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.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

  Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 48.3 percent, reactive services charges were 29.8 percent, synchronous condensing charges were 0.06 percent and black start services charges were 10.6 percent of total operating reserve charges in 2013.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh. The day-ahead operating reserve rate including unallocated congestion charges averaged $0.118 per MWh. The balancing operating reserve reliability rates averaged $0.052, $0.031 and $0.004 per MWh for the RTO, Eastern and Western Regions. The balancing operating reserve deviation rates averaged $0.886, $2.193 and $0.118 per MWh for the RTO, Eastern and Western Regions. The lost opportunity cost rate averaged $0.861 per MWh and the canceled resources rate averaged $0.001 per MWh.

- **Reactive Service Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $1.952, $1.557 and $0.631 per MWh. The reactive transfer interface support rate averaged $0.141 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 46.7 percent of all day-ahead generator credits and 52.6 percent of all balancing generator credits. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 91.4 percent of all reactive services credits.

- **Economic and Noneconomic Generation.** In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first nine months of 2013, 81.6 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.1 percent by transactions at hubs and aggregates and 12.3 percent by transactions at interfaces.

- Generators in the Eastern Region paid 15.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 75.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 13.9 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 24.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 9.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.96 percent of all credits.

1 See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 99-103 for a full description of how operating reserve credits and charges are calculated.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 34.5 percent of all credits. The top 10 organizations received 86.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5343, balancing operating reserves HHI was 3927 and lost opportunity cost HHI was 4699.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 65.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first nine months of 2013, lost opportunity cost credits decreased by $66.0 million compared to the first nine months of 2012. In the first nine months of 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.6 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 53.9 percent of the credits day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In the first nine months of 2013, lost opportunity cost credits would have been reduced by an additional $21.3 million, or 26.1 percent, if all changes proposed by the MMU had been implemented.
- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in the first nine months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.218 per MWh, which is $3.564 per MWh, 94.2 percent, less than the actual average rate paid.

Recommendations

- The MMU recommends that the impact of physical constraints of all types be reflected in market prices to the maximum extent possible, reducing the necessity for out of market operating reserve payments and improving the efficiency of market prices.
- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - 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.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and

diesels scheduled in the Day-Ahead Energy Market but not called in real time.

— The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by location and the detailed reasons for the level of operating reserve payments by location in the PJM region.

Conclusion

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

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

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

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, the details of the rules which define payments 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. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[2] 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 netting of transactions against internal bilateral transactions should be eliminated.

Overall, the MMU recommends that the goal 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 goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. 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.

Credits and Charges Categories

Operating reserves include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

2 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone and Non-zone Peak Transmission Use

Operating Reserve Results

Operating Reserve Charges

Table 4-3 shows total operating reserve charges for the first nine months of 2012 and 2013.[3] Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

Table 4-3 Total operating reserve charges: January through September 2012 and 2013

	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change
Total Operating Reserve Charges	$488,178,103	$652,904,574	$164,726,471	33.7%
Operating Reserve as a Percent of Total PJM Billing	2.2%	2.6%	0.4%	17.6%

Total operating reserve charges in the first nine months of 2013 were $652.9 million, up from the total of $488.2 million in the first nine months of 2012. Table 4-4 compares monthly operating reserve charges by category for 2012 and 2013. The increase of 33.7 percent in the first nine months of 2013 is comprised of a 13.7 percent decrease in day-ahead operating reserve charges, an 10.7 percent decrease in balancing operating reserve charges, a 294.0 percent increase in reactive services charges, a 453.1 percent increase in synchronous condensing charges and $68.9 million of black start services charges. Black start services operating reserve charges accounted for 10.6 percent of all operating reserve charges.

Table 4-4 Monthly operating reserve charges: 2012 and 2013

	2012						2013					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$8,311,574	$27,341,331	$2,934,337	$27,037	$0	$38,614,279	$11,161,579	$79,219,217	$23,604,234	$1,873	$8,453,397	$122,440,301
Feb	$5,858,308	$24,877,526	$13,108,017	$18,592	$0	$43,862,444	$5,126,444	$66,886,126	$17,624,984	$0	$6,988,632	$96,626,185
Mar	$3,852,873	$29,758,387	$6,731,994	$1,648	$0	$40,344,903	$6,900,582	$17,493,458	$14,350,138	$0	$6,768,618	$45,512,796
Apr	$2,967,302	$34,172,651	$4,521,280	$0	$0	$41,661,233	$5,712,618	$23,089,668	$13,670,581	$0	$9,242,815	$51,715,682
May	$7,956,965	$43,761,595	$5,392,428	$0	$0	$57,110,987	$10,437,734	$22,560,252	$17,214,142	$959	$8,667,665	$58,880,751
Jun	$6,973,548	$46,011,835	$5,133,009	$0	$0	$58,118,391	$9,350,026	$17,900,744	$22,055,239	$0	$7,954,457	$57,260,466
Jul	$11,773,179	$66,931,225	$2,960,922	$0	$0	$81,665,326	$8,309,568	$44,202,434	$20,305,968	$393,413	$5,858,221	$79,069,604
Aug	$8,692,702	$47,785,303	$4,112,186	$0	$0	$60,590,191	$4,159,471	$14,124,338	$30,738,131	$0	$7,584,998	$56,606,938
Sep	$28,877,736	$32,849,356	$4,458,891	$24,366	$0	$66,210,349	$12,452,502	$30,079,327	$34,875,468	$0	$7,384,554	$84,791,851
Oct	$23,235,166	$26,884,798	$1,253,642	$38,762	$0	$51,412,367						
Nov	$18,077,440	$24,488,338	$120,820	$0	$0	$42,686,598						
Dec	$7,868,340	$27,902,608	$25,282,650	$37,845	$8,384,651	$69,476,094						
Total (Jan - Sep)	$85,264,187	$353,489,210	$49,353,063	$71,643	$0	$488,178,103	$73,610,524	$315,555,563	$194,438,886	$396,245	$68,903,357	$652,904,574
Share (Jan - Sep)	17.5%	72.4%	10.1%	0.0%	0.0%	100.0%	11.3%	48.3%	29.8%	0.1%	10.6%	100.0%
Total	$134,445,132	$432,764,953	$76,010,175	$148,250	$8,384,651	$651,753,162						
Share	20.6%	66.4%	11.7%	0.0%	1.3%	100.0%						

3 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 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 July 9, 2013.

Table 4-5 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for load response and day-ahead operating reserve charges attributable to unallocated congestion charges.[4,5,6] Day-ahead operating reserve charges decreased 13.7 percent or $11.7 million in the first nine months of 2013 compared to the first nine months of 2012. Day-ahead operating reserve charges attributable to generators and imports decreased by $31.7 million in the first nine months of 2013 compared to the first nine months of 2012, but unallocated congestion charges increased from zero in the first nine months of 2012 to $20.0 million in the first nine months of 2013. These charges are paid by day-ahead demand, day-ahead exports and decrement bids.

Table 4-6 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for load response and balancing local constraint charges. In the first nine months of 2013, balancing operating reserve deviation charges accounted for 86.8 percent of all balancing operating reserve charges, 8.7 percentage points higher than in the first nine months of 2012.

Table 4-5 Day-ahead operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Day-Ahead Operating Reserve Charges	$85,264,108	$53,563,633	($31,700,475)	100.0%	72.8%
Day-Ahead Operating Reserve Charges for Load Response	$78	$3,561	$3,483	0.0%	0.0%
Unallocated Congestion Charges	$0	$20,043,330	$20,043,330	0.0%	27.2%
Total	$85,264,187	$73,610,524	($11,653,663)	100.0%	100.0%

Table 4-6 Balancing operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Balancing Operating Reserve Reliability Charges	$69,634,249	$41,394,880	($28,239,369)	19.7%	13.1%
Balancing Operating Reserve Deviation Charges	$276,011,360	$273,902,539	($2,108,821)	78.1%	86.8%
Balancing Operating Reserve Charges for Load Response	$312,874	$182,506	($130,368)	0.1%	0.1%
Balancing Local Constraint Charges	$7,530,727	$75,638	($7,455,089)	2.1%	0.0%
Total	$353,489,210	$315,555,563	($37,933,647)	100.0%	100.0%

4 Attributable means that these charges are the result of credits paid to the identified resources.

5 See OATT Attachment K - Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves ten times, totaling $26.9 million, of which 74.6 percent was charged in the first nine months of 2013.

6 See Section 12, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 4-7 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first nine months of 2013, 70.3 percent of all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 24.9 percentage points compared to the share in the first nine months of 2012.

Table 4-7 Balancing operating reserve deviation charges: January through September 2012 and 2013

Charge attributable to	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Make Whole Payments to Generators and Imports	$125,373,701	$192,650,537	$67,276,836	45.4%	70.3%
Energy Lost Opportunity Cost	$147,319,461	$81,117,893	($66,201,568)	53.4%	29.6%
Canceled Resources	$3,318,199	$134,109	($3,184,090)	1.2%	0.0%
Total	$276,011,360	$273,902,539	($2,108,821)	100.0%	100.0%

Table 4-8 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012.

Table 4-8 Additional operating reserve charges: January through September 2012 and 2013

Type	Jan - Sep 2012	Jan - Sep 2013	Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Reactive Services Charges	$49,353,063	$194,438,886	$145,085,823	99.9%	73.7%
Synchronous Condensing Charges	$71,643	$396,245	$324,602	0.1%	0.2%
Black Start Services Charges	$0	$68,903,357	$68,903,357	0.0%	26.1%
Total	$49,424,706	$263,738,487	$214,313,781	100.0%	100.0%

Table 4-9 and Table 4-10 show the amount and percentages of regional balancing charges allocation for the first nine months of 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints and resources providing quick start reserve.

In the first nine months of 2013, regional balancing operating reserve charges decreased by $30.3 million compared to the first nine months of 2012. Balancing operating reserve reliability charges decreased by $28.2 million or 40.6 percent and balancing operating reserve deviation charges decreased by $2.1 million or 0.8 percent. Total balancing operating reserve deviation charges decreased in the first nine months of 2013 compared to the first nine months of 2012, but in the first nine months of 2013, deviation charges in the Eastern Region increased by $89.3 million compared to the first nine months of 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[7,8] The remaining two deviation categories decreased by $91.4 million.

7 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx>.
8 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (MIC) (March 6, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx>.

Table 4-9 Regional balancing charges allocation: January through September 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13,502,197	3.9%	$7,743,241	2.2%	$45,958,032	13.3%	$67,203,469	19.4%
	Real-Time Exports	$391,518	0.1%	$163,838	0.0%	$1,875,423	0.5%	$2,430,780	0.7%
	Total	$13,893,715	4.0%	$7,907,079	2.3%	$47,833,455	13.8%	$69,634,249	20.1%
Deviation Charges	Demand	$153,237,456	44.3%	$9,169,952	2.7%	$3,801,990	1.1%	$166,209,398	48.1%
	Supply	$45,008,686	13.0%	$2,962,187	0.9%	$898,808	0.3%	$48,869,681	14.1%
	Generator	$56,717,131	16.4%	$2,549,568	0.7%	$1,665,582	0.5%	$60,932,281	17.6%
	Total	$254,963,272	73.8%	$14,681,707	4.2%	$6,366,381	1.8%	$276,011,360	79.9%
Total Regional Balancing Charges		$268,856,987	77.8%	$22,588,786	6.5%	$54,199,836	15.7%	$345,645,609	100%

Table 4-10 Regional balancing charges allocation: January through September 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$30,442,807	9.7%	$8,760,222	2.8%	$1,240,266	0.4%	$40,443,294	12.8%
	Real-Time Exports	$692,053	0.2%	$228,044	0.1%	$31,489	0.0%	$951,586	0.3%
	Total	$31,134,859	9.9%	$8,988,266	2.9%	$1,271,755	0.4%	$41,394,880	13.1%
Deviation Charges	Demand	$97,950,152	31.1%	$64,160,776	20.3%	$2,942,771	0.9%	$165,053,699	52.3%
	Supply	$26,694,910	8.5%	$17,299,379	5.5%	$833,154	0.3%	$44,827,443	14.2%
	Generator	$40,005,197	12.7%	$22,509,431	7.1%	$1,506,770	0.5%	$64,021,397	20.3%
	Total	$164,650,258	52.2%	$103,969,585	33.0%	$5,282,696	1.7%	$273,902,539	86.9%
Total Regional Balancing Charges		$195,785,117	62.1%	$112,957,851	35.8%	$6,554,450	2.1%	$315,297,419	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 region. See Table 4-1 for how these charges are allocated.[9]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2012 and the first nine months of 2013. The average rate in the first nine months of 2013 was $0.086 per MWh, $0.049 per MWh lower than the average in the first nine months of 2012. The highest rate occurred on July 16, when the rate reached $0.646 per MWh, 25.9 percent lower than the $0.871 per MWh reached during the first nine months of 2012, on September 20. Figure 4-1 also shows the daily day-ahead operating reserve rates including the congestion charges allocated to day-ahead operating reserves. The average rate in the first nine months of 2013, including unallocated congestion charges, was $0.118 per MWh, 37.4 percent higher than the day-ahead operating reserve rate without unallocated congestion charges.

The increase in the day-ahead operating reserve rate on July 16 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 25 percent of their scheduled run time. On July 16, 83 units received day-ahead operating reserve credits, forty nine were noneconomic for their entire scheduled run time and six were economic for 25 percent or less of their scheduled run time, the highest number of units scheduled noneconomic in day ahead in 2013. On July 16, fifty six units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; thirty four of these units received enough net revenues from day-ahead scheduling reserves to cover their total offer, which would have resulted in zero day-ahead operating reserve credits if the revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[10] The day-ahead operating reserve rate for July 16 would have been $0.244 per MWh or 62.2 percent lower if the offset had been credited. Similar circumstances occurred on July 17, 18, 19 and September 11.

9 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost rates and the canceled resources rate to the deviation rate for the RTO region since these three charges are allocated following the same rules.

10 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2012 and 2013[11]

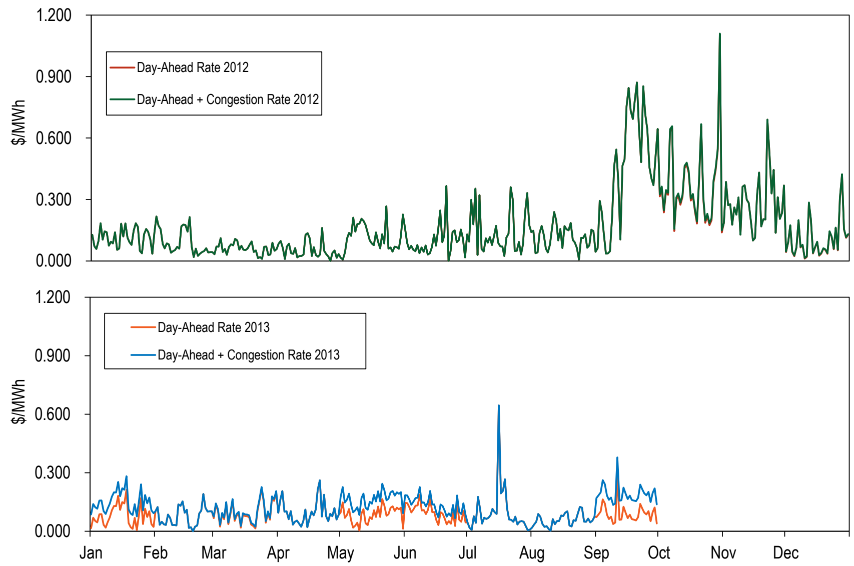


Figure 4-2 shows the RTO and the regional reliability rates for 2012 and the first nine months of 2013. The average daily RTO reliability rate was $0.052 per MWh. The highest RTO reliability rate of the first nine months of 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.031 per MWh. The highest Eastern Region reliability rate in the first nine months of 2013 also occurred on January 23, when the rate reached $2.887 per MWh.

The spikes in both rates were the result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system which resulted in overloads on the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their minimum run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[12]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013

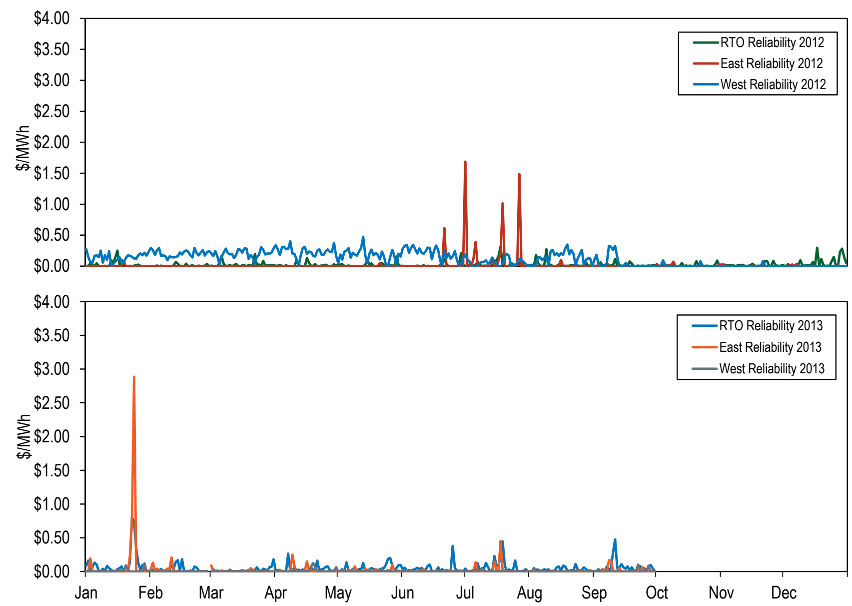


Figure 4-3 shows the RTO and regional deviation rates for 2012 and the first nine months of 2013. The average daily RTO deviation rate was $0.886 per MWh. The highest daily rate in the first nine months of 2013 occurred on January 23, when the RTO deviation rate reached $10.227 per MWh. Between

11 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 of certain operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market. See *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

12 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

January 1 and February 21, 2013, the Eastern Region deviation rate averaged $10.045 per MWh, reaching its highest rate on February 9, when it reached $32.876 per MWh. Prior to the 2012 – 2013 winter, the highest daily Eastern Region deviation rate had been $5.739 per MWh. The spikes in the Eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and Eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals).[13] The spike in the RTO deviation rate on September 11 was mainly a result of the commitment in real time of combustion turbines that did not clear the Day-Ahead Energy Market and did not recover their total offer through energy and ancillary services revenues. This commitment was triggered by the issuance of a maximum generation action on that day.

13 See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Balancing Operating Reserve Cost Allocation" p.101 for a more detailed description of how the cost of balancing operating reserves are allocated.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

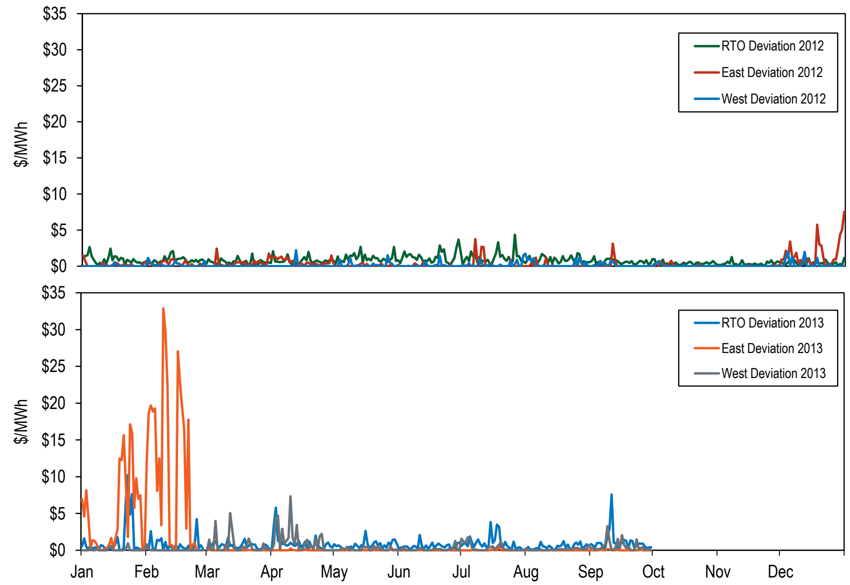


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and the first nine months of 2013. The lost opportunity rate averaged $0.861 per MWh. The highest lost opportunity cost rate occurred on September 11, when it reached $8.370 per MWh.

The LOC rate has shown smaller spikes in the first nine months of 2013 compared to the first nine months of 2012. In the first nine months of 2013 the top ten LOC daily rates averaged $5.001 per MWh, $3.078 per MWh less than the average of the top 10 LOC rates in the first nine months of 2012. The top LOC rates in the first nine months of 2013 occurred between July 16 and July 18 and between September 10 and 11. The main reasons for these spikes continue to be combustion turbines and diesels scheduled in day ahead and not called in real time. Another reason was the need to reduce the output of steam units due to transmission line limits. On September 11, the manual dispatch of a small number of units in the ATSI control zone was responsible for 54.7 percent of the LOC rate, the units were manually dispatched down because of a constraint within ATSI during hours when the ATSI interface was binding and DR was setting ATSI prices at $1,800 per MWh.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013

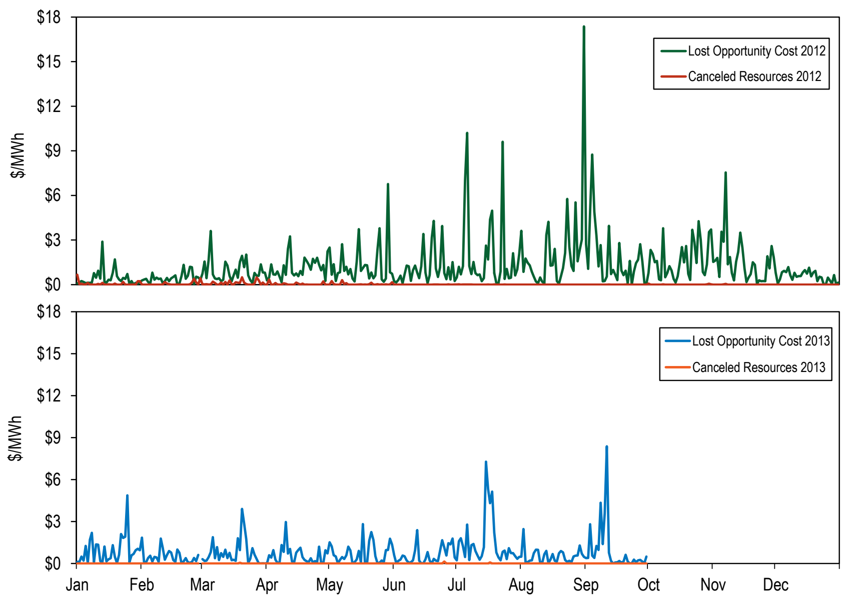


Table 4-11 shows the average rates for each region in each category for the first nine months of 2012 and 2013.

Table 4-11 Operating reserve rates ($/MWh): January through September 2012 and 2013

Rate	Jan - Sep 2012 ($/MWh)	Jan - Sep 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.135	0.086	(0.049)	(36.5%)
Day-Ahead with Unallocated Congestion	0.135	0.118	(0.017)	(12.7%)
RTO Reliability	0.023	0.052	0.029	125.5%
East Reliability	0.028	0.031	0.004	13.6%
West Reliability	0.151	0.004	(0.146)	(97.3%)
RTO Deviation	0.947	0.886	(0.061)	(6.5%)
East Deviation	0.242	2.193	1.951	804.8%
West Deviation	0.129	0.118	(0.011)	(8.2%)
Lost Opportunity Cost	1.337	0.861	(0.475)	(35.6%)
Canceled Resources	0.030	0.001	(0.029)	(95.3%)

Table 4-12 shows the operating reserve cost of a 1 MW transaction during the first nine months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $3.782 per MWh with a maximum rate of $33.056 per MWh, a minimum rate of $0.147 per MWh and a standard deviation of $5.607 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-12 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-12 Operating reserve rates statistics ($/MWh): January through September 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	33.024	3.663	0.024	5.613
	DEC	33.056	3.782	0.147	5.607
	DA Load	0.646	0.119	0.000	0.072
	RT Load	3.610	0.076	0.000	0.250
	Deviation	33.024	3.663	0.024	5.613
West	INC	15.997	1.726	0.024	1.991
	DEC	16.376	1.844	0.130	2.010
	DA Load	0.646	0.119	0.000	0.072
	RT Load	0.802	0.053	0.000	0.092
	Deviation	15.997	1.726	0.024	1.991

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer. Even though reactive services rates are not published, a local voltage support rate for each control zone can be calculated, also a reactive transfer interface support rate can calculated for the entire RTO.

Table 4-13 shows the reactive services rates associated with local voltage support for the first nine months of 2012 and 2013. Table 4-13 shows that in the first nine months of 2013 the DPL control zone had the highest rate. Real-time load in the DPL control zone paid an average of $1.952 per MWh for reactive services associated with local voltage support, $1.095 or 127.8 percent higher than the average rate paid in the first nine months of 2012.

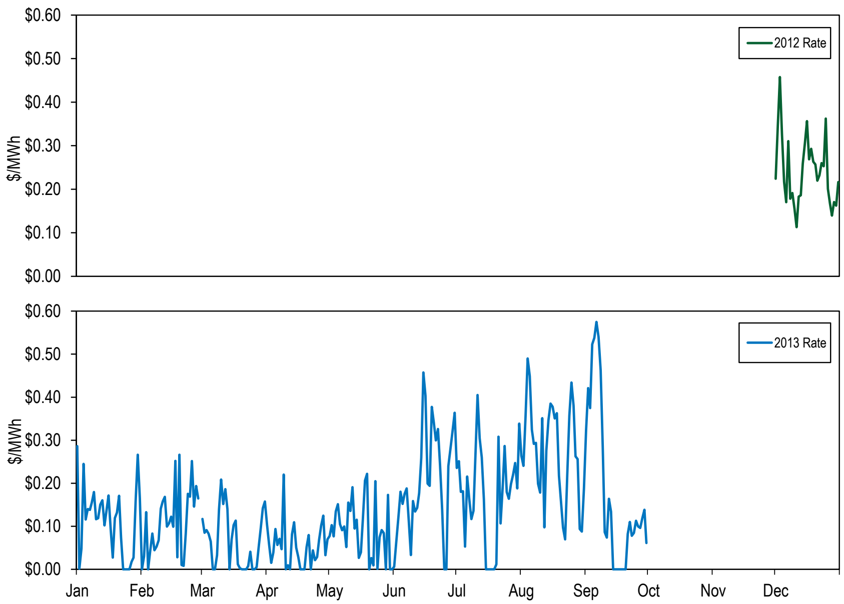
Table 4-13 Local voltage support rates: January through September 2012 and 2013

Control Zone	Jan - Sep 2012 ($/MWh)	Jan - Sep 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.069	0.269	0.200	288.6%
AEP	0.005	0.034	0.029	529.9%
AP	0.002	0.001	(0.001)	(46.6%)
ATSI	0.219	0.631	0.412	188.5%
BGE	0.107	0.279	0.173	161.8%
ComEd	0.001	0.002	0.001	108.8%
DAY	0.003	0.000	(0.003)	(100.0%)
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.001	0.000	(0.001)	(100.0%)
Dominion	0.014	0.030	0.015	106.1%
DPL	0.857	1.952	1.095	127.8%
EKPC	NA	0.010	NA	NA
JCPL	0.131	0.426	0.294	224.2%
Met-Ed	0.023	0.025	0.002	8.2%
PECO	0.031	0.021	(0.010)	(32.9%)
PENELEC	0.435	1.557	1.122	258.1%
Pepco	0.077	0.011	(0.066)	(85.3%)
PPL	0.083	0.025	(0.058)	(69.4%)
PSEG	0.145	0.264	0.119	82.3%
RECO	0.018	0.002	(0.016)	(89.7%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2012 and 2013. PJM began allocating these operating reserve charges to reactive services on December 1, 2012. This rate is charged to real-time load in the entire RTO. The average rate in the first nine months of 2013 was $0.141 per MWh. The increase in this reactive rate in the second half of 2013 has been in part a result of the inclusion of FMU adders in the cost-based offers of some of the units routinely used for this service. These units are eligible for FMU adders because they are being offer capped.[14]

14 See OATT Attachment K - Appendix § 6.4.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2012 and 2013



Operating Reserve Determinants

Table 4-14 shows the determinants used to allocate the regional balancing operating reserve charges for the first nine months of 2012 and 2013. Total real-time load and real-time exports were 3,803,726 MWh or 0.6 percent lower in the first nine months of 2013 compared to the first nine months of 2012. Total deviations summed across the demand, supply, and generator categories were lower in the first nine months of 2013 compared to the first nine months of 2012 by 16,033,525 MWh or 14.5 percent.

Table 4-14 Balancing operating reserve determinants (MWh): January through September 2012 and 2013

		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
Jan - Sep 2012	RTO	583,065,065	19,828,074	602,893,139	65,533,983	20,045,419	24,632,266	110,211,669
	East	277,605,000	7,555,552	285,160,552	37,727,176	11,735,893	11,101,723	60,564,793
	West	305,460,065	12,272,522	317,732,587	27,568,221	8,261,711	13,530,543	49,360,475
Jan - Sep 2013	RTO	583,845,687	15,243,726	599,089,413	55,395,477	14,788,584	23,994,082	94,178,144
	East	278,332,308	7,065,335	285,397,643	29,619,798	7,442,437	10,339,554	47,401,790
	West	305,513,379	8,178,391	313,691,770	24,021,589	6,934,081	13,654,528	44,610,197
Difference	RTO	780,622	(4,584,348)	(3,803,726)	(10,138,506)	(5,256,835)	(638,184)	(16,033,525)
	East	727,308	(490,217)	237,091	(8,107,378)	(4,293,456)	(762,169)	(13,163,003)
	West	53,314	(4,094,131)	(4,040,817)	(3,546,632)	(1,327,630)	123,985	(4,750,277)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-15 shows the different categories by the type of transactions that incur deviations. In the first nine months of 2013, 18.7 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 81.3 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-15 Deviations by transaction type: January through September 2013

		Deviation (MWh)			Share		
Deviation Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	844,002	388,397	455,605	0.9%	0.8%	1.0%
	DECs Only	5,723,448	2,141,817	1,827,541	6.1%	4.5%	4.1%
	Exports Only	4,036,620	2,145,161	1,891,460	4.3%	4.5%	4.2%
	Load Only	36,512,008	21,494,424	15,017,584	38.8%	45.3%	33.7%
	Combination with DECs	4,135,069	2,297,043	1,838,026	4.4%	4.8%	4.1%
	Combination without DECs	4,144,329	1,152,955	2,991,374	4.4%	2.4%	6.7%
Supply	Bilateral Purchases Only	1,057,097	724,654	332,443	1.1%	1.5%	0.7%
	Imports Only	5,963,091	3,048,405	2,914,685	6.3%	6.4%	6.5%
	INCs Only	4,189,936	1,204,325	2,573,544	4.4%	2.5%	5.8%
	Combination with INCs	3,517,793	2,411,681	1,106,112	3.7%	5.1%	2.5%
	Combination without INCs	60,668	53,371	7,296	0.1%	0.1%	0.0%
Generators		23,994,082	10,339,554	13,654,528	25.5%	21.8%	30.6%
Total		94,178,144	47,401,790	44,610,197	100.0%	100.0%	100.0%

Operating Reserve Credits

Table 4-16 shows the totals for each credit category for the first nine months of 2012 and 2013. During the first nine months of 2013, 49.9 percent of total operating reserve credits were in the balancing category. This percentage decreased 22.5 percentage points from the 72.4 percent in the first nine months of 2012. This decrease was in part due to the reallocation of operating reserve credits paid to units providing black start services and reactive services.

Table 4-16 Credits by operating reserve category: January through September 2012 and 2013

Category	Type	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Day-Ahead	Generators	$85,263,553	$53,563,623	($31,699,930)	(37.2%)	17.5%	8.5%
	Imports	$554	$9	($545)	(98.3%)	0.0%	0.0%
	Load Response	$78	$3,561	$3,483	4,451.1%	0.0%	0.0%
Balancing	Canceled Resources	$3,318,201	$134,109	($3,184,091)	(96.0%)	0.7%	0.0%
	Generators	$194,958,978	$234,006,802	$39,047,824	20.0%	39.9%	37.0%
	Imports	$48,972	$38,615	($10,357)	(21.1%)	0.0%	0.0%
	Load Response	$312,803	$182,396	($130,407)	(41.7%)	0.1%	0.0%
	Local Constraints Control	$7,530,727	$75,638	($7,455,089)	(99.0%)	1.5%	0.0%
	Lost Opportunity Cost	$147,319,459	$81,340,487	($65,978,972)	(44.8%)	30.2%	12.8%
Reactive Services	Day-Ahead	$0	$166,557,630	$166,557,630	NA	0.0%	26.3%
	Local Constraints Control	$37,266	$106,287	$69,022	185.2%	0.0%	0.0%
	Lost Opportunity Cost	$2,291,578	$3,492,177	$1,200,599	52.4%	0.5%	0.6%
	Reactive Services	$46,880,481	$24,065,823	($22,814,658)	(48.7%)	9.6%	3.8%
	Synchronous Condensing	$143,738	$216,968	$73,230	50.9%	0.0%	0.0%
Synchronous Condensing		$71,643	$396,245	$324,602	453.1%	0.0%	0.1%
Black Start Services	Day-Ahead	$0	$66,657,166	$66,657,166	NA	0.0%	10.5%
	Balancing	$0	$2,012,039	$2,012,039	NA	0.0%	0.3%
	Testing	$0	$295,411	$295,411	NA	0.0%	0.0%
Total		$488,178,030	$633,144,987	$144,966,957	29.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-17 shows the distribution of total operating reserve credits by unit type for the first nine months of 2012 and 2013. Credits paid to combined cycle units increased 248.3 percent or $121.2 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In the first nine months of 2013, 26.9 percent of all operating reserve credits paid to units were paid to combined cycle units, 16.9 percentage points more than the share in the first nine months of 2012.

Table 4-17 Operating reserve credits by unit type: January through September 2012 and 2013

Unit Type	Jan - Sep 2012	Jan - Sep 2013	Change	Percentage Change	Jan - Sep 2012 Share	Jan - Sep 2013 Share
Combined Cycle	$48,838,002	$170,078,457	$121,240,455	248.3%	10.0%	26.9%
Combustion Turbine	$188,821,294	$127,054,534	($61,766,761)	(32.7%)	38.7%	20.1%
Diesel	$3,557,166	$6,129,798	$2,572,632	72.3%	0.7%	1.0%
Hydro	$270,027	$201,199	($68,828)	(25.5%)	0.1%	0.0%
Nuclear	$337,984	$126,510	($211,473)	(62.6%)	0.1%	0.0%
Steam - Coal	$208,382,502	$290,949,199	$82,566,698	39.6%	42.7%	46.0%
Steam - Other	$33,071,399	$28,764,870	($4,306,529)	(13.0%)	6.8%	4.5%
Wind	$4,537,250	$9,615,836	$5,078,586	111.9%	0.9%	1.5%
Total	$487,815,623	$632,920,404	$145,104,780	29.7%	100.0%	100.0%

Table 4-18 shows the distribution of operating reserve credits by category and by unit type in the first nine months of 2013. Combined cycle units received 46.7 percent of the day-ahead generator credits in the first nine months of 2013, 30.2 percentage points higher than the share received in the first nine months of 2012. Combined cycle units received 52.6 percent of the balancing generator credits in the first nine months of 2013, 41.5 percentage points higher than the share received in the first nine months of 2012. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits, 18.0 percentage points lower than the share received in the first nine months of 2012.

Table 4-18 Operating reserve credits by unit type: January through September 2013

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	46.7%	52.6%	0.0%	13.7%	7.0%	8.3%	0.0%	0.0%
Combustion Turbine	12.3%	21.7%	23.3%	60.1%	73.5%	4.7%	100.0%	0.4%
Diesel	0.1%	0.3%	0.0%	16.2%	0.2%	2.7%	0.0%	0.0%
Hydro	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Steam - Coal	35.7%	15.2%	24.2%	10.1%	7.3%	83.1%	0.0%	99.6%
Steam - Others	5.1%	10.1%	52.6%	0.0%	0.2%	1.1%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	11.7%	0.0%	0.0%	0.0%
Total	$53,563,623	$234,006,802	$134,109	$75,638	$81,340,484	$194,438,886	$396,245	$68,964,616

Table 4-18 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first nine months of 2013, combined cycle and coal units received 91.4 percent of all reactive services credits, 9.4 percentage points higher than the share received in the first nine months of 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.6 percent of all black start services credits.

Economic and Noneconomic Generation[15]

Economic 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 4-19 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.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost.

15 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

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 hourly no load costs 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 for the day or segment. In the first nine months of 2013, 33.0 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 31.8 percent of the real-time generation was eligible for balancing operating reserve credits.[16]

Table 4-19 Day-ahead and real-time generation (GWh): January through September 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	610,622	201,481	33.0%
Real-Time	600,784	191,150	31.8%

Table 4-20 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-20 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-20 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	164,644	36,836	81.7%	18.3%
Real-Time	128,346	62,803	67.1%	32.9%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment scheduled or committed is noneconomic, including no load and startup costs. Table 4-21 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2013, 5.5 percent of the day-ahead generation eligible for operating reserve credits received credits and 8.4 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-21 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	201,481	10,994	5.5%
Real-Time	191,150	15,971	8.4%

Geography of Charges and Credits

Table 4-22 shows the geography of charges and credits in the first nine months of 2013. Table 4-22 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

16 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 operate as requested by PJM are eligible for balancing operating reserve credits.

Table 4-22 Geography of regional charges and credits: January through September 2013[17,18]

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$5,163,143	$3,411,012	($1,752,131)	1.4%	0.9%	1.3%	0.0%
	AEP	$33,513,218	$26,041,796	($7,471,422)	9.1%	7.1%	5.3%	0.0%
	AP - DLCO	$19,341,396	$14,997,060	($4,344,336)	5.2%	4.1%	3.1%	0.0%
	ATSI	$16,408,214	$19,059,648	$2,651,434	4.4%	5.2%	0.0%	1.9%
	BGE - Pepco	$34,304,948	$27,361,959	($6,942,990)	9.3%	7.4%	5.0%	0.0%
	ComEd - External	$28,739,224	$21,202,293	($7,536,931)	7.8%	5.7%	5.4%	0.0%
	DAY - DEOK	$12,793,338	$1,944,208	($10,849,130)	3.5%	0.5%	7.8%	0.0%
	Dominion	$33,866,930	$41,591,240	$7,724,311	9.2%	11.3%	0.0%	5.5%
	DPL	$10,495,875	$12,400,223	$1,904,349	2.8%	3.4%	0.0%	1.4%
	JCPL	$11,674,009	$13,497,524	$1,823,515	3.2%	3.7%	0.0%	1.3%
	Met-Ed	$8,728,397	$3,877,581	($4,850,815)	2.4%	1.1%	3.5%	0.0%
	PECO	$22,048,815	$5,374,156	($16,674,659)	6.0%	1.5%	11.9%	0.0%
	PENELEC	$14,988,170	$4,205,716	($10,782,453)	4.1%	1.1%	7.7%	0.0%
	PPL	$23,317,583	$27,825,550	$4,507,967	6.3%	7.5%	0.0%	3.2%
	PSEG	$24,697,034	$146,255,051	$121,558,017	6.7%	39.6%	0.0%	86.7%
	RECO	$951,869	$0	($951,869)	0.3%	0.0%	0.7%	0.0%
	All Zones	$301,032,162	$369,045,018	$68,012,856	81.6%	100.0%	51.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$2,070,078	$0	($2,070,078)	0.6%	0.0%	1.5%	0.0%
	Dominion	$2,606,602	$0	($2,606,602)	0.7%	0.0%	1.9%	0.0%
	Eastern	$300,965	$0	($300,965)	0.1%	0.0%	0.2%	0.0%
	New Jersey	$762,184	$0	($762,184)	0.2%	0.0%	0.5%	0.0%
	Ohio	$97,084	$0	($97,084)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$1,248,123	$0	($1,248,123)	0.3%	0.0%	0.9%	0.0%
	Western	$15,374,493	$0	($15,374,493)	4.2%	0.0%	11.0%	0.0%
	RTEP B0328 Source	$32	$0	($32)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$22,459,560	$0	($22,459,560)	6.1%	0.0%	16.0%	0.0%
Interfaces	CPLE Imp	$4,079	$0	($4,079)	0.0%	0.0%	0.0%	0.0%
	Hudson	$280,705	$0	($280,705)	0.1%	0.0%	0.2%	0.0%
	IMO	$5,075,114	$0	($5,075,114)	1.4%	0.0%	3.6%	0.0%
	Linden	$1,719,562	$0	($1,719,562)	0.5%	0.0%	1.2%	0.0%
	MISO	$5,979,439	$0	($5,979,439)	1.6%	0.0%	4.3%	0.0%
	Neptune	$924,747	$0	($924,747)	0.3%	0.0%	0.7%	0.0%
	NIPSCO	$22,773	$0	($22,773)	0.0%	0.0%	0.0%	0.0%
	Northwest	$165,190	$0	($165,190)	0.0%	0.0%	0.1%	0.0%
	NYIS	$7,814,553	$0	($7,814,553)	2.1%	0.0%	5.6%	0.0%
	OVEC	$1,252,475	$0	($1,252,475)	0.3%	0.0%	0.9%	0.0%
	South Exp	$4,959,166	$0	($4,959,166)	1.3%	0.0%	3.5%	0.0%
	South Imp	$17,171,527	$0	($17,171,527)	4.7%	0.0%	12.3%	0.0%
	All Interfaces	$45,369,330	$38,624	($45,330,706)	12.3%	0.0%	32.4%	0.0%
	Total	$368,861,052	$369,083,642	$222,590	100.0%	100.0%	100.0%	100.0%

17 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-22 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.
18 The total balance should be zero but due to resettlements performed while this report was been developed, total operating reserve charges do not match total operating reserve credits.

Charges are categorized by the location (control zone, hub, aggregate 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, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had an 1.3 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 6.7 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 39.6 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had an 86.9 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-22 also shows that 81.6 percent of all charges were allocated in control zones, 6.1 percent in hubs and aggregates and 12.3 percent in interfaces.

Table 4-23 and Table 4-24 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 4-23 shows that on average, 15.0 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 75.6 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 4-23 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through September 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,070,070	$7,239,642	$1,239,705	$10,549,416	$67,203,566
Feb	$596,857	$11,853,340	$474,443	$12,924,640	$62,194,876
Mar	$580,957	$576,090	$745,649	$1,902,696	$10,854,917
Apr	$989,136	$1,382,976	$576,404	$2,948,515	$18,105,690
May	$942,411	$202,584	$992,435	$2,137,429	$11,303,585
Jun	$686,381	$147,673	$769,465	$1,603,519	$12,220,617
Jul	$1,468,567	$506,086	$2,355,842	$4,330,495	$27,570,665
Aug	$529,501	$139,205	$581,930	$1,250,637	$8,425,775
Sep	$1,130,682	$461,835	$1,094,912	$2,687,430	$20,540,790
East Generators Total	$8,994,562	$22,509,431	$8,830,784	$40,334,777	$238,420,481
PJM Total	$83,398,256	$103,969,585	$81,252,002	$268,619,843	$315,520,013
Share	10.8%	21.7%	10.9%	15.0%	75.6%

Table 4-24 also shows that generators in the Western Region paid 13.9 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 24.3 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 4-24 Monthly balancing operating reserve charges and credits to generators (Western Region): January through September 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,545,383	$156,268	$1,707,943	$4,409,594	$11,986,551
Feb	$894,132	$54,981	$582,626	$1,531,739	$4,913,999
Mar	$859,696	$59,092	$1,007,486	$1,926,274	$6,606,397
Apr	$1,390,711	$18,514	$930,462	$2,339,687	$4,972,019
May	$1,121,750	$470,387	$1,296,967	$2,889,105	$11,214,216
Jun	$825,243	$223,560	$914,667	$1,963,470	$5,602,110
Jul	$1,602,805	$332,867	$2,410,705	$4,346,377	$16,347,409
Aug	$770,345	$119,450	$779,656	$1,669,452	$5,628,395
Sep	$1,401,325	$71,651	$1,137,948	$2,610,924	$9,478,927
West Generators Total	$11,411,391	$1,506,770	$10,768,460	$23,686,620	$76,750,024
PJM Total	$83,398,256	$5,282,696	$81,252,002	$169,932,953	$315,520,013
Share	13.7%	28.5%	13.3%	13.9%	24.3%

Table 4-25 Percentage of unit credits and charges of total credits and charges: 2012 and 2013

	2012		2013	
	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	10.8%	99.9%	12.2%	100.0%
Feb	8.2%	100.0%	15.0%	100.0%
Mar	11.7%	99.8%	8.4%	99.9%
Apr	13.6%	100.0%	10.2%	100.0%
May	14.0%	100.0%	8.6%	100.0%
Jun	13.6%	99.9%	6.2%	99.9%
Jul	15.6%	99.8%	11.0%	99.9%
Aug	14.6%	100.0%	5.2%	99.9%
Sep	9.4%	100.0%	6.2%	100.0%
Oct	12.7%	99.9%		
Nov	12.6%	99.8%		
Dec	8.8%	100.0%		
Average (Jan - Sep)	12.7%	99.9%	9.8%	100.0%
Average	12.3%	99.9%		

Table 4-25 shows that on average in the first nine months of 2013, operating reserve charges paid by generators were 9.8 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 2.9 percentage points lower than the average in the first nine months of 2012. Generators received 99.96 percent of all operating reserve credits, while the remaining 0.04 percent were credits paid to import transactions, load response resources and unallocated congestion charges.

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-26 shows the geography of reactive services charges. In the first nine months of 2013, 53.3 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 4.4 percent were paid by real-time load in multiple zones and 42.3 percent were paid by real-time load across the entire RTO. In the first nine months of 2013, resources in two control zones accounted for 99.7 percent of all reactive services costs allocated across the entire RTO.

Table 4-26 Geography of reactive services charges: January through September, 2013[19]

Location	Charges	Share of Charges
Single Zone	$103,618,183	53.3%
Multiple Zones	$8,543,206	4.4%
Entire RTO	$82,171,210	42.3%
Total	$194,332,599	100.0%

In the first nine months of 2013, the top three zones accounted for 76.4 percent of all the reactive services charges allocated to single zones.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.6 percent of all the black start services costs in the first nine months of 2013. These costs resulted from noneconomic operation of units providing black start service under the Automatic Load Rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in five control zones accounted for all synchronous condensing costs in the first nine months of 2013.[20]

Operating Reserve Issues

Concentration of Operating Reserve Credits

There continues to be a high level of concentration in the units and companies receiving operating reserve credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need for operating reserves in particular locations and the fact that the lack of transparency makes it impossible for competition to affect operating reserve credit payments.

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 in the top 10 units remains high and it increased in the first nine months of 2013 compared to the first nine months of 2012. Table 4-27 shows that the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 34.5 percent of total operating reserve credits in the first nine months of 2013, compared to 21.1 percent in the first nine months of 2012. The increase in the concentration of operating reserve credits was in part the result of lower lost opportunity cost credits paid to combustion turbines and diesels in the first nine months of 2013 compared to the first nine months of 2012, which increased the share of credits paid to the top 10 units receiving day-ahead operating reserve, balancing operating reserve, reactive services and black start services credits.

Table 4-27 Top 10 operating reserve credits units (By percent of total system): January through September 2012 and 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Sep 2012	21.1%	0.7%
Jan - Sep 2013	34.5%	0.7%

Table 4-28 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories paid to generators. The shares of the top 10 organizations in all categories separately were above 82.0 percent.

19 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

20 PJM and the MMU cannot publish more detailed information about the location of the costs of synchronous condensing because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Table 4-28 Top 10 units and organizations operating reserve credits: January through September 2013

		Top 10 units		Top 10 organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$32,162,611	60.0%	$48,379,427	90.3%
Balancing	Canceled Resources	$130,276	97.1%	$134,109	100.0%
	Generators	$134,520,722	57.5%	$209,181,362	89.4%
	Local Constraints Control	$71,358	94.3%	$75,638	100.0%
	Lost Opportunity Cost	$21,546,524	26.5%	$67,402,432	82.9%
Reactive Services		$120,569,775	62.0%	$185,419,966	95.4%
Synchronous Condensing		$161,775	40.8%	$396,245	100.0%
Black Start Services		$55,719,297	80.8%	$68,957,888	100.0%
Total		$218,664,826	34.5%	$544,955,010	86.1%

Table 4-29 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 2013, 90.1 percent of all credits paid to these units were allocated to deviations while the remaining 9.9 percent were paid for reliability reasons.

Table 4-29 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$10,550,254	$2,804,123	$0	$33,028,025	$88,138,320	$0	$134,520,722
Share	7.8%	2.1%	0.0%	24.6%	65.5%	0.0%	100.0%

Table 4-30 Daily operating reserve credits HHI: January through September 2013

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	5343	1254	10000	100.0%	55.7%
	Imports	10000	10000	10000	100.0%	38.1%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	10000	10000	10000	100.0%	52.6%
	Generators	3927	1084	9888	99.4%	48.4%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	92.8%
	Lost Opportunity Cost	4699	829	10000	100.0%	24.2%
Reactive Services		4797	1852	10000	100.0%	53.9%
Synchronous Condesing		8497	5002	10000	100.0%	74.0%
Black Start Services		9894	6160	10000	100.0%	99.6%
Total		9894	6160	10000	85.1%	23.1%

In the first nine months of 2013, concentration in all operating reserve credit categories was high.[21,22] The HHI for operating reserve credits was calculated based on each organization's daily credits for each category. Table 4-30 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 5343, for balancing operating reserve generator credits was 3927 and for lost opportunity cost credits was 4699.

Day-Ahead Unit Commitment for Reliability

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 puts such reliability issues in four categories: voltage issues (high and low); black start requirement (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[23] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant cannot set LMP and is not eligible for day-ahead operating reserve credits.[24] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 4-31 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, 1.9 percentage points higher than the first nine months of 2012.[25]

21 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
22 Table 4-30 excludes the local constraints control categories.
23 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>.
24 See "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2013) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>
25 PJM increased the amount of generation scheduled as must run on September 13, 2012. See *2012 State of the Market Report for PJM*: Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Table 4-31 Day-ahead generation scheduled as must run by PJM: 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%	57,570	2,522	4.4%
May	62,986	1,944	3.1%	61,169	2,848	4.7%
Jun	69,190	1,841	2.7%	68,452	3,724	5.4%
Jul	82,984	3,618	4.4%	78,639	4,395	5.6%
Aug	76,161	2,438	3.2%	73,783	3,678	5.0%
Sep	63,535	2,902	4.6%	64,757	3,162	4.9%
Oct	60,656	3,509	5.8%			
Nov	62,985	3,542	5.6%			
Dec	68,759	2,347	3.4%			
Total (Jan - Sep)	606,162	17,453	2.9%	610,622	28,888	4.7%
Total	798,561	26,851	3.4%			

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-32 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2013, 65.4 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 13.4 percent were credits paid to units scheduled to provide black start services, 40.7 percent were credits paid to units scheduled to provide reactive services and 11.3 percent were normal day-ahead operating reserve credits paid to units scheduled noneconomic. The remaining 34.6 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-32 Day-ahead generation scheduled as must run by PJM by category (GWh): 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr	451	840	439	792	2,522
May	429	1,058	346	1,016	2,848
Jun	484	1,601	459	1,181	3,724
Jul	420	1,616	234	2,124	4,395
Aug	465	1,644	387	1,182	3,678
Sep	338	1,460	453	911	3,162
Total	3,875	11,754	3,264	9,994	28,888
Share	13.4%	40.7%	11.3%	34.6%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2013 were $28.8 million, of which 53.7 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. The overall 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.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in day-ahead but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this lost opportunity cost will be referred to as day-ahead lost opportunity cost.[26] 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 due to a transmission constraint or other reliability issue, the unit will receive a credit for lost opportunity cost based on the desired output. For purposes of this report, this lost opportunity cost will be referred as real-time lost opportunity cost.

In the first nine months of 2013, lost opportunity cost credits decreased by $66.0 million or 44.8 percent compared to the first nine months of 2012. The decrease of $66.0 million is comprised of a decrease of $74.7 million in day-ahead lost opportunity cost and an increase of $8.7 million in real-time lost opportunity cost. Table 4-35 shows the monthly composition of lost opportunity cost credits in 2012 and 2013.

Day-ahead lost opportunity cost (payments to combustion turbines and diesels scheduled in the Day-Ahead Market and not requested in real time) continue to comprise the majority of lost opportunity cost credits. In the first nine months of 2013, day-ahead lost opportunity cost were 74.2 percent of all lost opportunity cost credits. Combustion turbines and diesels are only eligible for day-ahead lost opportunity cost if the units are scheduled in day ahead and follow PJM instructions in real time.[27] Table 4-34 shows, for combustion turbines and diesels 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 2013, PJM scheduled 11,060 GWh from combustion turbines and diesels, of which 44.1 percent was not requested by PJM in real time and of which 32.4 percent received lost opportunity cost credits, 17.7 percentage points lower than the first nine months of 2012.

Table 4-33 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,116,947	$332,282	$5,449,229	$8,862,207	$2,752,980	$11,615,188
Feb	$4,277,162	$366,971	$4,644,133	$2,050,724	$2,681,143	$4,731,868
Mar	$10,327,361	$450,299	$10,777,660	$4,854,970	$2,350,261	$7,205,230
Apr	$11,814,780	$696,258	$12,511,038	$3,893,834	$1,548,469	$5,442,303
May	$15,806,150	$3,502,912	$19,309,062	$5,357,701	$3,247,699	$8,605,401
Jun	$14,502,682	$677,375	$15,180,057	$6,235,079	$807,362	$7,042,441
Jul	$27,875,651	$3,066,115	$30,941,767	$17,250,646	$3,071,292	$20,321,938
Aug	$25,573,420	$1,346,343	$26,919,763	$5,455,830	$173,290	$5,629,120
Sep	$19,723,184	$1,863,565	$21,586,749	$6,377,820	$4,369,174	$10,746,995
Oct	$12,391,362	$7,990,739	$20,382,101			
Nov	$14,541,552	$4,094,304	$18,635,855			
Dec	$5,177,551	$1,139,539	$6,317,091			
Total (Jan - Sep)	$135,017,338	$12,302,120	$147,319,459	$60,338,812	$21,001,671	$81,340,484
Share (Jan - Sep)	91.6%	8.4%	100.0%	74.2%	25.8%	100.0%
Total	$167,127,804	$25,526,703	$192,654,507			
Share	86.8%	13.2%	100.0%			

26 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not called in real time incurs in balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

27 Combustion turbines and diesels with lead times of two hours or less are automatically eligible for lost opportunity cost credits. Combustion turbines and diesels with lead times greater than two hours are assumed to be committed in real time for the duration of their day-ahead schedule unless instructed not to run by PJM.

Table 4-34 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	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	579	439	377	886	638	565
Feb	758	590	546	430	206	173
Mar	1,392	1,076	921	809	397	283
Apr	1,872	1,432	1,249	684	325	256
May	1,928	1,250	1,047	1,031	389	262
Jun	2,588	1,624	1,235	1,284	699	442
Jul	3,900	1,424	988	2,950	963	761
Aug	2,358	1,386	1,125	1,769	779	545
Sep	1,635	1,169	1,032	1,217	480	295
Oct	1,079	895	797			
Nov	1,319	1,018	823			
Dec	851	678	625			
Total (Jan - Sep)	17,009	10,391	8,521	11,060	4,878	3,582
Share (Jan - Sep)	100.0%	61.1%	50.1%	100.0%	44.1%	32.4%
Total	20,258	12,981	10,765			
Share	100.0%	64.1%	53.1%			

Table 4-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total
Jan	$4,857,442	$355,007	$5,212,449	$8,166,901	$695,307	$8,862,207
Feb	$4,382,996	$154,019	$4,537,015	$1,860,546	$190,178	$2,050,724
Mar	$9,661,923	$894,042	$10,555,965	$3,031,710	$1,823,260	$4,854,970
Apr	$10,846,998	$1,028,201	$11,875,199	$2,476,452	$1,417,382	$3,893,834
May	$12,925,885	$2,775,886	$15,701,771	$3,686,814	$1,670,887	$5,357,701
Jun	$12,550,655	$2,163,079	$14,713,734	$4,785,844	$1,449,235	$6,235,079
Jul	$13,911,706	$13,967,989	$27,879,694	$8,278,481	$8,972,165	$17,250,646
Aug	$22,219,006	$3,415,961	$25,634,967	$3,383,866	$2,071,965	$5,455,830
Sep	$17,783,763	$2,196,639	$19,980,402	$4,200,542	$2,177,278	$6,377,820
Oct	$11,185,166	$1,296,974	$12,482,141			
Nov	$12,704,380	$2,130,370	$14,834,749			
Dec	$4,979,204	$364,570	$5,343,774			
Total (Jan - Sep)	$109,140,374	$26,950,822	$136,091,196	$39,871,156	$20,467,656	$60,338,812
Share (Jan - Sep)	80.2%	19.8%	100.0%	66.1%	33.9%	100.0%
Total	$138,009,125	$30,742,736	$168,751,861			
Share	81.8%	18.2%	100.0%			

In the first nine months of 2013, the top three control zones in which generation received lost opportunity cost credits, AEP, ComEd and Dominion, accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of all the day-ahead generation from combustion turbines and diesels and 53.9 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 diesels receive lost opportunity cost credits 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 4-35 shows the lost opportunity costs credits paid to combustion turbines and diesels 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 4-35 shows that in the first nine months of 2013, $39.9 million or 66.1 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time, 14.1 percentage points lower than the first nine months of 2012.

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-36 shows the total day-ahead generation from combustion turbines and diesels that were not called in real time by PJM and received lost opportunity cost credit. Table 4-36 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 2013, 69.1 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 30.9 percent was noneconomic.

Table 4-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[28]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445	548	121	669
Feb	422	248	670	171	53	224
Mar	805	287	1,092	272	145	417
Apr	1,126	329	1,455	225	93	318
May	875	363	1,237	229	130	359
Jun	835	667	1,501	365	272	636
Jul	826	402	1,228	725	203	928
Aug	946	397	1,343	437	275	712
Sep	880	305	1,185	293	166	459
Oct	710	193	903			
Nov	782	280	1,062			
Dec	434	298	732			
Total (Jan - Sep)	7,024	3,133	10,157	3,264	1,457	4,722
Share (Jan - Sep)	69.2%	30.8%	100.0%	69.1%	30.9%	100.0%
Total	8,950	3,904	12,853			
Share	69.6%	30.4%	100.0%			

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic.

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.[29] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU did not formally recommend these to the MIC for consideration although they were brought to the attention of the MIC.

28 The total generation in Table 4-36 is lower than the Day-Ahead Generation not requested in Real Time in Table 4-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-36 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

29 See "Meeting Minutes," from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (February 17, 2012)

- **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 incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **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 Energy 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 Energy Market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost. The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **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 actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the lost opportunity cost in the PJM Energy Markets 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. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

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' schedule on which it is committed.

Table 4-37 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 2013, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by a net of $21.3 million, or 29.0 percent, if all these changes had been implemented.[30]

30 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 4-37 Impact on energy market lost opportunity cost credits of rule changes: January through September 2013

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$21,001,671	$60,338,812	$81,340,484
Impact 1: Committed Schedule	$903,955	$15,033,146	$15,937,101
Impact 2: Eliminating DA LMP	NA	($436,556)	($436,556)
Impact 3: Using Offer Curve	($1,033,747)	$6,231,985	$5,198,238
Impact 4: Including No Load Cost	NA	($32,589,591)	($32,589,591)
Impact 5: Including Startup Cost	NA	($9,360,083)	($9,360,083)
Net Impact	($129,792)	($21,121,099)	($21,250,891)
Credits After Changes	$20,871,880	$39,217,713	$60,089,593

Black Start Service Units

Certain units located in the AEP control zone are relied on for their black start capability 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 costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[31]

In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 million, and 95.0 percent of these costs was paid by peak transmission use in the AEP control zone while the remaining 5.0 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP control zone. Load in the AEP control zone paid an average of $10.25 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.07 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

31 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP control zone. PJM awarded all viable solutions from the last RFP.[32] PJM has approved new rules concerning black start service procurement, and the new selection process will be effective on April 1, 2015.[33,34]

Con Edison – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the wheeling contracts between Con-Ed and PSEG.[35] These units are often run out-of-merit and receive substantial balancing operating reserve 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.

Reactive / Voltage Support Units

Certain units located in the BGE and Pepco control zones are committed to provide reactive support to the AP-South interface. The AP-South interface consists of four 500 kV transmission lines that connect the Western and Eastern regions of PJM. PJM approved in the 2012 Regional Transmission Expansion Planning (RTEP) seven reactive upgrades to solve identified N-1-1 low voltage NERC criteria violations, and five of the seven upgrades are located in substations at or near the AP-South interface. These upgrades may reduce the need for noneconomic operation of units to provide reactive support to the AP-South interface, although the results will not be known until the RTEP upgrades are in place.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[36] Under the rules providing for credits for reactive service,

32 See "Item 3: Black Start RFP Status," from the PJM's System Restoration Strategy Task Force June 14, 2013 meeting. <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.
33 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at "Black Start Service".
34 See "Manual 14D: Generator Operational Requirement" Revision 23 (April 1, 2013) at "Section 10: Black Start Generation Procurement".
35 See the *2012 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.
36 OATT Attachment K - Appendix § 3.2.3B (f).

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 or zones where the service is provided while balancing operating reserve are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

In the first nine months of 2013, units providing reactive services were paid $7.0 million in balancing operating reserve credits in order to cover their total energy offer.

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[37,38] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[39]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[40] Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[41] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing

37 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," from the PJM's MIC October 10, 2012 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>.

38 See "Minutes," from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

39 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}> (Accessed January 11, 2013).

40 See OATT 3.2.3 (o) for a complete description of how generators deviate.

41 Locations can be control zones, hubs, aggregates and interfaces. See the *2012 State of the Market Report for PJM, Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 102-103 for a full description of balancing operating reserve locations.

operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.[42]

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on 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 2013, 52.3 percent of all up-to congestion transactions were profitable.[43]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied and the other identified quantifiable recommendations had been implemented. It was assumed that up-to congestion transactions would have maintained the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, 66.0 percent of all up-to congestion transactions would have been made. 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.[44]

The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. Up-to congestion transactions would have paid an average rate between \$0.311 and \$0.407 per MWh in the first nine months of 2013 if the MMU's recommendations regarding operating reserves had been in place.[45]

Quantifiable Recommendations Impact

The MMU calculated the impact that all quantifiable recommendations would have had on the operating reserve rates paid by participants in the RTO, Eastern and Western Region. For reasons of confidentiality, these impacts cannot be disaggregated by issue. Five recommendations have been aggregated in this analysis: reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; reallocation of no load and startup costs of units providing reactive services; implementation of the proposed changes to lost opportunity cost calculations; elimination of internal bilateral transactions from the deviations calculation; and the allocation of operating reserve charges to up-to congestion transactions.

Table 4-38 shows the combined impact that these recommendations would have had on all operating reserve rates for the first nine months of 2013. The reduction in the rates is due to a decrease of 44.5 percent of the credits used to calculate these rates and a weighted average increase of 643.1 percent in the denominator used to calculate these rates.[46]

Table 4-38 MMU Recommendations Impact on Operating Reserve Rates: January through September 2013

	Current Rates (\$/MWh)	Proposed Rates (\$/MWh)	Difference (\$/MWh)	Percentage Difference
Day-Ahead	0.086	0.029	(0.056)	(65.7%)
RTO Reliability	0.052	0.035	(0.016)	(31.7%)
East Reliability	0.031	0.031	(0.000)	(0.0%)
West Reliability	0.004	0.004	0.000	0.0%
RTO Deviations	0.886	0.060	(0.825)	(93.2%)
East Deviations	2.193	0.059	(2.135)	(97.3%)
West Deviations	0.118	0.012	(0.107)	(90.0%)
Lost Opportunity Cost	0.861	0.065	(0.796)	(92.4%)
Canceled Resources	0.001	0.000	(0.001)	(89.7%)

42 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.
43 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.
44 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.
45 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.
46 The weighted average was calculated based on the total charges by rate.

Table 4-39 shows the operating reserve cost of a 1 MW transaction had these recommendations been implemented in the first nine months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.218 per MWh, $3.564 per MWh or 94.2 percent less than the actual average rate paid. An up-to congestion transactions sourced in the Eastern Region and sinking at the Western Region would have been charged an average rate of $0.359 per MWh. Table 4-39 illustrates the current and proposed averages operating reserve rates for all transactions.

Table 4-39 Current and Proposed Average Operating Reserve Rate by Transaction: January through September 2013

		Rates Charged ($/MWh)		
	Transaction	Current	Proposed	Change
East	INC	3.663	0.189	(3.474)
	DEC	3.782	0.218	(3.564)
	DA Load	0.119	0.028	(0.090)
	RT Load	0.076	0.058	(0.018)
	Deviation	3.663	0.189	(3.474)
West	INC	1.726	0.141	(1.584)
	DEC	1.844	0.170	(1.675)
	DA Load	0.119	0.028	(0.090)
	RT Load	0.053	0.035	(0.018)
	Deviation	1.726	0.141	(1.584)
UTC	East to East	NA	0.407	
	West to West	NA	0.311	
	East to/from West	NA	0.359	

Confidentiality of Operating Reserves Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current confidentiality rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[47]

Operating reserves are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. Operating reserve charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the units receiving operating reserve payments. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of operating reserves information does exactly the opposite. There is no market in operating reserves and the absence of relevant information creates a very effective barrier to entry. The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region. This information would include the publication of operating reserve information by zone, by owner and by unit.

47 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 9 (July 22, 2012), Market Data Posting.