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 $42.8 million, or 8.9 percent, from $479.8 million in the first nine months of 2011, to $437.0 million in the first nine months of 2012. Day-ahead operating reserve charges increased $17.8 million, or 26.3 percent to $85.3 million and balancing operating reserve charges decreased $59.9 million, or 14.5 percent to $351.7 million.
- Balancing operating reserve charges for reliability decreased by $5.3 million, or 7.1 percent compared to the first nine months of 2011. Balancing operating reserve charges for deviations decreased by $47.4 million, or 27.6 percent.
- The reduction in balancing operating reserve charges was comprised of a decrease of $52.7 million in generator and real-time import transactions balancing operating reserve charges, a decrease of $9.8 million in lost opportunity costs, a decrease of $2.6 million in canceled resources and an increase of $5.2 million in charges to participants requesting resources to control local constraints.
- Generators and real-time transactions balancing operating reserve charges were $194.2 million, 55.2 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 35.8 percent as reliability charges and 64.2 percent as deviation charges. Lost opportunity cost charges were $146.5 million or 41.7 percent of all balancing charges. The remaining 3.1 percent of balancing operating reserve charges were comprised of 0.9 percent canceled resources charges and 2.2 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 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832.
- The regional concentration of operating reserves remained high in the first nine months of 2012. In the first nine months of 2012, 47.1 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 13.5 percentage points from the first nine months of 2011.

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

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.

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, no load and startup costs.

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.

In addition, the allocation of operating reserve charges to participants should be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

Overall the goal should be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

Operating Reserve 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, no load and startup costs.

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.

© 2012 Monitoring Analytics, LLC

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
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
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 nine months of 2011 and 2012.[2] Total operating reserve charges decreased by 8.9 percent in the first nine months of 2012 compared to the first nine months of 2011, to a total of $437.0 million.

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

	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change
Total Operating Reserve Charges	$479,805,042	$436,984,853	($42,820,190)	(8.9%)
Operating Reserve as a Percent of Total PJM Billing	1.7%	2.0%	0.3%	18.7%
Day-Ahead Rate ($/MWh)	0.1092	0.1350	0.0258	23.6%
Balancing RTO Deviation Rate ($/MWh)	1.0510	0.9398	(0.1113)	(10.6%)
Balancing RTO Reliability Rate ($/MWh)	0.0832	0.0230	(0.0603)	(72.4%)

Total operating reserve charges in the first nine months of 2012 were $437.0 million, down from the total of $479.8 million in the first nine months of 2011. Table 3-4 compares monthly operating reserve charges by category for calendar years 2011 and 2012. The decrease of 8.9 percent in the first nine months of 2012 is comprised of a 26.3 percent increase in day-ahead operating reserve charges, a 93.0 percent decrease in synchronous condensing charges and a 14.5 percent decrease in balancing operating reserve charges.

The increase in day-ahead operating reserve charges was primarily a result of PJM scheduling units for reliability purposes in the Day-Ahead Energy Market in order to reduce divergence between the Day-Ahead and the Real-Time Energy Markets.

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 October 11, 2012.

3 The total operating reserve charges in Table 3-3 are $0.6 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 Report is published.

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

	2011				2012			
	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	$27,322,330	$35,649,266
Feb	$8,940,203	$139,287	$26,607,792	$35,687,282	$5,858,308	$18,592	$24,869,649	$30,746,549
Mar	$6,837,719	$66,032	$23,238,170	$30,141,921	$3,852,873	$1,648	$29,702,257	$33,556,779
Apr	$4,405,102	$13,011	$18,764,254	$23,182,366	$2,967,302	$0	$34,168,700	$37,136,002
May	$7,064,934	$39,417	$43,540,784	$50,645,135	$7,956,965	$0	$43,695,141	$51,652,106
Jun	$8,303,391	$9,056	$59,886,618	$68,199,066	$6,988,065	$0	$45,664,065	$52,652,130
Jul	$4,993,311	$238,127	$103,271,440	$108,502,878	$11,773,101	$0	$66,408,580	$78,181,681
Aug	$8,360,392	$104,982	$53,819,941	$62,285,315	$8,695,770	$0	$47,310,263	$56,006,033
Sep	$6,249,240	$40,878	$35,297,398	$41,587,517	$28,877,736	$17,512	$32,509,059	$61,404,307
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	$67,527,391	$760,886	$411,516,766	$479,805,042	$85,281,694	$53,115	$351,650,044	$436,984,853
Share of Charges	14.1%	0.2%	85.8%	100.0%	19.5%	0.0%	80.5%	100.0%

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 constraints. In the first nine months of 2012, generation and transactions charges decreased by $52.7 million or 21.3 percent, lost opportunity cost charges decreased by $9.8 million or 6.2 percent, canceled resources charges decreased by $2.6 million or 43.9 percent and charges for local constraints control increased by $5.2 million or 214.1 percent.

© 2012 Monitoring Analytics, LLC

Table 3-5 Monthly balancing operating reserve charges by category: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-8)

	2011				2012			
	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Jan	$43,170,696	$2,946,513	$639,107	$334,052	$20,440,833	$5,449,229	$777,386	$654,882
Feb	$22,698,872	$3,205,948	$208,046	$494,927	$18,907,159	$4,644,133	$517,613	$800,744
Mar	$15,456,921	$7,094,881	$358,223	$328,146	$16,982,255	$10,777,661	$1,120,962	$821,380
Apr	$11,096,912	$7,222,704	$303,514	$141,123	$20,252,666	$12,507,091	$409,047	$999,896
May	$20,331,609	$20,364,971	$2,742,644	$101,559	$23,216,158	$19,242,410	$452,294	$784,279
Jun	$30,610,434	$27,996,648	$901,825	$377,711	$29,111,054	$15,179,311	$13,031	$1,360,668
Jul	$56,569,143	$46,339,477	$299,607	$63,213	$34,779,195	$30,943,088	$21,256	$665,042
Aug	$29,236,518	$24,156,594	$311,184	$115,645	$19,632,482	$26,491,201	$0	$1,186,580
Sep	$17,735,689	$16,948,364	$151,195	$462,150	$10,902,289	$21,279,381	$4,624	$322,765
Oct	$10,460,806	$6,327,845	$1,250,928	$2,375,903				
Nov	$11,415,410	$6,181,160	$1,663,154	$268,983				
Dec	$20,477,899	$3,574,430	$306,260	$358,140				
Total	$246,906,793	$156,276,100	$5,915,345	$2,418,527	$194,224,092	$146,513,504	$3,316,212	$7,596,235
Share of Charges	60.0%	38.0%	1.4%	0.6%	55.2%	41.7%	0.9%	2.2%

Table 3-6 and Table 3-7 show the amount and percentages of regional balancing charge allocations for the first nine months of 2011 and 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 nine months of 2012, balancing operating reserve charges, excluding lost opportunity costs, canceled resources and local constraints control categories, decreased by $52.7 million compared to the first nine months of 2011. Balancing operating reserve charges for reliability decreased by $5.3 million or 7.1 percent and balancing reserve charges for deviations decreased by $47.4 million or 27.6 percent. Reliability charges in the Western Region increased by $30.9 million compared to the first nine months of 2011, as a result of payments to units providing black start and voltage support. The remaining two reliability categories decreased by $36.2 million.

© 2012 Monitoring Analytics, LLC

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

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$45,781,885	11.2%	$9,760,186	2.4%	$16,011,131	3.9%	$71,553,202	17.5%
	Real-Time Exports	$1,850,168	0.5%	$583,295	0.1%	$874,280	0.2%	$3,307,743	0.8%
	Total	$47,632,053	11.6%	$10,343,482	2.5%	$16,885,410	4.1%	$74,860,945	18.3%
Deviation Charges	Demand	$79,655,606	19.5%	$23,547,417	5.8%	$3,510,103	0.9%	$106,713,126	26.1%
	Supply	$23,726,418	5.8%	$6,097,061	1.5%	$1,248,814	0.3%	$31,072,294	7.6%
	Generator	$26,914,956	6.6%	$5,870,431	1.4%	$1,475,040	0.4%	$34,260,428	8.4%
	Total	$130,296,980	31.8%	$35,514,910	8.7%	$6,233,958	1.5%	$172,045,848	42.1%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$101,180,178	24.7%	$0	0.0%	$0	0.0%	$101,180,178	24.7%
	Supply	$27,636,347	6.8%	$0	0.0%	$0	0.0%	$27,636,347	6.8%
	Generator	$33,374,919	8.2%	$0	0.0%	$0	0.0%	$33,374,919	8.2%
	Total	$162,191,445	39.6%	$0	0.0%	$0	0.0%	$162,191,445	39.6%
Total Balancing Charges		$340,120,479	83.1%	$45,858,392	11.2%	$23,119,368	5.7%	$409,098,238	100%

Table 3-7 Regional balancing charges allocation: January through September 2012[5] (See 2011 SOM, Table 3-9)

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13,447,588	3.9%	$7,743,241	2.3%	$45,958,032	13.4%	$67,148,860	19.5%
	Real-Time Exports	$389,645	0.1%	$163,838	0.0%	$1,875,423	0.5%	$2,428,906	0.7%
	Total	$13,837,233	4.0%	$7,907,079	2.3%	$47,833,455	13.9%	$69,577,767	20.2%
Deviation Charges	Demand	$62,737,232	18.2%	$9,169,890	2.7%	$3,799,573	1.1%	$75,706,696	22.0%
	Supply	$18,211,804	5.3%	$2,962,176	0.9%	$898,364	0.3%	$22,072,344	6.4%
	Generator	$22,649,202	6.6%	$2,549,641	0.7%	$1,668,443	0.5%	$26,867,286	7.8%
	Total	$103,598,238	30.1%	$14,681,707	4.3%	$6,366,381	1.9%	$124,646,325	36.2%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$89,482,171	26.0%	$0	0.0%	$0	0.0%	$89,482,171	26.0%
	Supply	$26,555,929	7.7%	$0	0.0%	$0	0.0%	$26,555,929	7.7%
	Generator	$33,791,618	9.8%	$0	0.0%	$0	0.0%	$33,791,618	9.8%
	Total	$149,829,717	43.5%	$0	0.0%	$0	0.0%	$149,829,717	43.5%
Total Balancing Charges		$267,265,187	77.7%	$22,588,786	6.6%	$54,199,836	15.8%	$344,053,809	100%

Operating Reserve Rates

Under the operating reserves 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 nine months of 2011 and 2012. The average rate in the first nine months of 2012 was $0.1350 per MWh, $0.0258 per MWh higher than the average of the first nine months of 2011. The highest rate occurred on September 20, when the rate reached $0.8714 per MWh, 90.5 percent higher than the $0.4574 reached during the first nine months of 2011, on August 27. On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market.

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.

5 The total charges shown in Table 3-7 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 3-7 do not.

© 2012 Monitoring Analytics, LLC

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-1)

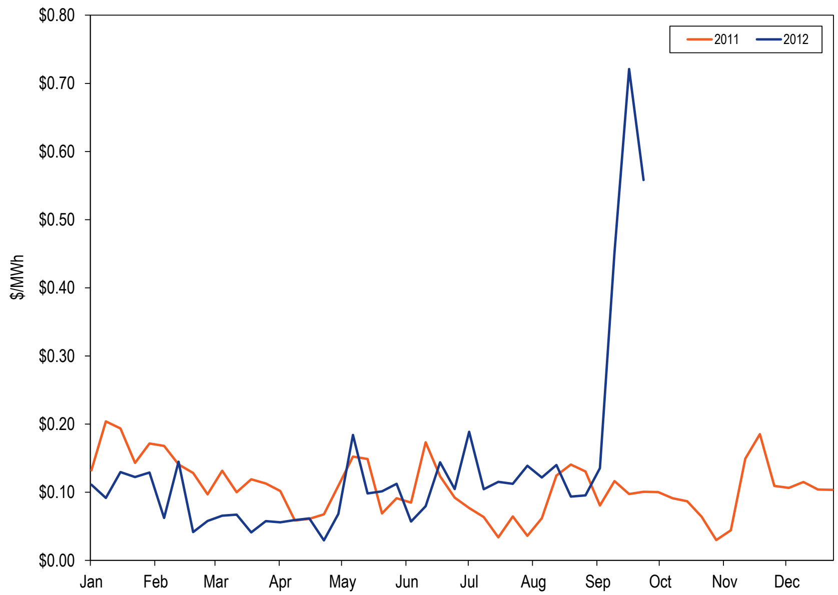


Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

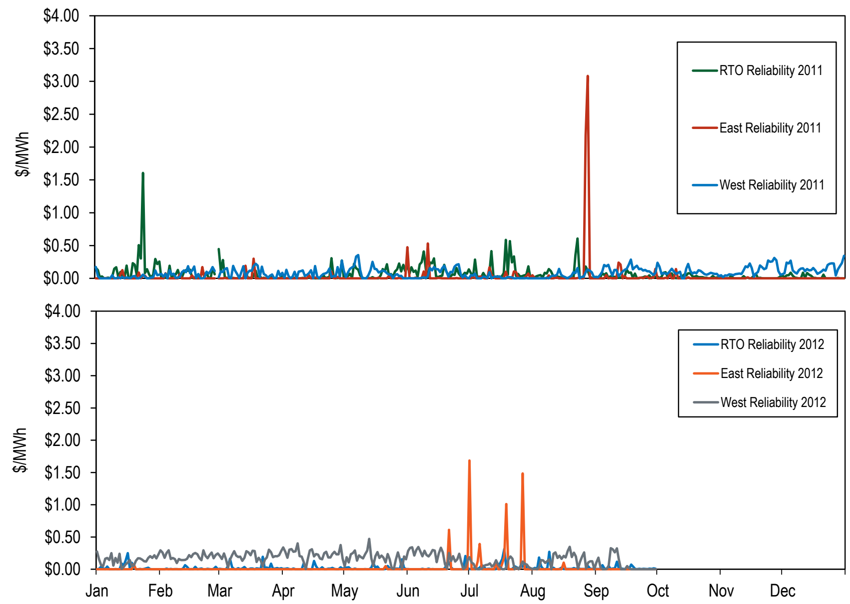


Figure 3-2 shows the RTO and the regional reliability rates for the first nine months of 2011 and 2012. The average daily RTO reliability rate was $0.0230 per MWh. The highest RTO reliability rate of 2012 occurred on July 18, when the rate reached $0.3160 per MWh. In the first nine months of 2012, reliability rates in the Eastern Region were positive for only 14 days. Hot weather related demand in the entire RTO and specifically in the Dominion control zone led to the top three Eastern Region reliability rates in 2012, on July 1, 19 and 27, the Eastern Region reliability rate reached $1.6869, $1.0099 and $1.4847 per MWh.[6] Reliability rates in the Western Region have been high primarily because of the use of certain units to provide black start and voltage support.

Figure 3-3 shows the RTO and the regional deviation rates for the first nine months of 2011 and 2012. The average daily RTO deviation rate was $0.9398 per MWh. The highest daily rate in the first nine months occurred on July 26, when the RTO deviation rate reached $3.7260 per MWh.[7] The highest Eastern Region rate occurred on July 7. The Western Region deviation rate increase on April 12 was due to the loss of a 345 kV transmission line in the Pittsburgh area.

6 PJM issued consecutive Hot Weather Alerts for the entire RTO region for June 20 and June 21, and for June 28 through July 7, for the Dominion and Mid-Atlantic zones for June 22 and July 27 and for the Dominion zone only on July 19.

7 The June 29, 2012, RTO deviation rate ($3.9347 per MWh) published in the *2012 Quarterly State of the Market Report for PJM: January through June* was higher than the July 26 rate, but the former was recalculated by PJM and resulted in a lower rate ($3.6802 per MWh).

© 2012 Monitoring Analytics, LLC

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

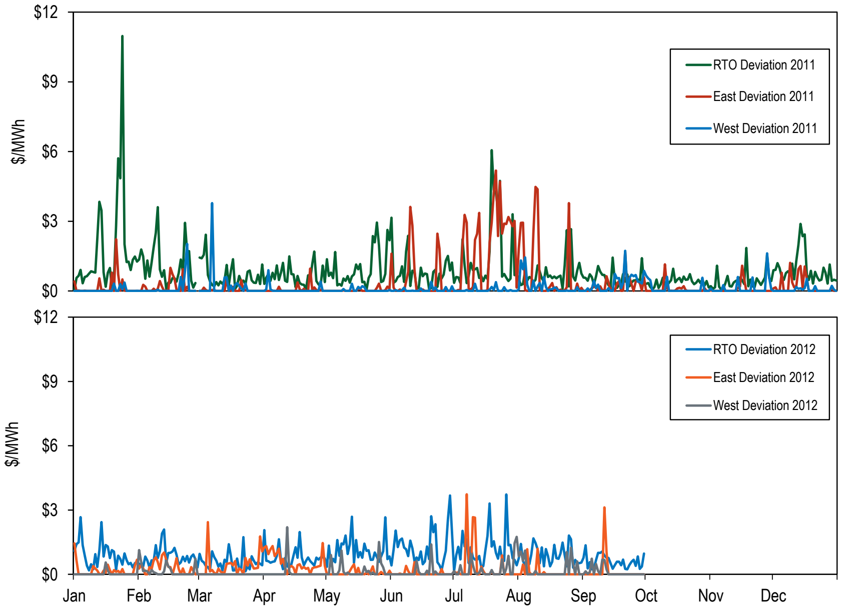


Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

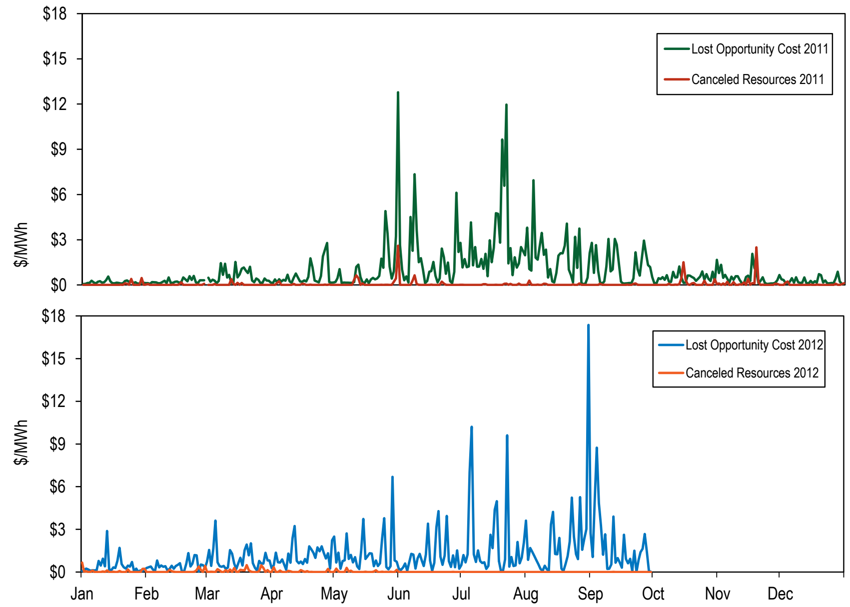


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for the first nine months of 2011 and 2012. The lost opportunity rate averaged $1.3291 per MWh. The highest lost opportunity cost rate occurred on August 31, when it reached $17.3678 per MWh. Increases in the lost opportunity rate are often caused by high real-time prices which increases the total lost opportunity cost credits paid to combustion turbines scheduled to run but not called in real time. The canceled resources rate averaged $0.0301 per MWh and credits were paid during 35.3 percent of all the days in the first nine months of 2012.

Table 3-8 shows the rates for each region in each category. RTO deviation charges and lost opportunity cost charges accounted for 71.1 percent of all balancing operating reserve charges in the first nine months of 2012.

Table 3-8 Balancing operating reserve rates ($/MWh): January through September 2011 and 2012 (See 2011 SOM, Table 3-10)

	2011				2012			
	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.0832	1.0510	1.2606	0.0477	0.0230	0.9398	1.3291	0.0301
East	0.0347	0.5087	NA	NA	0.0277	0.2424	NA	NA
West	0.0616	0.1160	NA	NA	0.1505	0.1289	NA	NA

© 2012 Monitoring Analytics, LLC

Table 3-9 shows the operating reserve cost of a 1 MW transaction during the first nine months of 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.5612 per MWh with a maximum rate of $17.9612 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $1.8549 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges. Table 3-9 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-9 Operating reserve rates statistics ($/MWh): January through September 2012 (See 2011 SOM, Table 3-11)

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.9166	2.4227	0.3299	1.8717
	DEC	17.9612	2.5612	0.4698	1.8549
	DA Load	0.8714	0.1385	0.0000	0.1572
	RT Load	1.6900	0.0428	0.0000	0.1637
	Deviation	17.9166	2.4227	0.3299	1.8717
West	INC	17.9166	2.3008	0.3299	1.9071
	DEC	17.9612	2.4393	0.4092	1.8964
	DA Load	0.8714	0.1385	0.0000	0.1572
	RT Load	0.4726	0.1788	0.0016	0.0990
	Deviation	17.9166	2.3008	0.3299	1.9071

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 3-10 shows monthly real-time deviations for demand, supply and generator categories for 2011 and the first nine 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 nine months of 2012 compared to the first nine months of 2011 by 13,744,693 MWh or 11.1 percent. Demand deviations decreased by 13.4 percent, supply deviations decreased by 10.7 percent, and generator deviations decreased by 4.6 percent. In the first nine months of 2012 compared to the first nine months of 2011, the share of total deviations in the demand category decreased by 1.6 percentage points, the share of supply deviations increased by 0.1 percentage points, and the share of generator deviations increased by 1.5 percentage points.

© 2012 Monitoring Analytics, LLC

Table 3-10 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	2,779,139	12,616,128
Feb	7,196,554	2,809,384	2,680,742	12,686,680	5,894,708	2,380,558	2,303,940	10,579,207
Mar	7,510,358	2,467,175	2,730,454	12,707,988	6,041,789	2,776,439	2,608,928	11,427,156
Apr	6,623,238	2,027,200	2,662,761	11,313,199	6,295,762	2,288,554	2,504,541	11,088,857
May	7,144,854	2,381,825	2,902,093	12,428,772	7,738,120	2,565,938	2,915,540	13,219,598
Jun	9,845,466	2,558,697	2,996,041	15,400,204	8,400,299	2,020,919	3,092,756	13,513,974
Jul	10,160,922	2,690,836	3,306,340	16,158,098	9,237,687	2,188,799	3,498,150	14,924,636
Aug	8,566,032	2,057,281	2,907,427	13,530,739	7,676,248	1,640,431	2,635,129	11,951,808
Sep	8,829,765	2,198,858	2,561,534	13,590,157	6,908,675	1,687,460	2,320,968	10,917,102
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	75,675,421	22,452,664	25,855,076	123,983,161	65,533,957	20,045,419	24,659,091	110,238,467
Share of Deviations	61.0%	18.1%	20.9%	100.0%	59.4%	18.2%	22.4%	100.0%

Real-time load, real-time exports, and deviations in each region are shown in Table 3-11. RTO deviations are defined as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Table 3-11 Regional charges determinants (MWh): January through September 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	583,065,065	19,828,074	602,893,139	65,533,957	20,045,419	24,659,091	110,238,467
East	277,605,000	7,555,552	285,160,552	37,727,176	11,735,893	11,106,979	60,570,049
West	305,460,065	12,272,522	317,732,587	27,568,221	8,261,711	13,552,112	49,382,044

Operating Reserve Credits by Category

Table 3-12 shows the totals for each credit category for the first nine months of 2011 and 2012. During the first nine months of 2012, 80.5 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 decreased 5.3 percentage points from the 85.8 percent for the first nine months of 2011.

© 2012 Monitoring Analytics, LLC

Table 3-12 Credits by operating reserve category: January through September 2011 and 2012 (See 2011 SOM, Table 3-12)

Category	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change	Jan-Sep 2011 Share of Credits	Jan-Sep 2012 Share of Credits
Day-Ahead Generator	$67,216,527	$85,281,139	$18,064,612	26.9%	14.0%	19.5%
Day-Ahead Transactions	$310,864	$554	($310,310)	(99.8%)	0.1%	0.0%
Synchronous Condensing	$760,885	$53,115	($707,771)	(93.0%)	0.2%	0.0%
Balancing Generator	$245,338,532	$194,175,120	($51,163,412)	(20.9%)	51.1%	44.4%
Balancing Transactions	$1,568,263	$48,972	($1,519,291)	(96.9%)	0.3%	0.0%
Lost Opportunity Cost	$156,276,098	$146,513,503	($9,762,596)	(6.2%)	32.6%	33.5%
Canceled Resources	$5,915,347	$3,316,214	($2,599,133)	(43.9%)	1.2%	0.8%
Local Constraints Control	$2,418,527	$7,596,235	$5,177,707	214.1%	0.5%	1.7%
Total	$479,805,044	$436,984,851	($42,820,193)	(8.9%)	100.0%	100.0%

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 3-13 Credits by unit types (By operating reserve category): January through September 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%	100.0%	0.0%	0.0%	0.0%	$1,938
Combined Cycle	34.4%	0.0%	53.1%	12.4%	0.0%	0.0%	$40,817,603
Combustion Turbine	3.7%	0.0%	22.5%	73.6%	0.0%	0.2%	$181,560,737
Diesel	1.0%	0.0%	50.8%	48.1%	0.0%	0.0%	$2,405,958
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Hydro	0.0%	0.0%	89.9%	0.0%	10.1%	0.0%	$270,027
Nuclear	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$337,984
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Steam - Coal	33.8%	0.0%	59.3%	2.8%	0.0%	4.1%	$175,368,663
Steam - Others	16.9%	0.0%	82.0%	1.1%	0.0%	0.0%	$31,826,060
Wind	0.0%	0.0%	1.1%	25.0%	74.0%	0.0%	$4,346,356

Table 3-14 shows the distribution of credits for each operating reserve category received by each unit type (each column sums to 100 percent). Combined cycle units and conventional steam units fueled by coal received 85.9 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 92.0 percent of the lost opportunity cost credits. Wind units received 97.0 percent of the canceled resources credits.

© 2012 Monitoring Analytics, LLC

Table 3-14 Credits by operating reserve category (By unit type): January through September 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	16.5%	0.0%	11.2%	3.5%	0.2%	0.1%
Combustion Turbine	7.8%	100.0%	21.0%	91.2%	2.0%	4.9%
Diesel	0.0%	0.0%	0.6%	0.8%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.1%	0.0%	0.8%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	69.4%	0.0%	53.6%	3.4%	0.0%	94.9%
Steam - Others	6.3%	0.0%	13.4%	0.2%	0.0%	0.1%
Wind	0.0%	0.0%	0.0%	0.7%	97.0%	0.0%
Total	$85,281,139	$53,115	$194,175,120	$146,513,503	$3,316,214	$7,596,235

Table 3-15 shows the total credits by unit type for the first nine months of 2011 and 2012. The reduction of the price spread between natural gas and coal prices resulted in an increase in operating reserve credits paid to steam turbines fueled by coal. In the first nine months of 2012, 40.1 percent of all credits were paid to coal units, 19.4 percentage points more than the share in the first nine months of 2011. In contrast, the share of total credits paid to gas fired combined cycles declined from 20.0 percent in the first nine months of 2011 to 9.3 percent in the first nine months of 2012.

Table 3-15 Credits by unit type: January through September 2011 and 2012 (New Table)

Unit Type	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change	Jan-Sep 2011 Share of Credits	Jan-Sep 2012 Share of Credits
Battery	$12,488	$1,938	($10,550)	(84.5%)	0.0%	0.0%
Combined Cycle	$95,458,909	$40,817,603	($54,641,306)	(57.2%)	20.0%	9.3%
Combustion Turbine	$193,268,239	$181,560,737	($11,707,502)	(6.1%)	40.4%	41.6%
Diesel	$14,691,893	$2,405,958	($12,285,935)	(83.6%)	3.1%	0.6%
Fuel Cell	$0	$0	$0	0.0%	0.0%	0.0%
Hydro	$285,577	$270,027	($15,550)	(5.4%)	0.1%	0.1%
Nuclear	$291,748	$337,984	$46,235	15.8%	0.1%	0.1%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$99,156,003	$175,368,663	$76,212,659	76.9%	20.7%	40.1%
Steam - Others	$69,645,774	$31,826,060	($37,819,714)	(54.3%)	14.6%	7.3%
Wind	$5,115,285	$4,346,356	($768,929)	(15.0%)	1.1%	1.0%
Total	$477,925,917	$436,935,325	($40,990,592)	(8.6%)	100.0%	100.0%

Wind Unit Credits

On June 1, 2012, PJM began to correctly categorize credits paid to wind units for lost opportunity cost and not as canceled resources credits. Also on June 1, 2012, PJM implemented new lost opportunity cost credit rules for wind units. Under the new rules, lost opportunity cost credits paid to wind units will be based on the lesser of the LMP desired output and the forecasted output of the unit.[8]

Credits paid to wind units decreased in the first nine months of 2012. In the first nine months of 2012 the total was $4.3 million, lower than the $5.1 million paid in the first nine months of 2011. Table 3-16 shows the monthly credits paid to wind units.

8 See "PJM Manual 28: Operating Agreement Accounting" Revision 52 (June 1, 2012), Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons.

© 2012 Monitoring Analytics, LLC

Table 3-16 Credits paid to wind units: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-15)

	2011				2012			
	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total
Jan	$0	$0	$468,059	$468,059	$0	$0	$741,979	$741,979
Feb	$0	$0	$182,151	$182,151	$0	$0	$517,612	$517,612
Mar	$0	$0	$344,622	$344,622	$0	$72	$1,098,130	$1,098,202
Apr	$0	$0	$271,810	$271,810	$20,990	$0	$409,047	$430,038
May	$0	$0	$2,446,129	$2,446,129	$23,212	$0	$448,836	$472,048
Jun	$0	$0	$839,074	$839,074	$817	$119,002	$0	$119,819
Jul	$0	$0	$167,310	$167,310	$129	$63,805	$0	$63,934
Aug	$0	$0	$244,935	$244,935	$0	$156,792	$0	$156,792
Sep	$0	$0	$151,194	$151,194	$683	$745,249	$0	$745,931
Oct	$0	$0	$1,325,128	$1,325,128				
Nov	$0	$0	$2,336,582	$2,336,582				
Dec	$0	$0	$420,210	$420,210				
Total	$0	$0	$5,115,285	$5,115,285	$45,831	$1,084,920	$3,215,605	$4,346,356

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

Economic and Noneconomic Generation[9]

Economic dispatch generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 3-17 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

9 The analysis of economic and noneconomic generation in previous *State of the Market Reports for PJM* was based on the relationship between the units' hourly average incremental offer and the LMP at the units' bus. The new analysis is based on the units' incremental offer, the value used by PJM to calculate the LMPs. Both analysis do not include no load and startup cost.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the additional hourly no load and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs. In the first nine months of 2012, 35.0 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.8 percent of the real-time generation was eligible for balancing operating reserve credits.

Table 3-17 Day-ahead and real-time generation (GWh): January through September 2012 (New Table)

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	606,162	211,986	35.0%
Real-Time	602,561	197,561	32.8%

Table 3-18 shows PJM's economic and noneconomic generation eligible for operating reserve credits. In the first nine months of 2012, 84.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic.

Table 3-18 Day-ahead and real-time economic and noneconomic generation (GWh): January through September 2012 (New Table)

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	179,884	32,102	84.9%	15.1%
Real-Time	131,678	65,882	66.7%	33.3%

Table 3-19 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2012, 7.4 percent of the day-ahead generation eligible for operating reserve credits was made whole and 8.9 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-19 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2012 (New Table)

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	211,986	15,610	7.4%
Real-Time	197,561	17,632	8.9%

Geography of Charges and Credits

Table 3-20 shows the geography of charges and credits in the first nine 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 AEP Control Zone paid 13.1 percent of all operating reserve charges, and resources were paid 19.8 percent of all operating reserve credits. The AEP Control Zone received more operating reserve credits than operating reserve charges paid. The JCPL Control Zone received fewer operating reserve credits than operating reserve charges paid. Table 3-20 also shows that 82.8 percent of all charges were allocated in control zones, 5.7 percent in hubs and 11.5 percent in interfaces.

© 2012 Monitoring Analytics, LLC

Table 3-20 Geography of charges and credits: January through September 2012[10] (New Table)

Location		Charges	Credits	Balance	Shares Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$4,980,372	$4,807,161	($173,211)	1.2%	1.1%	0.1%	0.0%
	AEP	$56,205,789	$84,919,362	$28,713,573	13.1%	19.8%	0.0%	18.9%
	AP - DLCO	$34,420,143	$30,663,883	($3,756,261)	8.0%	7.1%	2.5%	0.0%
	ATSI	$27,090,348	$36,374,286	$9,283,938	6.3%	8.5%	0.0%	6.1%
	BGE - Pepco	$33,435,320	$67,747,847	$34,312,528	7.8%	15.8%	0.0%	22.6%
	ComEd - External	$55,921,538	$36,776,061	($19,145,477)	13.0%	8.6%	12.6%	0.0%
	DAY - DEOK	$20,664,284	$3,633,613	($17,030,671)	4.8%	0.8%	11.2%	0.0%
	Dominion	$27,731,198	$67,256,877	$39,525,679	6.5%	15.7%	0.0%	26.1%
	DPL	$9,992,736	$20,457,633	$10,464,897	2.3%	4.8%	0.0%	6.9%
	JCPL	$10,225,784	$2,697,493	($7,528,291)	2.4%	0.6%	5.0%	0.0%
	Met-Ed	$7,417,545	$3,138,809	($4,278,736)	1.7%	0.7%	2.8%	0.0%
	PECO	$19,035,847	$6,718,471	($12,317,375)	4.4%	1.6%	8.1%	0.0%
	PENELEC	$9,511,188	$12,788,061	$3,276,873	2.2%	3.0%	0.0%	2.2%
	PPL	$17,614,334	$4,841,166	($12,773,169)	4.1%	1.1%	8.4%	0.0%
	PSEG	$20,463,106	$46,465,254	$26,002,148	4.8%	10.8%	0.0%	17.2%
	RECO	$621,692	$0	($621,692)	0.1%	0.0%	0.4%	0.0%
	All Zones	$355,331,223	$429,285,976	$73,954,753	82.8%	100.0%	51.2%	100.0%
Hubs	AEP - Dayton	$4,218,549	$0	($4,218,549)	1.0%	0.0%	2.8%	0.0%
	Dominion	$599,894	$0	($599,894)	0.1%	0.0%	0.4%	0.0%
	Eastern	$874,983	$0	($874,983)	0.2%	0.0%	0.6%	0.0%
	New Jersey	$404,860	$0	($404,860)	0.1%	0.0%	0.3%	0.0%
	Ohio	$135,530	$0	($135,530)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$74,224	$0	($74,224)	0.0%	0.0%	0.0%	0.0%
	Western	$18,260,962	$0	($18,260,962)	4.3%	0.0%	12.0%	0.0%
	All Hubs	$24,569,003	$0	($24,569,003)	5.7%	0.0%	16.2%	0.0%
Interfaces	IMO	$6,931,826	$0	($6,931,826)	1.6%	0.0%	4.6%	0.0%
	Linden	$1,631,401	$0	($1,631,401)	0.4%	0.0%	1.1%	0.0%
	MISO	$12,185,684	$0	($12,185,684)	2.8%	0.0%	8.0%	0.0%
	Neptune	$641,499	$0	($641,499)	0.1%	0.0%	0.4%	0.0%
	NIPSCO	$72,229	$0	($72,229)	0.0%	0.0%	0.0%	0.0%
	Northwest	$363,712	$0	($363,712)	0.1%	0.0%	0.2%	0.0%
	NYIS	$4,138,173	$0	($4,138,173)	1.0%	0.0%	2.7%	0.0%
	OVEC	$1,254,914	$0	($1,254,914)	0.3%	0.0%	0.8%	0.0%
	South Exp	$6,362,522	$0	($6,362,522)	1.5%	0.0%	4.2%	0.0%
	South Imp	$15,853,317	$0	($15,853,317)	3.7%	0.0%	10.5%	0.0%
	All Interfaces	$49,435,277	$49,526	($49,385,751)	11.5%	0.0%	32.6%	0.0%
	Total	$429,335,502	$429,335,502	$0	100.0%	100.0%	100.0%	100.0%

Table 3-21 and Table 3-22 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 3-21 shows that on average, 10.7 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 48.6 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-22 also shows that generators in the Western Region paid 12.3 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 51.4 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

10 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-20 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

© 2012 Monitoring Analytics, LLC

Table 3-21 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through September 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	$1,173,478	$234,258	$562,031	$1,969,766	$14,130,635
Feb	$733,719	$281,274	$433,268	$1,448,262	$9,874,828
Mar	$620,144	$477,947	$1,177,834	$2,275,925	$11,741,895
Apr	$803,236	$546,718	$1,263,975	$2,613,929	$17,370,555
May	$1,363,506	$73,346	$2,010,502	$3,447,354	$20,570,538
Jun	$1,917,827	$65,193	$1,644,838	$3,627,858	$22,401,191
Jul	$1,956,790	$619,582	$3,573,015	$6,149,388	$33,543,351
Aug	$1,195,834	$148,582	$2,939,872	$4,284,288	$23,678,824
Sep	$683,003	$102,742	$2,193,770	$2,979,514	$13,760,926
Oct					
Nov					
Dec					
East Generators Total	$10,447,537	$2,549,641	$15,799,105	$28,796,284	$167,072,744
PJM Total Charges	$103,598,238	$14,681,707	$149,829,717	$268,109,662	$344,004,837
Share	10.1%	17.4%	10.5%	10.7%	48.6%

Table 3-22 Monthly balancing operating reserve charges and credits to generators (Western Region): January through September 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	$1,309,915	$32,410	$787,486	$2,129,811	$12,526,783
Feb	$1,109,193	$282,686	$706,304	$2,098,184	$14,189,145
Mar	$827,049	$0	$1,515,079	$2,342,127	$17,113,158
Apr	$1,072,628	$139,080	$1,712,412	$2,924,120	$15,790,612
May	$1,775,248	$232,625	$2,441,180	$4,449,052	$22,297,577
Jun	$2,124,027	$128,649	$1,782,091	$4,034,767	$21,871,633
Jul	$2,165,402	$393,318	$3,850,561	$6,409,281	$32,184,308
Aug	$1,084,609	$316,755	$2,926,965	$4,328,329	$22,404,686
Sep	$733,593	$142,920	$2,270,434	$3,146,947	$18,398,444
Oct					
Nov					
Dec					
West Generators Total	$12,201,664	$1,668,443	$17,992,512	$31,862,620	$176,776,346
PJM Total	$103,598,238	$6,366,381	$149,829,717	$259,794,335	$344,004,837
Share	11.8%	26.2%	12.0%	12.3%	51.4%

Table 3-23 shows that on average in the first nine months of 2012, generator charges were 14.1 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 0.04 percentage points lower than the average of the first nine months of 2011. Generators received 99.99 percent of all operating reserve credits, while the remaining 0.01 percent were credits paid to import transactions.

© 2012 Monitoring Analytics, LLC

Table 3-23 Percentage of unit credits and charges of total credits and charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-19)

	2011		2012	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	11.2%	99.2%	11.7%	100.0%
Feb	11.8%	98.7%	11.8%	100.0%
Mar	12.9%	98.6%	14.1%	99.9%
Apr	15.5%	99.0%	15.3%	100.0%
May	16.0%	100.0%	15.5%	100.0%
Jun	13.4%	99.8%	14.9%	100.0%
Jul	16.6%	100.0%	16.2%	100.0%
Aug	14.2%	100.0%	15.7%	100.0%
Sep	13.1%	99.9%	10.0%	100.0%
Oct	11.3%	99.8%		
Nov	12.8%	99.6%		
Dec	11.4%	99.9%		
Average	14.2%	99.6%	14.1%	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 nine months of 2012, 4.7 percent of payments for demand reduction offers were covered by operating reserve credits while the remaining 95.3 percent were paid through the economic load response program as shown in Table 3-24.

Table 3-24 Day-ahead and balancing operating reserve for load response credits: Calendar year 2011 through September 2012 (See 2011 SOM, Table 3-20)

	2011				2012			
	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve
Jan	$140,236	$1,111	99.2%	0.8%	$8,664	$19,002	31.3%	68.7%
Feb	$88,599	$0	100.0%	0.0%	$14,994	$7,878	65.6%	34.4%
Mar	$11,469	$0	100.0%	0.0%	$6,749	$56,130	10.7%	89.3%
Apr	$37,533	$17,796	67.8%	32.2%	$195,706	$3,807	98.1%	1.9%
May	$271,955	$130,162	67.6%	32.4%	$484,756	$24,995	95.1%	4.9%
Jun	$906,532	$3,932	99.6%	0.4%	$1,389,134	$34,125	97.6%	2.4%
Jul	$379,570	$539	99.9%	0.1%	$3,395,517	$173,846	95.1%	4.9%
Aug	$87,943	$191	99.8%	0.2%	$1,156,156	$20,741	98.2%	1.8%
Sep	$19,670	$0	100.0%	0.0%	$188,429	$0	100.0%	0.0%
Oct	$48,863	$857	98.3%	1.7%				
Nov	$15,524	$0	100.0%	0.0%				
Dec	$45,102	$8,898	83.5%	16.5%				
Total	$1,943,507	$153,732	92.7%	7.3%	$6,840,104	$340,523	95.3%	4.7%

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 nine months of 2012 were $49.3 million, 192.4 percent higher than the $16.9 million in the first nine months of 2011. Table 3-25 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 quarter of 2012. The top three zones accounted for 62.8 percent of the total reactive costs, a decrease of 16.1 percentage points from the first nine months of 2011 share. The top three control zones were DPL, PENELEC and ATSI.

Table 3-25 Monthly reactive service credits: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-21)

	2011	2012	Change	Percentage Change
Jan	$1,546,278	$2,920,441	$1,374,163	88.9%
Feb	$1,912,027	$13,108,018	$11,195,991	585.6%
Mar	$1,438,306	$6,731,994	$5,293,688	368.1%
Apr	$2,077,101	$4,518,321	$2,441,220	117.5%
May	$2,712,293	$5,392,085	$2,679,792	98.8%
Jun	$1,868,004	$5,132,979	$3,264,975	174.8%
Jul	$929,807	$2,955,586	$2,025,779	217.9%
Aug	$1,696,735	$4,112,186	$2,415,451	142.4%
Sep	$2,688,094	$4,458,794	$1,770,700	65.9%
Oct	$15,523,789			
Nov	$7,105,062			
Dec	$1,790,778			
Total	$16,868,645	$49,330,404	$32,461,759	192.4%

© 2012 Monitoring Analytics, LLC

Table 3-26 shows the distribution of credits for each category of reactive service credit received by each unit type (each column sums to 100 percent). In the first nine months of 2012 combined cycles and coal steam turbines received 82.1 percent of all credits, 8.5 percentage points higher than the share received in the first nine months of 2011, combustion turbines received 14.4 percent, 8.2 percentage points lower than the share received in the first nine months of 2011.

Table 3-26 Reactive service credits by unit type: January through September 2012 (See 2011 SOM, Table 3-22)

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Locally Requested Reactive Service	Total Reactive Credits
Battery	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	16.6%	6.4%	0.0%	0.0%	16.1%
Combustion Turbine	14.7%	4.3%	100.0%	0.0%	14.4%
Diesel	2.0%	0.0%	0.0%	100.0%	1.9%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	65.2%	86.0%	0.0%	0.0%	66.0%
Steam - Others	1.5%	3.3%	0.0%	0.0%	1.6%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%
Total	$46,880,384	$2,291,235	$121,519	$37,266	$49,330,404

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 nine months of 2012 compared to the first nine months of 2011. Table 3-27 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 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. The top 20 units received 33.7 percent of total operating reserve credits in the first nine months of 2012.

Table 3-27 Top 10 operating reserve credits units (By percent of total system): Calendar years 2001 through September 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	21.1%	0.7%

Table 3-20 shows the distribution of operating reserve credits to units by zone. The AEP Control Zone had the largest share of credits with 19.8 percent, the BGE and Pepco Control Zones combined had the second highest with 15.8 percent, and the Dominion Control Zone had the third highest with a 15.7 percent share.

Table 3-28 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories. The shares of the top 10 organizations in all categories separately were above 80.0 percent.

© 2012 Monitoring Analytics, LLC

Table 3-28 Top 10 units and organizations operating reserve credits: January through September 2012 (New Table)

	Top 10 units		Top 10 organizations	
Category	Credits	Credits Share	Credits	Credits Share
Day-Ahead	$43,922,337	51.5%	$80,804,042	94.7%
Balancing	$64,867,193	33.4%	$171,340,678	88.2%
Canceled Resources	$2,572,219	77.6%	$3,244,269	97.8%
Local Constraints Control	$7,543,458	99.3%	$7,564,851	99.6%
Lost Opportunity Cost	$41,504,224	28.3%	$128,026,650	87.4%
Synchronous Condensing	$45,095	84.9%	$53,115	100.0%
Reactive Services	$33,769,238	68.5%	$45,326,877	91.9%
Total Operating Reserve Credits	$92,274,586	21.1%	$364,949,777	83.5%

HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832.

Table 3-29 Daily operating reserve credits HHI: January through September 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	3868	10000	10000	2847	10000	3832	5819	1676
Minimum	1044	10000	10000	996	10000	614	1009	521
Maximum	10000	10000	10000	7826	10000	10000	10000	5149
Highest market share (One day)	0.0%	100.0%	100.0%	88.2%	100.0%	100.0%	100.0%	70.7%
Highest market share (All days)	31.1%	60.3%	99.2%	27.5%	99.7%	25.3%	37.1%	16.8%
Numbers of Days	273	3	6	274	52	273	97	274
Days with HHI > 1800	249	3	6	246	52	228	84	94
% of Days with HHI > 1800	91.2%	100.0%	100.0%	89.8%	100.0%	83.5%	86.6%	34.3%
Days with HHI = 10000	4	3	6	0	52	5	36	0
% of Days with HHI = 10000	1.5%	100.0%	100.0%	0.0%	100.0%	1.8%	37.1%	0.0%

Table 3-30 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2012, 45.0 percent of all credits paid to these units were allocated to deviations while the remaining 55.0 percent were paid for reliability reasons.

Table 3-30 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2012 (See 2011 SOM, Table 3-35)

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$404,209	$6,677,489	$28,610,093	$26,064,727	$3,110,674	$0	$64,867,193
Share	0.6%	10.3%	44.1%	40.2%	4.8%	0.0%	100.0%

© 2012 Monitoring Analytics, LLC

Day-Ahead Unit Commitment for Reliability

The Day-Ahead Energy Market is solved with the objective function of minimizing total production cost of meeting day-ahead load plus reserves subject to security constraints.[11] Under some circumstances PJM deviates from the optimal day-ahead solution when PJM is reasonably certain that specific units will be needed for reliability reasons in real time. In that case, PJM schedules the units as must run in the day ahead also. Participants can submit units as self-scheduled (must run), meaning that the unit must be committed.[12] A unit submitted as must run by a participant cannot set LMP and is not eligible for operating reserve credits.

On September 13, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process of combustion turbines in real time. The increase in such scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Markets.

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM put such reliability issues in four categories:[13]

- Voltage issues (high and low).
- Black start requirement (from automatic load rejection units).
- Local contingencies not seen in the Day-Ahead Energy Market.
- Long lead time units not able to be scheduled in the Day-Ahead Energy Market.

The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO region. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions, while day-ahead operating reserve charges are not. In addition, reactive services charges (attributable to units providing voltage support) are paid by real-time load on a zonal level.

The effects of this decision on the operating reserve rates can be seen in Figure 3-1, Figure 3-2 and Figure 3-3. Figure 3-1 shows an increase in the day-ahead operating reserve rates in September 2012, and Figure 3-2 and Figure 3-3 show a decrease in the balancing operating reserve rates. Table 3-31 shows the average operating reserve rates from January 1 through September 12, 2012 and from September 13 through September 30, 2012. The average day-ahead operating reserve rate after September 13 increased by 501.4 percent compared to the average before September 13, while the average Western Region balancing operating reserve rate decreased by 97.8 percent after September 13.

Table 3-31 Average operating reserve rates before and after September 13, 2012 (New Table)

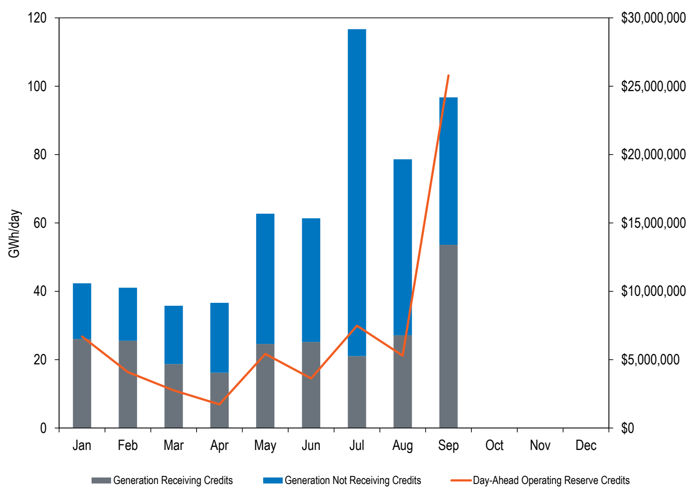
	Rate before September 13 ($/MWh)	Rate after September 13 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1043	0.6275	0.5231	501.4%
RTO Reliability	0.0237	0.0115	(0.0121)	(51.2%)
East Reliability	0.0294	0.0000	(0.0294)	(100.0%)
West Reliability	0.1596	0.0035	(0.1560)	(97.8%)
RTO Deviations	0.9638	0.5164	(0.4474)	(46.4%)
East Deviations	0.2554	0.0000	(0.2554)	(100.0%)
West Deviations	0.1367	0.0000	(0.1367)	(100.0%)
Lost Opportunity Cost	1.3482	0.9918	(0.3564)	(26.4%)
Canceled Resources	0.0318	0.0003	(0.0315)	(99.2%)

11 OATT Attachment K - Appendix § 1.10.8 (a)
12 See "PJM eMkt Users Guide" Section Managing Unit Data (version June, 2012) p. 40.
13 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>. (Accessed October 25, 2012)

© 2012 Monitoring Analytics, LLC

Figure 3-5 shows the total day-ahead generation of units scheduled as must run by PJM and the subset of generation from units scheduled as must run by PJM that received day-ahead operating reserve credits. Figure 3-5 also shows the day-ahead operating reserve credits paid to these units. September had the second highest day-ahead generation from units scheduled as must run by PJM in the first nine months of 2012, surpassed only by July.[14] Before September 13, the average daily day-ahead generation from units scheduled as must run by PJM receiving day-ahead operating reserve credits was 23.6 GWh per day. After September 13, the daily average increased to 67.1 GWh per day. Before September 13, day-ahead operating reserve credits averaged $0.2 million per day and balancing operating reserve credits (including lost opportunity costs and canceled resources credits) averaged $1.3 million per day. After September 13 the day-ahead operating reserve credits averaged $1.2 million per day and the balancing operating reserve credits averaged $0.1 million per day. Although these results show a distinct pattern, the time periods are not strictly comparable since operating reserve credits are historically low during shoulder months.

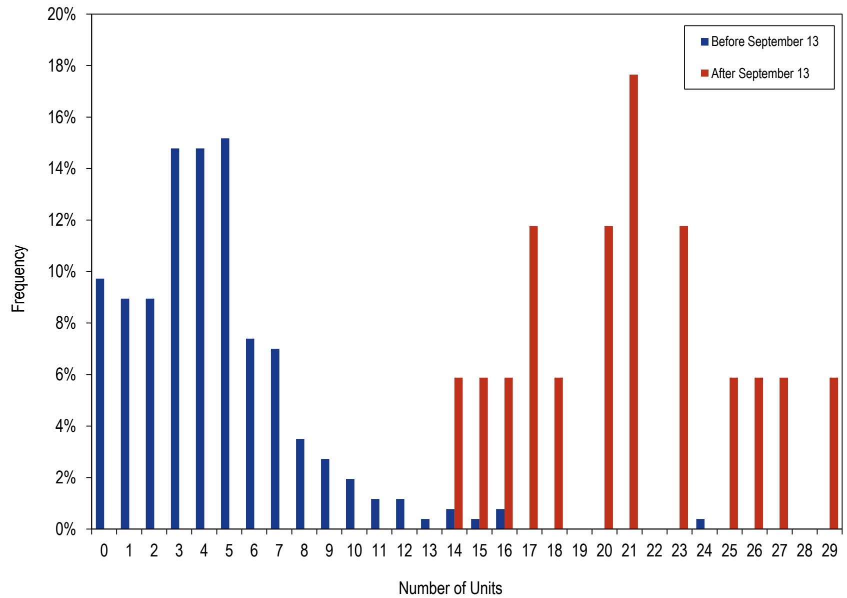
Figure 3-5 Daily average day-ahead generation from units scheduled as must run by PJM: January through September 2012 (New Figure)



14 PJM issued 12 hot weather alerts for the RTO region or the Mid-Atlantic region in July out of a total of 20 in the first nine months for those regions.

PJM scheduled an average of 9.4 units per day as must run before September 13 and on average 4.4 units received day-ahead operating reserve credits. After September 13, PJM scheduled as must run an average of 23.9 units per day and on average 20.8 units received day-ahead operating reserve credits. Figure 3-6 shows the frequency of the number of units scheduled as must run by PJM receiving day-ahead operating reserve credits before and after September 13 in the first nine months 2012. For example, before September 13, 5 units scheduled as must run by PJM received day-ahead operating reserve credits on 15.2 percent of the days. After September 13, 21 units scheduled as must run by PJM received day-ahead operating reserve credits on 17.6 percent of the days.

Figure 3-6 Units scheduled as must run by PJM receiving day-ahead operating reserve credits: January through September 2012 (New Figure)



© 2012 Monitoring Analytics, LLC

On October 10, 2012, PJM presented a problem statement at PJM's Market Implementation Committee (MIC) indicating the need to modify the allocation rules of day-ahead operating reserve charges as a result of the shift of balancing operating reserve charges to the Day-Ahead Energy Market. [15]

The MMU supports the concept of PJM's change in unit commitment since it improves the market's efficiency. The MMU also supports the position that the allocation of operating reserve charges en the Day-Ahead Energy Market must be made consistent with cost causation.

The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process.

The MMU recommends that this stakeholder process address three areas of incorrect allocation that are directly related to and part of the current issue. These areas are related to reactive service costs, black start service costs and the inclusion of no load costs in the lost opportunity cost calculation.[16,17,18] As part of the stakeholder process, the MMU recommends that PJM clearly identify and classify the reasons for operating reserve credits in the Day-Ahead and the Real-Time Energy Markets in order to ensure the correct allocation of the corresponding charges.

15 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>. (Accessed October 25, 2012)
16 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Black Start and Voltage Support Units".
17 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Reactive Service Credits and Operating Reserve Credits".
18 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Lost Opportunity Cost Calculation".

Lost Opportunity Cost Credits

In the first nine months of 2012, lost opportunity cost credits decreased by 6.2 percent, after increasing by 57.5 percent in the first quarter of 2012. In the first nine months of 2012 lost opportunity cost credits decreased by $9.8 million compared to the first nine months of 2011.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or an engine is scheduled to operate in the Day-Ahead Energy Market but is 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 lost opportunity cost based on the desired output.

On April, 2012 PJM implemented a new rule to reduce the unnecessary payment of operating reserve credits to combustion turbines and engines that are committed day ahead but not dispatched in real time. Under the new rule, such units are eligible for lost opportunity cost credits only if their lead times (notification plus start time) are less than or equal to two hours.[19]

Table 3-32 shows, for combustion turbines and engines scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In the first nine months of 2012, PJM scheduled 17,005 GWh from combustion turbines and engines, of which 61.1 percent was not requested by PJM in real time and of which 50.1 percent received lost opportunity cost credits. In the first nine months of 2011, PJM scheduled 7,102 GWh from combustion turbines and engines.

19 See "PJM Manual 28: Operational Agreement Accounting," Revision 53 (Effective July 26, 2012), p. 22.

© 2012 Monitoring Analytics, LLC

Table 3-32 Day-ahead generation from pool-scheduled combustion turbines and engines (GWh): Calendar years 2011 and 2012 (New Table)

	2011			2012		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time receiving LOC Credits
Jan	93	71	51	572	435	373
Feb	92	79	73	753	590	546
Mar	259	237	210	1,408	1,076	921
Apr	175	126	100	1,870	1,431	1,249
May	578	366	276	1,926	1,250	1,047
Jun	1,217	692	492	2,586	1,624	1,235
Jul	2,810	1,275	883	3,898	1,424	990
Aug	1,198	692	524	2,356	1,383	1,122
Sep	680	431	347	1,635	1,169	1,032
Oct	282	266	233			
Nov	351	324	254			
Dec	234	214	156			
Total	7,102	3,970	2,957	17,005	10,382	8,515
Share	100.0%	55.9%	41.6%	100.0%	61.1%	50.1%

In the first nine months of 2012, the top three control zones, AP, ATSI and Dominion combined for 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and engines, 64.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.1 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and engines receive lost opportunity cost credits when scheduled in the Day-Ahead Energy Market and not called in real time on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 3-33 shows the lost opportunity costs credits paid to combustion turbines and engines scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 3-33 shows that $109.1 million or 74.5 percent of all lost opportunity cost credits were paid to combustion turbines and engines that did not run for any hour in real time.

Table 3-33 Lost opportunity cost credits paid to pool-scheduled combustion turbines and engines by scenario (New Table)

	Lost Opportunity Cost Credits	
	From Units That Did Not Run in Real Time	From Units That Ran in Real Time for at least One Hour of Their Day-Ahead Schedule
Jan	$4,857,442	$355,007
Feb	$4,382,996	$154,019
Mar	$9,661,923	$894,042
Apr	$10,846,998	$1,028,201
May	$12,925,885	$2,775,886
Jun	$12,550,655	$2,163,079
Jul	$13,913,026	$13,967,989
Aug	$22,219,006	$3,408,932
Sep	$17,783,763	$2,196,639
Oct		
Nov		
Dec		
Total	$109,141,694	$26,943,793

© 2012 Monitoring Analytics, LLC

PJM may not run units in real time if the real-time value of that energy (defined as generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs).

Table 3-34 shows the total day-ahead generation from combustion turbines and engines that were not called in real time by PJM and received lost opportunity cost credit. Table 3-34 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first nine months of 2012, 30.8 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remainder 69.2 percent was noneconomic.[20]

Table 3-34 Day-ahead generation (GWh) from pool-scheduled turbines and engines receiving lost opportunity cost credits by value (New Table)

	Day-Ahead Generation Not Requested in Real Time		
	Economic Scheduled Generation	Noneconomic Scheduled Generation	Total
Jan	136	309	445
Feb	248	422	670
Mar	287	805	1,092
Apr	329	1,126	1,455
May	363	875	1,237
Jun	663	838	1,501
Jul	402	826	1,228
Aug	397	945	1,342
Sep	305	880	1,185
Oct			
Nov			
Dec			
Total	3,130	7,027	10,156
Share	30.8%	69.2%	100.0%

20 The total generation in Table 3-34 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-32 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-34 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[21] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU has not recommended these to the MIC for consideration.

- Unit Schedule Used: Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.
- No load and startup costs: Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real-time. Generating units do not incur no load or startup costs if they are not dispatched in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the energy offer is subtracted to calculate the actual value of the opportunity lost by the unit.
- Day-Ahead LMP: Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the day-ahead market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the day-ahead market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it

21 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (April 4, 2012)

should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost.

- Offer Curve: Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the desired or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between LMP and the offer curve) when calculating the lost opportunity cost in the energy market for units scheduled in day ahead but which are backed down or not dispatched in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real-time by PJM should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between the actual and desired output points. Units scheduled in day-ahead and not dispatched in real-time should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between zero output and scheduled output points.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' price schedule if available and the unit does not fail the TPS test.

Table 3-35 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first nine months of 2012, for the two categories of lost opportunity cost credits. Energy market lost opportunity cost credits would have been reduced by $46.6 million, or 31.8 percent, if all these changes had been implemented.[22]

22 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

Table 3-35 Impact on energy market lost opportunity cost credits of rule changes: January through September 2012 (New Table)

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$10,428,015	$136,085,488	$146,513,503
Impact 1: Committed Schedule	$689,492	$21,523,234	$22,212,726
Impact 2: Eliminating DA LMP	NA	($3,000,395)	($3,000,395)
Impact 3: Using Offer Curve	($516,221)	$18,731,749	$18,215,528
Impact 4: Including No Load Cost	NA	($63,548,330)	($63,548,330)
Impact 5: Including Startup Cost	NA	($20,448,955)	($20,448,955)
Net Impact	$173,271	($46,742,697)	($46,569,426)
Credits After Changes	$10,601,286	$89,342,791	$99,944,077

Table 3-36 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy market lost opportunity cost credits would have been reduced by $55.0 million, or 37.5 percent, if the two proposed modifications had been implemented.

Table 3-36 Impact on energy market lost opportunity cost credits of proposed rule changes: January through September 2012 (New Table)

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$10,428,015	$136,085,488	$146,513,503
Impact 1: Committed Schedule	$689,492	$21,523,234	$22,212,726
Impact 2: Including No Load Cost	NA	($58,674,824)	($58,674,824)
Impact 3: Including Startup Cost	NA	($18,501,959)	($18,501,959)
Net Impact	$689,492	($55,653,549)	($54,964,057)
Credits After Changes	$11,117,507	$80,431,939	$91,549,446

Black Start and Voltage Support Units

Certain units located in the Western Region zone are relied on for their black start capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start 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 are run out-of-merit to comply with

© 2012 Monitoring Analytics, LLC

black start requirements or voltage support in order to correctly assign the associated charges.

On August 8, 2012, the PJM Market Implementation Committee (MIC) endorsed a charge presented by the MMU to prepare a proposal to correct the allocation of make whole payments (in the form of operating reserve charges) attributable to the operation of units for black start requirement and black start testing.[23]

Credits categorized as reliability paid to units in the Western Region increased considerably in the first nine months of 2012 compared to the first nine months of 2011 because of these units used for black start 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 nine months of 2012, 51.5 percent of all up-to congestion transactions were profitable.[24]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve 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 reserve charges as actually occurred when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, only 28.5 percent of all up-to congestion transactions would have been made if such transactions had to pay operating reserve charges and the proportional distribution of profitable and unprofitable transactions remained the same.

23 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120808/20120808-minutes.ashx>. (Accessed October 16, 2012)

24 An up-to congestion transaction profitability is based on its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

Table 3-37 shows the impact that including the identified 28.5 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 nine months of 2012. For example, the RTO deviations rate would have been reduced by 54.8 percent.

Table 3-37 Up-to Congestion Transactions Impact on the Operating Reserve Rates: January through September 2012 (See 2011 SOM, Table 3-44)

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1350	0.1220	(0.0130)	(9.6%)
RTO Deviations	0.9398	0.4250	(0.5147)	(54.8%)
East Deviations	0.2424	0.1478	(0.0946)	(39.0%)
West Deviations	0.1289	0.0442	(0.0847)	(65.7%)
Lost Opportunity Cost	1.3291	0.6011	(0.7279)	(54.8%)
Canceled Resources	0.0301	0.0136	(0.0165)	(54.8%)

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[25] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve 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 reserve are paid by deviations from day-

25 OA Schedule 1 § 3.2.3B(f).

ahead or real-time load plus exports depending on the allocation process rather than by zone.[26]

In the first nine months of 2012, units providing reactive services were paid $19.4 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 94.6 percent were paid by deviations in the RTO Region, 5.1 percent by real-time load and real-time exports in the RTO Region and the remaining 0.3 percent by real-time load and real-time exports in the Western Region.

Table 3-38 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-38 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through September 2012 (New Table)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Credits to Units Providing Reactive Services	Current	($/MWh)	Percentage
Reliability	RTO	0.0213	0.0230	0.0016	7.7%
	East	0.0277	0.0277	0.0000	0.0%
	West	0.1504	0.1505	0.0002	0.1%
Deviation	RTO	0.7736	0.9398	0.1662	21.5%
	East	0.2424	0.2424	0.0000	0.0%
	West	0.1289	0.1289	0.0000	0.0%

26 The MMU presented this issue at the PJM Market Implementation Committee on October 10, 2012. See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge" from the PJM's MIC meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>. (Accessed October 16, 2012)

© 2012 Monitoring Analytics, LLC