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.[1] 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.

Highlights

- Operating reserve charges decreased $25.9 million, or 20.7 percent, from $125.2 million in the first three months of 2011, to $99.3 million in the first three months of 2012. Day-ahead operating reserve charges decreased $10.1 million, or 35.8 percent to $18.1 million and balancing operating reserve charges decreased $15.6 million, or 16.1 percent to $96.7 million.
- Balancing operating reserve charges for reliability decreased by $0.8 million, or 3.5 percent compared to the first three months of 2011. Balancing operating reserve charges for deviations decreased by $24.6 million, or 42.4 percent.
- The reduction in balancing operating reserve charges was comprised of a decrease of $25.4 million in generator and real-time import transactions balancing operating reserve charges, an increase of $7.6 million in lost opportunity costs, an increase of $1.1 million in canceled resources and an increase of $1.1 million in charges to participants requesting resources to control local constraints.
- Generators and real-time transactions balancing operating reserve charges were $55.7 million, 68.6 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 40.1 percent as reliability charges and 59.9 percent as deviation charges. Lost opportunity cost charges were $20.8 million or 25.7 percent of all balancing charges. The remaining 5.7 percent of balancing operating reserve charges were comprised of 2.9 percent canceled resources charges and 2.8 percent of local constraints control charges.
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 36.8 percent of total operating reserve credits in the first three months of 2012, compared to 50.3 percent in the first three months of 2011.
- The regional concentration of operating reserves remained high in the first three months of 2012, although lower than the first three months of 2011. In the first three months of 2012, 55.9 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 14.4 percent from the first three months of 2011.

Recommendations

- The MMU recommends that the reactive service make whole credits cover the entire cost of a unit providing reactive service rather than paying part of these costs through operating reserve charges. The result of paying part of the cost of reactive service through operating reserve credits is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone where the service is provided while balancing operating reserves are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

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

1 See the *2011 State of the Market Report for PJM: Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" for a full description of how operating reserve credits and charges are calculated.

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.

Operating Reserves Credits and Charges

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.

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 charges are allocated. Table 3-2 shows the different types of deviations.

Table 3-1 Operating reserve credits and charges (See 2011 SOM, Table 3-1)

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
	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
Local Constraints Control		→	Applicable Requesting Party
Providing Reactive Service		→	Zonal Real-Time Load

Table 3-2 Operating reserve deviations (See 2011 SOM, Table 3-2)

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

Operating Reserve Results

Operating Reserve Charges

Table 3-3 shows total operating reserve charges for the first three months of 2011 and 2012.[2] Total operating reserve charges decreased by 20.7 percent in the first three months of 2012 compared to the first three months of 2011, to a total of $99.3 million.

Table 3-3 Total operating reserve charges: January through March 2011 and 2012 (See 2011 SOM, Table 3-6)[3]

	2011	2012	Change	Percentage Change
Total Operating Reserve Charges	$125,194,704	$99,250,805	($25,943,899)	(20.7%)
Operating Reserve as a Percent of Total PJM Billing	1.3%	1.4%	0.1%	9.5%
Day-Ahead Rate ($/MWh)	0.143	0.088	(0.055)	(38.3%)
Balancing RTO Deviation Rate ($/MWh)	1.270	0.767	(0.503)	(39.6%)
Balancing RTO Reliability Rate ($/MWh)	0.093	0.021	(0.072)	(77.6%)

Total operating reserve charges in the first three months of 2012 were $99.3 million, down from the total of $125.2 million in the first three months of 2011. Table 3-4 compares monthly operating reserve charges by category for calendar years 2011 and 2012. The decrease of 20.7 percent in the first three months of 2012 is comprised of a 35.8 percent decrease in day-ahead operating reserve charges, an 88.7 percent decrease in synchronous condensing charges and a 16.1 percent decrease in balancing operating reserve charges.

The reduction in day-ahead operating reserve credits was primarily a result of a lower spread between the total energy offer of units receiving day-ahead operating reserve credits and the LMP at the units' buses.

Table 3-5 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. In the first three months of 2012, generation and transactions charges decreased by $25.4 million or 31.3 percent, lost opportunity cost charges increased by $7.6 million or 57.4 percent, canceled resources charges increased by $1.1 million or 92.9 percent and charges for local constraints control increased by $1.1 million or 96.8 percent.

2 Table 3-3 includes all categories of charges 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 current on April 10, 2012.

3 The total operating reserve charges in Table 3-3 are $3.2 million higher than the total charges published in the *2011 State of the Market Report for PJM*. PJM may recalculate new settlements after the State of the Market reports is published.

Table 3-4 Monthly operating reserve charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-7)

	2011 Charges				2012 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$12,373,099	$110,095	$47,090,369	$59,573,563	$8,311,574	$15,362	$27,177,428	$35,504,364
Feb	$8,940,203	$139,287	$26,607,792	$35,687,282	$5,858,308	$18,592	$24,532,362	$30,409,262
Mar	$6,837,719	$66,032	$23,030,108	$29,933,859	$3,894,926	$1,648	$29,440,606	$33,337,180
Apr	$4,405,102	$13,011	$18,762,006	$23,180,118				
May	$7,064,934	$39,417	$46,178,207	$53,282,558				
Jun	$8,303,391	$9,056	$62,118,948	$70,431,396				
Jul	$4,993,311	$238,127	$106,596,647	$111,828,085				
Aug	$8,360,392	$104,982	$55,142,158	$63,607,531				
Sep	$6,249,240	$40,878	$36,617,421	$42,907,539				
Oct	$5,133,837	$0	$20,415,483	$25,549,319				
Nov	$7,063,847	$0	$19,528,707	$26,592,554				
Dec	$7,593,046	$0	$24,716,729	$32,309,775				
Total	$28,151,021	$315,414	$96,728,269	$125,194,704	$18,064,808	$35,603	$81,150,395	$99,250,805
Share of Charges	22.5%	0.3%	77.3%	100.0%	18.2%	0.0%	81.8%	100.0%

Table 3-5 Monthly balancing operating reserve charges by category: January through March 2012 (See 2011 SOM, Table 3-8)

	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Total
Jan	$20,300,434	$5,449,229	$772,882	$654,882	$27,177,428
Feb	$18,581,149	$4,632,856	$517,612	$800,744	$24,532,362
Mar	$16,820,894	$10,763,338	$1,034,994	$821,380	$29,440,606
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Total	$55,702,477	$20,845,424	$2,325,489	$2,277,006	$81,150,395
Share of Charges	68.6%	25.7%	2.9%	2.8%	100.0%

Table 3-6 shows the amount and percentages of regional balancing charge allocations for the first three months of 2012. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints, resources providing quick start reserve and resources performing annual, scheduled black start tests.

In the first three months of 2012, balancing operating reserve charges, excluding lost opportunity costs, canceled resources and local constraints control categories, decreased by $25.4 million compared to the first three months of 2011. Balancing operating reserve charges for reliability decreased by $0.8 million or 3.5 percent and balancing operating reserve charges for deviations decreased by $24.6 million or 42.4 percent. Reliability charges in the Western Region increased by $13.4 million compared to the first three months of 2011, as a result of payments to units providing blackstart and voltage support in the AEP Control Zone. The remaining two reliability categories decreased by $14.2 million. The decrease in balancing operating reserve charges was mainly a result of a lower spread between the units' energy offer and the real-time LMP. The total real-time generation receiving balancing operating reserve credits increased by 3.2 percent.

Table 3-6 Regional balancing charges allocation: January through March 2012[4] (See 2011 SOM, Table 3-9)

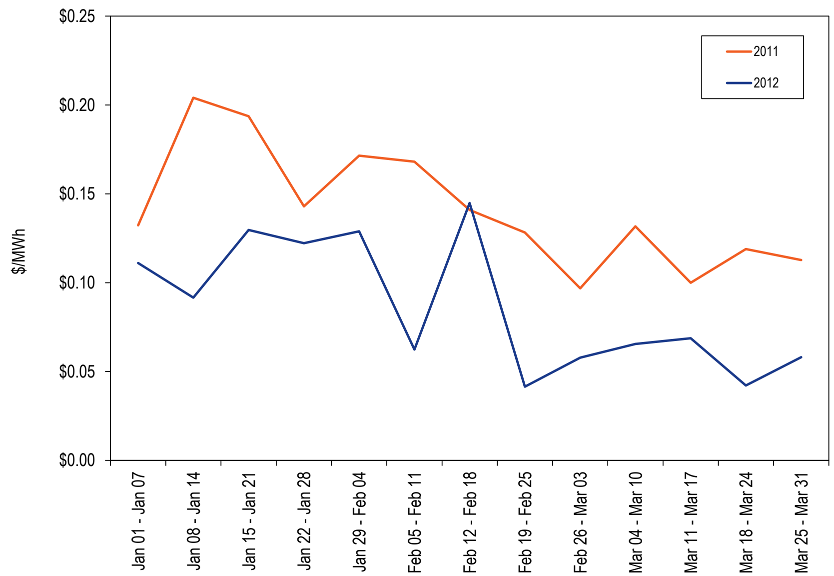
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$3,947,480	5.0%	$88,579	0.1%	$17,552,181	22.3%	$21,588,240	27.4%
	Real-Time Exports	$109,794	0.1%	$2,265	0.0%	$611,789	0.8%	$723,847	0.9%
	Total	$4,057,274	5.1%	$90,844	0.1%	$18,163,969	23.0%	$22,312,087	28.3%
Deviation Charges	Demand	$15,162,154	19.2%	$3,574,276	4.5%	$437,614	0.6%	$19,174,044	24.3%
	Supply	$5,740,759	7.3%	$1,326,944	1.7%	$172,663	0.2%	$7,240,366	9.2%
	Generator	$5,672,684	7.2%	$988,200	1.3%	$315,096	0.4%	$6,975,980	8.8%
	Total	$26,575,597	33.7%	$5,889,420	7.5%	$925,373	1.2%	$33,390,390	42.3%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$12,545,609	15.9%	$0	0.0%	$0	0.0%	$12,545,609	15.9%
	Supply	$5,458,363	6.9%	$0	0.0%	$0	0.0%	$5,458,363	6.9%
	Generator	$5,166,940	6.6%	$0	0.0%	$0	0.0%	$5,166,940	6.6%
	Total	$23,170,912	29.4%	$0	0.0%	$0	0.0%	$23,170,912	29.4%
Total Balancing Charges		$53,803,783	68.2%	$5,980,264	7.6%	$19,089,342	24.2%	$78,873,389	100%

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. See Table 3-1 for how these charges are allocated.

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for the first three months of 2011 and 2012. The average rate in the first three months of 2012 was $0.0882 per MWh, $0.0548 per MWh lower than the average of the first three months of 2011. The highest rate occurred on February 1, when the rate reached $0.2171 per MWh, 39.7 percent lower than the $0.3603 reached on January 14, 2011.

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): January through March 2012 (See 2011 SOM, Figure 3-1)



4 The total charges shown in Table 3-6 do not equal the total balancing charges shown in Table 3-5 because the totals in Table 3-5 include charges to resources controlling local constraints while the totals in Table 3-6 do not.

The top chart in Figure 3-2 shows the RTO and the regional reliability rates for the first three months of 2012. The average daily RTO reliability rate was $0.0208 per MWh. The highest RTO reliability rate of 2012 occurred on January 16, when the rate reached $0.2506 per MWh. Reliability rates in the Western Region have been high primarily because of the use of certain units in the AEP Control Zone to provide black start and voltage support.

The center chart in Figure 3-2 shows the RTO and the regional deviation rates for the first three months of 2012. The average daily RTO deviation rate was $0.7672 per MWh. The largest daily rate occurred on January 4, when the RTO deviation rate reached $2.6654 per MWh.

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 $0.6018 per MWh. The highest lost opportunity cost rate occurred on March 5, when it reached $3.6135 per MWh. The canceled resources rate averaged $0.0671 per MWh and credits were paid during 52.7 percent of all the days in the first three months of 2012. 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. The lost opportunity cost eligibility rule has been modified to address this issue.

Figure 3-2 Daily balancing operating reserve rates ($/MWh): January through March 2012 (See 2011 SOM, Figure 3-2)

Table 3-7 shows the rates for each region in each category. RTO deviation charges and lost opportunity cost charges accounted for 58.4 percent of all balancing operating reserve charges in the first three months of 2012.

Table 3-7 Balancing operating reserve rates ($/MWh): Calendar year 2012 (See 2011 SOM, Table 3-10)

	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.021	0.767	0.602	0.067
East	0.001	0.302	NA	NA
West	0.176	0.062	NA	NA

Table 3-8 shows the operating reserve cost of a 1 MW transaction during the first three months of 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.8063 per MWh with a maximum rate of $6.4533 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $0.8854 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges.

Table 3-8 Operating reserve rates statistics ($/MWh): January through March 2012 (See 2011 SOM, Table 3-11)

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	6.395	1.719	0.330	0.897
	DEC	6.453	1.806	0.470	0.885
	DA Load	0.217	0.087	0.010	0.050
	RT Load	0.251	0.021	0.000	0.043
	Deviation	6.395	1.719	0.330	0.897
West	INC	4.749	1.480	0.330	0.750
	DEC	4.803	1.568	0.409	0.741
	DA Load	0.217	0.087	0.010	0.050
	RT Load	0.354	0.200	0.057	0.065
	Deviation	4.749	1.480	0.330	0.750

Deviations

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.

Table 3-9 shows monthly real-time deviations for demand, supply and generator categories for 2011 and the first three months of 2012. These deviations are the sum of the regional deviations. Total deviations summed across the demand, supply, and generator categories were lower in the first three months of 2012 compared to the first three months of 2011 by 6,924,284 MWh or 16.7 percent. Demand deviations decreased by 21.3 percent, supply deviations decreased by 10.4 percent, and generator deviations decreased by 9.5 percent. In the first three months of 2012 compared to the first three months of 2011, the share of total deviations in the demand category decreased by 3.3 percentage points, the share of supply deviations increased by 1.6 percentage points, and the share of generator deviations increased by 1.8 percentage points.

Real-time load, real-time exports, and deviations in each region are shown in Table 3-10. RTO deviations are defined as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Table 3-9 Monthly balancing operating reserve deviations (MWh): Calendar years 2011 and 2012 (See 2011 SOM, Table 3-3)

	2011 Deviations				2012 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,798,230	3,261,409	3,107,683	16,167,323	7,340,668	2,496,321	2,780,753	12,617,743
Feb	7,196,554	2,809,384	2,680,742	12,686,680	5,894,539	2,380,558	2,310,547	10,585,644
Mar	7,510,358	2,467,175	2,730,454	12,707,988	6,041,789	2,776,433	2,616,098	11,434,320
Apr	6,623,238	2,027,200	2,662,761	11,313,199				
May	7,144,854	2,381,825	2,902,093	12,428,772				
Jun	9,845,466	2,558,697	2,996,041	15,400,204				
Jul	10,160,922	2,690,836	3,306,340	16,158,098				
Aug	8,566,032	2,057,281	2,907,427	13,530,739				
Sep	8,829,765	2,198,858	2,561,534	13,590,157				
Oct	7,140,856	2,514,963	2,388,186	12,044,005				
Nov	6,739,882	2,704,677	2,949,889	12,394,448				
Dec	7,646,566	2,606,633	2,629,846	12,883,045				
Total	24,505,143	8,537,968	8,518,879	41,561,991	19,276,997	7,653,312	7,707,398	34,637,707
Share of Deviations	59.0%	20.5%	20.5%	100.0%	55.7%	22.1%	22.3%	100.0%

Table 3-10 Regional charges determinants (MWh): January through March 2012 (See 2011 SOM, Table 3-4)

	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	188,414,264	6,264,066	194,678,331	19,276,997	7,653,312	7,707,398	34,637,707
East	88,335,848	2,908,310	91,244,158	11,851,856	4,441,592	3,237,459	19,530,908
West	100,078,417	3,355,756	103,434,173	7,341,579	3,193,434	4,469,939	15,004,951

Operating Reserve Credits by Category

Figure 3-3 shows that 81.8 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 4.5 percent from the 77.3 percent for the first three months of 2011.

Figure 3-3 Operating reserve credits: January through March 2012 (See 2011 SOM, Figure 3-3)

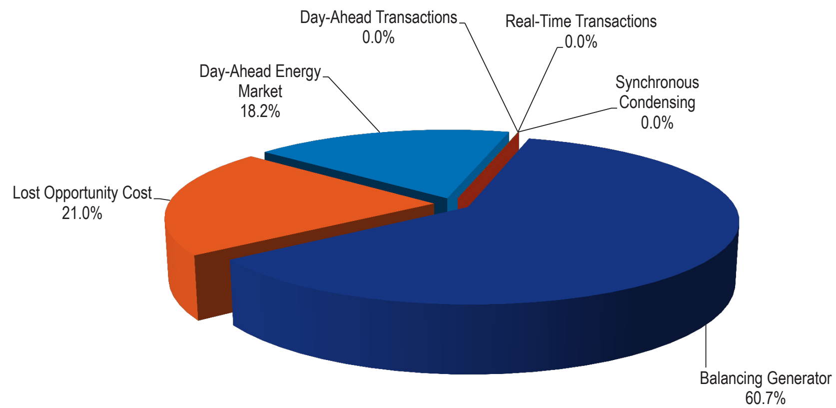


Table 3-11 shows the monthly totals for each credit category for the first three months of 2012.

Table 3-11 Credits by month (By operating reserve market): January through March 2012 (See 2011 SOM, Table 3-12)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$8,311,573	$0	$15,362	$21,718,168	$10,031	$5,449,229	$35,504,365
Feb	$5,858,308	$0	$18,592	$19,896,576	$2,929	$4,632,856	$30,409,262
Mar	$3,894,705	$220	$1,648	$18,658,434	$18,833	$10,763,337	$33,337,179
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$18,064,587	$220	$35,603	$60,273,178	$31,794	$20,845,423	$99,250,805
Share of Credits	18.2%	0.0%	0.0%	60.7%	0.0%	21.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-12 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 3-12 Credits by unit types (By operating reserve market): January through March 2012 (See 2011 SOM, Table 3-13)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Total
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Combined Cycle	41.8%	0.0%	53.7%	4.5%	0.0%	0.0%	$18,362,490
Combustion Turbine	5.4%	0.1%	31.7%	62.5%	0.0%	0.3%	$29,546,459
Diesel	0.3%	0.0%	26.0%	73.6%	0.0%	0.0%	$1,486,228
Hydro	0.0%	0.0%	88.9%	0.0%	11.1%	0.0%	$219,411
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Steam - Coal	18.8%	0.0%	75.8%	0.6%	0.0%	4.8%	$45,847,391
Steam - Others	11.6%	0.0%	76.3%	12.0%	0.0%	0.0%	$1,467,265
Wind	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	$2,289,547

Table 3-13 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 conventional steam units fueled by coal received 90.2 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 93.8 percent of the lost opportunity cost credits. Wind units received 98.5 percent of the canceled resources credits.

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 continued to increase in the first three months of 2012. In the first three months of 2012 the total was $2.3 million higher than the $0.9 million paid in the first three months of 2011. A total of 11 wind farms were paid credits under the canceled resources category of the operating reserve rules. Table 3-14 shows the monthly canceled resources credits paid to wind farms.

Table 3-13 Credits by operating reserve market (By unit type): January through March 2012 (See 2011 SOM, Table 3-14)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	42.5%	0.0%	17.7%	4.0%	0.0%	0.0%
Combustion Turbine	8.9%	100.0%	16.8%	88.6%	0.5%	3.7%
Diesel	0.0%	0.0%	0.7%	5.2%	0.0%	0.0%
Hydro	0.0%	0.0%	0.4%	0.0%	1.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	47.7%	0.0%	62.4%	1.4%	0.0%	96.3%
Steam - Others	0.9%	0.0%	2.0%	0.8%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	98.5%	0.0%
Total	$18,064,587	$35,603	$55,670,684	$20,845,423	$2,325,489	$2,277,006

Table 3-14 Canceled resources credits paid to wind units: January through March 2012 (See 2011 SOM, Table 3-15)

	Wind Units Canceled Resources Credits	Annual Share
Jan	$741,979	32.4%
Feb	$517,612	22.6%
Mar	$1,029,884	45.0%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Total	$2,289,475	100.0%

The AEP and ComEd Control Zones are 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.

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 3-15 shows the number of economic and noneconomic hours for each unit type. For example, of the 7,071 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit's bus was higher than its real-time energy offer in 2,244 hours, or 31.7 percent of those hours. Diesel engines had the highest proportion of economic hours with 37.3 percent.

Table 3-15 Economic vs. noneconomic hours: January through March 2012 (See 2011 SOM, Table 3-16)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	2,244	31.7%	4,827	68.3%	7,071
Combustion Turbine	519	20.5%	2,007	79.5%	2,526
Diesel	357	37.3%	599	62.7%	956
Hydro	0	0.0%	48	100.0%	48
Steam - Coal	5,277	18.0%	24,047	82.0%	29,324
Steam - Others	233	32.9%	476	67.1%	709
Total	8,630	21.2%	32,004	78.8%	40,634

Geography of Balancing Charges and Credits

Table 3-16 shows the geography of charges and credits in the first three months of 2012. Charges are categorized by the location (zone, hub or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, the transactions and resources in the AECO Control Zone paid 0.8 percent of all operating reserve charges, and resources were paid 0.9 percent of all operating reserve credits. The AECO Control Zone received more operating reserve credits than charges paid. The JCPL Control Zone paid more operating reserve charges than credits received. Table 3-16 also shows that 82.0 percent of all charges were allocated in control zones, 5.8 percent in hubs and 12.3 percent in interfaces.

Table 3-16 Geography of Balancing Charges and Credits: January through March 2012[5] (New Table)

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$780,582	$890,864	$110,282	0.8%	0.9%	0.0%	0.3%
	AEP	$14,807,680	$22,362,594	$7,554,914	15.3%	23.1%	0.0%	18.6%
	AP - DLCO	$8,451,336	$9,386,073	$934,737	8.7%	9.7%	0.0%	2.3%
	ATSI	$6,462,160	$8,806,019	$2,343,858	6.7%	9.1%	0.0%	5.8%
	BGE - Pepco	$6,633,539	$18,635,413	$12,001,874	6.8%	19.2%	0.0%	29.6%
	ComEd - External	$12,203,924	$4,060,193	($8,143,731)	12.6%	4.2%	20.1%	0.0%
	DAY - DEOK	$5,013,092	$277,367	($4,735,725)	5.2%	0.3%	11.7%	0.0%
	Dominion	$5,778,360	$6,395,868	$617,508	6.0%	6.6%	0.0%	1.5%
	DPL	$2,115,778	$3,935,900	$1,820,122	2.2%	4.1%	0.0%	4.5%
	JCPL	$1,895,733	$361,940	($1,533,793)	2.0%	0.4%	3.8%	0.0%
	Met-Ed	$1,467,375	$255,698	($1,211,676)	1.5%	0.3%	3.0%	0.0%
	PECO	$3,636,698	$198,138	($3,438,560)	3.8%	0.2%	8.5%	0.0%
	PENELEC	$2,160,540	$1,549,991	($610,549)	2.2%	1.6%	1.5%	0.0%
	PPL	$3,988,845	$685,035	($3,303,809)	4.1%	0.7%	8.2%	0.0%
	PSEG	$3,967,380	$19,105,090	$15,137,710	4.1%	19.7%	0.0%	37.4%
	RECO	$112,885	$0	($112,885)	0.1%	0.0%	0.3%	0.0%
	All Zones	$79,475,907	$96,906,182	$17,430,275	82.0%	100.0%	57.0%	100.0%
Hubs	AEP - Dayton	$444,475	$0	($444,475)	0.5%	0.0%	1.1%	0.0%
	Dominion	$140,897	$0	($140,897)	0.1%	0.0%	0.3%	0.0%
	Eastern	$206,028	$0	($206,028)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$124,311	$0	($124,311)	0.1%	0.0%	0.3%	0.0%
	Ohio	$26,077	$0	($26,077)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$12,754	$0	($12,754)	0.0%	0.0%	0.0%	0.0%
	Western	$4,622,901	$0	($4,622,901)	4.8%	0.0%	11.4%	0.0%
	All Hubs	$5,577,443	$0	($5,577,443)	5.8%	0.0%	13.8%	0.0%
Interfaces	IMO	$1,583,243	$0	($1,583,243)	1.6%	0.0%	3.9%	0.0%
	Linden	$277,560	$0	($277,560)	0.3%	0.0%	0.7%	0.0%
	MISO	$2,696,864	$0	($2,696,864)	2.8%	0.0%	6.7%	0.0%
	Neptune	$287,777	$0	($287,777)	0.3%	0.0%	0.7%	0.0%
	NIPSCO	$5,861	$0	($5,861)	0.0%	0.0%	0.0%	0.0%
	Northwest	$37,888	$0	($37,888)	0.0%	0.0%	0.1%	0.0%
	NYIS	$928,082	$0	($928,082)	1.0%	0.0%	2.3%	0.0%
	OVEC	$239,603	$0	($239,603)	0.2%	0.0%	0.6%	0.0%
	South Exp	$1,570,408	$0	($1,570,408)	1.6%	0.0%	3.9%	0.0%
	South Imp	$4,257,561	$0	($4,257,561)	4.4%	0.0%	10.5%	0.0%
	All Interfaces	$11,884,847	$32,014	($11,852,833)	12.3%	0.0%	29.3%	0.0%
	Total	$96,938,196	$96,938,196	$0	100.0%	100.0%	100.0%	100.0%

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

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 44.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-17 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through March 2012 (See 2011 SOM, Table 3-17)

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,152,259	$234,342	$561,494	$1,948,095	$13,988,700
Feb	$703,873	$284,761	$434,163	$1,422,796	$9,546,059
Mar	$614,429	$469,097	$1,170,534	$2,254,060	$11,548,489
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
East Generators Total	$2,470,561	$988,200	$2,166,190	$5,624,951	$35,083,248
PJM Total Charges	$26,575,597	$5,889,420	$23,170,912	$55,635,929	$78,841,596
Share	9.3%	16.8%	9.3%	10.1%	44.5%

Table 3-18 also shows that generators in the Western Region paid 12.9 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 55.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-18 Monthly balancing operating reserve charges and credits to generators (Western Region): January through March 2012 (See 2011 SOM, Table 3-18)

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,299,689	$32,410	$787,093	$2,119,192	$12,523,816
Feb	$1,085,106	$282,686	$706,392	$2,074,185	$14,180,627
Mar	$817,328	$0	$1,507,265	$2,324,592	$17,044,912
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
West Generators Total	$3,202,123	$315,096	$3,000,750	$6,517,969	$43,749,354
PJM Total	$26,575,597	$925,373	$23,170,912	$50,671,882	$78,841,596
Share	12.0%	34.1%	13.0%	12.9%	55.5%

Table 3-19 shows that on average in the first three months of 2012, generator charges were 12.5 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 1.3 percent lower than 2011. Generators received 99.97 percent of all operating reserve credits, while the remaining 0.03 percent were credits paid to import transactions.

Table 3-19 Percentage of unit credits and charges of total credit and charges: January through March 2012 (See 2011 SOM, Table 3-19)

	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	11.7%	100.0%
Feb	11.8%	100.0%
Mar	14.1%	99.9%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Average	12.5%	100.0%

Load Response Resource Operating Reserve Credits

End-use customers or their representative may make demand reduction offers 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.

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

In real-time, 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 offer, including any submitted shut-down costs. If total payments are less than the total value of the load response offer, PJM will make the resource whole through balancing operating reserve credits.

In the first three months of 2012, 32.2 percent of payments for demand reduction offers were covered by operating reserve credits while the remaining 67.8 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 March 2012 (See 2011 SOM, Table 3-20)

	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	$2,052,996	$154,589	93.0%	7.0%
2012	$30,302	$14,379	67.8%	32.2%

Reactive Service

Credits to resources providing reactive services are separate from operating reserve credits. These credits are divided into three categories. Reactive Service Credits are paid to units providing reactive services with an offer price higher than the LMP at the unit's bus. Reactive Service Lost Opportunity Cost Credits are paid to units reduced or suspended by PJM for reactive reliability purposes when their offer price is lower than the LMP at the unit's bus. Reactive Service Synchronous Condensing Credits are paid to units providing synchronous condensing for the purpose of maintaining the reactive reliability of the system. Reactive service charges are allocated daily to real-time load in the transmission zone where the reactive service was provided.

Total reactive service credits in the first three months of 2012 were $23.1 million, about 3.7 times higher than the $4.9 million in the first three months of 2011. Table 3-21 shows the monthly distribution of reactive service credits. This increase was in part a result of the need for reactive support in the ATSI Control Zone. In the first three months of 2012, seven units ran a combined

2,455 hours out of merit in order to support the area's voltage. The top three zones accounted for 68.9 percent of the total reactive costs, a decrease of 15.1 percent from the 2011 share. The top three control zones were JCPL, ATSI and Pepco.

Table 3-21 Monthly reactive service credits: January through March 2012 (See 2011 SOM, Table 3-21)

	Reactive Service Credits	Percent of Total Reactive Service Credits
Jan	$2,920,441	12.6%
Feb	$13,108,018	56.7%
Mar	$7,077,227	30.6%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Total	$23,105,685	100.0%

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). Credits received by combustion turbines decreased from 51.5 percent in 2011 to 10.6 percent in the first three months of 2012. Combined cycles and coal steam turbines credits share increased from 43.5 percent to 86.2 percent in the first three months of 2012.

Table 3-22 Reactive service credits by unit type: January through March 2012 (See 2011 SOM, Table 3-22)

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Total Reactive Credits
Battery	0.0%	0.0%	0.0%	0.0%
Combined Cycle	33.9%	0.1%	0.0%	32.8%
Combustion Turbine	10.6%	0.4%	100.0%	10.6%
Diesel	1.8%	0.0%	0.0%	1.8%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%
Steam - Coal	52.2%	96.8%	0.0%	53.4%
Steam - Others	1.4%	2.6%	0.0%	1.4%
Wind	0.0%	0.0%	0.0%	0.0%
Total	$22,330,909	$706,638	$68,139	$23,105,685

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.

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 the first three months of 2012 compared to the first three months of 2011. 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 36.8 percent of total operating reserve credits in the first three months of 2012, compared to 50.3 percent in the first three months of 2011. The top 20 units received 54.1 percent of total operating reserve credits in the first three months of 2012.

Table 3-23 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 through March 2012 (See 2011 SOM, Table 3-23)

	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%
2012	36.8%	0.7%

Table 3-16 shows the distribution of operating reserve credits to units by zone. The AEP Control Zone had the largest share of credits with 23.1 percent, the PSEG Control Zone had the second highest with 19.7 percent, and the BGE and Pepco Control Zones combined had the third highest with a 19.2 percent share.

Table 3-24 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserves categories. The share of the top 10 units in three of the categories: day-ahead generator, canceled resources and reactive services, was above 80.0 percent. The share of the top 10 units in all categories was above 90.0 percent.

Table 3-24 Top 10 units and organizations operating reserve credits: January through March 2012 (New Table)

	Top 10 units		Top 10 organizations	
Category	Credits	Credits Share	Credits	Credits Share
Total Operating Reserves	$36,544,135	36.8%	$91,993,962	92.7%
Day-Ahead Generator	$14,981,699	82.9%	$17,671,004	97.8%
Synchronous Condensing	$28,373	79.7%	$35,603	100.0%
Balancing Generator	$26,669,609	47.9%	$53,797,252	96.6%
Canceled Resources	$1,882,277	80.9%	$2,291,523	98.5%
Lost Opportunity Cost	$10,948,236	52.5%	$20,312,532	97.4%
Reactive Services	$18,649,307	80.7%	$21,954,096	95.0%

Concentration of Operating Reserves Credits

In the first three months of 2012, concentration in all operating reserve credits categories was high.[6] Operating reserves HHI was calculated based on each organization's daily credits for each category. Table 3-25 shows the average HHI for each category. Day-ahead operating reserve HHI was 4553. Balancing operating reserve HHI averaged 3209. Lost opportunity cost HHI was 4831.

Table 3-25 Daily Operating Reserve Credits HHI: January through March 2012 (See 2011 SOM, Table 3-34)

	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	4553	10000	10000	3209	10000	4831	4933	1944
Minimum	2249	10000	10000	1829	10000	1485	968	915
Maximum	9814	10000	10000	5379	10000	10000	10000	4209
Highest market share (One day)	99.1%	100.0%	100.0%	71.0%	100.0%	100.0%	100.0%	61.5%
Highest market share (All days)	42.2%	50.0%	98.8%	34.8%	100.0%	48.0%	40.5%	22.6%
Numbers of Days	91	1	5	91	26	91	48	91
Days with HHI > 1,800	91	1	5	91	26	88	40	50
% of Days with HHI > 1,800	100.0%	100.0%	100.0%	100.0%	100.0%	96.7%	83.3%	54.9%
Days with HHI = 10,000	0	1	5	0	26	1	10	0
% of Days with HHI = 10,000	0.0%	100.0%	100.0%	0.0%	100.0%	1.1%	20.8%	0.0%

Table 3-26 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2012, 48.6 percent of all credits paid to these units were allocated to deviations while the remaining 51.4 percent were paid for reliability reasons.

Table 3-26 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through March 2012 (See 2011 SOM, Table 3-35)

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$1,598,935	$0	$12,106,242	$11,383,434	$1,580,998	$0	$26,669,609
Share	6.0%	0.0%	45.4%	42.7%	5.9%	0.0%	100.0%

Lost Opportunity Cost Credits

In the first three months of 2012, total operating reserve credits decreased by 20.7 percent. In spite of the overall decrease in operating reserve credits, lost opportunity cost credits increased by 57.4 percent. In the first three months of 2012 lost opportunity cost credits increased by $7.6 million compared to the first three months of 2011.

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 dispatched 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 based on the desired output.

Units in PJM receive lost opportunity cost credits when they are scheduled in day-ahead and not called in real-time. Table 3-27 shows the generation scheduled in day-ahead and requested by PJM to run in real-time, which did not receive lost opportunity cost credits, and the generation scheduled in day-ahead and not requested by PJM to run in real-time which did receive lost opportunity cost credits. In the first three months of 2012, 73.6 percent of the day-ahead scheduled generation was not requested by PJM in real-time. This percentage increased 23.2 percent from 2011.

6 See the *2012 Quarterly State of the Market Report for PJM: January through March*, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Table 3-27 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits (MWh): Calendar year 2009 through March 2012 (See 2011 SOM, Table 3-37)

	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested 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%
2012	716,016	1,994,880	73.6%

Table 3-28 shows the distribution by zone of the generation not called in real time. In the first three months of 2012, the AP, ATSI and Dominion Control Zones combined had 76.2 percent of all the generation not called in real-time receiving lost opportunity cost credits.

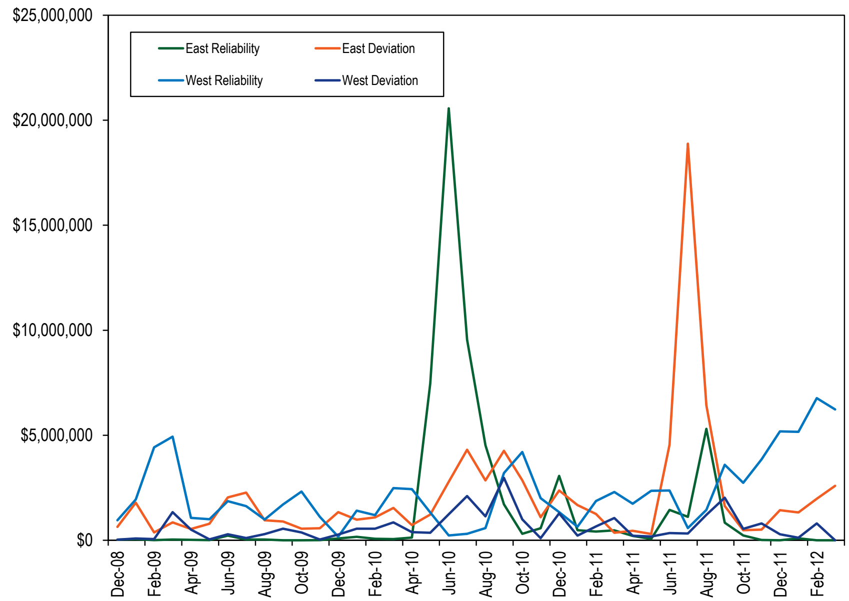
Table 3-28 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits by zone (MWh): January through March 2012 (See 2011 SOM, Table 3-38)

Zone	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Share of Day-Ahead Generation Not Called in Real-Time
AECO - JCPL - PSEG - PECO	20,393	50,006	2.5%
AEP - DAY - DEOK	56,329	89,122	4.5%
AP - DLCO	4,522	581,706	29.2%
ATSI - PENELEC	77,877	529,280	26.5%
BGE - DPL - Dominion - Pepco	544,257	480,158	24.1%
ComEd - External	10,702	259,050	13.0%
Met-Ed - PPL	1,936	5,560	0.3%
Total	716,016	1,994,880	100.0%

Regional Credits Allocation

Figure 3-4 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. The increase in west reliability credits was the result of credits paid to units providing blackstart and voltage support in the AEP Control Zone.

Figure 3-4 Monthly regional reliability and deviations credits: December 2008 through March 2012[7] (See 2011 SOM, Figure 3-5)



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 real-time load and exports. In the first three months of 2012, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In the first three months of 2012, $22.3 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.

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

Table 3-6 and Table 3-29 show how reliability credits were allocated across the RTO, Eastern and Western Regions.

Figure 3-5 Monthly balancing operating reserve categories: January through March 2012 (See 2011 SOM, Figure 3-6)

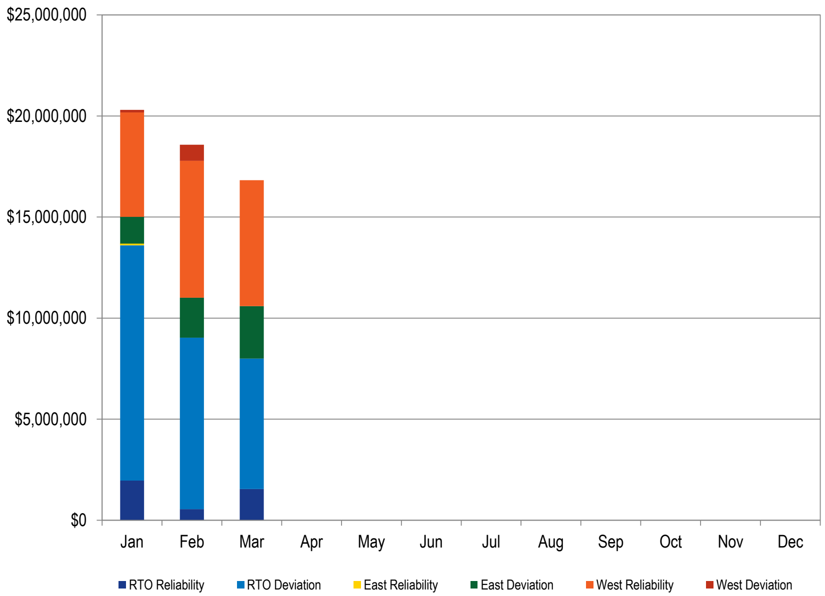


Table 3-29 Monthly balancing operating reserve categories: January through March 2012 (See 2011 SOM, Table 3-39)

Month	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$1,960,777	$90,844	$5,165,990	$11,636,173	$1,323,039	$123,612
Feb	$549,422	$0	$6,769,404	$8,485,052	$1,975,509	$801,761
Mar	$1,547,075	$0	$6,228,575	$6,454,372	$2,590,872	$0
Apr						
May						
Jun						
Jul						
Aug						
Sep						
Oct						
Nov						
Dec						
Total	$4,057,274	$90,844	$18,163,969	$26,575,597	$5,889,420	$925,373

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.[8] 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.

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. The MMU recommends that PJM dispatchers explicitly log the reasons that these units

8 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.

are run out of merit to comply with blackstart requirements or voltage support in order to correctly assign the associated charges.

Credits categorized as reliability paid to units in the Western Region increased considerably in the first three months of 2012 compared to the first three months of 2011 because of these units used in the AEP Control Zone for blackstart and voltage support

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 had paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do, while accounting for the impact of such payments on the profitability of the transactions.

In the first three months of 2012, 49.5 percent of all up-to congestion transactions were profitable.[9]

In order to address the reaction of participants using up-to congestion transactions to an allocation of operating reserves charges and the associated impact on profitability, the MMU calculated the up-to congestion transactions that would have remained if operating reserves charges had been applied. It was assumed that up-to congestion transactions would have had the same proportional distribution of profitable and unprofitable transactions after paying operating reserves charges as actually occurred when no operating reserves charges were paid. If up-to congestion transactions were allocated operating reserves charges, it would be reasonable to expect that some transactions would not be made if such charges were assigned. The result is that only 30.4 percent of all up-to congestion transactions would have been made if such transactions had to pay operating reserves charges and the proportional distribution of profitable and unprofitable transactions remained the same. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserves charges and the impact on other participants who pay those charges would have been significant.

9 An up-to congestion transaction position equals its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

Table 3-30 shows the impact that including the identified 30.4 percent of up-to congestion transactions in the allocation of balancing operating reserve charges would have had on the operating reserve charge rates in the first three months of 2012. For example, the RTO deviations rate would have been reduced by 57.9 percent.

Table 3-30 Up-to Congestion Transactions Impact on the Operating Reserve Rates: January through March 2012 (See 2011 SOM, Table 3-44)

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.088	0.079	(0.009)	(10.4%)
RTO Deviations	0.767	0.3232	(0.4440)	(57.9%)
East Deviations	0.302	0.1835	(0.1181)	(39.20%)
West Deviations	0.062	0.019	(0.0432)	(70.0%)
Lost Opportunity Cost	0.602	0.2535	(0.3483)	(57.9%)
Canceled Resources	0.067	0.028	(0.0389)	(57.9%)

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[10] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including start up and no load as they are under the operating reserves credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone where the service is provided while balancing operating reserves are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

10 OA Schedule 1 § 3.2.3B(f).

In the first three months of 2012, units providing reactive services were paid $7.9 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 92.8 percent were paid by deviations in the RTO Region, 6.5 percent by real-time load and real-time exports in the RTO Region and the remaining 0.7 percent by real-time load and real-time exports in the Western Region.

Table 3-31 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-31 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through March 2012 (New Table)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Credits to Units Providing Reactive Services	Current	($/MWh)	Percentage
Reliability	RTO	0.018	0.021	0.003	14.6%
	East	0.001	0.001	0.000	0.0%
	West	0.175	0.176	0.001	0.3%
Deviation	RTO	0.555	0.767	0.213	38.3%
	East	0.302	0.302	0.000	0.0%
	West	0.062	0.062	0.000	0.0%