is enabled during the hour of the DASR award.
- Effective 6/1/2014, unless otherwise approved by FERC based on PJM compliance filing regarding the ER14-822 proceeding (improve DR resource operational flexibility). Updated Section 11 for the inclusion of Pre-Emergency DR in the Emergency DR settlements.

Revision 64 (04/11/2014):

- Two of the eSuite Applications have been renamed. Moving forward EES will be known as ExSchedule and eMTR will be known as Power Meter.

Revision 63 (12/19/2013):

- Conforming changes to Section 6 describing how penalties are assessed to a resource that fails to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-

scheduled to provide when a synchronized event occurs as well as the allocation of these penalties. These changes are effective 1/1/2014 per Docket #ER13-297.

Conforming changes to Section 5 per Docket #ER13-2413 clarifying the requirements that must be satisfied in order for wind resources to be eligible to receive lost opportunity cost credits, effective 11/19/2013.

Revision 62 (10/01/2012):

- Conforming changes to Section 4 outlining settlements for Performance Based Regulation Credits and Charges per Docket #ER12-1204. Specifically, the credit changes include removal of the Marginal Benefits Factor for Regulation Capability Credit and Regulation Performance Credit and the application of the Mileage Ratio Multiplier for Regulation Performance Credit. Changes for the charge include specifics around the regulation obligation. Please note per the FERC Order these changes are retroactively effective to the Performance Based Regulation implementation date of October 1, 2012.

Revision 61 (08/29/2013):

- Section 5.2.6 and Section 5.2.8: Effective 6/1/2013, conforming changes to incorporate changes to limit lost opportunity cost compensation to the lesser of a unit's economic maximum or maximum facility output as approved by FERC in Docket ER13-1200.
- Section 7.2: Incorporation of Non-Synchronized Reserve Lost Opportunity Cost calculation details (shortage pricing clean-up), effective 10/1/2012
- Section 5.3: Clarifying revisions on exempting deviations during shortage conditions and revisions for associating interfaces to the East or West BOR regions.
- Section 5.2.3: Incorporated Lost Opportunity Cost Credit for Synchronous Condensing details
- Section 5.2.6: Wind Lost Opportunity Cost: clarified language to align with Tariff language

Revision 60 (06/01/2013):

- Section 5.3: Added EKPC to Western Region BOR
- Sections 3, 8, 9, and 11: Conforming changes to incorporate rules for Residual Zone Pricing as approved by FERC in Docket (s) ER13-347. Residual metered load pricing is effective 6/1/2015.

Revision 59 (04/22/2013):

Effective 4/22/2013:

- Changes to Section 2.1 required due to the elimination of the internal source and sink for Transmission Service products. Changes approved at 2/28/2013 MRC meeting.
- Incorporated changes to Section 13.1 endorsed at the 04/21/2010 MRC meeting but not included in subsequent manual versions. The approved change was to clarify Energy Storage Resources are Market Sellers excluded from the definition of Station Power.



Revision 58 (03/28/2013):

Effective 12/01/2012:

Changes to Section 5 outlining the allocation of Day-ahead Operating Reserve Credits for resources scheduled to provide Reactive Services or transfer interface control per Docket #ER13-418.

Effective 01/15/2013:

- Changes to Section 8 and Section 14 incorporating revenues paid to or received from NYISO for JOA market-to-market congestion relief measures to the total transmission congestion charges allocated to FTR holders.

Effective 03/28/2013:

- Clean-up per settlements formulation review – Added footnote stating that diesel units types are treated liked CTs based on their similar operating characteristics.

Revision 57 (12/01/2012):

- Changes to Section 5 outlining the allocation of Operating Reserve Credits for the scheduling of units for Black Start service and testing of Black Start units.
- References to the eSchedules application were updated to InSchedule to reflect the recent upgrade and renaming of this PJM application
- UPDATED 02/19/2013 – Restored portions of Section 11 that were endorsed as part of Revision 55 that had been mistakenly deleted from subsequent revisions.

Revision 56 (10/01/2012):

- Conforming changes to incorporate rules for Shortage Pricing as approved by FERC in Docket (s) ER09-1063, ER12-2262, and ER12-2385, effective 10/1/2012.
- Conforming revisions made to sections 5 & 6. An additional section created, Section 7 – Non-Synchronized Reserve Accounting, to incorporate new rules.
- Revisions endorsed by Markets & Reliability Committee on 10/25/2012.

Revision 55 (10/01/2012):

Conforming tariff changes for Order 745 (ER11-4106-000), and elimination of economic DR energy compensation under Net Benefits Test threshold (ER12-1705-000) as follows:

- Section 5.1 (added note to include dispatchable resources and section 5.2, added new bullet that operating reserve credits are calculated for DR that follows dispatch signal
- Section 10.3 – includes all the new and prior rules for economic DR compensation in energy market, and associated changes for cost allocation.

Revision 54 (10/01/2012):



Based on the FERC Order 755 for Frequency Regulation Compensation in the Organized Wholesale Power Markets encompassed in FERC Docket Nos. ER12-1204 and ER12-2391, the following changes were made to these sections in this Manual.

Section 4.1 – Regulation Accounting Overview added detail about two-part regulation settlement for capability and performance including the use of the marginal benefit factor and actual hourly performance score.

- Section 4.2 – Regulation Credits added detail about two-part regulation credit for capability and performance including the use of the marginal benefit factor and actual hourly performance score. Also added information about hydro lost opportunity cost calculation and after the fact lost opportunity cost.
- Section 4.3 – Regulation Charges added detail about two-part regulation settlement for capability and performance and regulation obligation for load.

Revision 53 (07/26/2012):

- Updated Section 3.5, 3.7, 4.4, 5.4, 6.4, 7.3, 8.3, 8.5, 11.1, 18.1, and 19.4 to reflect clarifications as recommended by the PJM Net Energy Metering Senior Task Force (NEMSTF).

Revision 52 (06/01/2012):

- Updated Section 5.2.6 to incorporate lost opportunity cost credit details for wind units per FERC Docket #ER12-1422.

Revision 51 (04/03/2012):

- Updated Section 6.1 to clarify that DR resources are compensated for shutdown costs via Operating Reserve credits.
- Updated Section 5.2.1 to clarify the applicability of 3.2.3(f-1) of the Tariff.

Revision 50 (01/01/2012):

- Updates to reflect integration of the DEOK zone

Revision 49 (09/15/2011):

- Section 2 Locational Marginal Pricing: Renamed Section 2 Interface Pricing and incorporated settlements interface pricing information. The Locational Marginal Pricing details were moved to Manual 11 in a previously approved revision.
- Section 4.2 Regulation Credits: Added details on the regulation tolerance amounts used in the calculation of regulation lost opportunity cost credits.
- Section 5.2.1 Credits for Pool-Scheduled Generating Resources: Clarified details on credits when PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert.



- Section 5.2.8 Credits for Resource Providing Reactive Services: Description of reactive credits for synchronous condensers corrected for consistency with the Tariff (Attachment K – Appendix Section 3.2.3B(i)).
- Section 7 Transmission Congestion Accounting – Replaced Total PJM Congestion Charges with Total Transmission Congestion Charges for consistency with Tariff terminology (Attachment K – Appendix Section 5.1.7). Clarified negative target allocations are hourly and based on net quantities.
- Section 7.4.4 Monthly Allocation of Excess Congestion Charges – Added details on the end of Planning Period ARR and FTR transmission rights uplift charges for completeness. This information was previously only documented in Manual 6 – Financial Transmission Rights.

Revision 48 (06/01/2011):

- Updates to reflect integration of ATSI zone

Revision 47 (04/01/2011):

- Correct adjusted obligation formulae in Sections 4 (Regulation) and 19 (Day-ahead Scheduling Reserve).

Revision 46 (10/01/2010):

- Revisions in Section 8, Transmission Losses Accounting, to exclude up-to congestion transaction MWh and to include a reduced amount of non-firm export MWh from the transmission loss credit allocation per FERC Order ER10-2280 effective September 17, 2010.
- Revisions in Section 12, Station Power Accounting, to exclude compressed air energy resources from the station power definition.

Revision 45 (06/23/2010):

- Revisions resulting from 2010 PJM review approved at June 16, 2010 MRC meeting.
- Revisions in Section 10, PJM Load Response Programs Accounting, for economic load response and Real-time index based contracts approved at June 16, 2010 MRC meeting.

Revision 44 (02/01/2010):

- Revised Meter Reconciliation Accounting section to reflect the changes to the Meter Correction Allocation as approved by FERC (Docket No. ER10-320).

Revision 43 (01/20/2010):

- Revised Transmission Losses Accounting section to reflect the changes to the distribution of Transmission Loss Charges as retroactively approved by FERC (EL08-14)



- Added clarifying item in the Operating Reserve Accounting section related to the Dayahead pumped storage optimization program

Revision 42 (07/31/2009):

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

Revision 41 (11/01/2008):

- Cleaned up to better align with new settlement system

Revision 40 (6/1/2008):

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

Revision 39 (1/01/2008):

- Added business rules for InSchedule and Power Meter Data Submissions

Revision 38 (06/01/2007):

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

Revision 37 (03/07/2007):

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

Revision 36 (01/01/2007):

- Section 5: Clarified the hourly Operating Reserve deviation charge eligibility for generators not following PJM dispatch signals.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual

Revision 35 (09/26/06):

- Section 4: Clarified the generator energy offer data used by PJM for Regulation lost opportunity cost credit calculations.



- Section 5: Clarified the hourly Operating Reserve credit eligibility for when a generator trips.

Revision 34 (08/28/06):

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

Revision 33 (05/01/06):

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

Revision 32 (03/01/06):

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

Revision 31 (11/01/05):

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

Revision 30 (08/01/05):

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



Revision 29 (05/20/05):

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

Revision 28 (05/05/05):

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

Revision 27 (10/01/04):

- Revised to reflect the integration of AEP/Dayton.

Revision 26 (05/01/04):

- Revised to reflect the integration of ComEd.

Revision 25 (04/23/04):

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

Revision 24 (07/01/03):

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

Revision 23 (02/01/03):



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

Revision 22 (12/01/02):

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

Revision 21 (10/01/02):

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

Revision 20 (06/01/02):

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

Revision 18 (07/01/01):

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

Revision 17 (06/01/01):

- Revised to reflect the implementation of the PJM Power Meter System.

Revision 16 (05/17/01):

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

Revision 15 (12/01/00):

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

Revision 14 (06/01/00):

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



Revision 13 (06/01/00):

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

Revision 12 (01/03/00):

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

Revision 11 (09/23/99):

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

Revision 10 (08/02/99):

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

Revision 09 (06/01/99):

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

Revision 08 (04/01/99):

- Section 03: Spot Market Energy Accounting o Addition of Reconciliation Billing
- Section 4: Regulation Accounting o Addition of Reconciliation Billing
- Section 5: Operating Reserves Accounting o Addition of Reconciliation Billing and updated Market-based Pricing in the calculation of Operating Reserves credits
- Section 7: Transmission Losses Accounting o Addition of Reconciliation Billing

Revision 07 (01/01/99):

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

Revision 06 (12/07/98):

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



Revision 05 (10/13/98):

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

Revision 04 (07/01/98):

- Section 01: Market Overview
 - o Corrections made to “Market Accounting Overview.”
- Section 03: Spot Market Energy Accounting o Corrections made to “PJM Actions” of “Interchange Seller’s Credits.”
- Section 05: Operating Reserves Accounting o Corrections made to “PJM Actions” of “Credits for Canceled Pool-Scheduled Resources” under “Credits for Operating Reserves.” o Corrections made to “PJM Actions” of “Credits for Pool-Scheduled Aggregate Resources” under “Credits for Operating Reserves.” o Corrections made to “PJM Actions” of “Cost of Operating Reserves.” o Corrections made to “PJM Actions” of “Charges for Operating Reserves.” o Section 13: Billing
 - o Corrections made to “Billing Process Overview.”

Revision 03 (06/15/98):

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

Revision 02 (05/01/98):

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

Revision 01 (01/06/98):

- Section 4: Regulation Accounting o Added “(6) PJM calculates the Average Cost of Regulation dispatched by PJM from all Generating Market Buyers and Market Sellers supplying excess Regulation at the direction of PJM” under “Regulation Credits.”



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

Revision 00 (09/02/97):

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