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 three 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, net revenues were not adequate to cover total fixed costs for a new entrant CT, CC or 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 the first three months of 2010, net revenues are mixed compared to the same period in 2009. For the new entrant CT, thirteen zones had higher net revenue and four zones had lower net revenue compared to the same period in 2009. (Table 3-8.) For the CT, all zones except for DLCO had a decrease in energy net revenue. The twelve zones that were part of the EMAAC or SWMAAC Locational Delivery Areas (LDAs) for the 2009/2010 delivery year had higher capacity revenues, which more than offset lower energy revenues. The five zones that cleared in the unconstrained RTO LDA had lower capacity revenues. However, the increase in energy net revenue was greater than the decrease in capacity revenues for the DLCO control zone. For the new entrant CC, fourteen zones had a decrease in net revenue through March 2010 compared to the same period in 2009, while DLCO, PPL and PSEG had an increase. For the CC, like the CT, all zones except DLCO had a decrease in energy net revenue. For the zones that were part of the EMAAC and SWMAAC LDAs, the decrease in energy net revenue was greater than the increase in capacity revenues. In PPL and PSEG, the increase in capacity revenue was greater than the decrease in energy net revenues, while, in DLCO, higher energy net revenues were greater than the decrease in capacity revenue associated with the RTO LDA. For the new entrant coal plant (CP), eight zones had an increase in net revenue for January through March 2010 compared to the same period in 2009, while nine zones show a decrease. For the CP, changes in results from 2009 to 2010 were primarily a result of changes in energy market net revenues. Of the eight zones that had an increase in net revenue, seven had an increase in energy net revenues. The AP zone had a slight decrease in energy net revenue compared to the same period in 2009, which was more than offset by higher capacity revenue.

All nine zones that had a decrease in net revenue compared to the same period in 2009 also had a decrease in energy net revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through March 31, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 167,794.8 MW on March 31, a decrease of 59 MW or 0.0 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of March 31, 2010, 40.7 percent was coal; 29.3 percent was natural gas; 18.2 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During the first three months of 2010, coal provided 53.9 percent, nuclear 34.7 percent, gas 7.0 percent, oil 0.1 percent, hydroelectric 2.3 percent, solid waste 0.8 percent and wind 1.3 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 three months of 2010.** PJM did not declare a scarcity event in the first three months of 2010.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. 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. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

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

  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 offset mechanism for RPM revenues; 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 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 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 Three Months of 2010.** The level of operating reserve credits and corresponding charges increased in the first three months of 2010 by 8.3 percent compared to the first three months of 2009. High levels of congestion led to increases in balancing operating reserve credits in January and February. This increase was comprised of an 8.4 percent increase, or $6,142,769, in the amount of balancing operating reserve credits, and an increase of 16.4 percent, or $4,299,551, in day-ahead credits.

- **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, determined to be real-time load and exports. The new operating reserve rules resulted in an increase of $15,642,681 in charges assigned to real-time load and exports for the first three months of 2010. These increases were matched by a decrease of $7,973,883 in charges to demand deviations, a decrease of $5,297,882 in charges to supply deviations, and a decrease of $2,370,915 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 $5,020,215 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 $1,451,963, or 2.2 percent, higher for the first three months of 2010 than what would have been credited under the old rules.

- **Parameter Limited Schedule Rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[1] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

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 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

1 126 FERC ¶61,251 (2009).

capacity markets. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity revenues in the energy market, 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.

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, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

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.

In the first three months of 2010, energy market revenues were generally lower for the two natural gas fired technologies, as energy market prices were lower in most zones while the average delivered price of natural gas in most zones stayed approximately the same or increased. Energy net revenues for the CP were mixed as many eastern zones showed a decrease compared to the same period in 2009, while several zones, including eastern and western zones, showed an increase. This reflects greater locational price separation in both energy market prices and input fuel prices compared to the prior period.

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 are small 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. Most zones had few high demand days and lower volatility through the first three months of 2010 compared to 2009, while the average on peak LMP in DLCO increased by 25.3 percent. As a result, most zones had a decrease in energy market net revenue while DLCO control zone had a 35 percent increase.

Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of avoidable 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 energy net revenues available for new entrants decreases rapidly, 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 CTs set price based on gas costs. For the period January through March 2010, with generally lower load levels, CTs ran less often, which reduced 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
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	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 March 2009 and 2010 (See 2009 SOM, Table 3-4)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$13,392	$17,219	29%
AEP	$10,073	$9,184	(9%)
AP	$10,073	$17,219	71%
BGE	$18,910	$21,360	13%
ComEd	$10,073	$9,184	(9%)
DAY	$10,073	$9,184	(9%)
DLCO	$10,073	$9,184	(9%)
Dominion	$10,073	$9,184	(9%)
DPL	$13,392	$17,219	29%
JCPL	$13,392	$17,219	29%
Met-Ed	$10,073	$17,219	71%
PECO	$13,392	$17,219	29%
PENELEC	$10,073	$17,219	71%
Pepco	$18,910	$21,360	13%
PPL	$10,073	$17,219	71%
PSEG	$13,392	$17,219	29%
RECO	$13,392	$17,219	29%
PJM	$11,212	$12,461	11%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM[2] (Dollars per MBtu): January through March 2009 and 2010 (See 2009 SOM, Table 3-5)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Natural Gas	$6.38	$6.44	1%
Low Sulfur Coal	$3.54	$3.03	(14%)

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)[3]: Net revenue for January through March 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$3,894	$1,821	(53%)
AEP	$1,739	$1,020	(41%)
AP	$5,998	$2,250	(62%)
BGE	$3,984	$3,287	(17%)
ComEd	$963	$454	(53%)
DAY	$1,242	$822	(34%)
DLCO	$790	$3,888	392%
Dominion	$4,981	$4,186	(16%)
DPL	$5,090	$2,522	(50%)
JCPL	$3,857	$2,177	(44%)
Met-Ed	$3,524	$1,905	(46%)
PECO	$3,372	$1,908	(43%)
PENELEC	$2,973	$957	(68%)
Pepco	$8,494	$7,012	(17%)
PPL	$3,406	$1,794	(47%)
PSEG	$2,661	$2,270	(15%)
RECO	$2,090	$1,432	(32%)
PJM	$3,474	$2,336	(33%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$16,130	$10,129	(37%)
AEP	$8,227	$5,132	(38%)
AP	$19,453	$10,204	(48%)
BGE	$15,418	$12,685	(18%)
ComEd	$6,758	$2,843	(58%)
DAY	$7,596	$4,870	(36%)
DLCO	$5,806	$7,860	35%
Dominion	$17,573	$12,881	(27%)
DPL	$17,545	$11,295	(36%)
JCPL	$16,634	$10,989	(34%)
Met-Ed	$14,468	$10,197	(30%)
PECO	$14,625	$10,362	(29%)
PENELEC	$14,601	$6,835	(53%)
Pepco	$24,507	$19,487	(20%)
PPL	$14,091	$9,454	(33%)
PSEG	$13,979	$10,839	(22%)
RECO	$11,995	$7,676	(36%)
PJM	$14,083	$9,632	(32%)

2 The average delivered fuel prices shown in Table 3-3 are included for illustrative purposes, represent single indices and do not represent a PJM aggregate fuel price. Most natural gas and coal price indices followed similar trends. However, actual delivered fuel prices varied significantly by location in the first three months of 2010.

3 The energy net revenues presented for "PJM" for the periods January through March 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 3-6 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 March 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$46,220	$33,276	(28%)
AEP	$12,415	$17,770	43%
AP	$29,721	$25,452	(14%)
BGE	$28,728	$33,776	18%
ComEd	$15,980	$25,343	59%
DAY	$12,746	$18,874	48%
DLCO	$13,371	$27,913	109%
Dominion	$29,173	$34,622	19%
DPL	$27,466	$31,177	14%
JCPL	$43,613	$32,246	(26%)
Met-Ed	$38,505	$30,561	(21%)
PECO	$43,038	$31,814	(26%)
PENELEC	$32,028	$20,936	(35%)
Pepco	$38,662	$36,129	(7%)
PPL	$41,848	$30,188	(28%)
PSEG	$42,672	$35,944	(16%)
RECO	$42,095	$30,042	(29%)
PJM	$31,664	$29,180	(8%)

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 March 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$3,474	$2,336	(33%)
Capacity	$9,992	$11,234	12%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$600	$600	0%
Total	$14,066	$14,169	1%

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 March 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$16,428	$17,944	9%
AEP	$11,316	$9,899	(13%)
AP	$15,575	$18,373	18%
BGE	$21,435	$23,143	8%
ComEd	$10,539	$9,333	(11%)
DAY	$10,818	$9,701	(10%)
DLCO	$10,367	$12,767	23%
Dominion	$14,557	$13,065	(10%)
DPL	$17,624	$18,645	6%
JCPL	$16,391	$18,301	12%
Met-Ed	$13,101	$18,028	38%
PECO	$15,906	$18,031	13%
PENELEC	$12,549	$17,080	36%
Pepco	$25,945	$26,868	4%
PPL	$12,982	$17,917	38%
PSEG	$15,195	$18,393	21%
RECO	$14,625	$17,555	20%
PJM	$14,066	$14,169	1%

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 March 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$14,083	$9,632	(32%)
Capacity	$10,832	$11,986	11%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$800	$800	0%
Total	$25,714	$22,418	(13%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$29,867	$27,491	(8%)
AEP	$18,758	$14,766	(21%)
AP	$29,984	$27,567	(8%)
BGE	$34,486	$34,031	(1%)
ComEd	$17,289	$12,476	(28%)
DAY	$18,127	$14,503	(20%)
DLCO	$16,337	$17,494	7%
Dominion	$28,104	$22,515	(20%)
DPL	$31,282	$28,658	(8%)
JCPL	$30,371	$28,352	(7%)
Met-Ed	$24,999	$27,559	10%
PECO	$28,362	$27,725	(2%)
PENELEC	$25,131	$24,197	(4%)
Pepco	$43,575	$40,832	(6%)
PPL	$24,622	$26,816	9%
PSEG	$27,717	$28,201	2%
RECO	$25,732	$25,039	(3%)
PJM	$25,714	$22,418	(13%)

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 March 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$31,664	$29,180	(8%)
Capacity	$10,108	$11,301	12%
Synchronized	$0	$0	0%
Regulation	$82	$33	(59%)
Reactive	$446	$446	0%
Total	$42,300	$40,960	(3%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$58,740	$49,366	(16%)
AEP	$21,942	$26,592	21%
AP	$39,248	$41,554	6%
BGE	$46,222	$53,618	16%
ComEd	$25,507	$34,208	34%
DAY	$22,273	$27,704	24%
DLCO	$22,898	$36,765	61%
Dominion	$38,700	$43,423	12%
DPL	$39,986	$47,270	18%
JCPL	$56,132	$48,337	(14%)
Met-Ed	$48,032	$46,654	(3%)
PECO	$55,558	$47,904	(14%)
PENELEC	$41,555	$37,040	(11%)
Pepco	$56,156	$55,971	(0%)
PPL	$51,375	$46,281	(10%)
PSEG	$55,191	$52,033	(6%)
RECO	$54,614	$46,136	(16%)
PJM	$42,300	$40,960	(3%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$2,039	$547	(73%)
AEP	$638	$110	(83%)
AP	$2,830	$805	(72%)
BGE	$2,227	$1,040	(53%)
ComEd	$105	$6	(94%)
DAY	$236	$25	(89%)
DLCO	$80	$340	326%
Dominion	$3,178	$2,408	(24%)
DPL	$2,754	$614	(78%)
JCPL	$1,780	$588	(67%)
Met-Ed	$1,653	$575	(65%)
PECO	$1,747	$592	(66%)
PENELEC	$1,795	$320	(82%)
Pepco	$6,797	$5,717	(16%)
PPL	$1,554	$561	(64%)
PSEG	$1,074	$312	(71%)
RECO	$705	$220	(69%)
PJM	$1,835	$869	(53%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$15,495	$9,827	(37%)
AEP	$6,623	$4,793	(28%)
AP	$16,835	$10,475	(38%)
BGE	$15,287	$13,596	(11%)
ComEd	$4,098	$2,039	(50%)
DAY	$5,070	$3,794	(25%)
DLCO	$3,299	$5,773	75%
Dominion	$17,655	$15,489	(12%)
DPL	$16,605	$10,132	(39%)
JCPL	$16,044	$11,920	(26%)
Met-Ed	$13,788	$10,505	(24%)
PECO	$14,470	$10,908	(25%)
PENELEC	$13,681	$8,525	(38%)
Pepco	$25,134	$22,605	(10%)
PPL	$13,296	$9,894	(26%)
PSEG	$13,186	$9,625	(27%)
RECO	$11,237	$7,885	(30%)
PJM	$13,047	$9,870	(24%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$48,583	$38,319	(21%)
AEP	$11,316	$18,595	64%
AP	$28,088	$28,055	(0%)
BGE	$32,085	$40,269	26%
ComEd	$15,906	$27,080	70%
DAY	$10,866	$19,194	77%
DLCO	$10,767	$27,875	159%
Dominion	$31,379	$41,602	33%
DPL	$28,578	$35,399	24%
JCPL	$46,173	$38,095	(17%)
Met-Ed	$40,862	$36,011	(12%)
PECO	$46,274	$37,424	(19%)
PENELEC	$32,808	$25,651	(22%)
Pepco	$41,984	$43,273	3%
PPL	$43,994	$35,836	(19%)
PSEG	$45,005	$40,338	(10%)
RECO	$44,385	$37,307	(16%)
PJM	$32,886	$33,548	2%

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 March 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 - Mar)	$2,336	$869	$1,466	63%

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 March 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 - Mar)	$9,632	$9,870	($238)	(2%)

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 March 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 - Mar)	$29,180	$33,548	($4,368)	(15%)

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 March 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$16,428	$17,944	$128,705	13%	14%
AEP	$11,316	$9,899	$128,705	9%	8%
AP	$15,575	$18,373	$128,705	12%	14%
BGE	$21,435	$23,143	$128,705	17%	18%
ComEd	$10,539	$9,333	$128,705	8%	7%
DAY	$10,818	$9,701	$128,705	8%	8%
DLCO	$10,367	$12,767	$128,705	8%	10%
Dominion	$14,557	$13,065	$128,705	11%	10%
DPL	$17,624	$18,645	$128,705	14%	14%
JCPL	$16,391	$18,301	$128,705	13%	14%
Met-Ed	$13,101	$18,028	$128,705	10%	14%
PECO	$15,906	$18,031	$128,705	12%	14%
PENELEC	$12,549	$17,080	$128,705	10%	13%
Pepco	$25,945	$26,868	$128,705	20%	21%
PPL	$12,982	$17,917	$128,705	10%	14%
PSEG	$15,195	$18,393	$128,705	12%	14%
RECO	$14,625	$17,555	$128,705	11%	14%
PJM	$14,066	$14,169	$128,705	11%	11%

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

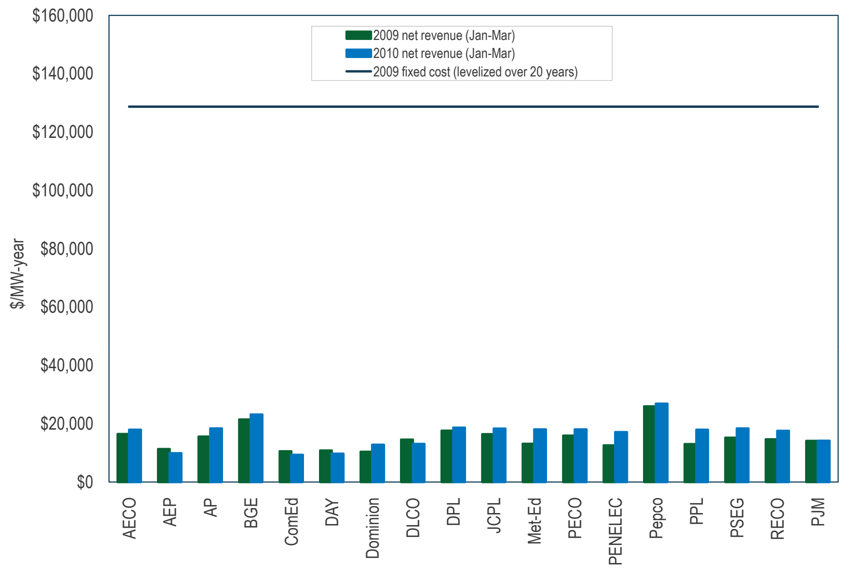


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$29,867	$27,491	$173,174	17%	16%
AEP	$18,758	$14,766	$173,174	11%	9%
AP	$29,984	$27,567	$173,174	17%	16%
BGE	$34,486	$34,031	$173,174	20%	20%
ComEd	$17,289	$12,476	$173,174	10%	7%
DAY	$18,127	$14,503	$173,174	10%	8%
DLCO	$16,337	$17,494	$173,174	9%	10%
Dominion	$28,104	$22,515	$173,174	16%	13%
DPL	$31,282	$28,658	$173,174	18%	17%
JCPL	$30,371	$28,352	$173,174	18%	16%
Met-Ed	$24,999	$27,559	$173,174	14%	16%
PECO	$28,362	$27,725	$173,174	16%	16%
PENELEC	$25,131	$24,197	$173,174	15%	14%
Pepco	$43,575	$40,832	$173,174	25%	24%
PPL	$24,622	$26,816	$173,174	14%	15%
PSEG	$27,717	$28,201	$173,174	16%	16%
RECO	$25,732	$25,039	$173,174	15%	14%
PJM	$25,714	$22,418	$173,174	15%	13%

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

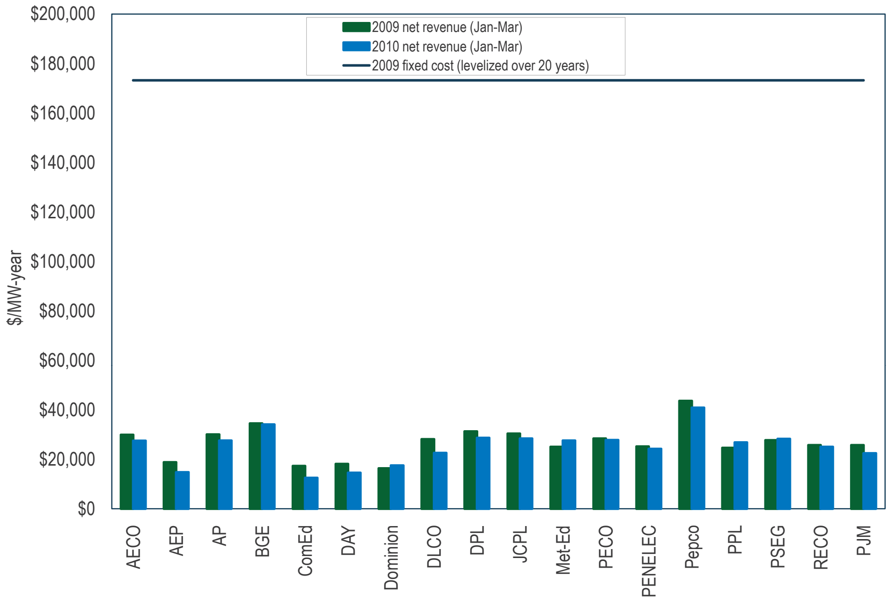
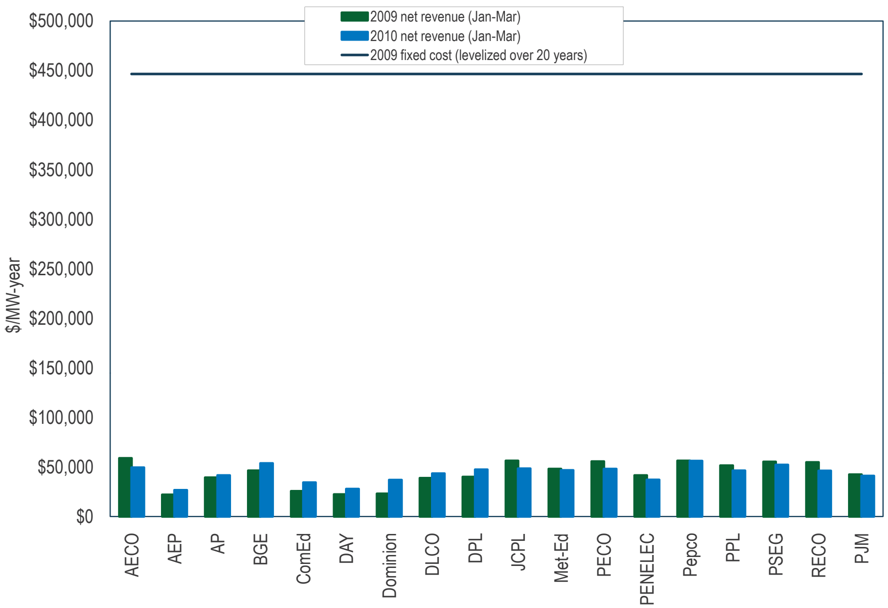


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$58,740	$49,366	$446,550	13%	11%
AEP	$21,942	$26,592	$446,550	5%	6%
AP	$39,248	$41,554	$446,550	9%	9%
BGE	$46,222	$53,618	$446,550	10%	12%
ComEd	$25,507	$34,208	$446,550	6%	8%
DAY	$22,273	$27,704	$446,550	5%	6%
DLCO	$22,898	$36,765	$446,550	5%	8%
Dominion	$38,700	$43,423	$446,550	9%	10%
DPL	$39,986	$47,270	$446,550	9%	11%
JCPL	$56,132	$48,337	$446,550	13%	11%
Met-Ed	$48,032	$46,654	$446,550	11%	10%
PECO	$55,558	$47,904	$446,550	12%	11%
PENELEC	$41,555	$37,040	$446,550	9%	8%
Pepco	$56,156	$55,971	$446,550	13%	13%
PPL	$51,375	$46,281	$446,550	12%	10%
PSEG	$55,191	$52,033	$446,550	12%	12%
RECO	$54,614	$46,136	$446,550	12%	10%
PJM	$42,300	$40,960	$446,550	9%	9%

Figure 3-3 New entrant CP real-time 2009 and 2010 net revenue for January through March 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, January 31, February 28, and March 31, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-Jan-10		28-Feb-10		31-Mar-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,420.1	40.8%	68,273.2	40.7%	68,273.2	40.7%
Gas	49,238.8	29.3%	49,238.8	29.3%	49,234.0	29.4%	49,243.2	29.3%
Hydroelectric	7,921.9	4.7%	7,921.9	4.7%	7,897.9	4.7%	7,897.9	4.7%
Nuclear	30,611.9	18.2%	30,611.9	18.2%	30,599.9	18.2%	30,599.9	18.2%
Oil	10,700.1	6.4%	10,700.1	6.4%	10,699.0	6.4%	10,699.0	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	672.1	0.4%
Wind	326.9	0.2%	326.9	0.2%	338.9	0.2%	409.5	0.2%
Total	167,853.8	100.0%	167,891.8	100.0%	167,715.0	100.0%	167,794.8	100.0%

Energy Production by Fuel Source

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

	GWh	Percent
Coal	98,548.0	53.9%
Nuclear	63,428.4	34.7%
Gas	12,817.2	7.0%
Natural Gas	12,432.7	6.8%
Landfill Gas	384.5	0.2%
Biomass Gas	0.1	0.0%
Hydroelectric	4,266.2	2.3%
Waste	1,403.6	0.8%
Solid Waste	1,069.4	0.6%
Miscellaneous	334.1	0.2%
Wind	2,336.4	1.3%
Oil	113.4	0.1%
Heavy Oil	80.6	0.0%
Light Oil	28.4	0.0%
Diesel	4.2	0.0%
Kerosene	0.2	0.0%
Jet Oil	0.0	0.0%
Solar	0.8	0.0%
Battery	0.1	0.0%
Total	182,914.1	100.0%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through March 2010[4] (See 2009 SOM, Table 3-37)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	830

PJM Generation Queues

Table 3-26 Queue comparison (MW): March 31, 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	20,181	(2,553)	(13%)
2011	15,873	15,544	(330)	(2%)
2012	11,053	11,947	894	7%
2013	6,350	8,781	2,431	28%
2014	13,439	12,790	(649)	(5%)
2015	3,091	2,958	(133)	(4%)
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	1,594	0	0%
Total	76,725	76,785	60	0%

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

Table 3-27 Capacity in PJM queues (MW): At March 31, 2010[5, 6] (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	2,133	223	6,663	10,397
O Expired 31-Jul-05	1,978	1,048	444	4,104	7,574
P Expired 31-Jan-06	931	989	1,799	4,768	8,486
Q Expired 31-Jul-06	2,245	707	3,583	8,133	14,668
R Expired 31-Jan-07	6,509	667	689	14,976	22,840
S Expired 31-Jul-07	7,526	967	1,321	11,079	20,892
T Expired 31-Jan-08	15,586	174	342	12,367	28,468
U Expired 31-Jan-09	12,136	110	464	22,151	34,861
V Expired 31-Jan-10	14,931	0	94	2,016	17,041
W Expires 31-Jan-11	3,759	0	0	0	3,759
Total	66,997	23,916	9,788	196,569	297,271

Table 3-28 Average project queue times: At March 31, 2010 (See 2009 SOM, Table 3-40)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	900	618	0	2,803
In-Service	738	638	0	3,287
Suspended	2,299	822	890	4,172
Under Construction	1,189	896	0	4,370
Withdrawn	492	478	0	2,793

5 The *2010 Quarterly State of the Market Report for PJM: January through March* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 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 March 31, 2010[7] (See 2009 SOM, Table 3-41)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	10	767	2	0	0	493	665	1,066	0	3,002
AEP	2	1,855	594	5	100	84	56	2,691	11,585	0	16,973
AP	0	958	4	19	68	0	310	774	1,388	0	3,522
BGE	0	0	0	6	0	1,640	0	132	0	25	1,803
ComEd	0	1,680	1,044	98	0	804	0	1,366	24,068	0	29,060
DAY	0	0	10	2	112	0	23	12	1,199	0	1,357
DLCO	0	0	0	0	0	91	0	0	0	0	91
DPL	14	0	55	0	0	0	120	43	450	0	682
Dominion	0	2,691	656	25	30	1,944	130	405	690	0	6,570
JCPL	0	1,430	27	33	0	0	113	0	0	0	1,603
Met-Ed	20	1,445	8	31	0	24	50	10	0	0	1,588
PECO	0	1,775	35	6	0	500	21	18	0	0	2,355
PENELEC	0	0	65	14	32	0	18	50	1,251	0	1,430
Pepco	20	2,670	249	0	0	0	0	0	0	0	2,939
PPL	0	0	128	8	143	1,600	38	116	179	11	2,222
PSEG	0	690	767	10	0	0	120	0	0	0	1,587
Total	56	15,203	4,409	259	485	6,687	1,492	6,281	41,877	36	76,785

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2010[8] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	14	3,905	1,651	51	0	500	867	726	1,516	0	9,230
SWMAAC	20	2,670	249	6	0	1,640	0	132	0	25	4,742
WMAAC	20	1,445	201	53	175	1,624	106	176	1,430	11	5,240
RTO	2	7,184	2,308	149	310	2,923	519	5,248	38,931	0	57,574
Total	56	15,203	4,409	259	485	6,687	1,492	6,281	41,877	36	76,785

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

Table 3-31 Existing PJM capacity: At March 31, 2010[9] (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	641	0	23	0	0	1,274	0	8	1,945
AEP	0	3,627	4,355	57	1,001	2,106	21,255	0	802	33,204
AP	0	1,140	1,129	36	108	0	7,974	0	431	10,818
BGE	0	862	0	7	0	1,735	3,039	0	0	5,643
ComEd	0	7,217	1,836	111	0	10,336	7,094	0	1,765	28,359
DAY	0	1,377	0	53	0	0	3,551	0	0	4,981
DLCO	0	188	101	0	6	1,741	1,259	0	0	3,295
DPL	0	2,487	364	95	0	0	2,016	0	0	4,962
Dominion	0	3,786	3,216	162	3,325	3,425	8,479	0	0	22,393
External	0	1,890	974	0	0	439	10,064	0	185	13,552
JCPL	0	1,430	1,196	25	400	615	318	0	0	3,983
Met-Ed	0	407	2,000	24	20	786	890	0	0	4,127
PECO	1	833	2,540	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	287	0	47	521	0	6,830	0	447	8,131
Pepco	0	1,571	0	12	0	0	4,707	0	0	6,290
PPL	0	1,362	960	63	571	2,275	5,530	0	217	10,977
PSEG	0	2,852	2,921	0	5	3,553	2,531	10	0	11,872
Total	1	31,955	21,592	723	7,599	31,499	88,938	13	3,854	186,173

9 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 March 31, 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	17,357	18,861	390	10	0	2,107	13	3,854	42,592
10 to 20	0	3,976	4,767	129	49	0	6,133	0	0	15,053
20 to 30	0	158	437	38	3,207	15,981	9,999	0	0	29,819
30 to 40	0	101	5,296	39	451	14,903	31,316	0	0	52,106
40 to 50	0	0	2,594	123	2,470	615	24,269	0	0	30,071
50 to 60	0	0	0	4	348	0	13,610	0	0	13,962
60 to 70	0	0	0	0	32	0	1,357	0	0	1,389
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	32	0	0	0	0	32
Total	1	21,592	31,955	723	7,599	31,499	88,938	13	3,854	186,173

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[10] (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%	14	15	0.0%
	Combined Cycle	0	0.0%	7,021	20.4%	3,905	10,926	28.9%
	Combustion Turbine	960	12.1%	8,242	24.0%	1,651	8,933	23.7%
	Diesel	49	0.6%	150	0.4%	51	152	0.4%
	Hydroelectric	2,042	25.8%	2,047	5.9%	0	2,047	5.4%
	Nuclear	615	7.8%	8,656	25.2%	500	8,541	22.6%
	Solar	0	0.0%	13	0.0%	867	880	2.3%
	Steam	4,243	53.6%	8,268	24.0%	726	4,750	12.6%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.0%
	EMAAC Total	7,909	100.0%	34,405	100.0%	9,230	37,768	100.0%

Table continued next page

10 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.

(cont'd) 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	Battery	0	0.0%	0	0.0%	20	20	0.2%
	Combined Cycle	0	0.0%	0	0.0%	2,670	2,670	20.8%
	Combustion Turbine	556	14.5%	2,433	20.4%	249	2,126	16.6%
	Diesel	0	0.0%	19	0.2%	6	25	0.2%
	Nuclear	0	0.0%	1,735	14.5%	1,640	3,375	26.3%
	Steam	3,266	85.5%	7,746	64.9%	132	4,612	35.9%
	Unknown	0	0.0%	0	0.0%	25	25	0.2%
	SWMAAC Total	3,822	100.0%	11,932	100.0%	4,743	12,834	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	20	20	0.1%
	Combined Cycle	0	0.0%	2,960	12.7%	1,445	4,405	20.0%
	Combustion Turbine	296	4.3%	2,055	8.8%	201	1,960	8.9%
	Diesel	35	0.5%	135	0.6%	53	152	0.7%
	Hydroelectric	444	6.5%	1,112	4.8%	175	1,286	5.8%
	Nuclear	0	0.0%	3,061	13.2%	1,624	4,685	21.2%
	Solar	0	0.0%	0	0.0%	106	106	0.5%
	Steam	6,052	88.6%	13,249	57.0%	176	7,373	33.4%
	Wind	0	0.0%	663	2.9%	1,430	2,094	9.5%
	Unknown	0	0.0%	0	0.0%	11	11	0.1%
	WMAAC Total	6,827	100.0%	23,235	100.0%	5,240	22,061	100.0%
RTO	Battery	0	0.0%	0	0.0%	2	2	0.0%
	Combined Cycle	0	0.0%	11,611	10.0%	7,184	18,794	12.9%
	Combustion Turbine	782	2.8%	19,225	16.5%	2,308	20,751	14.2%
	Diesel	43	0.2%	419	0.4%	149	526	0.4%
	Hydroelectric	1,396	5.0%	4,440	3.8%	310	3,354	2.3%
	Nuclear	0	0.0%	18,047	15.5%	2,923	20,970	14.4%
	Solar	0	0.0%	0	0.0%	519	519	0.4%
	Steam	25,824	92.1%	59,676	51.2%	5,248	39,100	26.8%
	Wind	0	0.0%	3,183	2.7%	38,931	42,114	28.8%
	RTO Total	28,045	100.0%	116,601	100.0%	57,574	146,127	100.0%
All Areas	Total	46,602		186,173		76,785	218,789	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through March 2010[11] (See 2009 SOM, Table 3-46)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	27.6%	31,351	1,336
Capacity Resource	34.4%	57,925	2,517
All Units	32.4%	89,276	3,854

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

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	491.8	388	1.50%
All Wind	1,343.7	588	2.27%

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

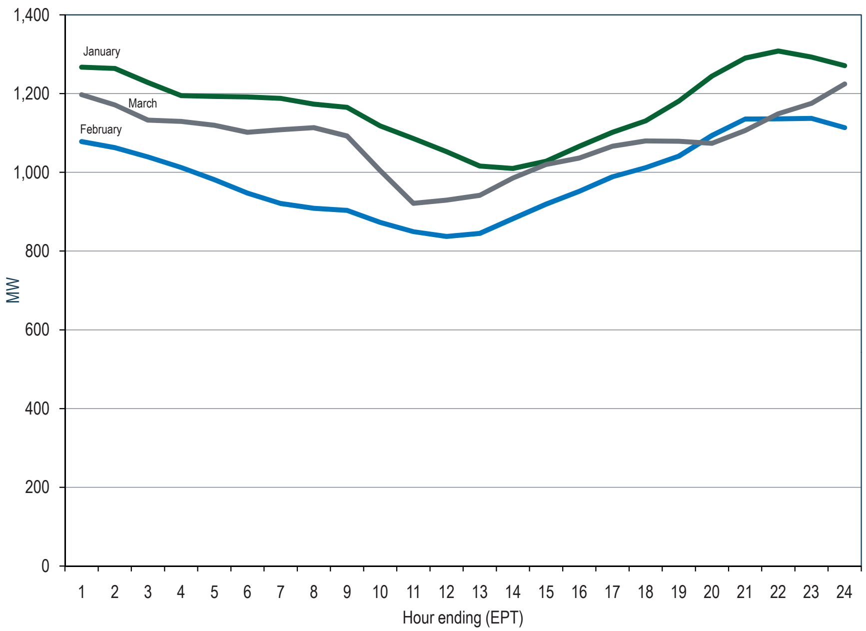


Table 3-36 Capacity factor of wind units in PJM by month, January through March 2010[12] (See 2009 SOM, Table 3-48)

Month	Generation (MWh)	Capacity Factor
January	869,954.9	36.9%
February	662,787.4	29.4%
March	803,642.1	31.0%
April		
May		
June		
July		
August		
September		
October		
November		
December		
Annual	2,336,384.4	32.4%

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

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	33.3%	27.2%			31.0%
	Average Wind Generation	1,086.7	950.8			1,037.1
	Average Load	91,305.2	78,083.9			86,478.4
Off-Peak	Capacity Factor	33.1%	34.7%			33.6%
	Average Wind Generation	1,078.9	1,210.0			1,121.6
	Average Load	80,380.7	66,406.2			75,827.7

11 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.

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

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

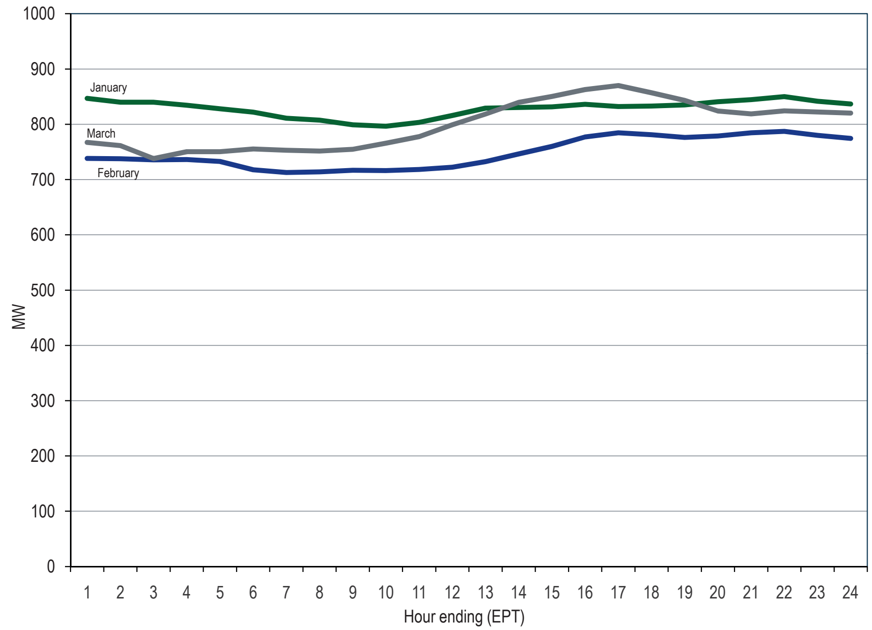
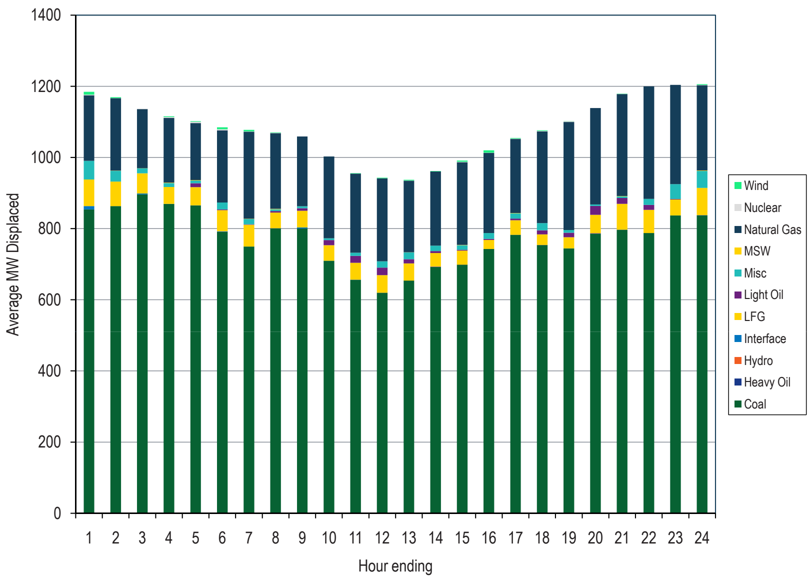


Figure 3-6 Marginal fuel at time of wind generation in PJM, January through March 2010 (See 2009 SOM, Figure 3-13)



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 March 2010 (See 2009 SOM, Table 3-54)

	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	$40,308,020	$50,639,393
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,365,749	$33,805,958
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,160,276	$25,119,979
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566				
May	$6,024,108	$5,543	$15,490,257	$21,519,908				
Jun	$6,722,329	$0	$19,339,846	$26,062,175				
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	$30,543,731	$187,554	$78,834,045	$109,565,330
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	27.9%	0.2%	72.0%	100.0%

Table 3-42 Regional balancing charges allocation: January through March 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	$10,176,719 16.1%	$383,645 0.6%	$10,560,364 16.7%	$21,710,093 34.3%	$13,665,395 21.6%	$6,456,026 10.2%	$41,831,514 66.1%	$52,391,878 82.8%
East	$278,704 0.4%	$11,446 0.0%	$290,150 0.5%	$1,802,666 2.8%	$1,400,649 2.2%	$392,516 0.6%	$3,595,832 5.7%	$3,885,982 6.1%
West	$4,925,038 7.8%	$157,162 0.2%	$5,082,200 8.0%	$1,023,136 1.6%	$533,414 0.8%	$391,554 0.6%	$1,948,105 3.1%	$7,030,305 11.1%
Total	$15,380,462 24.3%	$552,253 0.9%	$15,932,714 25.2%	$24,535,896 38.8%	$15,599,458 24.6%	$7,240,096 11.4%	$47,375,451 74.8%	$63,308,165 100%

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.

Deviations

Categories

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through March 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	8,172,164	3,297,121	2,572,113	14,041,398	9,439,465	5,707,965	2,707,378	17,854,808
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,675,656	5,332,236	2,460,549	15,468,441
Mar	6,392,821	2,520,387	2,405,061	11,318,269	8,101,950	5,138,264	2,274,537	15,514,752
Apr	5,951,654	3,127,726	2,224,157	11,303,537				
May	6,624,696	3,787,650	2,699,616	13,111,962				
Jun	8,117,669	3,179,999	2,644,016	13,941,684				
Jul	9,237,956	3,914,230	2,213,828	15,366,014				
Aug	8,296,485	4,000,974	2,275,294	14,572,753				
Sep	7,360,536	3,691,646	2,577,095	13,629,277				
Oct	6,792,603	3,538,950	2,404,069	12,735,621				
Nov	6,561,634	3,586,432	2,267,083	12,415,148				
Dec	8,399,099	4,898,506	1,775,964	15,073,569				
Total	88,635,377	42,589,911	28,604,806	159,830,094	25,217,072	16,178,465	7,442,464	48,838,001
Share of Annual Deviations	55.5%	26.6%	17.9%	100.0%	51.6%	33.1%	15.2%	100.0%

Table 3-44 Regional charges determinants (MWh): January through March 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	175,139,532	6,517,020	181,656,552	25,217,072	16,178,465	7,442,464	48,838,001	230,494,553
East	94,737,368	3,860,039	98,597,407	16,390,759	11,314,306	3,946,496	31,651,560	130,248,967
West	80,402,164	2,656,981	83,059,145	8,780,337	4,839,658	3,495,969	17,115,963	100,175,108

Balancing Operating Reserve Charge Rate

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

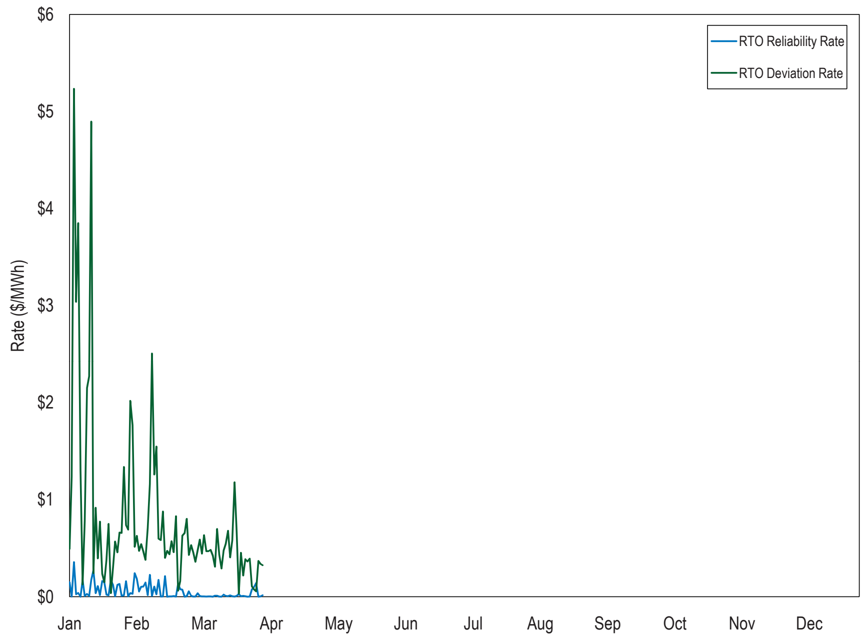


Figure 3-8 Daily regional reliability and deviation rates ($/MWh): January through March 2010 (See 2009 SOM, Figure 3-15)

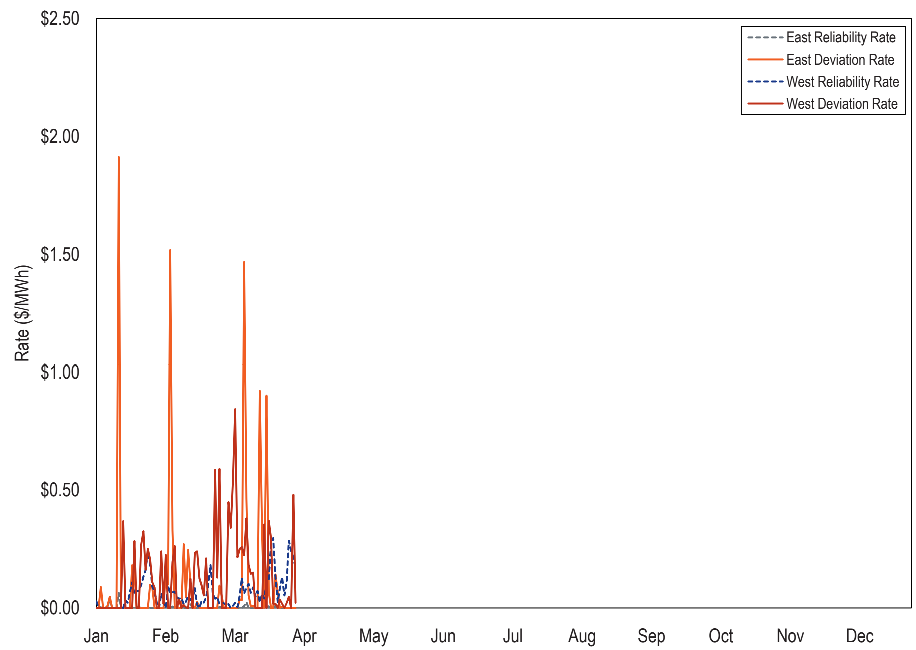


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through March 2010 (See 2009 SOM, Table 3-58)

	Reliability	Deviations
RTO	0.056	0.792
East	0.003	0.111
West	0.066	0.123

Operating Reserve Credits by Category

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

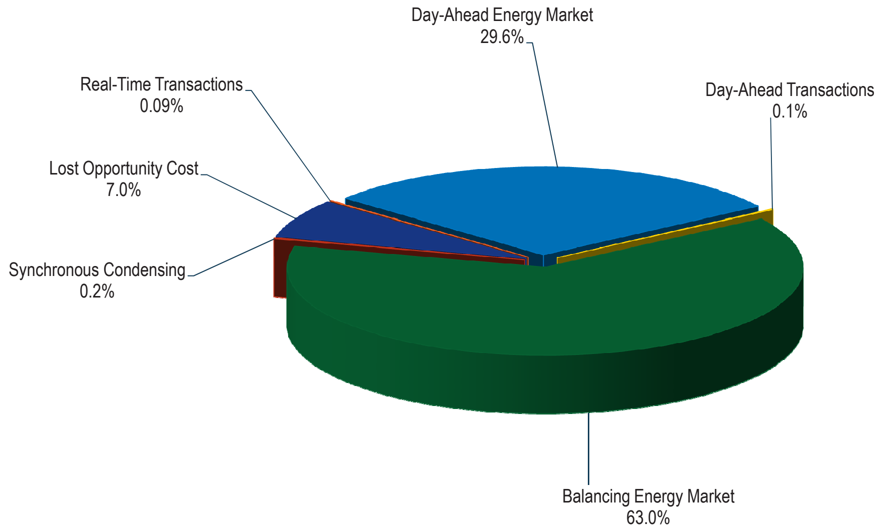


Table 3-46 Credits by month (By operating reserve market): January through March 2010 (See 2009 SOM, Table 3-59)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$33,833,103	$0	$3,483,087	$47,647,563
Feb	$11,382,585	$42,910	$14,715	$17,640,757	$77,139	$1,868,879	$31,026,985
Mar	$8,831,771	$5,115	$122,817	$13,348,277	$15,603	$1,891,859	$24,215,441
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$30,413,890	$129,841	$187,554	$64,822,137	$92,742	$7,243,826	$102,889,989
Share of Credits	29.6%	0.1%	0.2%	63.0%	0.1%	7.0%	100.0%

Characteristics of Credits and Charges

Types of Units

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

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	39.8%	0.0%	58.6%	1.6%	$51,800,402
Combustion Turbine	0.5%	1.2%	94.7%	3.7%	$16,242,447
Diesel	0.0%	0.0%	97.1%	2.9%	$36,916
Hydro	0.0%	0.0%	100.0%	0.0%	$3,539
Landfill	0.0%	0.0%	0.0%	100.0%	$4,440,478
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	32.6%	0.0%	63.9%	3.5%	$29,813,633
Wind Farm	0.0%	0.0%	2.8%	97.2%	$286,658

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

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	67.8%	0.0%	46.8%	11.6%
Combustion Turbine	0.2%	100.0%	23.7%	8.3%
Diesel	0.0%	0.0%	0.1%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%
Landfill	0.0%	0.0%	0.0%	61.7%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	31.9%	0.0%	29.4%	14.6%
Wind Farm	0.0%	0.0%	0.0%	3.9%
Total	$30,413,890	$187,554	$64,822,137	$7,200,493

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through March 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	$1,909,329	$261,994	$2,171,324	$29,019,219	$2,741,214	$31,760,432	$1,952,189	$273,280	$2,225,469	$4,813,885	$741,874	$5,555,758	8.7%	78.3%
Feb	$1,071,403	$151,355	$1,222,758	$14,105,775	$1,393,404	$15,499,179	$999,618	$145,424	$1,145,042	$3,534,982	$475,475	$4,010,457	7.0%	62.9%
Mar	$565,725	$120,609	$686,334	$7,861,107	$1,399,277	$9,260,384	$741,832	$160,071	$901,904	$5,487,170	$492,582	$5,979,752	6.3%	62.9%
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Average	49.0%	48.0%	48.9%	78.7%	76.4%	78.4%	51.0%	52.0%	51.1%	21.3%	23.6%	21.6%	7.3%	68.0%

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 March 2010 (See 2009 SOM, Table 3-66)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$10,270,330	$41,572,827	$51,843,157
East	$290,150	$3,595,832	$3,885,982
West	$5,082,200	$1,948,105	$7,030,305
Total	$15,642,681	$47,116,763	$62,759,444

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

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,910,065	16,031,262	7,371,964	48,313,290

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

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,910,065	16,031,262	7,371,964	48,313,290
Balancing Rate ($/MWh)	1.299	1.299	1.299	1.299
Charges ($)	$32,358,421	$20,824,768	$9,576,255	$62,759,444

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through March 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	$10,270,330	179,728,903	0.057	$10,270,330	$41,572,827	48,313,290	0.860	$41,572,827	$51,843,157
East	$290,150	98,597,407	0.003	$290,150	$3,595,832	31,651,560	0.114	$3,595,832	$3,885,982
West	$5,082,200	83,059,145	0.061	$5,082,200	$1,948,105	17,115,963	0.114	$1,948,105	$7,030,305
Total	$15,642,681	179,728,903	NA	$15,642,681	$47,116,763	48,313,290	NA	$47,116,763	$62,759,444

Table 3-54 Difference in total charges between old rules and new rules: January through March 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	$32,358,421	$20,824,768	$9,576,255	$62,759,444
Charges (Current)	$15,100,080	$542,601	$15,642,681	$24,384,538	$15,526,886	$7,205,339	$47,116,763
Difference	$15,100,080	$542,601	$15,642,681	($7,973,883)	($5,297,882)	($2,370,915)	($15,642,681)

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 March 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				
May				
Jun				
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Total	24,647,705	36,017,600	6,618,912	8,280,918

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

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$10,131,402	$12,596,576	($2,465,174)
Feb	$3,939,289	$5,368,599	($1,429,310)
Mar	$3,280,123	$4,405,853	($1,125,730)
Total	$17,350,813	$22,371,028	($5,020,215)

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

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Current Rules	Balancing Rate Under Old Rules	Charges Under Current Rules	Charges Under Old Rules	Differerence
RTO	6,618,912	8,280,918	14,899,830	0.94	1.38	$15,650,032	$22,371,028	($6,720,997)
East	4,481,203	4,848,963	9,330,165	0.12	0.00	$1,097,057	$0	$1,097,057
West	2,113,208	3,385,979	5,499,187	0.12	0.00	$603,725	$0	$603,725

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through March 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	$32,822,043	$33,772,219	$950,176
2010	Feb	$17,343,775	$17,631,590	$287,815
2010	Mar	$13,143,537	$13,357,509	$213,972
Total		$249,467,865	$258,880,263	$9,412,397

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

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	242	$4,685	$8,177	$3,492	$1,133,762	$1,978,773	$845,011
Medium Frame Combustion Turbine (30 - 65 MW)	434	$2,255	$2,802	$547	$978,722	$1,215,955	$237,233
Large Frame Combustion Turbine (135 - 180 MW)	24	$17,622	$24,943	$7,321	$422,925	$598,631	$175,705
Petroleum/Gas Steam (Post-1985)	13	$5,227	$11,677	$6,450	$67,946	$151,798	$83,852
Sub-Critical Coal	98	$51	$618	$567	$5,023	$60,591	$55,569
Medium-Large Frame Combustion Turbine (65 - 125 MW)	60	$3,960	$4,745	$786	$237,571	$284,716	$47,145
Small Frame Combustion Turbine (0 - 29 MW)	34	$3,177	$3,361	$183	$108,025	$114,264	$6,239
Diesel	1	$0	$1,210	$1,210	$0	$1,210	$1,210

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

Unit Type	Share of Increase
Combined-Cycle	58.2%
Steam	9.6%
Combustion Turbines	32.1%
Diesel	0.1%

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 - 125 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 March 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	1	1
Large Frame Combustion Turbine (135 - 180 MW)	2	3
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	33
Petroleum/Gas Steam (Pre-1985)	1	2
Sub-Critical Coal	13	76

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 March 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	$42,135	$3,971	$273,305	$0	$319,411	0.3%
AEP	$995,581	$8,047	$9,045,216	$410,759	$10,459,603	10.2%
AP	$431,867	$0	$971,017	$741,671	$2,144,555	2.1%
BGE	$1,105,035	$0	$1,378,204	$0	$2,483,240	2.4%
ComEd	$324,867	$0	$771,834	$533,951	$1,630,651	1.6%
DAY	$103,889	$0	$372,322	$9,670	$485,882	0.5%
Dominion	$548,253	$0	$5,092,436	$3,967,594	$9,608,283	9.4%
DPL	$1,120,432	$2,505	$2,429,764	$246,752	$3,799,454	3.7%
DLCO	$1,035,242	$0	$2,598,493	$2,114	$3,635,849	3.5%
JCPL	$1,981,371	$0	$2,282,765	$0	$4,264,136	4.2%
Met-Ed	$90,015	$0	$189,033	$0	$279,048	0.3%
PECO	$1,248,977	$2,095	$932,631	$77,206	$2,260,910	2.2%
PENELEC	$998	$8,905	$137,554	$158,869	$306,326	0.3%
Pepco	$1,292,229	$0	$5,228,386	$815,330	$7,335,946	7.2%
PPL	$77,060	$0	$3,448,549	$234,167	$3,759,776	3.7%
PSEG	$20,010,456	$156,309	$29,575,434	$33,977	$49,776,175	48.5%
External	$0	$0	$0	$0	$0	0.0%
Total	$30,408,409	$181,832	$64,726,942	$7,232,060	$102,549,243	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through March 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	$18,619,098	18.1%	18.1%	$49,165,106	47.9%	47.9%
2	$15,086,428	14.7%	32.8%	$8,141,922	7.9%	55.8%
3	$5,101,609	5.0%	37.8%	$6,291,698	6.1%	61.9%
4	$3,172,914	3.1%	40.9%	$5,679,306	5.5%	67.5%
5	$2,300,662	2.2%	43.1%	$4,714,947	4.6%	72.1%
6	$1,842,375	1.8%	44.9%	$3,933,095	3.8%	75.9%
7	$1,668,308	1.6%	46.5%	$3,172,914	3.1%	79.0%
8	$1,452,456	1.4%	48.0%	$3,020,195	2.9%	81.9%
9	$1,225,256	1.2%	49.2%	$2,263,372	2.2%	84.1%
10	$1,198,615	1.2%	50.3%	$1,381,434	1.3%	85.5%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through March 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	$9,030,534	29.7%	29.7%	$19,975,372	65.7%	65.7%
2	$4,481,756	14.7%	44.4%	$1,840,078	6.1%	71.7%
3	$3,300,358	10.9%	55.3%	$1,125,078	3.7%	75.4%
4	$1,840,078	6.1%	61.3%	$1,088,419	3.6%	79.0%
5	$1,593,833	5.2%	66.6%	$970,016	3.2%	82.2%
6	$1,086,840	3.6%	70.1%	$872,676	2.9%	85.1%
7	$963,905	3.2%	73.3%	$751,554	2.5%	87.5%
8	$585,511	1.9%	75.2%	$654,220	2.2%	89.7%
9	$348,635	1.1%	76.4%	$573,047	1.9%	91.6%
10	$323,106	1.1%	77.4%	$522,597	1.7%	93.3%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through March 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	$20,686	11.0%	11.0%	$156,309	83.3%	83.3%
2	$14,462	7.7%	18.7%	$13,768	7.3%	90.7%
3	$12,753	6.8%	25.5%	$8,905	4.7%	95.4%
4	$11,874	6.3%	31.9%	$6,477	3.5%	98.9%
5	$10,763	5.7%	37.6%	$2,095	1.1%	100.0%
6	$10,748	5.7%	43.3%			
7	$8,118	4.3%	47.7%			
8	$7,821	4.2%	51.8%			
9	$7,264	3.9%	55.7%			
10	$7,182	3.8%	59.5%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through March 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	$14,137,342	21.8%	21.8%	$28,999,449	44.7%	44.7%
2	$6,055,299	9.3%	31.2%	$7,136,836	11.0%	55.7%
3	$1,801,251	2.8%	33.9%	$5,328,108	8.2%	64.0%
4	$1,598,443	2.5%	36.4%	$5,217,078	8.0%	72.0%
5	$1,441,118	2.2%	38.6%	$2,827,369	4.4%	76.4%
6	$1,332,836	2.1%	40.7%	$1,982,601	3.1%	79.4%
7	$1,198,615	1.8%	42.5%	$1,845,025	2.8%	82.3%
8	$1,181,333	1.8%	44.3%	$1,332,836	2.1%	84.3%
9	$930,953	1.4%	45.8%	$1,171,163	1.8%	86.1%
10	$904,293	1.4%	47.2%	$1,158,356	1.8%	87.9%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through March 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	$886,383	12.2%	12.2%	$4,713,550	65.1%	65.1%
2	$682,772	9.4%	21.7%	$762,534	10.5%	75.6%
3	$635,812	8.8%	30.4%	$391,996	5.4%	81.0%
4	$591,740	8.2%	38.6%	$390,543	5.4%	86.4%
5	$544,001	7.5%	46.1%	$208,377	2.9%	89.3%
6	$522,921	7.2%	53.3%	$132,410	1.8%	91.1%
7	$427,283	5.9%	59.2%	$70,289	1.0%	92.1%
8	$335,251	4.6%	63.9%	$65,973	0.9%	93.0%
9	$241,343	3.3%	67.2%	$61,475	0.8%	93.8%
10	$216,586	3.0%	70.2%	$57,968	0.8%	94.6%

January 3, 2010

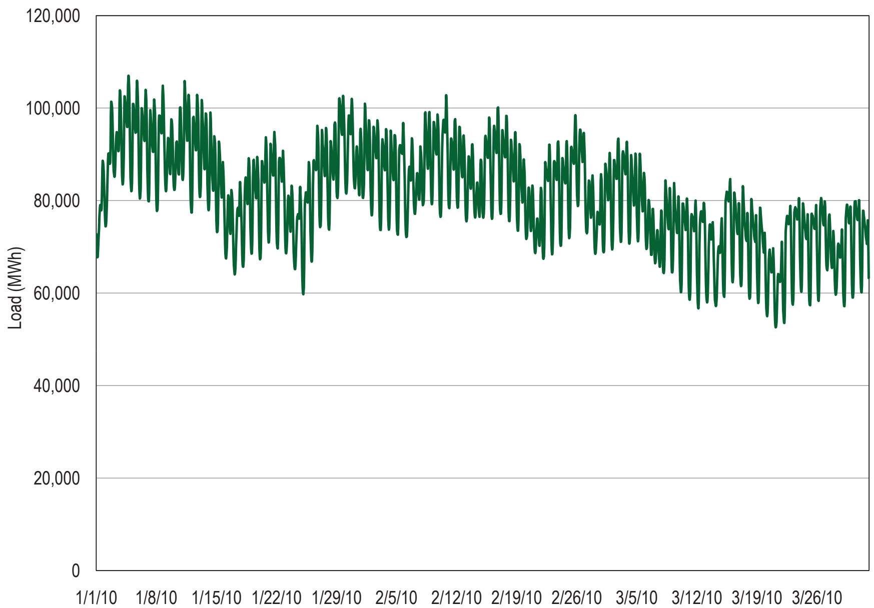
A Spike in Operating Reserves Charges

The spike in the RTO Balancing Deviation Rate that occurred on Sunday, January 3, 2010, was largely the result of $3,873,457 paid to generators in RTO Deviation Credits, which accounted for 81.6 percent of the balancing operating reserve credits for that day. The RTO Deviation rate on January 3 was 5.2333 $/MWh (or $3,873,457 divided by 740,159 MWh). See Table 3-69. The deviation rate was 4.88 standard deviations higher than the average RTO Deviation Rate of 0.7924 $/MWh for the period of January 1, 2010 through March 31, 2010.

The high level of balancing operating reserve credits can be attributed to multiple high voltage and interface constraints which limited power transfers from west to the east. As a result, multiple natural gas fired combined-cycles and combustion turbines in the eastern region were turned on during off-peak hours and were made whole to their minimum run times, or kept on for reliability or to compensate for other units not following day ahead schedules or not following dispatch.

January 3, 2010 was a relatively high PJM load day for the first quarter of the year. At HE 19, the PJM load reached 106,383 MW, which is in the top 0.5 percent of hourly loads for the first quarter of 2010. Figure 3-10 shows the hourly PJM load for the first three months of 2010.

Figure 3-10 Figure 4 Hourly PJM Load: January 1, 2010 through March 31, 2010 (New Figure)



There was significant price separation among the 5-minute real-time zonal LMPs throughout the day on January 3. The highest levels of price separation occurred during the morning off-peak hours. Figure 3-11 shows the five minute zonal LMPs. Figure 3-12 shows the hourly zonal and PJM loads.

Figure 3-11 Five Minute Zonal LMPs: January 3, 2010 (New Figure)

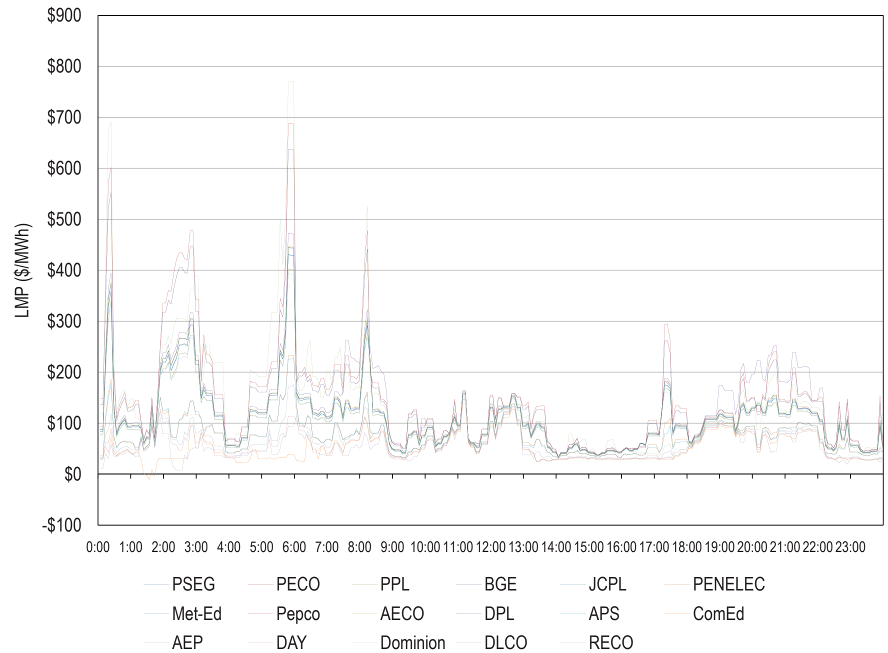


Figure 3-12 Hourly Zonal Loads: January 3, 2010 (New Figure)

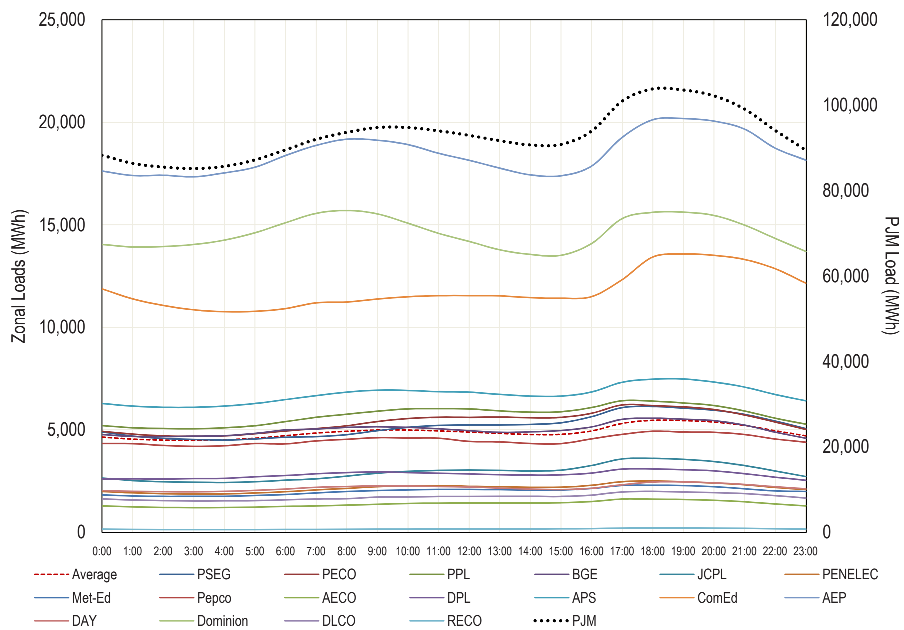


Figure 3-13 shows the real-time constraints on the PJM system and relative shadow prices for January 3, 2010. The constraints that contributed to RTO credits (units called on for transmission constraints 500kV and above) were the 5004/5005 interface, the AEP—DOM interface, the AP South interface, the Bedington—Black Oak interface, Cloverdale—Lexington, Harrison—Pruntytown, Mt. Storm—Pruntytown, and Line 500kV 539 (Bristers—Ox). The credits associated with all other constraints would be allocated to either Eastern or Western credits.

Figure 3-13 Figure 7 Real-time constraints and shadow prices: January 3, 2010 (New Figure)

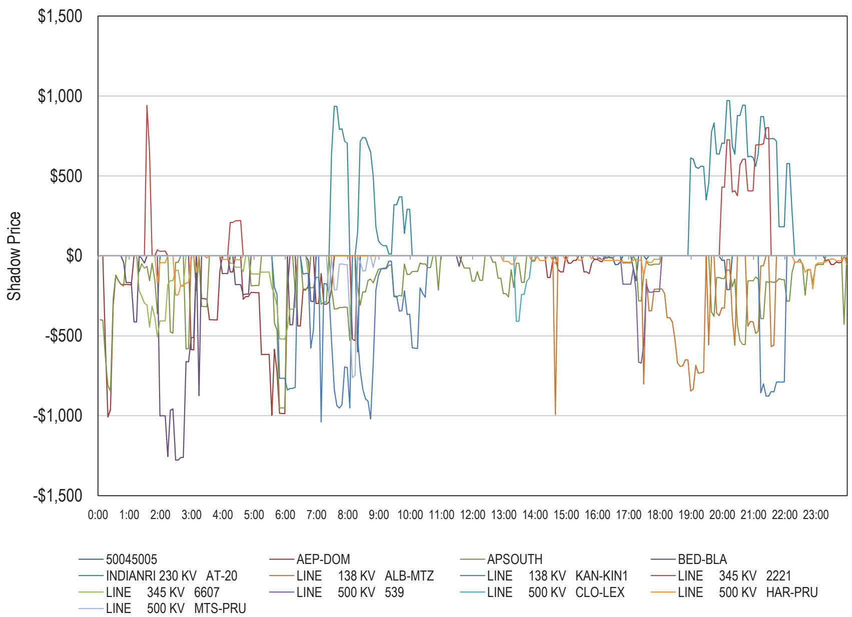


Table 3-69 shows RTO, East, and West charges, credits, and MWh for January 3. RTO deviation credits accounted for $3,873,457, or 81.6 percent, of the total credits for the day of $4,746,701. Charges paid by demand deviations were 46.4 percent of the total charges for the day, while charges paid by supply deviations were 21.2 percent and generator deviations 14.0 percent.

Table 3-69 Regional Credits, Charges, and Deviations Breakdown: January 3, 2010 (New Table)

	Reliability			Deviations				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO (MWh)	2,230,391	64,695	2,295,086	420,621	192,274	127,264	740,159	3,035,244
RTO (Charges / Credits)	$794,170	$23,036	$817,205	$2,201,228	$1,006,222	$666,006	$3,873,457	$4,690,662
RTO (% of Total Charges)	16.7%	0.5%	17.2%	46.4%	21.2%	14.0%	81.6%	98.8%
East (MWh)	1,245,523	46,585	1,292,108	276,559	110,748	85,088	472,394	1,764,503
East (Charges / Credits)	$13,581	$508	$14,089	$24,559	$9,835	$7,556	$41,950	$56,039
East (% of Total Charges)	0.3%	0.0%	0.3%	0.5%	0.2%	0.2%	0.9%	1.2%
West (MWh)	984,867	18,110	1,002,977	143,503	81,506	42,724	267,733	1,270,710
West (Charges / Credits)	$0	$0	$0	$0	$0	$0	$0	$0
West (% of Total Charges)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sum of Charges	$807,751	$23,544	$831,294	$2,225,788	$1,016,057	$673,562	$3,915,407	$4,746,701

Table 3-70 shows that 88.0 percent of credits paid to combined cycles were in the form of balancing generator credits, 95.2 percent of credits earned by combustion turbines were balancing generator credits, and 74.6 percent of credits earned by steam units were balancing generator credits.

Table 3-70 Credits by unit types (By operating reserve market): January 3, 2010 (New Table)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	11.9%	0.0%	88.0%	0.1%	$2,194,558
Combustion Turbine	0.0%	0.7%	95.2%	4.1%	$2,357,343
Diesel	0.0%	0.0%	100.0%	0.0%	$1,350
Hydro	0.0%	0.0%	0.0%	0.0%	$0
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	5.7%	0.0%	74.6%	19.7%	$462,624
Wind Farm	0.0%	0.0%	0.0%	0.0%	$0

The data shown in Table 3-71 shows that 49.6 percent of the balancing generator credits were paid to combustion turbines, 42.7 to combined-cycles, and 7.6 percent to steam units.

Table 3-71 Credits by operating reserve market (By unit type): January 3, 2010 (New Table)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	90.8%	0.0%	42.7%	1.1%
Combustion Turbine	0.0%	100.0%	49.6%	50.7%
Diesel	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	9.2%	0.0%	7.6%	48.1%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$288,090	$16,466	$4,522,371	$188,946

Table 3-72 shows the top 10 units in each category that received operating reserve credits. The top 10 units receiving balancing generator credits received 52.7 percent of the total balancing generator credits, or $2,578,795.

Table 3-72 Top 10 units receiving operating reserve credits: January 3, 2010 (New Table)

Unit Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$178,592	62.0%	62.0%	$2,318	14.1%	14.1%	$445,291	9.1%	9.1%
2	$73,680	25.6%	87.6%	$2,149	13.0%	27.1%	$421,415	8.6%	17.7%
3	$16,147	5.6%	93.2%	$2,149	13.0%	40.2%	$401,681	8.2%	25.9%
4	$9,200	3.2%	96.4%	$2,052	12.5%	52.6%	$292,022	6.0%	31.9%
5	$8,818	3.1%	99.4%	$1,920	11.7%	64.3%	$178,228	3.6%	35.5%
6	$1,566	0.5%	100.0%	$900	5.5%	69.8%	$171,209	3.5%	39.0%
7	$88	0.0%	100.0%	$900	5.5%	75.2%	$168,277	3.4%	42.5%
8	$0	0.0%	100.0%	$887	5.4%	80.6%	$167,576	3.4%	45.9%
9	$0	0.0%	100.0%	$887	5.4%	86.0%	$167,433	3.4%	49.3%
10	$0	0.0%	100.0%	$887	5.4%	91.4%	$165,664	3.4%	52.7%

Unit Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$62,651	20.7%	20.7%	$445,291	8.0%	8.0%
2	$38,910	12.9%	33.6%	$421,415	7.6%	15.6%
3	$32,501	10.7%	44.3%	$401,681	7.2%	22.9%
4	$22,577	7.5%	51.8%	$292,022	5.3%	28.2%
5	$18,092	6.0%	57.7%	$218,680	3.9%	32.1%
6	$17,833	5.9%	63.6%	$178,228	3.2%	35.3%
7	$17,149	5.7%	69.3%	$171,209	3.1%	38.4%
8	$15,326	5.1%	74.4%	$168,277	3.0%	41.4%
9	$11,519	3.8%	78.2%	$167,576	3.0%	44.5%
10	$8,687	2.9%	81.1%	$167,433	3.0%	47.5%