SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for the first six months of 2010. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue quantifies the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue quantifies the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  In 2009, total net revenues were not adequate to cover total fixed costs for a new entrant combustion turbine (CT), combined cycle (CC) or coal plant (CP) in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues in a year with reduced energy market revenues.

  In the first six months of 2010, total net revenues were generally higher compared to the same period in 2009. The changes in total net revenues by technology type are the result of changes in energy revenues, resulting from energy prices, and changes in capacity revenues, resulting from prior RPM auctions. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

  For the new entrant CT, fourteen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009, while AEP, ComEd and DAY had lower total net revenues. (Table 3-8.) For the new entrant CT, all zones except AP had higher energy net revenue. The six zones that were part of the MAAC+AP Locational Delivery Area (LDA) for the 2009/2010 delivery year, which previously cleared in the EMAAC LDA, had slightly higher capacity revenues. The two zones that were part of the SWMAAC LDA and the five zones that cleared in the unconstrained RTO LDA for the 2009/2010 delivery year had lower capacity revenues. The AP, Met-Ed, PENELEC and PPL zones, which had cleared with unconstrained RTO LDA in the 2008/2009 delivery year, had significantly higher capacity revenues associated with the constrained MAAC+AP LDA. For AP, higher capacity revenues more than offset lower energy net revenues.

  For the new entrant CC, fourteen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009, while AEP, ComEd and DAY had lower total net revenues. (Table 3-10.) For the new entrant CC, AP, ComEd and PENELEC had a decrease in energy net revenue. For AP and PENELEC, higher capacity revenues more than offset this decrease. For AEP and DAY, slightly higher energy net revenues were more than offset by the decrease in capacity revenues.

For the new entrant coal plant (CP), all seventeen zones had higher total net revenue in the first half of 2010 compared to the same period in 2009. (Table 3-12.) For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones and five RTO zones, higher energy net revenue more than offset decreases in capacity revenues.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through June 30, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,621.8 MW on June 30, a decrease of 1,232.0 MW or 0.7 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of June 30, 2010, 40.7 percent was coal; 29.1 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.3 percent was wind.

- **Generation Fuel Mix.** During the first six months of 2010, coal provided 50.8 percent, nuclear 35.6 percent, gas 9.1 percent, oil 0.2 percent, hydroelectric 2.3 percent, solid waste 0.8 percent and wind 1.2 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in the first six months of 2010.** PJM did not declare a scarcity event in the first six months of 2010.

  In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity.

- **Modifications to Scarcity Pricing.** PJM's scarcity pricing rules need refinement.

  Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

  The essential components of a new approach to scarcity pricing include: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective scarcity pricing revenue true up mechanism; a rule governing the recall of the energy from capacity resources during scarcity events; and maintaining local market power mitigation mechanisms.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve 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. From the perspective of those participants paying the operating reserve charges that equal these credits, 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 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.

- **Operating Reserve Charges in the First Six Months of 2010.** The level of operating reserve credits and corresponding charges increased in the first six months of 2010 by 44.7 percent compared to the first six months of 2009. Most of this increase occurred in the second quarter of 2010. The level of operating reserve credits in the first quarter of 2010 increased by only 9.0 percent compared to the first quarter of 2009. The increase in total operating reserve credits was comprised of a 1.8 percent, or $826,461, increase in the amount of day-ahead credits, an 80.7 percent, or $1,856,299, decrease in synchronous condensing credits, and a 63.5 percent, or $76,634,160, increase in balancing credits. The increase in balancing credits can primarily be attributed to a large increase in Eastern reliability credits. Eastern reliability credits accounted for $290,150 in the first quarter of 2010 and $28,161,278 in the second quarter of 2010.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in the second quarter of 2010. The new operating reserve rules resulted in an increase of $54,057,630 in charges assigned to real-time load and exports for the first six months of 2010. These increases were matched by a decrease of $29,315,256 in charges to demand deviations, a decrease of $16,159,640 in charges to supply deviations, and a decrease of $8,582,734 in charges to generator deviations.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $18,106,662 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

  The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $6,257,231, or 4.5 percent, higher for the first six months of 2010 than they would have been under the old rules. The most significant difference since the new rule went into effect was for June 2010, when the increase in payments due to the rule change was $2,602,710.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The second quarter of 2010 showed a reversal of trends noted in the first quarter of 2010 when compared to the same time period in the prior year. In the second quarter of 2010, energy market revenues were generally higher for combustion turbines and combined cycles, both using natural gas, as energy market prices in the second quarter increased more than the average delivered price of natural gas in most zones. Energy market net revenues for the CP were substantially higher in all zones as a result of higher energy market prices in the second quarter.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Several zones had more high demand days in the second quarter of 2010 compared to 2009. The average on peak LMP for Dominion and DLCO increased by 14.6 and 15.8 percent. As a result, while the average increase in energy net revenue for a new entrant CT was 99 percent, the Dominion and DLCO zones show increases of 142 and 315 percent respectively.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of total costs for existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The Capacity Market is also a significant source of net revenue to cover the fixed costs of investing in new peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when there is a mismatch between the energy net revenues used as the offset in determining Capacity Market prices and actual energy net revenues, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. For the first six months of 2010, particularly in May and June, CCs and CTs ran more often, which increased the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2010 (See 2009 SOM, Table 3-3)

	Delivery Year 2009/2010			Delivery Year 2010/2011			RPM Revenue 2010
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	(Jan - Dec) $/MW
AECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL-SOUTH	$186.12	$39,830	$68,719
JCPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PJM	NA	$138.46	$20,907	NA	$174.42	$37,327	$58,234

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-4)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$28,208	$28,889	2%
AEP	$19,961	$15,408	(23%)
AP	$22,640	$28,889	28%
BGE	$38,847	$35,837	(8%)
ComEd	$19,961	$15,408	(23%)
DAY	$19,961	$15,408	(23%)
DLCO	$19,961	$15,408	(23%)
Dominion	$19,961	$15,408	(23%)
DPL	$28,208	$28,889	2%
JCPL	$28,208	$28,889	2%
Met-Ed	$22,640	$28,889	28%
PECO	$28,208	$28,889	2%
PENELEC	$22,640	$28,889	28%
Pepco	$38,847	$35,837	(8%)
PPL	$22,640	$28,889	28%
PSEG	$28,208	$28,889	2%
RECO	$28,208	$28,889	2%
PJM	$22,965	$20,907	(9%)

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM[1] (Dollars per MBtu): January through June 2009 and 2010 (See 2009 SOM, Table 3-5)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Natural Gas	$4.95	$5.32	7%
Delivered Coal	$3.26	$2.50	(23%)

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[2] : Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$5,450	$12,236	125%
AEP	$2,313	$2,410	4%
AP	$8,213	$7,779	(5%)
BGE	$7,346	$17,441	137%
ComEd	$1,595	$1,696	6%
DAY	$1,941	$2,317	19%
DLCO	$1,633	$6,771	315%
Dominion	$7,709	$18,632	142%
DPL	$6,784	$12,676	87%
JCPL	$6,199	$11,522	86%
Met-Ed	$5,416	$11,068	104%
PECO	$4,733	$11,051	133%
PENELEC	$3,596	$4,055	13%
Pepco	$11,729	$22,484	92%
PPL	$4,666	$9,512	104%
PSEG	$4,371	$11,752	169%
RECO	$3,626	$10,219	182%
PJM	$5,136	$10,213	99%

1 The average delivered fuel prices shown in Table 3-3 are included for illustrative purposes, and represent the simple average of several indices for various delivery points throughout the PJM footprint.

2 The energy net revenues presented for "PJM" for the periods January through June 2009 and 2010 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for "PJM" represent the simple average energy net revenue.

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$25,588	$36,518	43%
AEP	$14,814	$15,284	3%
AP	$30,922	$28,962	(6%)
BGE	$28,065	$44,508	59%
ComEd	$12,192	$11,478	(6%)
DAY	$14,505	$15,586	7%
DLCO	$13,010	$19,160	47%
Dominion	$29,532	$44,704	51%
DPL	$27,532	$37,913	38%
JCPL	$27,643	$36,167	31%
Met-Ed	$23,875	$33,683	41%
PECO	$23,309	$34,471	48%
PENELEC	$22,215	$21,127	(5%)
Pepco	$37,313	$53,216	43%
PPL	$22,156	$30,948	40%
PSEG	$24,641	$36,705	49%
RECO	$21,913	$32,078	46%
PJM	$23,484	$31,324	33%

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through June 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$55,686	$88,154	58%
AEP	$17,349	$54,788	216%
AP	$35,617	$68,308	92%
BGE	$32,123	$94,799	195%
ComEd	$26,197	$50,436	93%
DAY	$22,324	$43,901	97%
DLCO	$18,800	$50,387	168%
Dominion	$34,847	$85,647	146%
DPL	$28,682	$69,366	142%
JCPL	$51,802	$83,895	62%
Met-Ed	$43,014	$77,670	81%
PECO	$51,543	$84,385	64%
PENELEC	$49,034	$60,925	24%
Pepco	$46,748	$93,005	99%
PPL	$49,206	$79,420	61%
PSEG	$69,576	$88,584	27%
RECO	$49,545	$80,786	63%
PJM	$40,123	$73,792	84%

New Entrant Combustion Turbine

Table 3-7 Real-time PJM average net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$5,136	$10,213	99%
Capacity	$20,466	$18,849	(8%)
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,199	$1,199	0%
Total	$26,801	$30,261	13%

Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$31,788	$39,481	24%
AEP	$21,301	$17,500	(18%)
AP	$29,588	$35,023	18%
BGE	$43,163	$50,948	18%
ComEd	$20,582	$16,786	(18%)
DAY	$20,929	$17,407	(17%)
DLCO	$20,621	$21,861	6%
Dominion	$26,696	$33,722	26%
DPL	$33,121	$39,921	21%
JCPL	$32,536	$38,766	19%
Met-Ed	$26,790	$38,312	43%
PECO	$31,071	$38,295	23%
PENELEC	$24,971	$31,299	25%
Pepco	$47,547	$55,992	18%
PPL	$26,041	$36,756	41%
PSEG	$30,709	$38,997	27%
RECO	$29,964	$37,464	25%
PJM	$26,801	$30,261	13%

New Entrant Combined Cycle

Table 3-9 Real-time PJM average net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$23,484	$31,324	33%
Capacity	$22,186	$20,111	(9%)
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$1,599	$1,599	0%
Total	$47,269	$53,034	12%

Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$54,438	$65,906	21%
AEP	$35,697	$31,705	(11%)
AP	$54,393	$58,350	7%
BGE	$67,192	$80,579	20%
ComEd	$33,075	$27,898	(16%)
DAY	$35,388	$32,006	(10%)
DLCO	$33,893	$35,581	5%
Dominion	$50,415	$61,124	21%
DPL	$56,382	$67,301	19%
JCPL	$56,494	$65,555	16%
Met-Ed	$47,345	$63,071	33%
PECO	$52,159	$63,859	22%
PENELEC	$45,685	$50,515	11%
Pepco	$76,441	$89,287	17%
PPL	$45,626	$60,336	32%
PSEG	$53,491	$66,092	24%
RECO	$50,763	$61,466	21%
PJM	$47,269	$53,034	12%

New Entrant Coal Plant

Table 3-11 Real-time PJM average net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through June 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
Energy	$40,123	$73,792	84%
Capacity	$20,705	$18,960	(8%)
Synchronized	$0	$0	0%
Regulation	$137	$58	(58%)
Reactive	$892	$892	0%
Total	$61,857	$93,701	51%

Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$82,208	$115,515	41%
AEP	$36,395	$69,937	92%
AP	$57,064	$95,676	68%
BGE	$68,139	$128,463	89%
ComEd	$45,593	$65,562	44%
DAY	$41,706	$58,928	41%
DLCO	$37,864	$65,495	73%
Dominion	$53,855	$100,698	87%
DPL	$55,093	$96,597	75%
JCPL	$78,299	$111,247	42%
Met-Ed	$64,466	$105,003	63%
PECO	$78,050	$111,744	43%
PENELEC	$71,059	$88,283	24%
Pepco	$82,825	$126,633	53%
PPL	$70,683	$106,781	51%
PSEG	$96,634	$115,938	20%
RECO	$76,028	$108,144	42%
PJM	$61,857	$93,701	51%

New Entrant Day-Ahead Net Revenues

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$2,438	$5,634	131%
AEP	$739	$597	(19%)
AP	$3,314	$3,432	4%
BGE	$3,338	$9,478	184%
ComEd	$239	$532	123%
DAY	$350	$613	75%
DLCO	$224	$2,201	884%
Dominion	$4,073	$10,371	155%
DPL	$3,066	$4,966	62%
JCPL	$2,106	$4,774	127%
Met-Ed	$1,926	$4,955	157%
PECO	$2,030	$4,605	127%
PENELEC	$1,967	$1,440	(27%)
Pepco	$7,911	$15,602	97%
PPL	$1,775	$3,369	90%
PSEG	$1,378	$4,481	225%
RECO	$950	$4,080	329%
PJM	$2,225	$4,772	114%

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$23,204	$32,703	41%
AEP	$10,796	$12,695	18%
AP	$24,872	$27,062	9%
BGE	$25,069	$41,715	66%
ComEd	$6,900	$8,317	21%
DAY	$9,212	$12,124	32%
DLCO	$7,841	$16,556	111%
Dominion	$27,288	$41,764	53%
DPL	$24,570	$32,782	33%
JCPL	$24,738	$33,324	35%
Met-Ed	$20,553	$30,641	49%
PECO	$21,541	$31,580	47%
PENELEC	$19,402	$22,077	14%
Pepco	$35,424	$53,078	50%
PPL	$19,487	$27,485	41%
PSEG	$22,143	$32,240	46%
RECO	$18,957	$28,965	53%
PJM	$20,117	$28,536	42%

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	Percent Change
AECO	$57,249	$91,588	60%
AEP	$14,442	$55,505	284%
AP	$31,212	$70,267	125%
BGE	$33,849	$99,933	195%
ComEd	$23,685	$50,824	115%
DAY	$18,754	$43,193	130%
DLCO	$14,184	$51,144	261%
Dominion	$34,963	$89,659	156%
DPL	$28,992	$71,438	146%
JCPL	$52,416	$87,906	68%
Met-Ed	$43,004	$81,730	90%
PECO	$53,977	$88,737	64%
PENELEC	$49,787	$67,261	35%
Pepco	$48,096	$99,139	106%
PPL	$50,190	$83,421	66%
PSEG	$72,594	$91,826	26%
RECO	$50,273	$87,064	73%
PJM	$39,863	$77,096	93%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-18)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
2010 (Jan - Jun)	$10,213	$4,772	$5,441	53%

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
2010 (Jan - Jun)	$31,324	$28,536	$2,788	9%

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through June 2010 (See 2009 SOM, Table 3-20)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
2010 (Jan - Jun)	$73,792	$77,096	($3,305)	(4%)

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2009 SOM, Table 3-21)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$31,788	$39,481	$128,705	25%	31%
AEP	$21,301	$17,500	$128,705	17%	14%
AP	$29,588	$35,023	$128,705	23%	27%
BGE	$43,163	$50,948	$128,705	34%	40%
ComEd	$20,582	$16,786	$128,705	16%	13%
DAY	$20,929	$17,407	$128,705	16%	14%
DLCO	$20,621	$21,861	$128,705	16%	17%
Dominion	$26,696	$33,722	$128,705	21%	26%
DPL	$33,121	$39,921	$128,705	26%	31%
JCPL	$32,536	$38,766	$128,705	25%	30%
Met-Ed	$26,790	$38,312	$128,705	21%	30%
PECO	$31,071	$38,295	$128,705	24%	30%
PENELEC	$24,971	$31,299	$128,705	19%	24%
Pepco	$47,547	$55,992	$128,705	37%	44%
PPL	$26,041	$36,756	$128,705	20%	29%
PSEG	$30,709	$38,997	$128,705	24%	30%
RECO	$29,964	$37,464	$128,705	23%	29%
PJM	$26,801	$30,261	$128,705	21%	24%

Figure 3-1 New entrant CT real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-3)

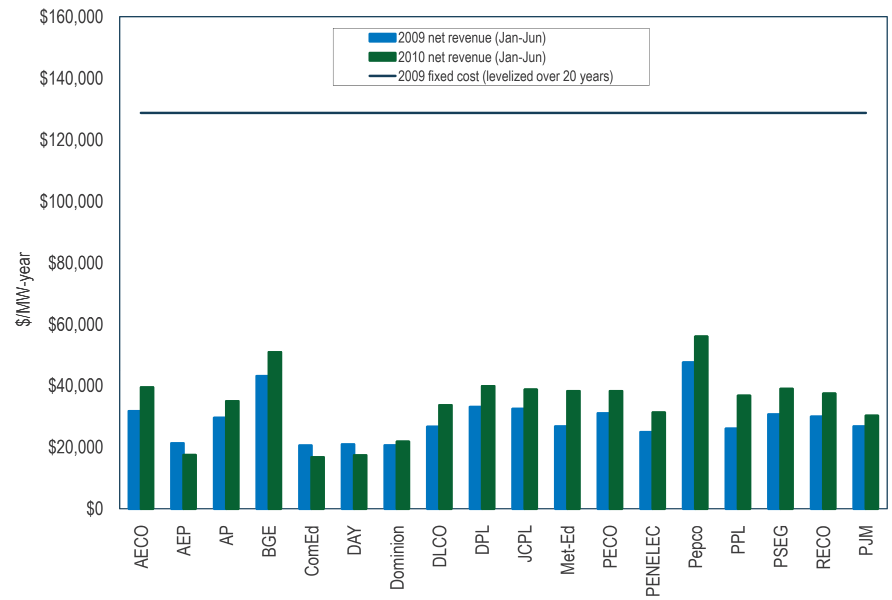


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$54,438	$65,906	$173,174	31%	38%
AEP	$35,697	$31,705	$173,174	21%	18%
AP	$54,393	$58,350	$173,174	31%	34%
BGE	$67,192	$80,579	$173,174	39%	47%
ComEd	$33,075	$27,898	$173,174	19%	16%
DAY	$35,388	$32,006	$173,174	20%	18%
DLCO	$33,893	$35,581	$173,174	20%	21%
Dominion	$50,415	$61,124	$173,174	29%	35%
DPL	$56,382	$67,301	$173,174	33%	39%
JCPL	$56,494	$65,555	$173,174	33%	38%
Met-Ed	$47,345	$63,071	$173,174	27%	36%
PECO	$52,159	$63,859	$173,174	30%	37%
PENELEC	$45,685	$50,515	$173,174	26%	29%
Pepco	$76,441	$89,287	$173,174	44%	52%
PPL	$45,626	$60,336	$173,174	26%	35%
PSEG	$53,491	$66,092	$173,174	31%	38%
RECO	$50,763	$61,466	$173,174	29%	35%
PJM	$47,269	$53,034	$173,174	27%	31%

Figure 3-2 New entrant CC real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-5)

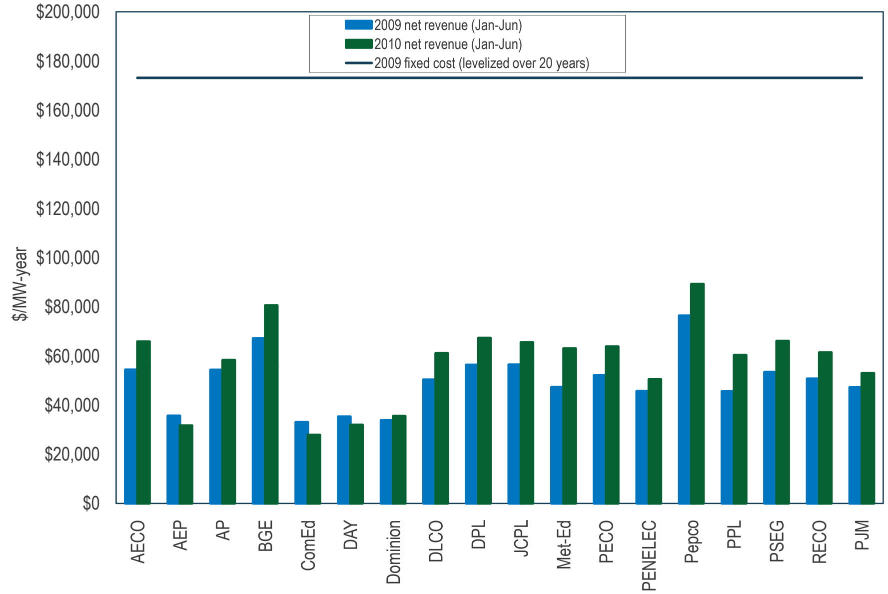
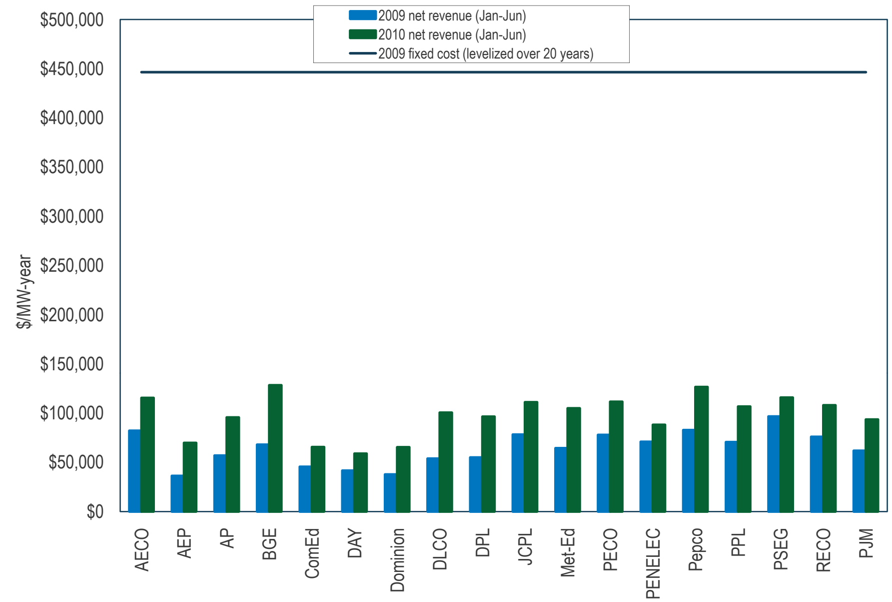


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through June 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Jun)	2010 (Jan - Jun)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$82,208	$115,515	$446,550	18%	26%
AEP	$36,395	$69,937	$446,550	8%	16%
AP	$57,064	$95,676	$446,550	13%	21%
BGE	$68,139	$128,463	$446,550	15%	29%
ComEd	$45,593	$65,562	$446,550	10%	15%
DAY	$41,706	$58,928	$446,550	9%	13%
DLCO	$37,864	$65,495	$446,550	8%	15%
Dominion	$53,855	$100,698	$446,550	12%	23%
DPL	$55,093	$96,597	$446,550	12%	22%
JCPL	$78,299	$111,247	$446,550	18%	25%
Met-Ed	$64,466	$105,003	$446,550	14%	24%
PECO	$78,050	$111,744	$446,550	17%	25%
PENELEC	$71,059	$88,283	$446,550	16%	20%
Pepco	$82,825	$126,633	$446,550	19%	28%
PPL	$70,683	$106,781	$446,550	16%	24%
PSEG	$96,634	$115,938	$446,550	22%	26%
RECO	$76,028	$108,144	$446,550	17%	24%
PJM	$61,857	$93,701	$446,550	14%	21%

Figure 3-3 New entrant CP real-time 2009 and 2010 net revenue for January through June and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-7)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-May-10		1-Jun-10		30-Jun-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	67,858.1	40.7%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	48,426.5	29.1%
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,923.5	4.8%
Nuclear	30,611.9	18.2%	30,599.3	18.3%	30,619.0	18.4%	30,619.0	18.4%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,645.5	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	668.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	481.1	0.3%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,621.8	100.0%

Energy Production by Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through June 2010 (See 2009 SOM, Table 3-36)

		GWh	Percent
Coal		180,931.2	50.8%
Nuclear		126,789.7	35.6%
Gas		32,244.2	9.1%
	Natural Gas	31,455.3	8.8%
	Landfill Gas	788.7	0.2%
	Biomass Gas	0.2	0.0%
Hydroelectric		8,146.2	2.3%
Wind		4,183.0	1.2%
Waste		3,020.1	0.8%
	Solid Waste	2,325.0	0.7%
	Miscellaneous	695.1	0.2%
Oil		875.5	0.2%
	Heavy Oil	687.0	0.2%
	Light Oil	175.0	0.0%
	Diesel	10.3	0.0%
	Kerosene	3.2	0.0%
	Jet Oil	0.1	0.0%
Solar		2.1	0.0%
Battery		0.2	0.0%
Total		356,192.2	100.0%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 2010[3] (See 2009 SOM, Table 3-37)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

PJM Generation Queues

Table 3-26 Queue comparison (MW): June 30, 2010 vs. December 31, 2009 (See 2009 SOM, Table 3-38)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

Table 3-27 Capacity in PJM queues (MW): At June 30, 2010[4, 5] (See 2009 SOM, Table 3-39)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	3,978	4,482
N Expired 31-Jan-05	1,377	2,143	223	6,663	10,407
O Expired 31-Jul-05	1,978	1,048	444	4,104	7,574
P Expired 31-Jan-06	853	1,008	1,886	4,918	8,665
Q Expired 31-Jul-06	1,945	707	3,583	8,413	14,648
R Expired 31-Jan-07	5,511	648	708	15,974	22,840
S Expired 31-Jul-07	7,421	1,034	1,260	11,068	20,782
T Expired 31-Jan-08	12,886	397	299	10,979	24,560
U Expired 31-Jan-09	10,980	112	770	19,572	31,434
V Expired 31-Jan-10	13,639	3	128	2,996	16,766
W Expires 31-Jan-11	7,546	0	0	0	7,546

Table 3-28 Average project queue times: At June 30, 2010 (See 2009 SOM, Table 3-40)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	864	659	0	4,420
In-Service	737	620	0	3,287
Suspended	2,296	744	890	3,622
Under Construction	1,182	892	0	4,370
Withdrawn	503	503	0	3,186

3 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

4 The *2010 Quarterly State of the Market Report for PJM*: January through June contains all projects in the queue including reratings of existing generating units and energy only resources..

5 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2010[6] (See 2009 SOM, Table 3-41)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	15,228	(7,506)	(49)%
2011	15,873	17,356	1,483	9%
2012	11,053	12,579	1,526	12%
2013	6,350	7,506	1,156	15%
2014	13,439	12,474	(965)	(8)%
2015	3,091	2,958	(133)	(4)%
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	3,194	1,600	50%
Total	76,725	74,286	(2,439)	(3)%

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2010[7] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	4,293	1,576	51	0	510	1,533	771	1,516	67	10,316
SWMAAC	0	2,025	230	6	0	1,640	0	132	0	25	4,058
WMAAC	40	650	201	53	175	1,624	120	133	1,279	16	4,289
RTO	22	7,184	3,546	135	350	2,818	553	4,802	36,206	8	55,624
Total	62	14,151	5,552	245	524	6,592	2,206	5,837	39,001	116	74,286

6 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.
7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-31 Existing PJM capacity: At June 30, 2010[8] (By zone and unit type (MW)) (See 2009 SOM, Table 3-43)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	608	23	0	0	1,281	0	8	1,919
AEP	0	4,355	3,629	57	1,005	2,106	21,256	0	901	33,308
AP	0	1,129	1,178	36	108	0	7,963	0	431	10,845
BGE	0	0	849	7	0	1,705	3,026	0	0	5,587
ComEd	0	1,814	7,110	111	0	10,376	7,090	0	1,765	28,265
DAY	0	0	1,358	52	0	0	3,572	3	0	4,985
DLCO	0	101	188	0	6	1,777	1,239	0	0	3,311
Dominion	0	3,173	3,853	160	3,558	3,494	8,617	0	0	22,855
DPL	0	376	2,496	96	0	0	2,007	0	0	4,975
External	0	974	1,890	0	0	439	10,064	0	185	13,552
JCPL	0	1,192	1,423	25	400	615	318	0	0	3,972
Met-Ed	0	2,000	406	23	20	805	890	0	0	4,143
PECO	1	2,552	836	7	1,642	4,509	2,129	3	0	11,679
PENELEC	0	0	287	45	505	0	6,834	0	447	8,117
Pepco	0	0	1,555	12	0	0	4,706	0	0	6,273
PPL	0	956	1,362	63	571	2,375	5,532	0	217	11,075
PSEG	0	2,921	2,856	0	5	3,553	2,535	10	0	11,880
Total	1	21,542	31,883	717	7,820	31,753	89,057	16	3,953	186,741

8 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-32 PJM capacity age: At June 30, 2010 (MW) (See 2009 SOM, Table 3-44)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,307	18,886	380	10	0	2,089	16	3,953	42,641
10 to 20	0	3,976	4,740	129	49	0	6,148	0	0	15,042
20 to 30	0	158	480	38	3,438	16,186	9,997	0	0	30,296
30 to 40	0	101	5,276	39	435	14,953	31,345	0	0	52,149
40 to 50	0	0	2,501	128	2,480	615	24,363	0	0	30,086
50 to 60	0	0	0	4	348	0	13,611	0	0	13,963
60 to 70	0	0	0	0	32	0	1,356	0	0	1,388
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	27	0	0	0	0	27
Total	1	21,542	31,883	717	7,820	31,753	89,057	16	3,953	186,741

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (See 2009 SOM, Table 3-45)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	0	1	0.0%
	Combined Cycle	0	0.0%	7,041	20.5%	4,293	11,334	29.1%
	Combustion Turbine	955	12.1%	8,220	23.9%	1,576	8,840	22.7%
	Diesel	49	0.6%	150	0.4%	51	152	0.4%
	Hydroelectric	2,042	25.8%	2,047	5.9%	0	2,047	5.3%
	Nuclear	615	7.8%	8,676	25.2%	510	8,572	22.0%
	Solar	0	0.0%	13	0.0%	1,533	1,546	4.0%
	Steam	4,240	53.7%	8,269	24.0%	771	4,800	12.3%
	Wind	0	0.0%	8	0.0%	1,516	1,524	3.9%
	Unknown	0	0.0%	0	0.0%	67	67	3.2%
	EMAAC Total	7,901	100.0%	34,425	100.0%	10,316	38,882	100.0%

Table continued next page

9 Percents shown in Table 3-33 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018 (See 2009 SOM, Table 3-45) (continued)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
SWMAAC	Combined Cycle	0	0.0%	0	0.0%	2,025	2,025	16.7%
	Combustion Turbine	540	14.2%	2,404	20.3%	230	2,093	17.3%
	Diesel	0	0.0%	19	0.2%	6	25	0.2%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	27.6%
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	38.0%
	Unknown	0	0.0%	0	0.0%	25	25	0.2%
	SWMAAC Total	3,807	100.0%	11,859	100.0%	4,058	12,110	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	40	40	0.2%
	Combined Cycle	0	0.0%	2,956	12.7%	650	3,606	17.0%
	Combustion Turbine	296	4.3%	2,054	8.8%	201	1,958	9.2%
	Diesel	35	0.5%	131	0.6%	53	148	0.7%
	Hydroelectric	444	6.5%	1,096	4.7%	175	1,270	6.0%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	22.6%
	Solar	0	0.0%	0	0.0%	120	120	0.6%
	Steam	6,042	88.6%	13,256	56.8%	133	7,346	34.6%
	Wind	0	0.0%	663	2.8%	1,279	1,942	9.2%
	Unknown	0	0.0%	0	0.0%	16	16	0.1%
	WMAAC Total	6,817	100.0%	23,335	100.0%	4,289	21,211	100.0%
RTO	Battery	0	0.0%	0	0.0%	22	22	0.0%
	Combined Cycle	0	0.0%	11,545	9.9%	7,184	18,729	12.9%
	Combustion Turbine	709	2.5%	19,206	16.4%	3,546	22,043	15.2%
	Diesel	48	0.2%	417	0.4%	135	504	0.3%
	Hydroelectric	1,401	5.0%	4,677	4.0%	350	3,626	2.5%
	Nuclear	0	0.0%	18,192	15.5%	2,818	21,010	14.5%
	Solar	0	0.0%	3	0.0%	553	555	0.4%
	Steam	25,931	92.3%	59,800	51.1%	4,802	38,671	26.7%
	Wind	0	0.0%	3,282	2.8%	36,206	39,488	27.3%
	Unknown	0	0.0%	0	0.0%	8	8	0.0%
	RTO Total	28,089	100.0%	117,121	100.0%	55,624	144,656	100.0%
All Areas	Total	46,614		186,741		74,286	216,859	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through June 2010[10] (See 2009 SOM, Table 3-46)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.2%	60,730	1,412
Capacity Resource	32.3%	123,154	2,540
All Units	30.1%	183,884	3,953

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through June 2010 (See 2009 SOM, Table 3-47)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	510.6	815	1.56%
All Wind	1,415.2	1,142	2.19%

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through June 2010 (See 2009 SOM, Figure 3-11)

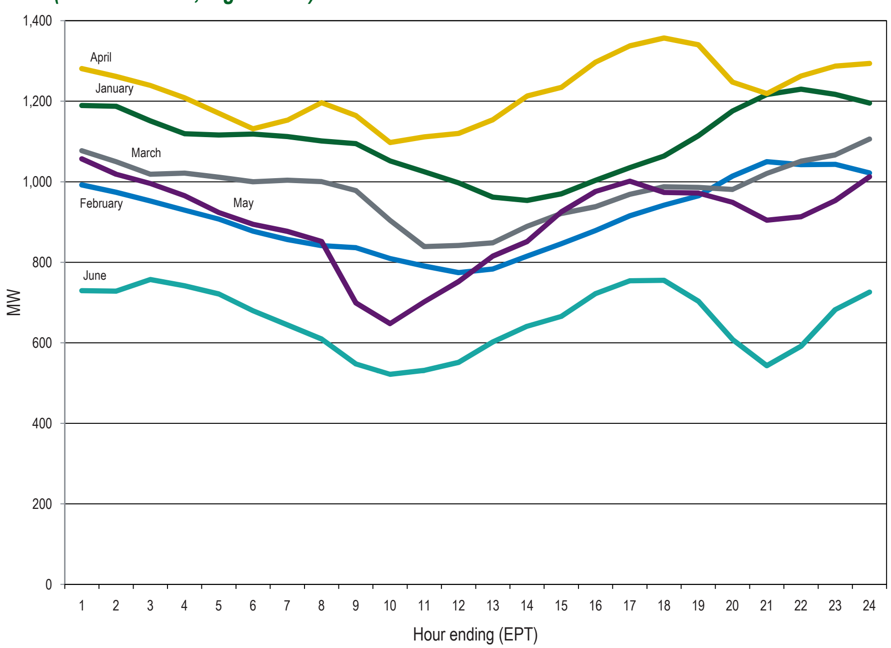


Table 3-36 Capacity factor of wind units in PJM by month, January through June 2010[11] (See 2009 SOM, Table 3-48)

Month	Generation (MWh)	Capacity Factor
January	818,423.9	38.2%
February	612,044.4	29.8%
March	727,819.1	30.7%
April	881,317.4	36.9%
May	670,571.5	27.2%
June	472,775.6	19.3%
July		
August		
September		
October		
November		
December		
Annual	4,182,951.9	30.1%

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, January through June 2010 (See 2009 SOM, Table 3-49)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.5%	35.8%	22.5%		29.1%
	Average Wind Generation	960.6	1,188.6	755.3		932.2
	Average Load	86,485.1	73,871.4	89,018.4		85,137.8
Off-Peak	Capacity Factor	34.1%	37.9%	23.9%		31.0%
	Average Wind Generation	1,033.9	1,257.9	802.8		990.4
	Average Load	75,824.0	59,326.6	70,803.5		71,476.4

10 The corresponding table in the *2009 Quarterly State of the Market Report for PJM: January through June*, reversed the labels for energy only resources and capacity resources data.

11 Capacity factor shown in Table 3-36 is based on all hours in January through June, 2010.

Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through June 2010 (See 2009 SOM, Figure 3-12)

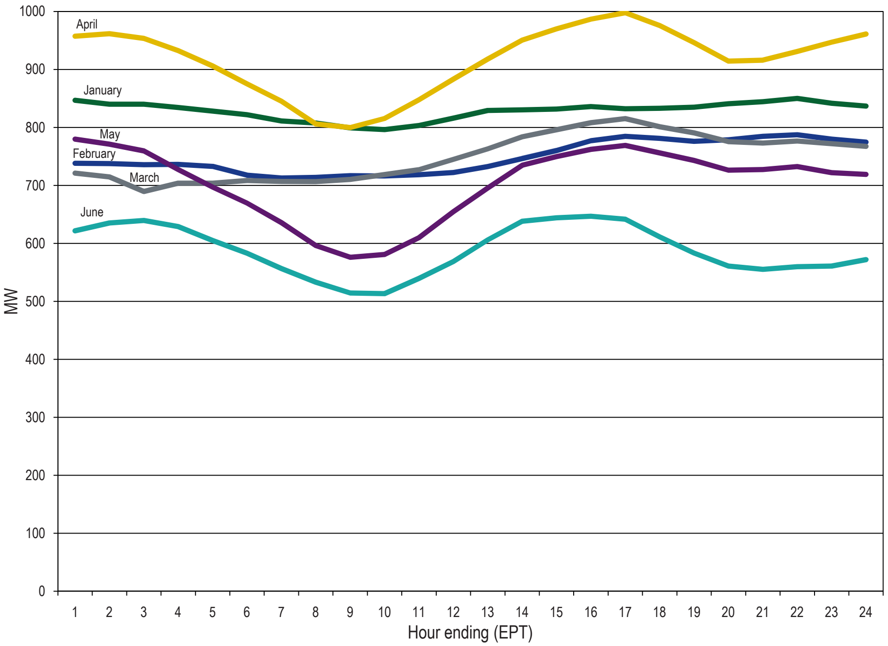
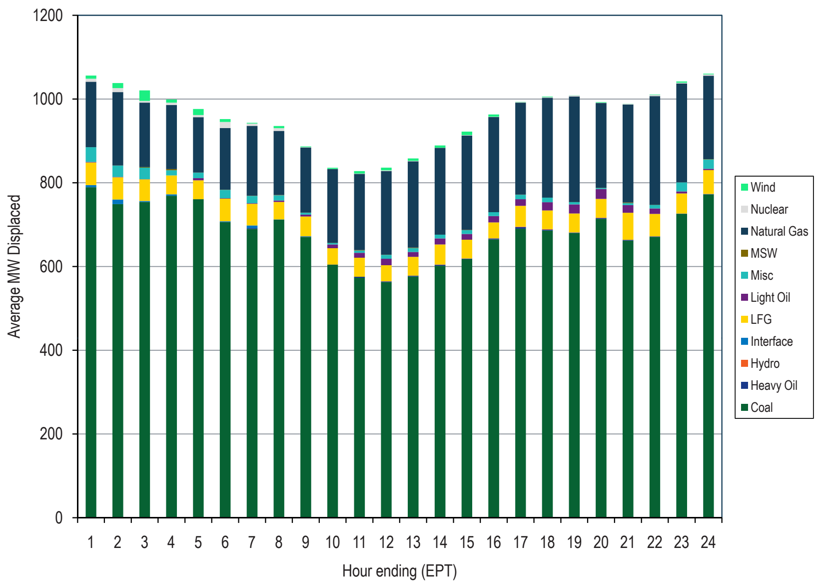


Figure 3-6 Marginal fuel at time of wind generation in PJM, January through June 2010 (See 2009 SOM, Figure 3-13)



Operating Reserve

Credit and Charge Categories

Table 3-38 Operating reserve credits and charges (See 2009 SOM, Table 3-50)

For Credits Received		By Charges Paid
Day ahead:		Day-ahead demand
Day-Ahead Energy Market	→	Decrement bids
Day-ahead import transactions		Day-ahead export transactions
Synchronous condensing	→	Real-time load
		Real-time export transactions
Balancing:		
Balancing energy market		Real-time deviations
Lost opportunity cost	→	from day-ahead schedules
Real-time import transactions		

Balancing Energy Market Credits Received		By Balancing Energy Market Charges Paid
By (RTO, Eastern Region, Western Region)		Real-time load
Reliability Credits	→	Real-time export transactions
Deviation Credits	→	Real-time deviations
		from day-ahead schedules

Table 3-39 Operating reserve deviations (See 2009 SOM, Table 3-51)

Deviations		
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Balancing Credits and Charges

Table 3-40 Balancing operating reserve allocation process (See 2009 SOM, Table 3-52)

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Credit and Charge Results

Overall Results

Table 3-41 Monthly operating reserve charges: Calendar year 2009 and January through June 2010 (See 2009 SOM, Table 3-54)[12]

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,461,023	$50,792,396
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,344,500	$33,784,709
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,227	$25,782,929
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,674,231	$30,400,625
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$38,584,716	$43,843,623
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,519,115	$60,064,302
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255				
Aug	$7,697,174	$1	$21,164,586	$28,861,761				
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577				
Oct	$7,046,301	$0	$17,026,425	$24,072,727				
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519				
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245				
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$46,815,443	$446,330	$197,406,812	$244,668,585
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	19.1%	0.2%	80.7%	100.0%

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The figures reported in this section reflect the figures at the time this report was created.

Table 3-42 Regional balancing charges allocation: January through June 2010[13] (See 2009 SOM, Table 3-55)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$15,917,613 11.3%	$619,122 0.4%	$16,536,736 11.7%	$40,184,542 28.5%	$22,663,866 16.1%	$11,833,894 8.4%	$74,682,303 53.0%	$91,219,038 64.7%
East	$27,351,105 19.4%	$1,100,323 0.8%	$28,451,428 20.2%	$4,599,507 3.3%	$2,650,810 1.9%	$1,054,579 0.7%	$8,304,896 5.9%	$36,756,324 26.1%
West	$8,784,110 6.2%	$285,356 0.2%	$9,069,466 6.4%	$2,130,462 1.5%	$961,154 0.7%	$797,715 0.6%	$3,889,331 2.8%	$12,958,797 9.2%
Total	$52,052,828 36.9%	$2,004,802 1.4%	$54,057,630 38.4%	$46,914,512 33.3%	$26,275,830 18.6%	$13,686,188 9.7%	$86,876,529 61.6%	$140,934,159 100%

Deviations

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through June 2010 (See 2009 SOM, Table 3-56)

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,128,112	5,575,170	2,630,917	17,334,199	9,439,465	5,707,965	2,709,298	17,856,728
Feb	7,044,702	4,153,575	2,107,229	13,305,505	7,675,656	5,332,236	2,462,260	15,470,152
Mar	7,214,090	4,352,550	2,409,507	13,976,146	8,101,950	5,138,264	2,266,934	15,507,148
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,152,689	13,828,078
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,430,731	15,662,769
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,937,311	3,964,478	3,217,112	18,118,902
Jul	9,233,511	5,129,409	2,243,337	16,606,257				
Aug	9,961,944	5,425,344	2,427,539	17,814,827				
Sep	7,972,378	4,171,876	2,109,506	14,253,759				
Oct	7,028,775	4,543,635	2,203,723	13,776,133				
Nov	6,742,675	4,248,221	2,193,013	13,183,910				
Dec	8,301,680	4,682,157	3,113,047	16,096,884				
Total	95,029,874	55,906,867	28,731,313	179,668,054	52,165,400	29,039,354	15,239,023	96,443,777
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	54.1%	30.1%	15.8%	100.0%

13 The total charges shown in Table 3-42 do not equal the total balancing charges shown in Table 3-41 because the totals in Table 3-41 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-42 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Table 3-44 Regional charges determinants (MWh): January through June 2010 (See 2009 SOM, Table 3-57)

	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	Total
RTO	339,214,651	13,026,941	352,241,592	52,165,400	29,039,354	15,239,023	96,443,777	448,685,369
East	185,390,813	7,537,156	192,927,969	33,818,304	20,029,790	7,984,909	61,833,003	254,760,972
West	153,823,838	5,489,785	159,313,623	18,202,862	8,959,850	7,254,114	34,416,826	193,730,449

Balancing Operating Reserve Charge Rate

Figure 3-7 Daily RTO reliability and deviation rates ($/MWh): January through June 2010 (See 2009 SOM, Figure 3-14)

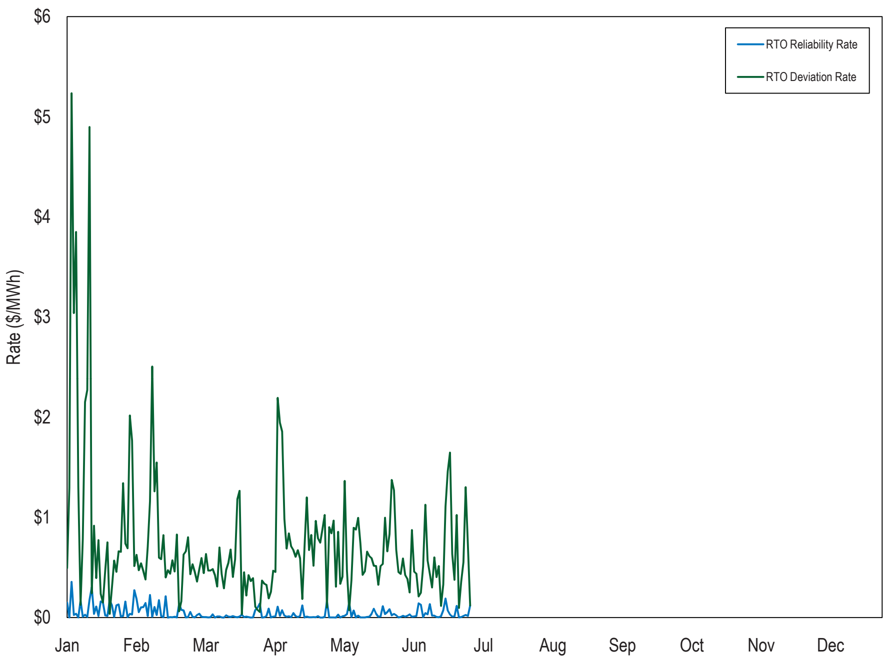


Figure 3-8 Daily regional reliability and deviation rates ($/MWh): January through June 2010 (See 2009 SOM, Figure 3-15)

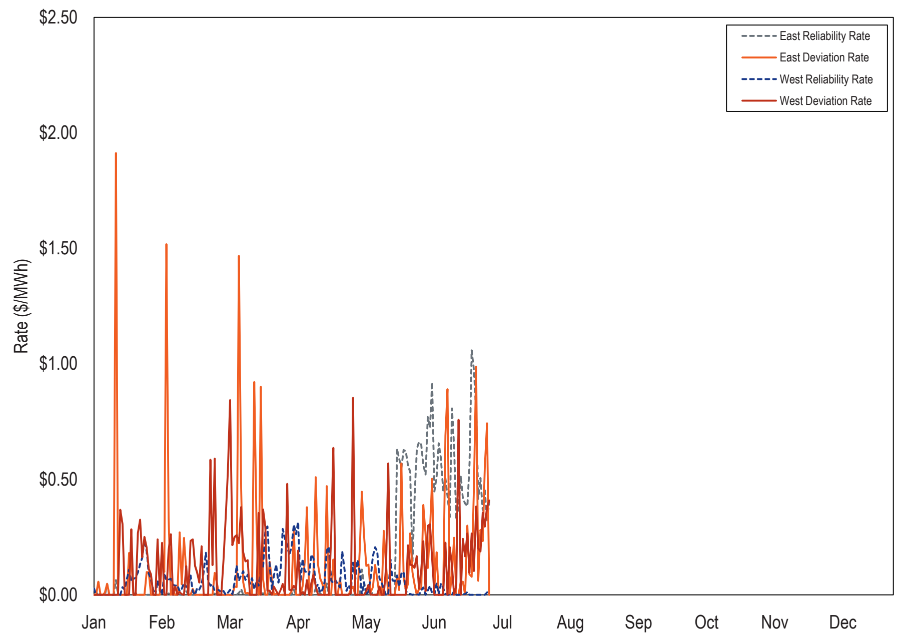


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through June 2010 (See 2009 SOM, Table 3-58)

	Reliability	Deviations
RTO	0.044	0.736
East	0.862	0.133
West	0.058	0.117

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through June 2010 (See 2009 SOM, Figure 3-16)

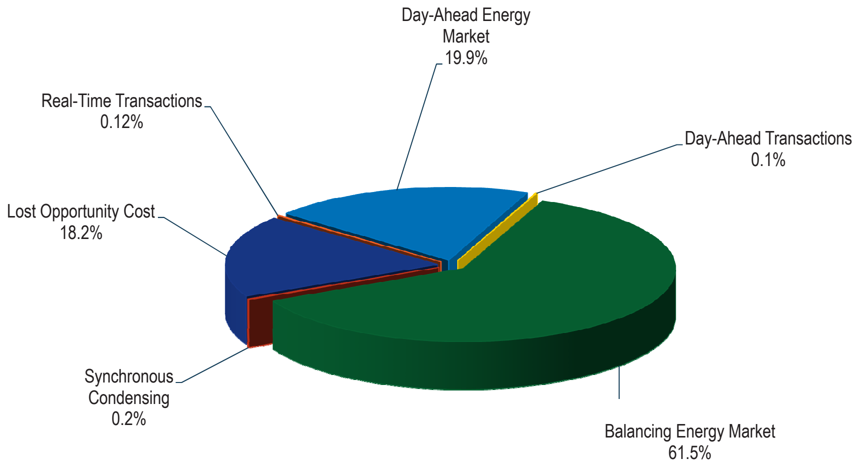


Table 3-46 Credits by month (By operating reserve market): January through June 2010 (See 2009 SOM, Table 3-59)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$34,146,809	$0	$3,322,385	$47,800,567
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,710,205	$31,005,735
Mar	$8,831,771	$5,115	$122,817	$13,931,246	$15,603	$1,971,841	$24,878,393
Apr	$7,633,141	$0	$93,253	$16,911,974	$0	$4,512,804	$29,151,173
May	$5,117,845	$9,462	$131,600	$23,011,853	$1,236	$15,434,268	$43,706,265
Jun	$3,469,143	$42,121	$33,923	$38,429,261	$196,537	$15,598,399	$57,769,384
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$46,634,019	$181,424	$446,330	$144,209,326	$290,515	$42,549,903	$234,311,518
Share of Credits	19.9%	0.1%	0.2%	61.5%	0.1%	18.2%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-47 Credits by unit types (By operating reserve market): January through June 2010 (See 2009 SOM, Table 3-60)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	36.6%	0.0%	58.5%	4.9%	$72,453,861
Combustion Turbine	0.7%	0.7%	58.4%	40.1%	$61,763,265
Diesel	0.7%	0.0%	89.4%	9.9%	$220,336
Hydro	0.0%	0.0%	100.0%	0.0%	$30,592
Landfill	0.0%	0.0%	0.0%	100.0%	$9,140,793
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	21.9%	0.0%	72.5%	5.6%	$89,992,739
Wind Farm	0.0%	0.0%	100.0%	0.0%	$154,268

Table 3-48 Credits by operating reserve market (By unit type): January through June 2010 (See 2009 SOM, Table 3-61)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	56.8%	0.0%	29.4%	8.4%
Combustion Turbine	0.9%	100.0%	25.0%	58.3%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%
Landfill	0.0%	0.0%	0.0%	21.5%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	42.2%	0.0%	45.3%	11.8%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$46,634,019	$446,330	$144,125,601	$42,549,903

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through June 2010 (See 2009 SOM, Table 3-65)

	Eastern Region						Western Region							
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	$1,913,490	$248,583	$2,162,073	$29,069,084	$2,719,515	$31,788,599	$1,971,007	$262,958	$2,233,964	$5,077,725	$602,870	$5,680,596	8.6%	78.4%
Feb	$1,069,496	$138,135	$1,207,631	$14,194,451	$1,373,952	$15,568,403	$998,751	$132,513	$1,131,264	$3,583,730	$336,253	$3,919,983	6.9%	62.9%
Mar	$591,603	$125,603	$717,206	$8,223,758	$1,399,277	$9,623,035	$754,381	$166,300	$920,681	$5,707,488	$572,564	$6,280,053	6.3%	63.9%
Apr	$899,527	$342,395	$1,241,923	$12,315,307	$3,367,832	$15,683,139	$1,096,031	$391,699	$1,487,730	$4,596,667	$1,144,973	$5,741,640	9.0%	73.5%
May	$912,304	$1,201,575	$2,113,879	$17,594,661	$13,639,265	$31,233,926	$923,809	$1,180,445	$2,104,254	$5,417,192	$1,795,003	$7,212,196	9.6%	88.0%
Jun	$1,333,270	$1,469,883	$2,803,154	$33,433,440	$14,468,721	$47,902,161	$1,222,519	$1,360,982	$2,583,502	$4,995,821	$1,129,678	$6,125,499	8.9%	93.5%
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Average	49.1%	50.2%	49.5%	79.6%	86.9%	81.3%	50.9%	49.8%	50.5%	20.4%	13.1%	18.7%	8.2%	76.7%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-50 Regional balancing operating reserve credits: January through June 2010 (See 2009 SOM, Table 3-66)[14]

	Reliability Credits	Deviation Credits	Total Credits
RTO	$16,536,736	$74,682,303	$91,219,038
East	$28,451,428	$8,304,896	$36,756,324
West	$9,069,466	$3,889,331	$12,958,797
Total	$54,057,630	$86,876,529	$140,934,159

Table 3-51 Total deviations: January through June 2010 (See 2009 SOM, Table 3-67)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	52,165,400	29,039,354	15,239,023	96,443,777

Table 3-52 Charge allocation under old operating reserve construct: January through June 2010 (See 2009 SOM, Table 3-68)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	52,165,400	29,039,354	15,239,023	96,443,777
Balancing Rate ($/MWh)	1.461	1.461	1.461	1.461
Charges ($)	$76,229,768	$42,435,470	$22,268,922	$140,934,159

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through June 2010 (See 2009 SOM, Table 3-69)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$16,536,736	352,241,592	0.047	$16,536,736	$74,682,303	96,443,777	0.774	$74,682,303	$91,219,038
East	$28,451,428	192,927,969	0.147	$28,451,428	$8,304,896	61,833,003	0.134	$8,304,896	$36,756,324
West	$9,069,466	159,313,623	0.057	$9,069,466	$3,889,331	34,416,826	0.113	$3,889,331	$12,958,797
Total	$54,057,630	352,241,592	NA	$54,057,630	$86,876,529	96,443,777	NA	$86,876,529	$140,934,159

14 Credits may not equal charges due to adjustments made by Settlements that are only reflected on customers' final bills.

Table 3-54 Difference in total charges between old rules and new rules: January through June 2010 (See 2009 SOM, Table 3-70)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$76,229,768	$42,435,470	$22,268,922	$140,934,159
Charges (Current)	$52,052,828	$2,004,802	$54,057,630	$46,914,512	$26,275,830	$13,686,188	$86,876,529
Difference	$52,052,828	$2,004,802	$54,057,630	($29,315,256)	($16,159,640)	($8,582,734)	($54,057,630)

Impact on decrement bids and incremental offers

Table 3-55 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through June 2010 (see 2009 SOM, Table 3-71)

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047
Feb	8,323,844	11,828,780	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
Apr	7,568,471	9,989,951	2,214,314	2,066,270
May	8,306,597	11,573,314	2,250,271	3,437,786
Jun	8,304,139	12,735,819	2,223,204	4,058,044
Total	48,826,912	70,316,684	13,306,701	17,843,017

Table 3-56 Comparison of balancing operating reserve charges to virtual bids: January through June 2010 (See 2009 SOM, Table 3-72)

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,703,717	$10,186,571	($2,517,146)
Feb	$5,381,782	$3,935,858	($1,445,924)
Mar	$4,614,252	$3,470,186	($1,144,066)
Apr	$6,472,900	$5,265,681	($1,207,219)
May	$13,650,729	$9,963,541	($3,687,188)
Jun	$18,578,834	$10,473,714	($8,105,120)
Total	$61,402,214	$43,295,552	($18,106,662)

Table 3-57 Summary of impact on virtual bids under balancing operating reserve allocation: January through June 2010 (See 2009 SOM, Table 3-73)

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Old Rules	Balancing Rate Under Current Rules	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	13,306,701	17,843,017	31,149,718	1.87	1.19	$61,402,213	$39,270,576	($22,131,638)
East	8,947,802	11,120,832	20,068,635	0.00	0.11	$0	$2,843,731	$2,843,731
West	4,309,184	6,577,952	10,887,136	0.00	0.00	$0	$1,181,245	$1,181,245

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through June 2010 (See 2009 SOM, Table 3-74)

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,059	$13,672,111	$214,052
2010	Apr	$16,283,918	$16,880,164	$596,246
2010	May	$21,738,521	$23,352,543	$1,614,023
2010	Jun	$36,113,341	$38,716,050	$2,602,710
Total		$337,199,307	$351,630,944	$14,431,637

Table 3-59 Impact of segmented make whole payments (By unit type): January through June 2010 (See 2009 SOM, Table 3-75)[15]

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	3926	$10,065	$10,800	$735	$39,514,755	$42,399,714	$2,884,959
Large Frame Combustion Turbine (135 - 180 MW)	1181	$11,330	$12,414	$1,085	$13,380,221	$14,661,191	$1,280,970
Medium Frame Combustion Turbine (30 - 65 MW)	3781	$3,204	$3,446	$241	$12,115,045	$13,027,503	$912,457
Medium-Large Frame Combustion Turbine (65 - 125 MW)	944	$6,791	$7,129	$338	$6,410,706	$6,730,045	$319,339
Petroleum/Gas Steam (Post-1985)	958	$2,597	$2,902	$306	$2,487,584	$2,780,314	$292,729
Sub-Critical Coal	15002	$1,385	$1,403	$18	$20,783,500	$21,053,521	$270,021
Petroleum/Gas Steam (Pre-1985)	365	$94,958	$95,601	$644	$34,659,502	$34,894,504	$235,002
Small Frame Combustion Turbine (0 - 29 MW)	1734	$1,050	$1,082	$32	$1,820,508	$1,876,677	$56,169
Diesel	2204	$87	$89	$3	$191,491	$197,075	$5,584
Super-Critical Coal	4736	$1,380	$1,380	$0	$6,533,948	$6,533,948	$0
Hydro	379	$0	$0	$0	$0	$0	$0
Nuclear	638	$0	$0	$0	$0	$0	$0

Table 3-60 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through June 2010 (See 2009 SOM, Table 3-76)

Unit Type	Share of Increase
Combined-Cycle	46.1%
Steam	9.8%
Combustion Turbines	35.1%
Diesel	0.1%

15 In previous State of the Market reports, the columns Average Daily Balancing Credits (Old and New rules), and Total Balancing Credits (Old and Current rules), were the average and sums of only the observations in which there was a difference for a unit's balancing credits for the day under each method of calculation. The table now reflects the average and total credits for all observations in the time period, regardless of whether there was a difference for that day when calculating credits under each rule. While the differences between the new and old rules remain the same, the Total Balancing Credits columns now reflect the total sum of the time period's balancing operating reserves credits, as shown in Table 3-46.

Unit Operating Parameters

Table 3-61 Unit Parameter Limited Schedule Matrix (See 2009 SOM, Table 3-77)

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 65 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Table 3-62 Units receiving credits from a parameter limited schedule: January through June 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	2	7
Large Frame Combustion Turbine (135 - 180 MW)	5	38
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	74
Petroleum/Gas Steam (Pre-1985)	2	5
Sub-Critical Coal	17	151
Super-Critical Coal	1	1

Concentration of Unit Ownership for Operating Reserve Credits

Concentration of Operating Reserve Credits

Table 3-63 Unit operating reserve credits for units (By zone): January through June 2010 (See 2009 SOM, Table 3-80)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$261,191	$3,971	$859,214	$496,445	$1,620,822	0.7%
AEP	$1,559,386	$9,688	$17,218,803	$447,100	$19,234,977	8.2%
AP	$979,263	$0	$2,404,974	$3,920,835	$7,305,072	3.1%
BGE	$2,770,122	$0	$3,591,870	$28,866	$6,390,858	2.7%
ComEd	$604,478	$4,080	$3,694,172	$1,172,345	$5,475,075	2.3%
DAY	$134,187	$0	$834,618	$25,350	$994,155	0.4%
Dominion	$809,590	$0	$12,110,290	$25,837,179	$38,757,058	16.6%
DPL	$1,719,157	$7,490	$4,128,086	$564,229	$6,418,962	2.7%
DLCO	$1,941,979	$0	$5,226,057	$15,712	$7,183,748	3.1%
JCPL	$2,230,184	$0	$3,285,093	$317,970	$5,833,248	2.5%
Met-Ed	$217,258	$0	$1,002,053	$73,804	$1,293,116	0.6%
PECO	$1,550,729	$2,095	$2,476,531	$758,569	$4,787,925	2.0%
PENELEC	$54,374	$23,603	$482,424	$386,671	$947,072	0.4%
Pepco	$2,173,991	$0	$37,917,784	$7,549,667	$47,641,442	20.4%
PPL	$105,981	$0	$4,140,949	$546,149	$4,793,079	2.0%
PSEG	$29,522,149	$395,402	$44,836,406	$409,013	$75,162,970	32.1%
External	$0	$0	$0	$0	$0	0.0%
Total	$46,634,019	$446,330	$144,209,326	$42,549,903	$233,839,578	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through June 2010 (See 2009 SOM, Table 3-81)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$26,565,270	11.4%	11.4%	$74,478,710	31.9%	31.9%
2	$19,227,389	8.2%	19.6%	$33,759,344	14.4%	46.3%
3	$14,170,856	6.1%	25.6%	$33,170,782	14.2%	60.5%
4	$13,069,594	5.6%	31.2%	$15,360,288	6.6%	67.0%
5	$10,953,365	4.7%	35.9%	$9,600,111	4.1%	71.1%
6	$3,475,866	1.5%	37.4%	$8,824,067	3.8%	74.9%
7	$3,164,328	1.4%	38.8%	$8,477,542	3.6%	78.5%
8	$3,084,478	1.3%	40.1%	$7,873,726	3.4%	81.9%
9	$2,740,601	1.2%	41.2%	$5,108,985	2.2%	84.1%
10	$2,523,122	1.1%	42.3%	$3,830,642	1.6%	85.7%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through June 2010 (See 2009 SOM, Table 3-82)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$11,916,077	25.6%	25.6%	$29,477,589	63.2%	63.2%
2	$7,522,447	16.1%	41.7%	$2,834,009	6.1%	69.3%
3	$6,408,267	13.7%	55.4%	$2,076,778	4.5%	73.7%
4	$1,875,580	4.0%	59.4%	$1,875,580	4.0%	77.8%
5	$1,770,278	3.8%	63.2%	$1,303,964	2.8%	80.6%
6	$1,242,597	2.7%	65.9%	$1,295,994	2.8%	83.3%
7	$1,225,594	2.6%	68.5%	$1,001,121	2.1%	85.5%
8	$1,001,121	2.1%	70.7%	$850,710	1.8%	87.3%
9	$784,389	1.7%	72.4%	$839,016	1.8%	89.1%
10	$715,837	1.5%	73.9%	$832,632	1.8%	90.9%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through June 2010 (See 2009 SOM, Table 3-83)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$36,267	8.1%	8.1%	$395,402	88.6%	88.6%
2	$30,100	6.7%	14.9%	$23,603	5.3%	93.9%
3	$29,935	6.7%	21.6%	$11,462	2.6%	96.4%
4	$27,984	6.3%	27.8%	$9,688	2.2%	98.6%
5	$27,723	6.2%	34.1%	$4,080	0.9%	99.5%
6	$25,458	5.7%	39.8%	$2,095	0.47%	100.0%
7	$23,378	5.2%	45.0%			
8	$19,037	4.3%	49.3%			
9	$18,865	4.2%	53.5%			
10	$18,401	4.1%	57.6%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through June 2010 (See 2009 SOM, Table 3-84)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$20,157,003	14.0%	14.0%	$44,196,706	30.6%	30.6%
2	$13,832,542	9.6%	23.6%	$32,397,635	22.5%	53.1%
3	$10,952,636	7.6%	31.2%	$13,774,804	9.6%	62.7%
4	$7,309,374	5.1%	36.2%	$13,395,009	9.3%	72.0%
5	$5,546,947	3.8%	40.1%	$7,312,384	5.1%	77.0%
6	$3,084,478	2.1%	42.2%	$6,593,455	4.6%	81.6%
7	$2,523,122	1.7%	44.0%	$4,918,949	3.4%	85.0%
8	$2,103,750	1.5%	45.4%	$2,090,078	1.4%	86.5%
9	$1,977,893	1.4%	46.8%	$1,790,532	1.2%	87.7%
10	$1,856,180	1.3%	48.1%	$1,742,895	1.2%	88.9%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through June 2010 (See 2009 SOM, Table 3-85)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$2,859,534	6.7%	6.7%	$18,936,757	44.5%	44.5%
2	$1,867,852	4.4%	11.1%	$9,597,489	22.6%	67.1%
3	$1,666,721	3.9%	15.0%	$2,975,894	7.0%	74.1%
4	$1,664,106	3.9%	18.9%	$2,571,183	6.0%	80.1%
5	$1,349,602	3.2%	22.1%	$1,829,329	4.3%	84.4%
6	$1,343,538	3.2%	25.3%	$765,678	1.8%	86.2%
7	$1,319,649	3.1%	28.4%	$689,365	1.6%	87.8%
8	$1,293,233	3.0%	31.4%	$588,540	1.4%	89.2%
9	$1,292,035	3.0%	34.4%	$446,261	1.0%	90.2%
10	$1,281,785	3.0%	37.5%	$442,924	1.0%	91.3%

Eastern Reliability

A Change in Market Conditions

For the first six months of 2009, Eastern and Western regional charges were 25.9 percent of all balancing operating reserve charges. Eastern and Western regional reliability charges were 16.7 percent of all balancing operating reserve reliability charges ($15,478,488 of $92,960,347) and of that 16.7 percent, only 0.4 percent was in the East, or $336,190. (See Table 3-69.)

Table 3-69 Regional balancing charges allocation: January through June 2009 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$2,749,936 3.0%	$108,748 0.1%	$2,858,684 3.1%	$34,212,966 36.8%	$20,980,028 22.6%	$10,893,912 11.7%	$66,086,906 71.1%	$68,945,590 74.2%
East	$324,661 0.3%	$11,529 0.0%	$336,190 0.4%	$3,382,299 3.6%	$1,927,684 2.1%	$989,854 1.1%	$6,299,837 6.8%	$6,636,027 7.1%
West	$14,474,332 15.6%	$667,966 0.7%	$15,142,298 16.3%	$1,111,579 1.2%	$755,649 0.8%	$369,206 0.4%	$2,236,433 2.4%	$17,378,731 18.7%
Total	$17,548,928 18.9%	$788,243 0.8%	$18,337,172 19.7%	$38,706,844 41.6%	$23,663,360 25.5%	$12,252,972 13.2%	$74,623,176 80.3%	$92,960,347 100%

The results for the first six months of 2010 were significantly different than the results for the first six months of 2009. Overall balancing operating reserve charges increased, comprised of an increase in RTO charges, a significant increase in Eastern charges and a decrease in Western charges. In particular, Eastern regional reliability charges increased disproportionately between 2009 and 2010. Overall, the proportion of deviation charges decreased substantially and the proportion of reliability charges increased correspondingly. Table 3-70 shows the allocation of balancing charges for the first six months of 2010.

Table 3-70 Regional balancing charges allocation: January through June 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$15,917,613 11.3%	$619,122 0.4%	$16,536,736 11.7%	$40,184,542 28.5%	$22,663,866 16.1%	$11,833,894 8.4%	$74,682,303 53.0%	$91,219,038 64.7%
East	$27,351,105 19.4%	$1,100,323 0.8%	$28,451,428 20.2%	$4,599,507 3.3%	$2,650,810 1.9%	$1,054,579 0.7%	$8,304,896 5.9%	$36,756,324 26.1%
West	$8,784,110 6.2%	$285,356 0.2%	$9,069,466 6.4%	$2,130,462 1.5%	$961,154 0.7%	$797,715 0.6%	$3,889,331 2.8%	$12,958,797 9.2%
Total	$52,052,828 36.9%	$2,004,802 1.4%	$54,057,630 38.4%	$46,914,512 33.3%	$26,275,830 18.6%	$13,686,188 9.7%	$86,876,529 61.6%	$140,934,159 100.0%

Table 3-71 shows the differences between the allocation of balancing operating reserve charges for the first six months of 2009 and the first six months of 2010. The percentages in the table are the differences in the share of total allocation between the two time periods. For example, RTO deviation charges represented 71.1 percent of all balancing operating reserve charges for the first half of 2009, and 53.0 percent of all balancing operating reserve charges for the first half of 2010, a decrease in share of 18.1 percentage points.

Table 3-71 Differences between regional balancing charges allocation: January through June 2009 and 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$13,167,677 8.3%	$510,375 0.3%	$13,678,052 8.7%	$5,971,577 (8.3%)	$1,683,838 (6.5%)	$939,982 (3.3%)	$8,595,397 (18.1%)	$22,273,449 (9.4%)
East	$27,026,444 19.1%	$1,088,794 0.8%	$28,115,238 19.8%	$1,217,208 (0.4%)	$723,127 (0.2%)	$64,725 (0.3%)	$2,005,059 (0.9%)	$30,120,298 18.9%
West	($5,690,222) (9.3%)	($382,610) (0.5%)	($6,072,832) (9.9%)	$1,018,884 0.3%	$205,505 (0.1%)	$428,509 0.2%	$1,652,898 0.4%	($4,419,934) (9.5%)
Total	$34,503,900 18.1%	$1,216,559 0.6%	$35,720,458 18.6%	$8,207,668 (8.3%)	$2,612,470 (6.8%)	$1,433,216 (3.5%)	$12,253,354 (18.6%)	$47,973,812 0.0%

Table 3-72 shows the change in the total balancing operating reserve charges allocated to each category between the first six months of 2009 and the first six months of 2010. For example, the total balancing operating reserve charges allocated to RTO deviations increased 13.0 percent ($74,682,303 compared to $66,086,906).

Table 3-72 Table 35 Percent differences between regional balancing charges allocation: January through June 2009 and 2010 (New Table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	478.8%	469.3%	478.5%	17.5%	8.0%	8.6%	13.0%	32.3%
East	8324.5%	9443.6%	8362.9%	36.0%	37.5%	6.5%	31.8%	453.9%
West	(39.3%)	(57.3%)	(40.1%)	91.7%	27.2%	116.1%	73.9%	(25.4%)
Total	196.6%	154.3%	194.8%	21.2%	11.0%	11.7%	16.4%	51.6%

As shown in Table 3-71 and Table 3-72, the total balancing operating reserves charges allocated to Eastern reliability charges increased $28,115,238, from $336,190 in the first half of 2009, to $28,451,429 in the first half of 2010. Of this increase, 96.1 percent, or $27,026,444, was paid by real-time load, while the remainder, $1,088,794 was paid by real-time exports.

Figure 3-10 shows the regional reliability and deviation credits since the introduction of the modified Operating Reserve Business Rules on December 1, 2008. Under the old operating reserve construct, all balancing operating reserve credits were allocated to demand, supply, and generator deviations. Under the new rules, only credits that are assigned for deviation purposes (credits to units that are used in real-time to offset deviations from day-ahead unit commitments) are allocated to demand, supply, and generator deviations. Credits to units that are used for conservative operations to ensure the maintenance of system reliability are categorized as reliability credits and allocated to real-time load and exports. Reliability and deviation credits are further categorized as RTO, East, and West credits, depending on the voltage and location of the transmission constraint the unit is considered to be running for. Credits to units operating for transmission constraints at the 765kV and 500kV level are categorized as RTO credits, and for lower voltages are categorized as East or West credits, depending on location. Reliability credits to date were 19.7 percent of total balancing operating reserve credits in the first half of 2009 but increased to 38.4 percent in the first half of 2010. As shown in Figure 3-10, Eastern reliability credits increased from $290,150 for the first quarter of 2010, to $28,161,278 in the second quarter, with most of the increase occurring in June. Table 3-73 shows the actual credits for each month since December 2008.

Figure 3-10 Regional reliability and deviation balancing operating reserve credits: December 2008 through June 2010 (New Figure)

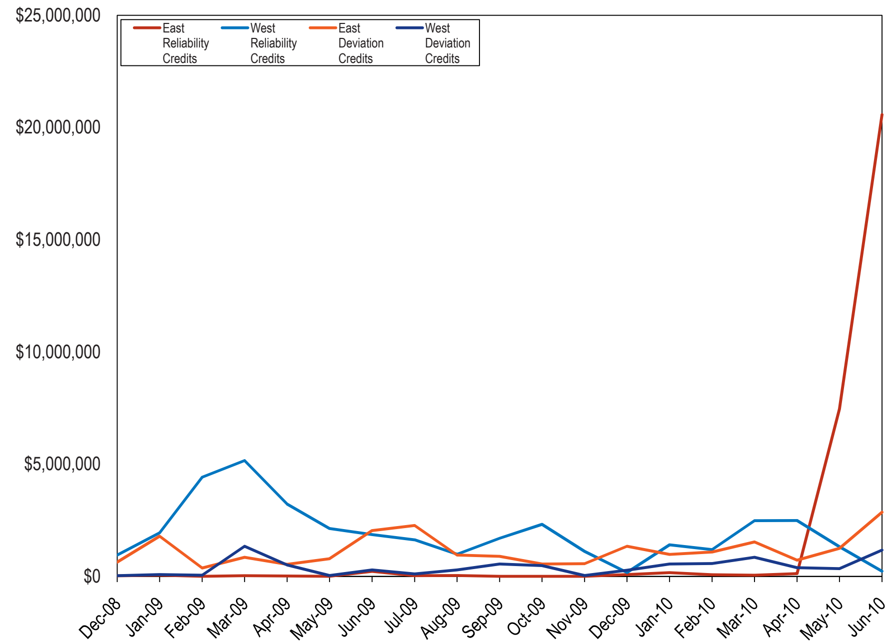


Table 3-73 Regional reliability and deviation balancing operating reserve credits: December 2008 through June 2010 (New Table)

Date	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Dec-08	$1,122,812	$24,194	$953,097	$15,947,328	$638,315	$29,114
Jan-09	$1,206,262	$50,436	$1,942,604	$21,345,280	$1,789,530	$84,818
Feb-09	$437,339	$2,900	$4,422,782	$31,413,796	$371,385	$55,703
Mar-09	$625,452	$34,935	$5,162,875	$14,284,193	$851,527	$1,341,292
Apr-09	$474,138	$18,775	$3,225,567	$6,014,192	$537,604	$507,227
May-09	$220,958	$6,847	$2,132,991	$10,624,328	$789,721	$38,640
Jun-09	$199,855	$222,308	$1,863,966	$11,443,774	$2,041,684	$286,959
Jul-09	$205,809	$33,195	$1,625,620	$11,281,232	$2,269,772	$108,287
Aug-09	$241,597	$38,108	$989,805	$13,133,000	$954,148	$290,021
Sep-09	$438,538	$0	$1,701,221	$7,077,114	$894,704	$549,820
Oct-09	$405,037	$2,136	$2,320,472	$11,003,375	$553,038	$483,214
Nov-09	$109,713	$6,171	$1,113,913	$7,288,862	$568,942	$37,264
Dec-09	$3,259,547	$81,790	$173,475	$15,070,034	$1,341,044	$272,917
Jan-10	$6,213,523	$164,034	$1,408,756	$24,669,068	$980,832	$551,706
Feb-10	$3,787,129	$71,112	$1,192,894	$10,932,772	$1,085,923	$573,703
Mar-10	$1,149,901	$55,004	$2,480,550	$7,598,771	$1,537,198	$850,687
Apr-10	$1,373,143	$127,499	$2,488,915	$11,937,201	$721,388	$387,016
May-10	$1,655,979	$7,462,340	$1,320,404	$11,351,038	$1,248,001	$345,411
Jun-10	$2,830,020	$20,571,439	$229,942	$11,108,209	$2,860,370	$1,174,841

In mid May, maintenance work began on a 230kV line in the eastern region of the RTO. This transmission outage, coupled with higher average loads due to high temperatures in the region and the physical characteristics and operating parameters of these units, required certain units to operate continuously in order to maintain system reliability. This continuous operation required a significant payment of balancing operating reserve credits to cover the offers of the units, given that LMP did not result in adequate revenues. Physical operating parameters, such as minimum run times and minimum down times, can have a significant impact on such credits when they result in a unit operating during uneconomic hours. The balancing operating reserve credits paid to these units were allocated to real-time load and exports.

One of the purposes of the modified Operating Reserve Business Rules was the reallocation of reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In the first six months of 2010, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In the first half of 2010, $54,057,630 of reliability charges, which included $28,033,779 of Eastern reliability credits in May and June, were allocated to participants serving real-time load and exports, which would have been charged to supply, demand, and generator deviations under the prior rules.