Operating Reserve

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges in 2011 were $578.1 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 15.1 percent, the synchronous condensing charges proportion was 0.1 percent, and the balancing charges proportion was 84.8 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.1068 per MWh, the balancing operating reserve RTO deviation rate averaged $0.9455 per MWh and the balancing operating reserve RTO reliability rate averaged $0.0681 per MWh. Lost opportunity cost rate average $1.0678 per MWh and canceled resources rate averaged $0.0560 per MWh.
- **Operating Reserve Credits.** Balancing generator operating reserve credits were 53.3 percent, lost opportunity cost credits were 30.7 percent and day-ahead operating reserve credits were 15.5 percent of all credits. The remaining 0.5 percent was the sum of day-ahead and real-time transactions credits plus synchronous condensing credits.

Characteristics of Credits

- **Types of units receiving operating reserve credits.** Combined cycle and conventional steam units fueled by coal received 91.5 percent of all day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesel engines received 86.7 percent of the lost opportunity cost credits. Wind units received 91.0 percent of the canceled resources credits.
- **Economic – Noneconomic Generation.** In 2011, units receiving balancing operating reserve credits were economic during 34.3 percent of all hours. Combined cycle units had the highest proportion of economic hours with 43.4 percent.
- **Geography of Balancing Credits and Charges.** Generators in the Eastern Region paid 10.1 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 74.1 percent of such credits. Generators in the Western Region paid 10.2 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 25.9 percent of such credits.
- **Generators Credits and Charges.** Generators paid 13.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.6 percent of all credits.

Load Response Resource Operating Reserve Credits

- In 2011, 7.1 percent of all accepted demand reduction bids were paid through operating reserve credits. The remaining 92.9 percent was credited to end-use customers through the economic load response program.

Reactive Service

- Total reactive service credits in 2011 were $41.3 million. The top three zones accounted for 84.0 percent of the total credits. Combustion turbines received 51.5 percent of the total reactive service credits.

Operating Reserve Issues

- The top 10 units receiving total operating reserve credits received 28.1 percent of all credits. The top 10 organizations received 82.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 4710, balancing operating reserves was 3299 and lost opportunity cost HHI was 5385.
- It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of

merit and received substantial balancing operating reserves credits. Of the total balancing operating reserve credits paid to these units, 75.6 percent was allocated as RTO deviation charges, 20.6 percent as RTO reliability charges and the remaining 3.8 percent was allocated regionally.

- Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. In 2011 an estimated total of $6.5 million or 33.6 percent of all balancing operating reserve credits paid to ALR capable units was for the purpose of providing blackstart service.
- Up-to congestion transactions do not pay balancing operating reserve charges despite that they affect dispatch in the Day-Ahead Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant.

Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, PJM should take another step towards more precise definition of the reasons for incurring operating reserve charges and about the necessity of paying operating reserve charges in some cases. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Detailed Recommendations

- The MMU recommends improving the process of identifying and classifying the reasons for paying operating reserve charges to both generation and demand side resources in order to ensure that market transactions pay only appropriate operating reserve charges.
  - The MMU recommends that PJM determine if units are being dispatched for the PSEG – ConEd wheel, that the reasons for the dispatch of these units be logged, and that PJM consider whether the operating reserve charges associated with running these units is being allocated properly.
  - The MMU recommends that PJM dispatchers explicitly log the reasons that ALR units are run out-of-merit to ensure that the resultant operating reserve charges are appropriately assigned to blackstart service or for voltage support.
  - The MMU recommends that after the fact adjustments to the operating reserve charge and credit portions of the bills of PJM members be specifically identified so that they may be properly categorized.

Table 3-1 Operating reserve credits and charges

Credits received for:		Charges paid by:
	Day-Ahead	
Day-Ahead Import Transactions Demand-Side Response Resources Generation Resources	→	Day-Ahead Demand Bid Day-Ahead Export Transactions Decrement Bids
Synchronous Condensing	→	Real-Time Export Transactions Real-Time Load
	Balancing	
Generation Resources: Deviations	→	Real-Time Deviations from Day-Ahead Schedule by RTO, East and West Region
Generation Resources: Reliability	→	Real-Time Load plus Export Transactions by RTO, East and West Region
Canceled Resources Demand-Side Response Resources Lost Opportunity Cost Performing Annual Scheduled Black Start Tests Providing Quick Start Reserve Real-Time Import Transactions	→	Real-Time Deviations from Day-Ahead Schedule in the entire RTO
Controlling Local Transmission Constraints	→	Applicable Requesting Party
Providing Reactive Service	→	Zonal Real-Time Load

— The MMU recommends that lost opportunity cost paid to wind units be properly categorized as such, not as canceled resources credits.

- The MMU recommends that up-to congestion transactions pay balancing operating reserve charges.

Description of Operating Reserves

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the LMP, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 shows the categories of credits and charges and their relationship. This table shows how credits are allocated. Table 3-2 shows the different types of deviations.

Day-Ahead Operating Reserves

Day-ahead operating reserve credits consist of Day-Ahead Energy Market credits and day-ahead import transaction credits.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-7 shows monthly day-ahead operating reserve charges for calendar years 2010 and 2011.

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services; such as voltage regulation.[1]

1 "Manual 28: Operating Agreement Accounting," Revision 50 (January 1, 2012).

Table 3-2 Operating reserve deviations

Deviations		
Day-Ahead		Real-Time
Day-Ahead Demand Bid Day-Ahead Sales Day-Ahead Export Transactions Decrement Bids	Demand (Withdrawal) (RTO, East, West)	Real-Time Load Real-Time Sales Real-Time Export Transactions
Day-Ahead Purchases Day-Ahead Import Transactions Increment Offers	Supply (Injection) (RTO, East, West)	Real-Time Purchases Real-Time Import Transactions
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-7 shows monthly synchronous condensing charges for calendar years 2010 and 2011.

Balancing Operating Reserves

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, canceled pool-scheduled resources credits, real-time import transaction credits and credits to resources controlling local transmission constraints. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction, the market participant is made whole. Balancing operating reserve credits are also paid to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Reactive Services

Reactive service credits are paid to units for the purpose of maintaining the reactive reliability of the PJM region if such unit is reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price. Credits are also paid to resources if their output is increased at the request of PJM for the purpose of reactive services and the offered price is higher than the LMP at the unit's bus. Synchronous condensers may also receive reactive service credits by providing synchronous condensing for the purpose of maintaining reactive reliability at the request of PJM. Reactive service charges are allocated daily to real-time load in the transmission zone where the reactive service was provided.

Deviation Categories

Under PJM's operating reserve rules, credits allocated to generators defined to be operating to control deviations on the system, lost opportunity credits and credits to canceled resources are charged to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES) plus day-ahead sale transactions; and b) the sum of real-time load plus real-time sales scheduled through eSchedules plus real-time exports scheduled through the EES.[2,3]
- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES plus day-

2 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

3 PJM's eSchedules is an application used by participants for internal bilateral transactions.

Table 3-3 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,798,230	3,261,409	3,107,683	16,167,323
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,680,742	12,686,680
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	2,730,454	12,707,988
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,623,238	2,027,200	2,662,761	11,313,199
May	9,004,034	4,228,004	2,416,103	15,648,141	7,144,854	2,381,825	2,902,093	12,428,772
Jun	10,936,989	3,964,478	3,174,230	18,075,697	9,845,466	2,558,697	2,996,041	15,400,204
Jul	10,928,408	3,847,011	3,412,498	18,187,917	10,160,922	2,690,836	3,306,340	16,158,098
Aug	9,747,045	3,417,328	3,188,437	16,352,810	8,566,032	2,057,281	2,907,427	13,530,739
Sep	9,480,237	3,587,356	2,524,213	15,591,806	8,829,765	2,198,858	2,561,534	13,590,157
Oct	7,170,712	2,913,554	2,368,303	12,452,569	7,140,856	2,514,963	2,388,186	12,044,005
Nov	7,606,971	2,860,054	2,485,153	12,952,178	6,739,882	2,704,677	2,949,889	12,394,448
Dec	10,069,627	4,027,236	3,513,489	17,610,352	7,646,566	2,606,633	2,629,846	12,883,045
Total	107,168,079	49,691,893	32,634,039	189,494,011	97,202,725	30,278,937	33,822,997	161,304,659
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	60.3%	18.8%	21.0%	100.0%

ahead purchase transactions; and b) the sum of the real-time purchase transactions scheduled through eSchedules plus real-time imports scheduled through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted. On December 1, 2008, the ramp limited desired (RLD) MW was implemented as a tool to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate. The goal of this rule change was to further incent generators to follow PJM dispatch instruction in order to increase market efficiency, and improve reliability. A deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

Demand and supply deviations are netted by zone, hub, or interface. For example, a negative deviation at a bus can be offset by a positive deviation at another bus in the same zone.

The sum of each organization's netted deviations by zone, hub, or interface is assigned to either the eastern or western region, depending on the location of the zone, hub, or interface.[4] The RTO region deviations are the sum of an organization's eastern and western region deviations, plus deviations that occurred at hubs that include buses in both regions.[5] Generating units that deviate from real-time dispatch may offset deviations by another generating unit at the same bus if that unit is electrically equivalent and owned by the same participant.

An organization's total daily balancing operating reserve charges based on deviations are the sum of the three deviation categories, by region (including the RTO), for the day, multiplied by each regional deviation rate plus lost opportunity cost and canceled resources operating reserve rates.

Table 3-3 shows monthly real-time deviations for demand, supply and generator categories for 2010 and 2011. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were lower in 2011 than 2010 by 28,189,352 MWh or 14.9 percent. Demand deviations decreased by 9.3 percent, supply deviations decreased by 39.1 percent, and generator deviations increased by 3.6. From 2010 to 2011, the share of total deviations in the demand category increased by 3.7 percentage points, the share of supply deviations

4 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ATSI, ComEd, DLCO, and DAY Control Zones.

5 Only two hubs include buses in both the eastern and western regions: the Dominion Hub and the Western Interface Hub.

Table 3-4 Regional charges determinants (MWh): Calendar year 2011

	Reliability Charge Determinants			Deviation Charge Determinants			
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
RTO	722,865,995	32,677,860	755,543,855	97,202,725	30,278,937	33,822,997	161,304,659
East	371,881,388	13,907,345	385,788,732	57,598,101	16,594,151	15,418,402	89,610,653
West	350,984,607	18,770,515	369,755,122	39,199,674	13,557,237	18,404,595	71,161,506

Table 3-5 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

decreased by 7.4 percentage points, and the share of generator deviations increased by 3.8 percentage points.

Real-time load, real-time exports, and deviations in each region are shown in Table 3-4. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Balancing Operating Reserve Allocation

Table 3-5 shows the process for identifying balancing operating reserves credits as related either to reliability or deviations. Credits are assigned to units during two periods, the reliability analysis (performed after the Day-Ahead Market is cleared) and the Real-Time Market.

During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations or to meet forecasted real-time load. Conservative operations mean that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are committed to operate to meet the forecasted real time load plus any operating reserve requirements if needed in addition to the physical units committed in the Day-Ahead Market. The resultant credits are defined as deviation credits.

In the Real-Time Market, credits are also identified as related to either reliability or deviations. Credits are paid to units that are called on by PJM for reliability purposes if the LMP at the unit's bus is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as reliability credits and are allocated to real-time load plus exports.

Credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations.

Reliability and deviations credits are categorized by region based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

Table 3-6 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead Rate ($/MWh)	Balancing RTO Deviation Rate ($/MWh)	Balancing RTO Reliability Rate ($/MWh)
1999	$133,897,428	NA	7.5%	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	0.535*	NA
2001	$290,867,269	34.0%	8.7%	0.275	1.070*	NA
2002	$237,102,574	(18.5%)	5.0%	0.164	0.787*	NA
2003	$289,510,257	22.1%	4.2%	0.226	1.197*	NA
2004	$414,891,790	43.3%	4.8%	0.230	1.236*	NA
2005	$682,781,889	64.6%	3.0%	0.076	2.758*	NA
2006	$322,315,152	(52.8%)	1.5%	0.078	1.331*	NA
2007	$459,124,502	42.4%	1.5%	0.057	2.331*	NA
2008	$429,253,836	(6.5%)	1.3%	0.084	2.113*	NA
2009	$325,842,346	(24.1%)	1.2%	0.120	0.672	0.009
2010	$572,286,706	75.6%	1.6%	0.113	0.912	0.058
2011	$578,072,070	1.0%	1.6%	0.107	0.946	0.068

Operating Reserve Results

Operating Reserve Charges

Table 3-6 shows total operating reserve charges from 1999 through 2011.[6,7] Total operating reserve credits increased by 1.0 percent in 2011 from 2010, to a total of $578.1 million.[8] In 2011, operating reserve charges remained high, 30.2 percent higher than the annual average from 2005 through 2009. Table 3-6 shows the ratio of total operating reserve credits to the total value of PJM billings.[9] This ratio remained the same as 2010 at 1.6 percent.

Table 3-6 shows the average day-ahead operating reserve rate and the average balancing operating reserve RTO deviation rate for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.0062 per MWh or 5.5 percent from $0.1130 per MWh in 2010 to $0.1068 per MWh in 2011. The balancing operating reserve RTO deviation rate increased $0.0335 per MWh, or 3.7 percent, from $0.9120 per MWh in 2010 to $0.9455 per MWh in 2011. The balancing operating reserve RTO reliability rate increased $0.0101 per MWh or 17.4 percent from $0.0580 per MWh in 2010 to $0.0681 per MWh in 2011. The balancing operating reserve RTO deviation rates prior to 2009 (as indicated with asterisk) represent what the rates were under the old operating construct rules, taking each day's total balancing operating reserve credits, and dividing by total demand, supply, and generator deviations.

Total operating reserve charges in 2011 were $578.1 million, up from the total of $572.3 million in 2010. Table 3-7 compares monthly operating reserve charges by category for calendar years 2010 and 2011. The overall increase of 1.0 percent in 2011 is comprised of a 3.7 percent decrease in day-ahead operating reserve charges, a 5.7 percent increase in synchronous condensing charges and a 1.9 percent increase in balancing operating reserve charges. The day-ahead operating reserve charges proportion of total operating reserve charges decreased 0.7 percentage points to 15.1 percent, the synchronous condensing charges proportion remained the same at 0.1 percent, and the balancing charges proportion increased 0.7 percentage points to 84.8 percent.

Table 3-8 shows the monthly composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing generation, real-time import transaction, lost opportunity cost charges, canceled pool-scheduled resources, and charges paid to resources controlling local transmission constraints.

Table 3-9 shows the amount and percentages of regional balancing charge allocations for 2011. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not

6 Table 3-6 includes all categories of credits as defined in Table 3-1 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 16, 2012.

7 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

8 The total operating reserve charges for 2010 were inflated by an import transaction which was made whole through balancing operating reserve credits. Without this transaction, operating reserve charges would have been 4.9 percent higher in 2011.

9 See the *2011 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at Table 10-14, "Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011," for the value of PJM billings during the period indicated.

Table 3-7 Monthly operating reserve charges: Calendar years 2010 and 2011

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,499,142	$50,830,516	$12,373,099	$110,095	$49,326,904	$61,810,098
Feb	$11,425,494	$14,715	$22,453,018	$33,893,227	$8,940,203	$139,287	$26,567,990	$35,647,480
Mar	$8,836,886	$122,817	$17,209,663	$26,169,365	$6,837,719	$66,032	$24,021,865	$30,925,615
Apr	$7,633,141	$93,253	$23,024,746	$30,751,141	$4,405,102	$13,011	$18,762,006	$23,180,118
May	$5,127,307	$131,600	$39,239,806	$44,498,713	$7,064,934	$39,417	$46,178,207	$53,282,558
Jun	$3,511,264	$33,923	$57,141,785	$60,686,972	$8,303,391	$9,056	$62,118,948	$70,431,396
Jul	$4,601,788	$88,136	$63,394,961	$68,084,886	$4,993,311	$238,127	$106,596,647	$111,828,085
Aug	$3,622,670	$66,535	$41,720,756	$45,409,961	$8,360,392	$104,982	$55,142,158	$63,607,531
Sep	$8,433,892	$27,971	$40,808,601	$49,270,464	$6,249,240	$40,878	$36,617,421	$42,907,539
Oct	$7,719,744	$1,543	$30,640,894	$38,362,181	$5,133,837	$0	$20,415,483	$25,549,319
Nov	$6,556,715	$29,674	$20,978,750	$27,565,138	$7,063,847	$0	$19,528,707	$26,592,554
Dec	$12,951,879	$59,954	$83,752,310	$96,764,143	$7,593,046	$0	$24,716,729	$32,309,775
Total	$90,702,132	$720,142	$480,864,432	$572,286,706	$87,318,120	$760,886	$489,993,064	$578,072,070
Share of Annual Charges	15.8%	0.1%	84.0%	100.0%	15.1%	0.1%	84.8%	100.0%

Table 3-8 Monthly balancing operating reserve charges by category: Calendar year 2011

	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Charges due to Local Transmission Constraint	Total
Jan	$43,170,696	$2,946,513	$590,321	$2,619,374	$49,326,904
Feb	$22,698,871	$3,205,948	$168,244	$494,927	$26,567,990
Mar	$15,248,859	$7,094,881	$358,223	$1,319,902	$24,021,865
Apr	$11,094,664	$7,222,704	$303,514	$141,123	$18,762,006
May	$20,285,073	$20,364,971	$2,742,644	$2,785,518	$46,178,207
Jun	$30,605,916	$27,996,648	$901,825	$2,614,560	$62,118,948
Jul	$56,565,647	$46,241,739	$299,606	$3,489,655	$106,596,647
Aug	$29,078,083	$24,142,105	$302,975	$1,618,995	$55,142,158
Sep	$17,735,689	$16,948,063	$151,195	$1,782,474	$36,617,421
Oct	$10,460,806	$6,327,845	$1,250,928	$2,375,903	$20,415,483
Nov	$11,415,410	$6,181,160	$1,663,154	$268,983	$19,528,707
Dec	$20,477,899	$3,574,430	$306,260	$358,140	$24,716,729
Total	$288,837,612	$172,247,007	$9,038,890	$19,869,554	$489,993,064
Share of Annual Charges	58.9%	35.2%	1.8%	4.1%	100.0%

include charges attributed for resources controlling local transmission constraints, resources providing quick start reserve and resources performing annual, scheduled black start tests.

Operating Reserve Rates

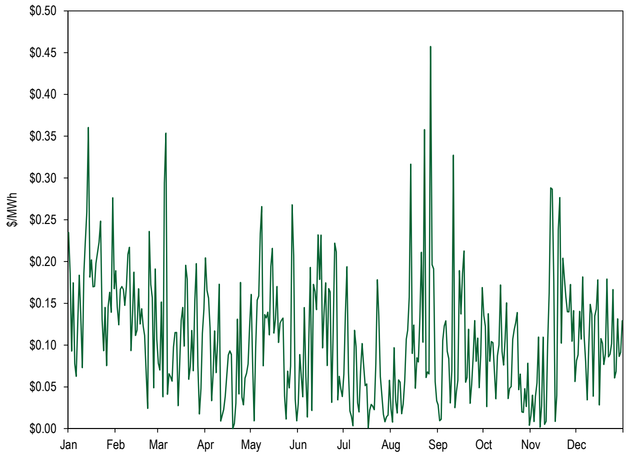
Under the operating reserve cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO. The day-ahead operating reserve rates are equal to the total day-ahead operating reserve credits divided by the sum of the day-ahead demand bids, decrement bids and day-ahead export transactions. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. Lost opportunity cost and canceled resources rates are calculated by dividing each daily credit by the daily demand, supply, and generation deviations. See Table 3-1 and Table 3-5 for how these credits are allocated.

Figure 3-1 shows the daily day-ahead operating reserve rate for 2011. The average rate was $0.1068 per MWh. The highest rate occurred August 27, when the rate reached $0.4574 per MWh mainly because of the precautions taken by PJM due to Hurricane Irene. Day-ahead operating reserve rates also show a weekly pattern. Rates on weekends are on average 61.5 percent higher than rates on weekdays. This could be a result of holding units on during the lower load weekend periods so that they are available on Monday.

Table 3-9 Regional balancing charges allocation: Calendar year 2011[10]

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$49,417,097	10.5%	$9,996,503	2.1%	$27,029,746	5.7%	$86,443,346	18.4%
	Real-Time Exports	$2,032,004	0.4%	$589,969	0.1%	$1,626,901	0.3%	$4,248,873	0.9%
	Total	$51,449,101	10.9%	$10,586,472	2.3%	$28,656,646	6.1%	$90,692,219	19.3%
Deviation Charges	Demand	$92,658,511	19.7%	$25,062,023	5.3%	$4,296,258	0.9%	$122,016,792	26.0%
	Supply	$28,234,803	6.0%	$6,642,217	1.4%	$1,482,909	0.3%	$36,359,930	7.7%
	Generator	$31,622,306	6.7%	$6,223,171	1.3%	$1,923,194	0.4%	$39,768,671	8.5%
	Total	$152,515,621	32.4%	$37,927,411	8.1%	$7,702,362	1.6%	$198,145,393	42.1%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$112,133,882	23.9%	$0	0.0%	$0	0.0%	$112,133,882	23.9%
	Supply	$31,779,830	6.8%	$0	0.0%	$0	0.0%	$31,779,830	6.8%
	Generator	$37,372,185	7.9%	$0	0.0%	$0	0.0%	$37,372,185	7.9%
	Total	$181,285,897	38.6%	$0	0.0%	$0	0.0%	$181,285,897	38.6%
Total Balancing Charges		$385,250,619	81.9%	$48,513,882	10.3%	$36,359,008	7.7%	$470,123,510	100%

Figure 3-1 Daily day-ahead operating reserve rate ($/MWh): Calendar year 2011



The top chart in Figure 3-2 shows the RTO and the regional reliability rates for 2011. The average daily RTO reliability rate was $0.0681 per MWh. On August 26, PJM declared conservative operations in the Mid-Atlantic and Dominion zones for the evening period of Saturday, August 27 and the midnight, day and evening periods of Sunday, August 28 due to Hurricane Irene. The August 28 Eastern region reliability rate was $3.0844 per MWh, the largest in 2011.

The center chart in Figure 3-2 shows the RTO and the regional deviations rates for 2011. The average daily RTO deviation rate for 2011 was $0.9455 per MWh. The largest daily rate occurred on January 24, 2011, when the RTO deviation rate was $10.9541 per MWh.

In 2011, two specific periods experienced higher than normal balancing operating reserve charges, specifically RTO deviation charges. The three days from January 22 through January 24 accounted for 8.8 percent or $17.9 million of all balancing operating reserve charges allocated in the RTO in 2011. The five days from July 19 through July 23, the balancing operating reserve charges allocated in the RTO totaled $18.6 million or 9.1 percent of all balancing operating reserve charges allocated in the RTO in 2011. These days were at or near the time of the peak load days in their respective seasons. January 24 had the highest daily real-time demand of the winter season and five of the top 6 peak load days of 2011 occurred between July 19 and July 23.[11]

The bottom chart in Figure 3-2 shows the daily lost opportunity cost rate and the daily canceled resources rate. The lost opportunity rate averaged $1.0678 per MWh. The highest lost opportunity cost rate occurred on May 31, when it reached $12.7818 per MWh. The canceled resources rate averaged $0.0560 per MWh and credits were paid during 56.4 percent of the days in 2011. Spikes in the lost opportunity cost charge rate are often caused by credits paid to combustion turbines with long start-up and notification time. Combustion turbines with long start-up and notification time are generally not dispatched in real time because their availability is outside the PJM dispatcher window. PJM has proposed a rule change to address this issue.

10 The total charges shown in Table 3-9 do not equal the total balancing charges shown in Table 3-8 because the totals in Table 3-8 include charges to resources controlling local transmission constraints while the totals in Table 3-9 do not.

11 Including PJM's net interface position (real-time imports and exports).

Figure 3-2 Daily balancing operating reserve rates ($/MWh)

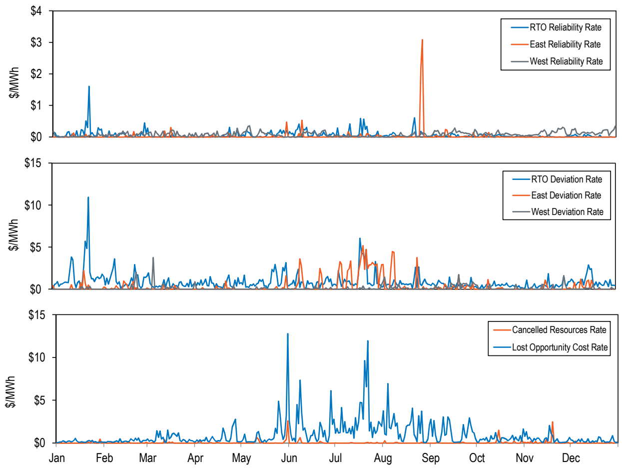


Table 3-10 shows the rates for each region in each category. Regional reliability rates are higher than the RTO reliability rate. RTO deviation charges and lost opportunity cost charges accounted for 66.3 percent of all balancing operating reserve charges in 2011. The RTO deviation and lost opportunity cost rates were substantially higher than the regional deviation rates.

Table 3-10 Balancing operating reserve rates ($/MWh): Calendar year 2011

	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.068	0.946	1.068	0.056
East	0.027	0.423	NA	NA
West	0.078	0.108	NA	NA

Table 3-11 Operating reserve rates statistics ($/MWh): Calendar year 2011

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	18.208	2.249	0.238	2.521
	DEC	18.235	2.358	0.347	2.504
	DA Load	0.457	0.109	0.000	0.073
	RT Load	3.201	0.091	0.000	0.245
	Deviation	18.208	2.249	0.238	2.521
West	INC	17.621	2.001	0.087	2.083
	DEC	17.630	2.110	0.321	2.069
	DA Load	0.457	0.109	0.000	0.073
	RT Load	1.665	0.146	0.000	0.140
	Deviation	17.621	2.001	0.087	2.083

Table 3-11 also shows the operating reserve cost of a 1 MW transaction during 2011. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.3581 per MWh with a maximum rate of $18.2352 per MWh, a minimum rate of $0.3475 per MWh and a standard deviation of $2.5039 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges.

Operating Reserve Credits by Category

Figure 3-3 shows that 84.3 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits. This percentage increased 4.9 percent from the 79.4 percent accumulated in 2010.

Figure 3-3 Operating reserve credits: Calendar year 2011

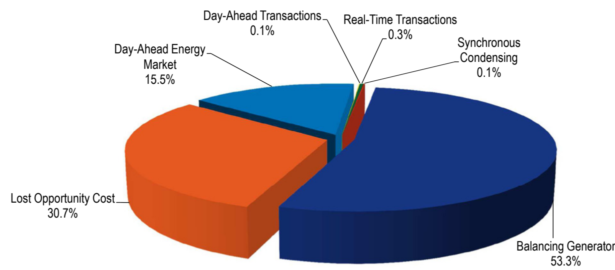


Table 3-12 shows the monthly totals for each type of credit for 2011. The winter months, January, February, November, and December, accounted for 27.4 percent of operating reserve credits for the year, while the summer months, May, June, July and August, accounted for 51.6 percent, and the shoulder months 21.0 percent. These credits do not equal the total amount of charges paid of $578.1 million. The difference of $17.2 million was operating reserve billing adjustments made by PJM directly to participants' bills.[12]

Characteristics of Credits

Types of Units

Table 3-13 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.) Credits to demand resources are not included.

Table 3-14 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and

12 PJM Settlements makes offline adjustments for credits to participants on a continuous basis. The adjusted amount corresponds to charges paid by a transmission owner for local constraint control that were not reflected in the corresponding credits.

Table 3-12 Credits by month (By operating reserve market): Calendar year 2011[13]

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$43,621,831	$473,239	$2,946,513	$59,524,777
Feb	$8,844,162	$96,041	$139,287	$22,983,987	$378,056	$3,205,948	$35,647,482
Mar	$6,830,696	$7,024	$66,032	$15,513,366	$421,862	$7,094,881	$29,933,860
Apr	$4,395,461	$9,641	$13,011	$11,323,487	$215,816	$7,222,703	$23,180,118
May	$7,057,377	$7,557	$39,417	$23,115,911	$13,365	$20,364,971	$50,598,598
Jun	$8,158,879	$144,512	$9,056	$31,865,375	$20,077	$27,996,648	$68,194,548
Jul	$4,972,654	$20,657	$238,127	$56,927,399	$1,068	$46,241,740	$108,401,646
Aug	$8,355,563	$4,828	$104,982	$29,491,930	$4,774	$24,142,105	$62,104,182
Sep	$6,249,124	$116	$40,878	$18,309,027	$40,005	$16,948,063	$41,587,213
Oct	$5,133,838	$0	$0	$11,672,870	$38,865	$6,327,845	$23,173,418
Nov	$7,063,848	$0	$0	$12,994,147	$114,037	$6,181,160	$26,353,192
Dec	$7,593,046	$0	$0	$20,920,854	$43,712	$3,574,430	$32,132,042
Total	$87,007,258	$310,864	$760,885	$298,740,185	$1,764,877	$172,247,006	$560,831,075
Share of Credits	15.5%	0.1%	0.1%	53.3%	0.3%	30.7%	100.0%

Table 3-13 Credits by unit types (By operating reserve market): Calendar year 2011

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Credits due to Local Transmission Constraints	Total
Battery	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	$12,488
Combined Cycle	30.3%	0.0%	65.6%	3.9%	0.2%	0.0%	$112,881,400
Combustion Turbine	2.3%	0.4%	35.3%	61.8%	0.2%	0.0%	$212,434,080
Diesel	0.2%	0.0%	3.4%	96.4%	0.0%	0.0%	$18,695,125
Hydro	39.3%	0.0%	25.7%	0.0%	35.1%	0.0%	$307,331
Nuclear	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$431,172
Steam - Coal	33.9%	0.0%	53.0%	11.2%	0.0%	1.9%	$133,977,613
Steam - Others	3.4%	0.0%	92.3%	4.2%	0.1%	0.0%	$71,789,303
Wind	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	$8,226,822

Table 3-14 Credits by operating reserve market (By unit type): Calendar year 2011

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Credits due to Local Transmission Constraints
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	39.3%	0.0%	25.8%	2.6%	3.0%	0.0%
Combustion Turbine	5.6%	100.0%	26.2%	76.2%	4.0%	1.3%
Diesel	0.0%	0.0%	0.2%	10.5%	0.0%	0.0%
Hydro	0.1%	0.0%	0.0%	0.0%	1.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%
Steam - Coal	52.2%	0.0%	24.7%	8.7%	0.0%	98.7%
Steam - Others	2.8%	0.0%	23.1%	1.8%	0.8%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	91.0%	0.0%
Total	$87,007,258	$760,885	$287,072,737	$172,247,006	$9,038,892	$2,628,556

conventional steam units fueled by coal received 91.5 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 86.7 percent of the lost opportunity cost credits. Wind units received 91.0 percent of the canceled resources credits.

13 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills. Balancing generator credits include canceled resources and credits to resources controlling local transmission constraints.

Wind Unit Credits

PJM calculates credits for scheduled resources that are canceled by PJM before coming on line. PJM credits each participant for cancellations based on actual costs incurred and submitted in writing to PJM. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer. The total cancellation credits are allocated to RTO demand, supply and generator deviations on a daily basis.

PJM categorizes lost opportunity costs credits paid to wind units as canceled resources credits. Canceled resources credits should reflect the actual cost of starting a unit. None of the wind units that received canceled resources credits submitted start-up costs. This categorization does not have any impact on the allocation of the charges since both are allocated to RTO demand, supply and generator deviations. However these credits appear to have been misclassified.

Credits paid to wind units increased considerably in 2011. The total credits paid in 2010 amounted to $1.9 million. In 2011 the total increased to $8.2 million. A total of 11 wind farms were paid credits under the canceled resources category of the operating reserve rules. Table 3-15 shows the monthly canceled resources credits paid to wind farms.

Table 3-15 Canceled resources credits paid to wind units: Calendar year 2011

	Wind Units Canceled Resources Credits	Annual Share
Jan	$419,273	5.1%
Feb	$142,349	1.7%
Mar	$344,622	4.2%
Apr	$271,810	3.3%
May	$2,446,129	29.7%
Jun	$839,074	10.2%
Jul	$167,310	2.0%
Aug	$244,935	3.0%
Sep	$151,194	1.8%
Oct	$1,237,631	15.0%
Nov	$1,663,153	20.2%
Dec	$297,803	3.6%
Total	$8,225,285	100.0%

The AEP and ComEd Control Zones were the only zones with wind units receiving operating reserve credits.

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the day ahead schedule or minimum run time. It is possible for a unit to have a segment during which some hours are economic and some hours are noneconomic. For example, if a unit is turned on to control a constraint, it would be considered economic at that time if the unit set the price in the constrained area or was inframarginal. However, if that unit needs to satisfy a minimum runtime because of physical operating characteristics, the unit may become noneconomic for the remainder of its runtime. Noneconomic and economic status may also change when units are run through the overnight hours in order to be available for morning load pickups.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each hour was first determined to be economic or noneconomic based solely on the unit's hourly energy offer. The hourly energy offer does not include the hourly no-load cost or any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-16 shows the number of economic and noneconomic hours for each unit type. For example, of the 33,493 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit was higher than its real-time energy offer in 14,534 hours, or 43.4 percent of those hours.

Geography of Balancing Credits and Charges

Table 3-17 and Table 3-18 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table 3-17 shows that on average, 10.1 percent of balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 74.1 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-18 also shows that generators in the Western Region paid 10.2 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 25.9 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-16 Economic vs. noneconomic hours: Calendar year 2011

Unit Type	Economic Hours	Economic HoursPercentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Battery	0	0.0%	5	100.0%	5
Combined Cycle	14,534	43.4%	18,959	56.6%	33,493
Combustion Turbine	6,412	25.6%	18,659	74.4%	25,071
Diesel	159	9.5%	1,517	90.5%	1,676
Hydro	2	7.7%	24	92.3%	26
Steam - Coal	25,873	34.8%	48,545	65.2%	74,418
Steam - Others	1,122	19.7%	4,579	80.3%	5,701
Total	48,102	34.3%	92,288	65.7%	140,390

Table 3-17 Monthly balancing operating reserve charges and credits to generators (Eastern Region): Calendar year 2011

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$3,070,704	$291,380	$344,834	$3,706,918	$41,598,008
Feb	$1,576,213	$215,195	$347,413	$2,138,821	$21,168,662
Mar	$978,106	$74,479	$821,184	$1,873,769	$17,326,859
Apr	$863,354	$95,458	$860,974	$1,819,786	$14,084,125
May	$1,449,060	$43,532	$2,271,151	$3,763,743	$26,487,430
Jun	$1,237,386	$744,317	$2,562,452	$4,544,155	$42,604,913
Jul	$2,685,205	$3,189,175	$4,537,061	$10,411,441	$80,396,433
Aug	$925,573	$986,451	$2,195,676	$4,107,700	$42,161,925
Sep	$637,068	$236,673	$1,451,588	$2,325,329	$23,933,140
Oct	$374,150	$79,258	$629,708	$1,083,115	$10,837,188
Nov	$483,347	$67,950	$636,498	$1,187,795	$9,968,778
Dec	$957,032	$199,303	$344,218	$1,500,553	$16,363,481
East Generators Total	$15,237,197	$6,223,171	$17,002,758	$38,463,125	$346,930,942
PJM Total Charges	$152,515,621	$45,629,772	$181,285,897	$379,431,291	$468,358,635
Share	10.0%	13.6%	9.4%	10.1%	74.1%

Table 3-18 Monthly balancing operating reserve charges and credits to generators (Western Region): Calendar year 2011

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,578,577	$47,499	$326,035	$2,952,110	$4,636,283
Feb	$1,522,145	$131,300	$352,814	$2,006,259	$4,526,346
Mar	$870,491	$249,134	$825,573	$1,945,197	$4,953,242
Apr	$815,107	$58,219	$883,301	$1,756,627	$4,320,942
May	$1,518,008	$61,151	$2,747,197	$4,326,356	$16,891,893
Jun	$1,377,451	$67,645	$3,089,719	$4,534,815	$16,879,400
Jul	$2,706,819	$78,287	$4,800,103	$7,585,209	$22,709,492
Aug	$1,249,870	$303,951	$3,119,842	$4,673,663	$11,356,465
Sep	$812,317	$437,602	$1,804,622	$3,054,542	$10,861,799
Oct	$529,500	$141,761	$853,380	$1,524,641	$7,163,528
Nov	$834,089	$271,391	$1,072,998	$2,178,478	$9,176,908
Dec	$1,570,735	$75,254	$493,844	$2,139,833	$7,951,396
West Generators Total	$16,385,110	$1,923,194	$20,369,427	$38,677,731	$121,427,693
PJM Total	$152,515,621	$45,629,772	$181,285,897	$379,431,291	$468,358,635
Share	10.7%	4.2%	11.2%	10.2%	25.9%

Table 3-19 shows that on average in 2011, generator charges were 13.8 percent of all operating reserve charges, excluding charges for resources controlling local transmission constraints which are allocated to the requesting transmission owner, 3.4 percent higher than 2010. Generators received 99.6 percent of all operating reserve credits the remaining 0.4 percent were credits paid to import transactions.

Table 3-19 Percentage of unit credits and charges of total credit and charges: Calendar year 2011

	Generators Share of Total Operating Reserves Charges	Generators Share of Total Operating Reserves Credits
Jan	11.3%	99.2%
Feb	11.8%	98.7%
Mar	12.9%	98.6%
Apr	15.5%	99.0%
May	16.0%	100.0%
Jun	13.4%	99.8%
Jul	16.6%	100.0%
Aug	14.2%	100.0%
Sep	13.1%	99.9%
Oct	11.3%	99.8%
Nov	12.8%	99.6%
Dec	11.4%	99.9%
Average	13.8%	99.6%

Load Response Resource Operating Reserve Credits

End-use customers or their representative may offer demand reduction bids which include the day-ahead LMP above which the end-use customer would not consume, and which may also include shut-down costs. Payment for reducing load is based on the MWh reductions committed in the Day-Ahead market. An end-use customer or representative that submits a load reduction bid day-ahead that is accepted by PJM was paid the day-ahead LMP less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are those charges the participant would have otherwise paid the LSE absent the load reduction.

Total payments to end-use customers or their representative for accepted day-ahead Economic Load Response bids will not be less than the total value of the load response bid, included any submitted shut-down costs. If total payments are less than the total value of the load response bid, PJM will made the resource whole through day-ahead operating reserve credits.

In real-time operations reimbursement for reducing load is based on the actual MWh reduction in excess of committed day-ahead load reductions plus an adjustment for losses. In cases where load response is dispatched by PJM, the total payment to end-use customers or their representative will not be less than the total value of the load response bid, including any submitted shut-down costs. If total payments are less than the total value of the load response bid, PJM will made the resource whole through balancing operating reserve credits.

In 2011, the operating reserve credits for load response decreased by 57.5 percent. This year 7.1 percent of all accepted demand reduction bids were covered by operating reserve credits while the remaining 92.9 percent was paid through the economic load response program as shown in Table 3-20.

Table 3-20 Day-ahead and balancing operating reserve for load response credits: Calendar year 2009 through 2011

	Economic Program Load Response Credits	Operating Reserves for Load Response Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve Credits
2009	$1,389,136	$287,402	82.9%	17.1%
2010	$3,088,049	$363,469	89.5%	10.5%
2011	$2,007,612	$154,589	92.9%	7.1%

Table 3-21 Monthly reactive service credits: Calendar year 2011

	Reactive Service Credits	Percent of Total Reactive Service Credits
Jan	$1,546,278	3.7%
Feb	$1,912,027	4.6%
Mar	$1,438,306	3.5%
Apr	$2,077,101	5.0%
May	$2,712,293	6.6%
Jun	$1,868,004	4.5%
Jul	$929,807	2.3%
Aug	$1,696,735	4.1%
Sep	$2,688,094	6.5%
Oct	$15,523,789	37.6%
Nov	$7,105,062	17.2%
Dec	$1,790,778	4.3%
Total	$41,288,274	100.0%

Table 3-22 Reactive service credits by unit type: Calendar year 2011

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Total Reactive Credits
Combined Cycle	8.2%	15.4%	0.0%	8.8%
Combustion Turbine	56.2%	1.6%	100.0%	51.5%
Diesel	3.9%	0.0%	0.0%	3.6%
Steam - Coal	30.5%	79.6%	0.0%	34.7%
Steam - Others	1.2%	3.3%	0.0%	1.4%
Total	$37,584,680	$3,609,380	$94,214	$41,288,274

Table 3-23 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2011

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%

Reactive Service

Credits to resources providing reactive services are separate from operating reserve credits. These credits are divided into three categories:

- Reactive Service Credit: For units providing reactive services while having an offered price higher than the LMP at the unit's bus.
- Reactive Service Lost Opportunity Cost Credit: For units reduced or suspended by PJM for reactive reliability purposes while having an offered price lower than the LMP at the unit's bus.
- Reactive Service Synchronous Condensing Credit: For units providing synchronous condensing for the purpose of maintaining the reactive reliability of the system.

Total reactive service credits in 2011 were $41.3 million, down from $68.9 million in 2010. Table 3-21 shows the monthly distribution of reactive service credits. In October 37.6 percent of annual credits were paid. During October PJM issued 24 High System Voltage alerts out of an annual total of 37. During this type of system condition PJM calls generators to improve the system reactive reliability by altering their active power output in order to absorb reactive energy.

The top three zones accounted for 84.0 percent of the total, a decrease of 7.5 percent from the 2010 share. The top three zones were the DPL Control Zone, the JCPL Control Zone and the PENELEC Control Zone.

Table 3-22 shows the distribution of credits for each category of reactive service credit received by each unit type. (Each column sums to 100 percent.) Combustion turbines received 51.5 percent of all credits.

Operating Reserve Issues

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

Table 3-24 Operating reserve credits for units (By zone): Calendar year 2011[14]

Zone	Day Ahead Generator	Balancing Generator	Lost Opportunity Cost	Total	Percent of Total Credits
AECO	$430,984	$4,529,506	$4,078,894	$9,039,384	1.6%
AEP - DAY	$3,228,567	$43,573,308	$12,613,913	$59,415,788	11.8%
AP - DLCO	$2,287,456	$12,312,190	$13,153,948	$27,753,595	5.0%
ATSI	$741,167	$1,210,742	$7,256,119	$9,208,028	1.6%
BGE - Pepco	$21,224,868	$57,548,751	$2,477,936	$81,251,555	14.6%
ComEd	$1,314,324	$4,996,562	$17,990,778	$24,301,665	5.2%
Dominion	$6,696,887	$45,183,811	$96,696,281	$148,576,979	26.6%
DPL	$1,824,056	$17,567,397	$4,783,331	$24,174,783	4.3%
JCPL - PSEG	$46,305,825	$76,616,066	$5,614,218	$128,536,109	23.2%
Met-Ed - PPL	$1,355,949	$12,659,910	$2,892,002	$16,907,862	3.0%
PECO	$978,570	$7,227,478	$673,619	$8,879,667	1.7%
PENELEC	$618,605	$3,647,014	$4,015,968	$8,281,586	1.5%
RECO	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	0.0%
Total	$87,007,258	$287,072,737	$172,247,006	$546,327,001	100.0%

14 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

The concentration of operating reserve credits remains high, but decreased in 2011 compared to 2010. Table 3-23 shows the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 28.1 percent of total operating reserve credits in 2011, compared to 33.2 percent in 2010. The top 20 units received 38.9 percent of total operating reserve credits in 2011 and 42.2 percent in 2010. In 2011, the top generation owner received 21.0 percent of the total operating reserve credits paid, a decrease from 2010, when the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-24 shows the distribution of operating reserve credits to units by zone. The Dominion Control Zone had the largest share of credits with 26.6 percent, the JCPL and PSEG Control Zones combined had the second highest with 23.2 percent, and the BGE and Pepco Control Zones combined had the third highest with a 14.6 percent share

Table 3-25 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $35.3 million in 2011, or 6.3 percent of the total operating reserve credits paid to all units, a decrease from 2010 when the top unit received 8.3 percent. The cumulative distribution column shows that the top 10 units had a 28.1 percent share of the total operating reserve credits in 2011. The top organization had a 21.0 percent share of the total credits, or $117.9 million, compared to 24.9 percent in 2010. The top 10 organizations receiving credits had a cumulative share of 82.1 percent.

Table 3-26 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $16.5 million, or 18.9 percent of the total day-ahead generator credits, compared to 21.5 percent in 2010. The second unit had a 15.4 percent share, which when combined with the top unit was 34.3 percent of the total credits. The top organization in 2011 received 51.1 percent of the day-ahead credits, which is nearly identical to the 51.0 percent received in 2010. The top 10 organizations received 94.7 percent of the day-ahead credits.

PJM may schedule units in the Day-Ahead Market with a daily total offer higher than the LMP if consistent with cost minimization. For example, a unit might be marginal for one hour and kept scheduled for an additional hour if the alternative cost of running another unit for only one hour is higher than running the first unit for two hours.

Table 3-27 rank orders the top 10 units receiving synchronous condensing credits, and the top organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 99.3 percent of synchronous condensing credits, up from 91.3 percent in 2010.

Table 3-28 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.1 percent of total credits, slightly lower than the 24.5 percent in 2010. The top ten organizations received a total of 67.7 percent of all the balancing generator credits. Units receive balancing operating reserve credits for several reasons. During the real-time operation, PJM may use units to match the generation to the system's demand on a regional basis. Real-time demand, supply and generation deviations from the day-ahead forecast provoke the necessity of using units out of merit order to compensate the variation. Additionally, real-time constraints are also relief by PJM with units that might be marginal for a certain period, but that might have to be kept on-line due to parameters limitations.

Table 3-29 rank orders the top 10 units receiving canceled resources credits, and the top 10 organizations receiving canceled resources credits. The top 10 units received 86.2 percent of the total canceled resources credits and 95.6 percent were received by the top 10 organizations. The top unit receiving canceled resources credits was a wind farm; wind farms received 91.0 percent of all canceled resources credits in 2011.

Table 3-25 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2011

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$35,344,000	6.3%	6.3%	$117,897,474	21.0%	21.0%
2	$28,394,004	5.1%	11.4%	$116,427,595	20.8%	41.8%
3	$21,177,436	3.8%	15.2%	$46,228,293	8.2%	50.0%
4	$18,083,292	3.2%	18.4%	$40,015,254	7.1%	57.2%
5	$12,889,230	2.3%	20.7%	$37,844,468	6.7%	63.9%
6	$8,872,694	1.6%	22.3%	$26,141,774	4.7%	68.6%
7	$8,631,744	1.5%	23.9%	$20,706,101	3.7%	72.3%
8	$8,358,084	1.5%	25.4%	$20,355,568	3.6%	75.9%
9	$7,750,994	1.4%	26.8%	$20,180,674	3.6%	79.5%
10	$7,244,337	1.3%	28.1%	$14,817,890	2.6%	82.1%

Table 3-26 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2011

	Units			Organizations		
Rank	Day-Ahead Generator Credit	Day-Ahead Generator Credit Share	Day-Ahead Generator Credit Cumulative Distribution	Day-Ahead Generator Credit	Day-Ahead Generator Credit Share	Day-Ahead Generator Credit Cumulative Distribution
1	$16,452,908	18.9%	18.9%	$44,438,422	51.1%	51.1%
2	$13,411,194	15.4%	34.3%	$13,923,006	16.0%	67.1%
3	$7,425,138	8.5%	42.9%	$9,426,380	10.8%	77.9%
4	$7,240,542	8.3%	51.2%	$6,017,262	6.9%	84.8%
5	$3,338,557	3.8%	55.0%	$2,479,631	2.8%	87.7%
6	$2,877,342	3.3%	58.3%	$1,972,578	2.3%	89.9%
7	$2,581,422	3.0%	61.3%	$1,312,815	1.5%	91.5%
8	$1,529,182	1.8%	63.0%	$1,169,725	1.3%	92.8%
9	$1,451,224	1.7%	64.7%	$886,604	1.0%	93.8%
10	$1,366,387	1.6%	66.3%	$810,080	0.9%	94.7%

Table 3-27 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2011

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$54,950	7.2%	7.2%	$755,826	99.3%	99.3%
2	$54,772	7.2%	14.4%	$4,692	0.6%	100.0%
3	$51,039	6.7%	21.1%	$368	0.0%	100.0%
4	$50,856	6.7%	27.8%			
5	$46,721	6.1%	34.0%			
6	$46,106	6.1%	40.0%			
7	$44,997	5.9%	45.9%			
8	$44,031	5.8%	51.7%			
9	$43,681	5.7%	57.5%			
10	$40,101	5.3%	62.7%			

Table 3-30 rank orders wind farms and their respective organizations receiving canceled resources credits. The top wind farm received 44.3 percent of all canceled resources credits.

Table 3-31 rank orders the top 10 units receiving credits due to local transmission constraints, and the top 10 organizations receiving credits due to local transmission constraints. Only 6 units received this credit in 2011, owned by 3 organizations. The top organization received 98.7 percent of all credits.

Table 3-32 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 41.5 percent of the total lost opportunity cost credits and 87.9 percent were received by the top 10 organizations.

Table 3-33 rank orders the top 10 units receiving reactive service credits, and the top 10 organizations receiving reactive service credits. The top 3 units received 47.7

Table 3-28 Top 10 units and organizations receiving balancing generator credits: Calendar year 2011

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$27,878,841	9.7%	9.7%	$69,042,449	24.1%	24.1%
2	$18,061,887	6.3%	16.0%	$13,923,006	16.0%	40.1%
3	$12,189,823	4.2%	20.2%	$9,426,380	10.8%	50.9%
4	$11,919,282	4.2%	24.4%	$6,017,262	6.9%	57.8%
5	$8,872,694	3.1%	27.5%	$2,479,631	2.8%	60.7%
6	$7,762,569	2.7%	30.2%	$1,972,578	2.3%	62.9%
7	$7,244,337	2.5%	32.7%	$1,312,815	1.5%	64.4%
8	$7,104,881	2.5%	35.2%	$1,169,725	1.3%	65.8%
9	$5,375,038	1.9%	37.1%	$886,604	1.0%	66.8%
10	$4,417,252	1.5%	38.6%	$810,080	0.9%	67.7%

Table 3-29 Top 10 units and organizations receiving canceled resources credits: Calendar year 2011

	Units			Organizations		
Rank	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution
1	$1,482,845	16.4%	16.4%	$4,282,234	47.4%	47.4%
2	$913,462	10.1%	26.5%	$913,462	10.1%	57.5%
3	$858,854	9.5%	36.0%	$858,854	9.5%	67.0%
4	$797,941	8.8%	44.8%	$732,564	8.1%	75.1%
5	$732,564	8.1%	52.9%	$714,079	7.9%	83.0%
6	$686,899	7.6%	60.5%	$416,195	4.6%	87.6%
7	$679,887	7.5%	68.1%	$220,095	2.4%	90.0%
8	$634,662	7.0%	75.1%	$220,095	2.4%	92.5%
9	$564,877	6.2%	81.3%	$148,252	1.6%	94.1%
10	$440,190	4.9%	86.2%	$135,457	1.5%	95.6%

Table 3-30 Wind farms and respective organizations receiving canceled resources credits: Calendar year 2011

	Wind Farm			Organizations		
Rank	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution
1	$3,647,572	44.3%	44.3%	$4,282,234	52.1%	52.1%
2	$1,367,226	16.6%	61.0%	$913,462	11.1%	63.2%
3	$991,119	12.0%	73.0%	$858,854	10.4%	73.6%
4	$858,854	10.4%	83.5%	$732,564	8.9%	82.5%
5	$564,877	6.9%	90.3%	$564,877	6.9%	89.4%
6	$440,190	5.4%	95.7%	$220,095	2.7%	92.1%
7	$134,721	1.6%	97.3%	$220,095	2.7%	94.7%
8	$80,543	1.0%	98.3%	$148,252	1.8%	96.5%
9	$58,558	0.7%	99.0%	$134,721	1.6%	98.2%
10	$44,987	0.5%	99.6%	$77,656	0.9%	99.1%
11	$36,639	0.4%	100.0%	$72,475	0.9%	100.0%

percent of all credits and 93.7 percent of all credits were paid to the top 10 organizations.

Operating Reserves Concentration

In 2011, concentration in all operating reserve credits categories was high. Operating reserves HHI was calculated based on each organization's daily credits for each category. Table 3-34 shows the average HHI for each category. Day-ahead operating reserves HHI was 4710 and it reached 10000 during 4 days of the year. Balancing operating reserve HHI averaged 3299 in 2011. Lost opportunity cost HHI was 5385 and during 6 days of the year lost opportunity credits were paid solely to one supplier.

Table 3-35 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. Table 3-36 shows that 74.7 percent of all credits paid to these units were allocated to deviations while the remaining 25.3 percent were paid for reliability reasons.

Table 3-31 Top 10 units and organizations receiving credits due to local transmissions constraints: Calendar year 2011

	Units			Organizations		
Rank	Credits due to Local Transmission Constraints	Credits due to Local Transmission Constraints Share	Credits due to Local Transmission Constraints Cumulative Distribution	Credits due to Local Transmission Constraints	Credits due to Local Transmission Constraints Share	Credits due to Local Transmission Constraints Cumulative Distribution
1	$1,401,944	53.3%	53.3%	$2,594,890	98.7%	98.7%
2	$717,083	27.3%	80.6%	$32,162	1.2%	99.9%
3	$475,864	18.1%	98.7%	$1,504	0.1%	100.0%
4	$32,162	1.2%	99.9%			
5	$1,052	0.0%	100.0%			
6	$452	0.0%	100.0%			
7						
8						
9						
10						

Table 3-32 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2011

	Units			Organizations		
Rank	Lost Opportunity Cost Credit	Lost Opportunity Cost Credit Share	Lost Opportunity Cost Credit Cumulative Distribution	Lost Opportunity Cost Credit	Lost Opportunity Cost Credit Share	Lost Opportunity Cost Credit Cumulative Distribution
1	$7,583,583	4.4%	4.4%	$71,422,692	41.5%	41.5%
2	$6,766,749	3.9%	8.3%	$20,654,892	12.0%	53.5%
3	$6,128,373	3.6%	11.9%	$14,838,964	8.6%	62.1%
4	$5,969,665	3.5%	15.4%	$10,612,983	6.2%	68.2%
5	$5,068,077	2.9%	18.3%	$8,901,427	5.2%	73.4%
6	$4,979,459	2.9%	21.2%	$5,957,734	3.5%	76.9%
7	$4,422,980	2.6%	23.8%	$5,669,330	3.3%	80.2%
8	$4,161,345	2.4%	26.2%	$4,815,117	2.8%	82.9%
9	$4,053,842	2.4%	28.5%	$4,595,349	2.7%	85.6%
10	$3,718,985	2.2%	30.7%	$3,913,309	2.3%	87.9%

Table 3-33 Top 10 units and organizations receiving reactive service credits: Calendar year 2011

	Units			Organizations		
Rank	Reactive Service Credit	Reactive Service Credit Share	Reactive Service Credit Cumulative Distribution	Reactive Service Credit	Reactive Service Credit Share	Reactive Service Credit Cumulative Distribution
1	$7,032,812	17.0%	17.0%	$14,554,987	35.3%	35.3%
2	$6,386,130	15.5%	32.5%	$9,995,342	24.2%	59.5%
3	$6,262,971	15.2%	47.7%	$2,749,772	6.7%	66.1%
4	$2,889,773	7.0%	54.7%	$2,077,975	5.0%	71.2%
5	$2,077,975	5.0%	59.7%	$1,999,850	4.8%	76.0%
6	$1,275,099	3.1%	62.8%	$1,842,015	4.5%	80.5%
7	$1,045,561	2.5%	65.3%	$1,725,762	4.2%	84.6%
8	$966,712	2.3%	67.7%	$1,363,183	3.3%	87.9%
9	$939,174	2.3%	69.9%	$1,275,099	3.1%	91.0%
10	$888,561	2.2%	72.1%	$972,539	2.4%	93.4%

Lost Opportunity Cost Credits

In 2011, total operating reserve charges increased by only 1.0 percent but the overall level of operating reserve charges remains relatively high. The change in total operating reserve charges included a 51.5 increase in lost opportunity cost credits. Total balancing generator credits for 2011, excluding lost opportunity cost credits, decreased by $49.4 million from 2010. Lost opportunity cost credits increased by $58.5 million.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine is scheduled to operate in the day-ahead market but not requested by PJM in real-time, the unit will receive a credit which covers the day-ahead financial position of the unit plus any balancing spot energy market charge that the unit will have to pay. If a unit generating in real-time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM, the unit will receive a credit for the lost opportunity cost of not being able to produce the desired output.

Table 3-37 shows that 50.3 percent of the generation scheduled in the day-ahead market corresponding to units receiving lost opportunity cost credits was not requested by PJM in real-time. This percentage increased 10.8 percent from 2010.

Table 3-38 shows the distribution by zone of the generation not called in real time. In 2011, 56.0 percent of the day-ahead generation of units receiving lost opportunity cost credits in the Dominion Control Zone was not called in real time.

Daily Distribution of Credits

Figure 3-4 shows the distribution of daily balancing generator credits for 2009 through 2011. The distribution curve for 2011 is similar to the 2010 curve but and starts to diverge towards the upper end of the distribution. The highest level of balancing generator credits paid for one day in 2011 was $13.1 million, compared to $10.7 million in 2010. In 2011, the top 10 days accounted for 19.1 percent share of the total credits, 6.2 percent higher than 2010.

Table 3-34 Daily Operating Reserve Credits HHI: Calendar year 2011

	Daily Operating Reserve Credits HHI							
	Day-Ahead Generators	Day-Ahead Transactions	Synchronous Condensing	Balancing Generators	Balancing Transactions	Lost Opportunity Cost	Canceled Resources	Total Credits
Average	4710	9990	9905	3299	9957	5385	7485	2449
Minimum	1204	9731	7902	1090	5917	872	1236	753
Maximum	10000	10000	10000	9401	10000	10000	10000	7784
Highest market share (One day)	100.0%	100.0%	100.0%	96.9%	100.0%	100.0%	100.0%	88.0%
Highest market share (All days)	51.1%	88.5%	99.3%	24.1%	71.0%	41.5%	47.4%	21.0%
Numbers of Days	365	49	24	365	162	365	206	365
Days with HHI > 1,800	354	49	24	328	162	348	198	255
% of Days with HHI > 1,800	97.0%	100.0%	100.0%	89.9%	100.0%	95.3%	96.1%	69.9%
Days with HHI = 10,000	4	47	22	0	151	6	97	0
% of Days with HHI = 10,000	1.1%	95.9%	91.7%	0.0%	93.2%	1.6%	47.1%	0.0%

Table 3-35 Identification of balancing operating reserve credits received by the top 10 units by category and region

	Credits for Reliability			Credits for Deviations			
Rank	RTO	East	West	RTO	East	West	Total Credits
1	$7,256,380	$0	$0	$20,622,462	$0	$0	$27,878,841
2	$562,133	$0	$0	$666,620	$16,833,134	$0	$18,061,887
3	$3,103,545	$0	$0	$8,117,646	$968,632	$0	$12,189,823
4	$1,417,100	$151,488	$0	$10,303,057	$47,638	$0	$11,919,282
5	$1,076,370	$0	$0	$7,796,324	$0	$0	$8,872,694
6	$1,420,635	$591,704	$0	$5,216,184	$266,382	$267,665	$7,762,569
7	$71,475	$507,544	$0	$45,716	$6,619,603	$0	$7,244,337
8	$72,891	$0	$6,917,112	$114,878	$0	$0	$7,104,881
9	$885,962	$172,175	$0	$3,944,397	$372,504	$0	$5,375,038
10	$139,025	$0	$3,712,715	$298,322	$0	$267,190	$4,417,252
Total	$16,005,513	$1,422,910	$10,629,827	$57,125,606	$25,107,893	$534,855	$110,826,604

Table 3-36 Proportion of the top 10 units receiving balancing operating reserve credits by category and region: Calendar year 2011

	Share of Credits for Reliability			Share of Credits for Deviations			Share of Credits	
Rank	RTO	East	West	RTO	East	West	Reliability	Deviations
1	26.0%	0.0%	0.0%	74.0%	0.0%	0.0%	26.0%	74.0%
2	3.1%	0.0%	0.0%	3.7%	93.2%	0.0%	3.1%	96.9%
3	25.5%	0.0%	0.0%	66.6%	7.9%	0.0%	25.5%	74.5%
4	11.9%	1.3%	0.0%	86.4%	0.4%	0.0%	13.2%	86.8%
5	12.1%	0.0%	0.0%	87.9%	0.0%	0.0%	12.1%	87.9%
6	18.3%	7.6%	0.0%	67.2%	3.4%	3.4%	25.9%	74.1%
7	1.0%	7.0%	0.0%	0.6%	91.4%	0.0%	8.0%	92.0%
8	1.0%	0.0%	97.4%	1.6%	0.0%	0.0%	98.4%	1.6%
9	16.5%	3.2%	0.0%	73.4%	6.9%	0.0%	19.7%	80.3%
10	3.1%	0.0%	84.1%	6.8%	0.0%	6.0%	87.2%	12.8%
Top 10 units	14.4%	1.3%	9.6%	51.5%	22.7%	0.5%	25.3%	74.7%

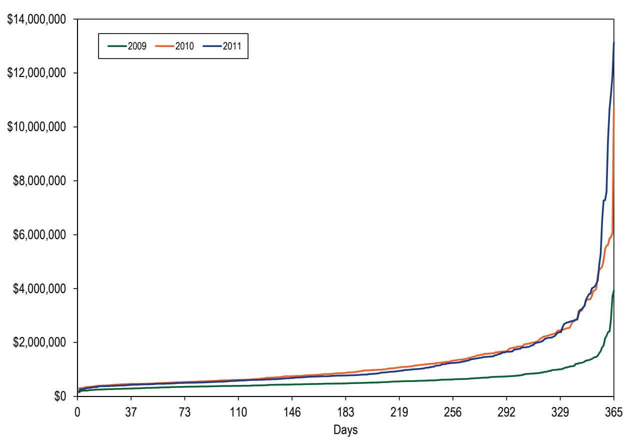
Table 3-37 Reduced / Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits (MWh): Calendar year 2009 through 2011

	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Called in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
2009	4,077,730	1,621,867	28.5%
2010	5,285,833	3,444,165	39.5%
2011	4,648,666	4,713,960	50.3%

Table 3-38 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits by zone (MWh): Calendar year 2011

Zone	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Called in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
AECO	572	61,893	1.3%
AEP - DAY	627,380	368,820	7.8%
AP - DLCO	151,159	399,091	8.5%
ATSI	50,727	246,391	5.2%
BGE - Pepco	60,147	92,658	2.0%
ComEd	245,307	461,294	9.8%
Dominion	2,437,122	2,639,898	56.0%
DPL	6,963	102,265	2.2%
JCPL - PSEG	342,874	118,615	2.5%
Met-Ed - PPL	175,996	79,373	1.7%
PECO	176,081	44,582	0.9%
PENELEC	374,338	99,081	2.1%
RECO	0	0	0.0%
External	0	0	0.0%
Total	4,648,666	4,713,960	100.0%

Figure 3-4 Balancing Generator Credits Daily Distribution: Calendar years 2009 through 2011



Regional Allocation Impact

Regional Credits Allocation Figure 3-5 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules in December 2008. The figure shows the impact of the regional allocation of balancing operating reserve credits during events that only affect a specific region. High east reliability credits during the summer of 2010 were due to transmission maintenance on a 230kV line, while high east deviations credits during the summer of 2011 were the result of high load levels during the peak months.

Figure 3-5 Monthly regional reliability and deviations credits: December 2008 through December 2011[15]

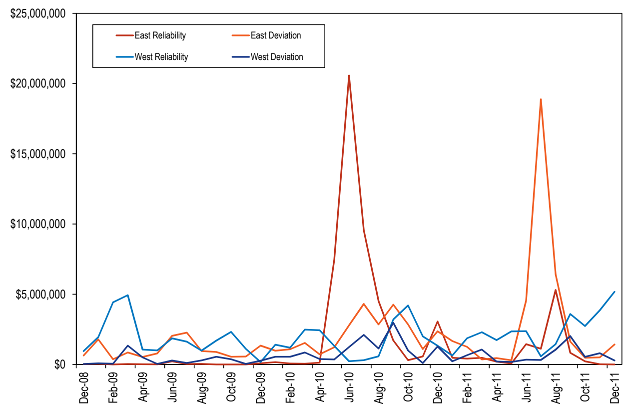
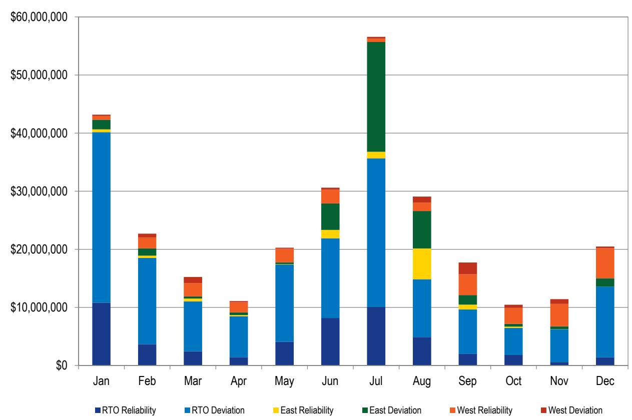


Figure 3-6 Monthly balancing operating reserve categories: Calendar year 2011



One of the purposes of the operating reserve rules implemented on December 1, 2008, was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be

15 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost, canceled resources or resources controlling local transmission constraints.

real-time load and exports. In 2011, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In 2011, $90.7 million of reliability charges were allocated to participants serving real-time load and exports, which would have been charged to deviations under the prior rules.

Eastern reliability credits were a primary reason for the decrease in balancing generator operating reserve charges in 2011. Charges paid by real-time load and real-time exports in the East Region decreased by 78.0 percent in 2011, from $48.2 million to $10.6 million.

Con-Ed – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG.[16] These units are often run out of merit and received substantial balancing operating reserves credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly. Of the total balancing operating reserve credits paid to these units, 75.6 percent was allocated as RTO deviation charges, 20.6 percent as RTO reliability charges and the remaining 3.8 percent was allocated regionally. Table 3-41 shows the impact that the total credits paid to these units had on the balancing operating reserve rates.

AEP Blackstart and Voltage Support Units

Certain units located in the AEP zone are relied on for their blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. Units providing blackstart service under the ALR option could remain running at a minimum level, disconnected from the grid. In 2011 an estimated total of $6.5 million or 33.6 percent of all balancing operating reserve credits paid to ALR capable units was for the purpose of providing blackstart and an estimated total of $7.0 million or 52.1 percent of all balancing operating reserve credits paid to ALR units and units capable of providing voltage support was for the purpose of providing voltage support. The MMU recommends that PJM dispatchers explicitly log the reasons that these units are run out-of-merit to comply with blackstart requirements or voltage support in order to correctly assign the associated charges. Of the total balancing operating reserve credits paid to these units, 83.8 percent was allocated as Western Region reliability charges, 12.3 percent as RTO deviation charges and 4.0 percent as RTO reliability and Western Region deviation charges. Table 3-42 shows the impact that the total credits paid to these units had on the balancing operating reserve rates.

Operating Reserve Transaction Credits

Balancing operating reserve transaction credits are paid to real-time import transactions and interchange transactions under the PEC JOA if the balancing market value does not cover the transactions' real-time offer.[17]

The $22.5 million level of dispatchable transaction credits in December 2010 was unprecedented. Table 3-43 shows that in 2011, the dispatchable transaction credits dropped to $1.3 million.

Emergency Load Response Program Credits Allocation

The cost of emergency load reduction used by PJM to provide relief in the system is allocated to participants' real-time deviations from their net interchange in the Day-Ahead Energy Market. PJM should identify whether such resources are being used for reliability purposes or deviations from the Day-Ahead Energy Market.

Up-to Congestion Transactions

Up-to congestion transactions do not pay balancing operating reserve charges. The MMU calculated the impact on balancing operating reserve rates if up-to congestion transactions paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do.

Table 3-44 shows the impact that including up-to congestion transactions in the allocation of balancing

16 See the *2011 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

17 See the *2011 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" for a description of these transactions.

Table 3-39 Monthly balancing operating reserve categories: Calendar year 2011

Month	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$10,806,714	$477,269	$640,786	$29,352,529	$1,671,868	$221,530
Feb	$3,681,952	$415,538	$1,866,911	$14,822,319	$1,250,992	$661,159
Mar	$2,463,616	$474,514	$2,296,476	$8,597,357	$357,289	$1,059,607
Apr	$1,435,954	$202,956	$1,736,060	$7,055,852	$451,405	$212,437
May	$4,103,637	$65,753	$2,354,336	$13,281,781	$299,705	$179,861
Jun	$8,165,971	$1,447,838	$2,371,314	$13,729,792	$4,548,997	$342,003
Jul	$10,072,493	$1,118,709	$577,816	$25,595,411	$18,882,232	$318,986
Aug	$4,898,914	$5,307,572	$1,446,631	$9,947,911	$6,422,833	$1,054,221
Sep	$2,001,833	$833,334	$3,595,082	$7,650,135	$1,629,589	$2,025,717
Oct	$1,812,773	$227,427	$2,735,378	$4,666,347	$477,293	$541,589
Nov	$599,014	$15,562	$3,854,610	$5,637,319	$507,559	$801,346
Dec	$1,406,230	$0	$5,181,248	$12,178,866	$1,427,650	$283,905
Total	$51,449,101	$10,586,472	$28,656,646	$152,515,621	$37,927,411	$7,702,362

Table 3-40 Charges to real-time load, real-time exports and deviations by region: Calendar year 2009 through 2011

Credit Type	Region	2009	2010	2011	2011 - 2010 Difference	Percentage Difference
Deviations	RTO	$125,850,691	$184,318,710	$152,515,621	($31,803,088)	(17.3%)
	East	$12,904,076	$25,983,926	$37,927,411	$11,943,484	46.0%
	West	$3,968,820	$12,516,876	$7,702,362	($4,814,514)	(38.5%)
	Total	$142,723,586	$222,819,512	$198,145,394	($24,674,118)	(11.1%)
Reliability	RTO	$7,061,503	$43,812,027	$51,449,101	$7,637,073	17.4%
	East	$497,589	$48,187,002	$10,586,472	($37,600,530)	(78.0%)
	West	$23,066,804	$20,692,661	$28,656,646	$7,963,986	38.5%
	Total	$30,625,896	$112,691,690	$90,692,219	($21,999,471)	(19.5%)
Total		$173,349,483	$335,511,201	$288,837,612	($46,673,589)	(13.9%)

Table 3-41 Potential wheeling units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.052	0.068	0.016	29.8%
	East	0.024	0.027	0.003	13.1%
	West	0.078	0.078	0.000	0.0%
Deviation	RTO	0.677	0.946	0.269	39.8%
	East	0.416	0.423	0.008	1.8%
	West	0.104	0.108	0.004	3.6%

Table 3-42 ALR and voltage support units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.067	0.068	0.001	1.9%
	East	0.027	0.027	0.000	0.0%
	West	0.004	0.078	0.074	2,017.5%
Deviation	RTO	0.921	0.946	0.025	2.7%
	East	0.423	0.423	0.000	0.0%
	West	0.103	0.108	0.005	4.9%

Table 3-43 Monthly balancing transaction credits: Calendar year 2011

Month	Dispatchable Transaction Credits	JOA Make-Whole Credit	Total Balancing Transaction Credits
Jan	$392,816	$80,423	$473,239
Feb	$330,419	$47,637	$378,056
Mar	$363,835	$58,027	$421,862
Apr	$165,633	$50,183	$215,816
May	$0	$13,365	$13,365
Jun	$142	$19,935	$20,077
Jul	$0	$1,068	$1,068
Aug	$0	$4,774	$4,774
Sep	$0	$40,005	$40,005
Oct	$0	$38,865	$38,865
Nov	$0	$114,037	$114,037
Dec	$0	$43,712	$43,712
Total	$1,252,846	$512,031	$1,764,877

Table 3-44 Up-to Congestion Transactions Impact on the Operating Reserve Rates: Calendar year 2011

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.107	0.086	(0.020)	(19.1%)
RTO Deviations	0.946	0.281	(0.665)	(70.3%)
East Deviations	0.423	0.171	(0.252)	(59.5%)
West Deviations	0.108	0.024	(0.084)	(77.8%)
Lost Opportunity Cost	1.068	0.317	(0.751)	(70.3%)
Canceled Resources	0.056	0.017	(0.039)	(70.3%)

operating reserve charges would have had on 2011 operating reserve rates. For example, the RTO deviations rate would have been reduced $0.6648 per MWh or 70.3 percent. The impact on deviations also means that all deviations rates plus lost opportunity cost and canceled resources rates are affected.

Lost Opportunity Cost Calculation

Lost Opportunity Cost Billing Error

On November 22, 2011, PJM filed a petition with FERC requesting a procedural framework within which to correct settlements of balancing operating reserve lost opportunity cost billings between 2009 and 2011.[18] The tariff provides for the calculation of opportunity cost as LMP less the higher of the price or cost offer.[19] However, the software code included in the Market Settlement Calculation System (MSCS) calculated opportunity cost as LMP less the price offer.[20] As a result, certain participants who regularly included cost offers higher than price offers and received operating reserves credits, received significant overpayments during the relevant period. Likewise, LSEs were overcharged. PJM estimates that it would need to correct its billings as provided in the tariff for an amount of approximately $99.7 million.[21] PJM and the Market Monitor are engaged in discussions with the participants who received most of the overpayments.[22]

Lost Opportunity Cost Eligibility

Under the current rules, CTs and Diesel engines are eligible to receive day-ahead lost opportunity cost if they are scheduled in the Day-Ahead Market but are not called in real time. These unit types need to be called by PJM in the real-time in order to be turned on, even when they have been scheduled in the Day-Ahead Market. PJM has proposed that all units (regardless of their technology) with a lead time (notification plus start-up time) longer than 2 hours be in effect called in real-time when scheduled in the Day-Ahead Market. The result is that PJM is not obligated to call the unit on and there is no obligation to opportunity cost credits if the unit is not called on in real time. This will prevent such units with lead times longer than 2 hours from receiving day-ahead LOC credits unless PJM explicitly directs the unit to not come on line. In 2011, 68.1 percent of all lost opportunity cost credits or $117.4 million were paid to units that were scheduled in the Day-Ahead Market and not called in real-time and had lead times longer than 2 hours.

Unit Parameters: Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers. This issue is currently in discussion in the PJM stakeholder process.

Limits on these parameters will help ensure that capacity resources, paid for in RPM, meet their obligation to make legitimate and competitive offers in the Day-Ahead Market every day.

18 See Petition of PJM Interconnection, L.L.C. for Institution of Proceeding to Determine Proper Billing Adjustments and for Waiver of Tariff, Docket No. ER12-469-000 (December 22, 2011) (December 22nd Petition).
19 OA Schedule 1 § 3.2.3(f) & (f-1).
20 December 22nd Petition at 2–3.
21 Id. at 4; OA Schedule 1 § 15.6.
22 Id. at 8–9.