

PJM Manual 28:

Operating Agreement Accounting

Revision: 88

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Prepared by
Market Settlements Development Department

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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:

*Scheduled MWh * Day ahead LMP*

- PJM calculates the daily Day-ahead Operating Reserve credits for each resource as follows:
 - o Sum hourly day-ahead offer amounts, including applicable no-load and startup costs, for the day
 - o Sum hourly day-ahead energy market values for the day
 - o Day-ahead Operating Reserve credit equals any portion of the resource's total 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:

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

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

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

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

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

- PJM sums the Day-ahead Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.
- PJM determines eligibility for Balancing Operating Reserve credits for each generating resource from dispatcher logs. The following operating guidelines are used in the determination of Operating Reserve credits:
 - o Resource must operate according to the on and off times requested by PJM, and units tripping during pool-scheduled periods of operation will retain their eligibility up through the five minute interval in which the unit trips.
 - o Resources that trip or fail to start are required to notify PJM per the Synchronization and Disconnection procedures in PJM Manual 14D: Generator Operational Requirements.
 - o Resources that trip, are requested to restart by PJM, and return to operate as requested, are eligible to receive credits for the latter period of operation. Resources that trip or failed to start, are requested to restart by PJM for reliability, and operate as requested, are eligible for additional startup costs.
- PJM determines the resource's five minute Real-time MW as described in Section 1A of this PJM Manual.
- Generation resources that are scheduled in the Day-ahead Market are financially responsible for selling their output in real-time. Section 3.2.3(f-1)(ii) of the PJM OATT details provisions for lost opportunity credits for those Flexible Resources that were scheduled in the Day-ahead Market but are not called on by PJM to run in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons). Flexible Resources eligible to be called on in real-time must have a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less for PJM to accurately assess the economic value of the unit and are therefore the only units eligible for these provisions. Any resource scheduled in the Day-ahead Market with a startup plus notification time of greater than 2 hours and a

minimum run time of greater than 2 hours should assume that they are committed by PJM in real-time for the duration of the Day-ahead commitment and are therefore only eligible for the aforementioned make whole provisions if PJM denies the commitment of that unit in real-time for either a transmission constraint or reliability.

- If a generation owner calls PJM to bring on a Flexible Resource per its Day-ahead schedule and PJM does not permit the unit to operate in real-time either for reliability or a transmission constraint, it may receive lost opportunity costs as described in section 3.2.3(f-1)(ii) of the OATT as it was not permitted to run by PJM in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons).
- If a Flexible Resource is committed in the Day-ahead Market with a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less at the time of the Day-ahead commitment and then extends its startup plus notification time to more than 2 hours or its minimum run time to more than 2 hours, it will not be eligible to receive the aforementioned lost opportunity cost provisions in section 3.2.3(f-1)(ii) of the PJM Tariff.
- PJM determines the resource's five minute interval Operating Reserve Desired MW based on its ramp-limited desired MW or UDS basepoint MW, when available. If available, UDS basepoint MW is used when 1.) the UDS basepoint MW are less than or equal to the ramp-limited desired MW or 2.) the UDS basepoint MW is greater than the ramp-limited desired MW and the resource's Real-time MW is greater than the ramp-limited desired MW.
- PJM determines the resource's percent off dispatch for each five minute interval as the lesser of the difference between the resource's Real-time MW and the UDS basepoint MW or the Real-time MW and the ramp-limited desired MW, if available. UDS LMP desired MW is used to calculate a resource's percent off dispatch when 1.) data is unavailable due to technical difficulties or 2.) a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum 5% or 5MW, whichever is lower.
- If the resource's UDS basepoint MW and ramp-limited desired MW are not available or the percent off dispatch is greater than 20%, PJM determines the resource's five minute interval UDS LMP Desired MW based on its dispatch rate, applicable schedule's offer data, where the applicable schedule's offer is the Final Offer and minimum and maximum energy limits for that five minute interval. For steam units, the lesser of the day-ahead scheduled and real-time economic minimum limits and the greater of the day-ahead scheduled and real-time economic maximum limits are used. For Combustion Turbine units, operating at PJM direction, the actual five minute interval real-time output is used as the Operating Reserve Desired MW value.
- PJM calculates the resource's five minute interval real-time energy offer amount based on its applicable schedule's offer data, where the applicable schedule's offer is lesser of the Committed Offer and the Final Offer, and its Real-time MW for that five minute interval. However, for any five minute interval where the resource's Real-time MW is

greater than 110% of its Operating Reserve Desired MW, Operating Reserve Desired MW is used to determine the five minute interval real-time energy offer amount.

- PJM applies the startup and hourly no-load bids if the startup and no-load switch is set in the resource offer data and if the startup bid is applicable for the status of the resource.
- If applicable, when a resource is started during the day at the direction of PJM, the resource's real-time offer amount for that day includes its startup costs based on the appropriate hot, intermediate, or cold state of the resource. For resources that start generating for PJM from a condensing state, the applicable startup cost for that resource equals the amount submitted in writing to the PJM Market Settlement Operations Department to be in effect that Operating Day.
- PJM calculates the resource's balancing energy market value for each five minute interval in an hour as:

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

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 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~~ Generator Interconnection Agreement. If a unit does not have an ~~Interconnection Service Agreement~~ Generator Interconnection Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.

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

5.2.6.2 Self-Scheduled Generators

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

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

- The LOC Deviation is the difference between the generating resource's Desired MW output using the applicable real-time offer based on the five minute real-time LMP at the generator bus and the generating resource's actual output. The Desired MW output is adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the ~~Interconnection Service Agreement~~Generator Interconnection Agreement. If a unit does not have an ~~Interconnection Service Agreement~~Generator Interconnection Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.
- The Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the LOC Deviation as determined below:
 - o For a self-scheduled generator operating on a cost-based offer, the applicable offer curve is the greater of the originally submitted cost-based offer or the cost-based offer that the generator was dispatched.
 - o For a self-scheduled generator operating on a market-based offer, the applicable offer is determined by the following process:
 - If there is only one available cost-based offer:
 - Step 1: Select the greater of cost-based Day-ahead offer and the updated cost-based Real-time offer.
 - Step 2: Compare the offer from Step 1 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.
 - If there are multiple cost-based offers available,
 - Step 1: For each available cost-based offer, select the greater of the Dayahead offer and the updated Real-time offer.
 - Step 2: Compare the cost-based offers from Step 1 and select the lesser of all the cost-based offers.

- Step 3: Compare the cost-based offer from Step 2 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.

5.2.6.3 Flexible Resources

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

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

Or

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

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

Flexible Resources that submit a Real-time offer greater than their resource's Committed Offer in the Day-ahead energy market are not eligible to receive 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~~ Generator Interconnection Agreement. If a unit does not have an ~~Interconnection Service Agreement~~ Generator Interconnection 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) 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~~Generator Interconnection Agreement
- 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) oresource 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.
 - o

- 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:

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

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” 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 maximum facility output MW from ~~Interconnection Service Agreements~~Generator Interconnection Agreement
- 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

- o five minute revenue meter generation MW values from PJM Power Meter, if available
- o state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual)
- o five minute real-time LMPs

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

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

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

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

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

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

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

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

5.3 Charges for Operating Reserve

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

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

Any Operating Reserve charges attributable to generators operated on behalf of transmission owners for local constraints, or on behalf of generation owners for special unit constraints, are directly assessed to the applicable requesting party.

5.3.1 Day-ahead Operating Reserves

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

PJM Actions

- PJM retrieves the following information for Day-ahead Operating Reserve Charges:
 - 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 $Day\text{-}ahead\ Operating\ Reserve\ Charge = Total\ Day\text{-}ahead\ Operating\ Credits * ((Cleared\ Day\text{-}ahead\ demand + decrement\ bids + up\text{-}to\ congestion\ transactions + exports) / (Total\ cleared\ Day\text{-}ahead\ demand + decrement\ bids + exports))$
 - o $Total\ Day\text{-}ahead\ Operating\ Credits = Total\ Day\text{-}ahead\ Operating\ Reserve\ generating\ resource\ credits + Total\ Day\text{-}ahead\ Operating\ Reserve\ transaction\ credits$

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:

- o

- 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:
 - o Each pool-scheduled or dispatchable self-scheduled generator not following PJM dispatch due to its actual output not being between its ramp-limited Desired MW and UDS Basepoint MW, and its % off dispatch is > 10%, will be assessed deviations as Real-time MW – ramp-limited desired MW. If the % off dispatch is > 20%, deviations

- will be assessed as Real-time MW – UDS LMP Desired MW (as determined in the Credits for Pool-Scheduled Generating Resources section of this manual).
- o For each self-scheduled generating resource with an economic maximum limit less than or equal to 110% of the economic minimum limit or not dispatched by PJM above its economic minimum, unless the resource is lowering its output in accordance with PJM direction in response to a minimum generation emergency event (or declaration) will be assessed deviations as Real-time MW – Day-ahead Schedule MW.
 - o Each unit that has tripped or is scheduled Day-ahead and does not run in Real-time will be assessed deviations as Real-time MW – Day-ahead scheduled MW
 - o Each unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will be assessed deviations as Real-time MW – UDS LMP Desired MW
 - o Each unit that is not dispatchable in both the Day-ahead and Real-time market will be assessed deviations as Real-time MW – Day-ahead scheduled MW. Units that choose to participate in the Day-ahead pumped storage optimization program are considered not dispatchable in the Day-ahead market.
 - o Each unit where the real-time economic minimum is greater than its Day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum by 5% or 5MW, whichever is lower, and UDS LMP Desired MW for the hours is either below the real-time economic minimum or above the real-time economic maximum, will be assessed deviations as Real-time MW – UDS LMP Desired MW
 - o Deviations are not calculated if the absolute value of the deviation MW ratio to applicable day-ahead scheduled MW or desired MW is less than or equal to 5%
 - Five minute intervals during which a generator is assigned by PJM for Regulation, assigned by PJM for Synchronized Reserve and reduced from its economic dispatch base point (and actual MW are less than day-ahead scheduled MW), assigned by PJM for Non-Synchronized Reserve (and actual MW are less than the day-ahead scheduled MW), or assigned by PJM for Secondary Reserve and reduced from its economic base point (and actual MW are less than the day-ahead 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 reach market Participant based on their Load Ratio Share in the applicable transmission zone(s).

5.3.6 Dispatch Differential Lost Opportunity Cost

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

5.4 Reconciliation for Operating Reserve Charges

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

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

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

PJM calculates the Synchronous Condensing charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the PJM Region by the Synchronous Condensing billing determinants for that day. The daily Synchronous Condensing billing

determinant (in \$/MWh) for the PJM Region is calculated by dividing the total Synchronous Condensing charges in the PJM Region by the total real-time load (de-rated for transmission losses) and real-time exports in the PJM Region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for synchronous condensing for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.