SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2011. As part of the review of market performance, the MMU analyzed 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.

Highlights

- Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent. Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent. Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent.

- There were no scarcity pricing events in the first nine months of 2011 under PJM's current Emergency Action based scarcity pricing rules.

- Operating reserve charges increased $83,751,028, or 20.5 percent, from $408,267,759 in the first nine months of 2010, to $492,018,787 in the first nine months of 2011. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent.

- Reliability charges were $74,733,573, 15.6 percent of all balancing operating reserve charges for the first nine months 2011, a decrease of $7,801,659 or 9.4 percent from the first nine months of 2010. Deviation charges were $405,744,328, or 84.4 percent in the first nine months of 2011, an increase of $262,622,763, or 183.5 percent from the first nine months of 2010.

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 29.7 percent of total operating reserve credits in the first nine months of 2011, compared to 36.4 percent in the first nine months of 2010. In the first nine months of 2011, the top generation owner received 22.7 percent of the total operating reserve credits paid.

- The regional concentration of balancing operating reserves for the first nine months of 2011 is higher than the first nine months of 2010, with 28.7 percent of the credits paid to units operating in the Dominion zone, 21.8 percent in the PSEG zone, and 10.1 percent in the AEP zone.

- In the first nine months of 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, and generation from nuclear units increased 1.5 percent, while generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent.

- At the end of September 2011, 86,864 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 since the June 1, 2011, ATSI integration. Wind projects account for approximately 39,459 MW of capacity, 45.4 percent of the capacity in the queues and combined-cycle projects account for 26,785 MW, 30.8 percent, of the capacity in the queues.

- Three large plants (over 550 MW) started generating in PJM since January 1, 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, and Longview Power in the APS zone. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,639 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI zone additions), the most since 2002.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is 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 is 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.

- **Net Revenue.** Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent (Table 3-6). Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent (Table 3-8). Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent (Table 3-10).

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through September 30, 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 179,571.6 as a result of the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of September 30, 2011, 41.9 percent was coal; 28.2 percent was gas; 18.5 percent was nuclear; 6.2 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, 0.4 percent was wind, and 0.0 percent was solar.

- **Generation Fuel Mix.** During the period January 1 through September 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, generation from nuclear units increased 1.5 percent, generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent.

- **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.

Environmental Rules

- **Cross-State Air Pollution Rule.** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS).[1] CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia.[2] This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to an order of the U.S. Court of Appeals for the District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act. The CSAPR and its initial emissions caps will become effective January 1, 2012. Two years later, on January 1, 2014, those emission caps will drop substantially.

  CSPAR establishes two groups of states with separate requirements standards. "Group 1" includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excepting the District of Columbia.[3] "Group 2" does not include any states in the PJM region.[4] Group 1 states must reduce both annual SO_2 and NO_x emissions to help downwind areas attain the 24-Hour and/or Annual PM2.5 NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

  Emission reductions are effective starting January 1, 2012, for SO_2 and annual NO_x reductions and May 1, 2012, for ozone season NO_x reductions. CSAPR requires reductions of emissions for each state below certain "assurance levels," established separately for each emission type. Assurance levels are the state allowance budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a "variability limit," an additional level of allowances that may be obtained by trading for allowances allocated to out of state units in states included in the same group.

  Significant additional SO_2 emission reductions are required in 2014 from certain states, including all of the PJM states except Delaware, and also excepting the District of Columbia.

  EPA estimates that by 2014 this rule and other federal rules will lower power plant annual emissions of SO_2, NO_x from 2005 levels in the CSAPR region by 73 percent (6.4 million tons/year) and 54 percent (1.4 million tons/year).

  The rule implements a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, PJM states may only trade with other Group 1 states.

  If state emissions exceed the applicable assurance level, including the variability limit, a penalty will be assessed that is allocated to resources within the state in proportion to their responsibility for the excess. The penalty will be a requirement to surrender two additional allowances for each allowance needed to the cover the excess. In response to concerns raised by stakeholders about the liquidity of allowance trading markets upon implementation of CSAPR on January 1, 2012, the EPA has postponed the assessment of assurance level penalty provisions until January 1, 2014.[5]

- **EPA Mercury Air Toxics Standards Proposed Rule.** On March 16, 2011, the EPA issued a notice of proposed rulemaking that would apply the Clean Air Act's maximum achievable control technology (MACT) requirement to new or modified sources of mercury and acid gas emissions. The EPA plans to finalize the rule in November 2011. It is proposed to become effective in 2015. The Clean Air Act defines MACT as the average emission rate of the best performing 12 percent of existing resources.

- **EPA Greenhouse Gas Tailoring Rule.** On May 13, 2010, the EPA issued a rule regulating CO_2 and other greenhouse gas emissions under

1 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011).
2 76 Fed. Reg. 40662 (July 11, 2011) (Proposed Revised CSAPR).
3 Group 1 states include PJM states: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.
4 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
5 *See* Proposed Revised CSAPR II at 63870.

the existing framework of new source review (NSR) and prevention of significant deterioration (PSD). As a result, new or modified units that increase emissions must install or implement the best available control technology (BACT). State environmental regulators determine BACT project by project, with guidance from the EPA.

- **NJ High Energy Demand Day (HEDD) Rule.** The EPA's transport rules, which apply to annual and seasonal emissions, affect units based on total annual or seasonal emissions. Units with relatively low capacity factors have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules. The New Jersey Department of Environmental Protection estimates that regulations targeting such units have the potential for region wide emission reductions of 1–2 ppb and greater localized reductions.[6]

  New Jersey has addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as "High Energy Demand Days" or "HEDD," and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on HEDD. New Jersey's HEDD rule,[7] which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBTU and lack identified emission control technologies.[8]

  New Jersey's HEDD rule will be implemented in two phases. For the first and currently effective phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol) and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include the following measures: installation of emissions controls at the HEDD unit or a non-HEDD unit; run-time limitations; commitment to use natural gas on HEDD units if dual fueled; implementation of energy efficiency, demand response or renewable energy measures; or other approved measures. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports.The second phase involves performance standards applicable after May 1, 2015. New, reconstructed or modified turbines must comply with State of the Art (SOTA), Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT) standards, as applicable. Owners/operators of existing HEDD units were each required to submit a 2015 HEDD Emission Limit Achievement Plan by May 1, 2010, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates.

6 *See* Tonalee Carlson Key, New Jersey Department of Environmental Protection, "Electric Generation on High Electric Demand Days," presentation at annual public hearing (April 1, 2009) at 11–12. This document may be accessed at: <http://www.state.nj.us/dep/cleanair/hearings/powerpoint/09_electric_gen.ppt>.
7 N.J.A.C. § 7:27–19.
8 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Scarcity

- **Scarcity Pricing Events in the first nine months of 2011.** PJM did not declare a scarcity event in the first nine months of 2011.

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 payments, operating reserve credits 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, 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 nine months of 2011.** Operating reserve charges increased 20.5 percent in the first nine months of 2011 compared to the first nine months of 2010. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent.

  The overall increase in operating reserve charges in 2011 is comprised of a 6.4 percent increase in day-ahead operating reserve charges, a 21.0 percent increase in synchronous condensing charges and a 23.1 percent increase in balancing operating reserve charges. Much of the increase came due to weather events in July, when operating reserve charges increased 64 percent.

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 nonmarket 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 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 and other inframarginal units.

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 the energy net revenues used as the offset in determining Capacity Market prices are higher than 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. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are reduced and there is little contribution to fixed costs. In addition, coal plants had, on average across all zones, 31 fewer profitable days in the first nine months of 2011 as compared to the first nine months of 2010.

Net Revenue

Capacity Market Net Revenue

Table 3-1 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2010 and 2011[9] (See 2010 SOM, Table 3-4)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$46,178	$36,675	(21%)
AEP	$33,384	$36,066	8%
AP	$46,330	$36,677	(21%)
ATSI	NA	NA	NA
BGE	$52,392	$36,730	(30%)
ComEd	$33,884	$36,720	8%
DAY	$33,961	$36,500	7%
DLCO	$33,599	$36,342	8%
Dominion	$46,597	$37,157	(20%)
DPL	$33,757	$36,434	8%
JCPL	$46,162	$36,436	(21%)
Met-Ed	$46,232	$36,590	(21%)
PECO	$46,334	$36,706	(21%)
PENELEC	$46,450	$36,693	(21%)
Pepco	$46,401	$36,622	(21%)
PPL	$46,270	$36,748	(21%)
PSEG	$50,165	$36,466	(27%)
RECO	NA	NA	NA
PJM	$41,002	$36,549	(11%)

9 The capacity market revenues reflect modifications to the calculations from prior State of the Market Reports. The calculations here reflect payments to generation capacity resources by zone. The RECO zone is reported as NA because there are no capacity resources in the RECO zone.

New Entrant Net Revenues[10,11]

Table 3-2 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year):[12,13] Net revenue for January through September 2010 and 2011 (See 2010 SOM, Table 3-5)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$48,990	$51,299	5%
AEP	$11,188	$22,761	103%
AP	$28,773	$36,860	28%
ATSI	NA	$15,660	NA
BGE	$60,741	$56,754	(7%)
ComEd	$10,105	$17,278	71%
DAY	$11,190	$24,349	118%
DLCO	$16,445	$26,295	60%
Dominion	$50,962	$45,652	(10%)
DPL	$48,046	$46,524	(3%)
JCPL	$42,847	$50,124	17%
Met-Ed	$45,207	$44,234	(2%)
PECO	$41,936	$46,675	11%
PENELEC	$19,533	$36,480	87%
Pepco	$56,186	$47,246	(16%)
PPL	$38,739	$46,774	21%
PSEG	$42,398	$44,259	4%
RECO	$37,754	$34,734	(8%)
PJM	$35,944	$38,553	7%

10 New entrant units are assumed to operate at full output.
11 Fuel prices are calculated by zone. PEPCO zone gas costs differ from the gas costs used in prior State of the Market Reports.
12 The energy net revenues presented for the PJM area for 2010 and 2011 in this section represent the simple average of all zonal energy net revenues.
13 The capacity market revenues reflect modifications to the calculations from prior State of the Market Reports. The calculations here assume that the CT plant could be dispatched by PJM operations in blocks of a minimum of four hours from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block in which the revenue generated was greater than the cost to generate, including the cost for a complete startup.

Table 3-3 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch[14] (Dollars per installed MW-year): Net revenue for January through September 2010 and 2011 (See 2010 SOM, Table 3-6)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$88,359	$88,757	0%
AEP	$33,754	$48,752	44%
AP	$61,722	$71,534	16%
ATSI	NA	$29,877	NA
BGE	$101,923	$92,769	(9%)
ComEd	$29,833	$36,456	22%
DAY	$34,624	$50,143	45%
DLCO	$37,460	$51,939	39%
Dominion	$88,251	$79,822	(10%)
DPL	$87,707	$82,706	(6%)
JCPL	$81,576	$86,333	6%
Met-Ed	$82,249	$77,409	(6%)
PECO	$79,271	$81,493	3%
PENELEC	$48,062	$70,440	47%
Pepco	$95,916	$80,683	(16%)
PPL	$73,798	$80,164	9%
PSEG	$82,150	$80,054	(3%)
RECO	$74,608	$65,415	(12%)
PJM	$69,486	$69,708	0%

Table 3-4 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 September 2010 and 2011 (See 2010 SOM, Table 3-7)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$133,621	$90,567	(32%)
AEP	$56,105	$79,589	42%
AP	$89,006	$107,386	21%
ATSI	NA	$31,502	NA
BGE	$78,725	$75,345	(4%)
ComEd	$100,302	$99,831	(0%)
DAY	$73,987	$73,715	(0%)
DLCO	$72,909	$62,239	(15%)
Dominion	$125,086	$88,932	(29%)
DPL	$131,552	$106,446	(19%)
JCPL	$126,946	$86,767	(32%)
Met-Ed	$125,845	$72,970	(42%)
PECO	$123,518	$81,267	(34%)
PENELEC	$99,601	$96,853	(3%)
Pepco	$138,370	$83,840	(39%)
PPL	$104,880	$89,931	(14%)
PSEG	$110,494	$62,399	(44%)
RECO	$120,939	$68,304	(44%)
PJM	$106,582	$80,994	(24%)

14 All starts associated with combined cycle units are assumed to be hot starts.

New Entrant Combustion Turbine

Table 3-5 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-8)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$35,944	$38,553	7%
Capacity	$40,290	$35,914	(11%)
Synchronized	$0	$0	NA
Regulation	$0	$0	NA
Reactive	$1,794	$1,794	0%
Total	$78,027	$76,261	(2%)

Table 3-6 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-9)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$96,160	$89,131	(7%)
AEP	$45,786	$59,994	31%
AP	$76,092	$74,694	(2%)
ATSI	NA	NA	NA
BGE	$114,017	$94,639	(17%)
ComEd	$45,194	$55,155	22%
DAY	$46,355	$62,009	34%
DLCO	$51,254	$63,799	24%
Dominion	$98,544	$83,957	(15%)
DPL	$83,010	$84,119	1%
JCPL	$90,001	$87,722	(3%)
Met-Ed	$92,429	$81,982	(11%)
PECO	$89,258	$84,537	(5%)
PENELEC	$66,969	$74,329	11%
Pepco	$103,574	$85,026	(18%)
PPL	$85,999	$84,678	(2%)
PSEG	$93,485	$81,886	(12%)
RECO	NA	NA	NA
PJM	$78,027	$76,261	(2%)

New Entrant Combined Cycle

Table 3-7 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-10)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$69,486	$69,708	0%
Capacity	$42,570	$37,947	(11%)
Synchronized	$0	$0	NA
Regulation	$0	$0	NA
Reactive	$2,392	$2,392	0%
Total	$114,448	$110,047	(4%)

Table 3-8 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-11)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$138,694	$129,227	(7%)
AEP	$70,807	$88,589	25%
AP	$112,215	$112,005	(0%)
ATSI	NA	NA	NA
BGE	$158,710	$133,295	(16%)
ComEd	$67,404	$76,972	14%
DAY	$72,275	$90,430	25%
DLCO	$74,736	$92,062	23%
Dominion	$139,021	$120,791	(13%)
DPL	$125,146	$122,926	(2%)
JCPL	$131,895	$126,554	(4%)
Met-Ed	$132,640	$117,790	(11%)
PECO	$129,769	$121,995	(6%)
PENELEC	$98,679	$110,927	12%
Pepco	$146,483	$121,097	(17%)
PPL	$124,229	$120,709	(3%)
PSEG	$136,625	$120,306	(12%)
RECO	NA	NA	NA
PJM	$114,448	$110,047	(4%)

New Entrant Coal Plant

Table 3-9 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-12)

	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
Energy	$106,582	$80,994	(24%)
Capacity	$39,844	$35,517	(11%)
Synchronized	$0	$0	NA
Regulation	$896	$773	(14%)
Reactive	$1,334	$1,334	0%
Total	$148,655	$118,617	(20%)

Table 3-10 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-13)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$180,624	$128,304	(29%)
AEP	$90,899	$116,589	28%
AP	$136,231	$144,923	6%
ATSI	NA	NA	NA
BGE	$132,335	$113,333	(14%)
ComEd	$135,488	$137,550	2%
DAY	$109,214	$111,168	2%
DLCO	$107,974	$99,620	(8%)
Dominion	$172,546	$127,185	(26%)
DPL	$166,491	$143,884	(14%)
JCPL	$173,938	$124,290	(29%)
Met-Ed	$172,915	$110,704	(36%)
PECO	$170,689	$119,060	(30%)
PENELEC	$146,864	$134,448	(8%)
Pepco	$185,614	$121,533	(35%)
PPL	$152,060	$127,737	(16%)
PSEG	$161,437	$100,292	(38%)
RECO	NA	NA	NA
PJM	$148,655	$118,617	(20%)

New Entrant Day-Ahead Net Revenues

Table 3-11 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-14)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$30,036	$33,837	13%
AEP	$5,893	$12,434	111%
AP	$17,788	$21,466	21%
ATSI	NA	$10,773	NA
BGE	$38,886	$34,388	(12%)
ComEd	$5,748	$8,369	46%
DAY	$6,276	$12,045	92%
DLCO	$8,888	$13,449	51%
Dominion	$31,136	$24,743	(21%)
DPL	$28,597	$30,982	8%
JCPL	$26,864	$30,003	12%
Met-Ed	$28,028	$26,490	(5%)
PECO	$26,553	$31,895	20%
PENELEC	$13,070	$21,016	61%
Pepco	$35,713	$29,883	(16%)
PPL	$22,978	$27,969	22%
PSEG	$25,791	$24,758	(4%)
RECO	$23,689	$19,356	(18%)
PJM	$22,114	$22,992	4%

Table 3-12 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-15)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$75,960	$82,661	9%
AEP	$28,883	$43,814	52%
AP	$55,887	$66,249	19%
ATSI	NA	$27,176	NA
BGE	$89,383	$80,748	(10%)
ComEd	$24,712	$28,505	15%
DAY	$29,248	$43,384	48%
DLCO	$33,423	$44,528	33%
Dominion	$79,295	$68,259	(14%)
DPL	$74,926	$77,866	4%
JCPL	$72,689	$78,561	8%
Met-Ed	$70,770	$68,927	(3%)
PECO	$70,477	$78,389	11%
PENELEC	$47,225	$63,573	35%
Pepco	$86,210	$74,208	(14%)
PPL	$62,788	$70,737	13%
PSEG	$71,719	$70,305	(2%)
RECO	$66,646	$57,895	(13%)
PJM	$61,191	$62,544	2%

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-16)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	Percent Change
AECO	$129,484	$85,659	(34%)
AEP	$53,672	$78,816	47%
AP	$87,301	$105,478	21%
ATSI	NA	$29,359	NA
BGE	$69,319	$61,798	(11%)
ComEd	$98,853	$98,106	(1%)
DAY	$71,194	$70,724	(1%)
DLCO	$73,448	$56,837	(23%)
Dominion	$125,057	$81,308	(35%)
DPL	$127,368	$105,693	(17%)
JCPL	$127,014	$79,412	(37%)
Met-Ed	$123,359	$64,994	(47%)
PECO	$123,973	$78,979	(36%)
PENELEC	$105,031	$92,737	(12%)
Pepco	$139,062	$79,580	(43%)
PPL	$102,670	$82,458	(20%)
PSEG	$109,538	$53,125	(52%)
RECO	$124,402	$66,509	(47%)
PJM	$105,338	$76,198	(28%)

Table 3-14 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-17)

	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	$11,182	62%
2008	$12,442	$6,623	$5,819	47%
2009	$13,384	$6,030	$7,354	55%
2010	$42,604	$24,485	$18,120	43%
2011 (Jan - Sep)	$38,553	$22,992	$15,561	40%

Table 3-15 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-18)

	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	$2,632	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,195	20%
2006	$44,692	$31,670	$13,022	29%
2007	$66,616	$44,434	$22,182	33%
2008	$62,039	$47,342	$14,697	24%
2009	$41,211	$39,151	$2,060	5%
2010	$83,555	$72,718	$10,837	13%
2011 (Jan - Sep)	$69,708	$62,544	$7,164	10%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through September 2011 (See 2010 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,160)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,373)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,570	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,266	3%
2009	$69,659	$68,354	$1,305	2%
2010	$128,933	$126,758	$2,176	2%
2011 (Jan - Sep)	$80,994	$76,198	$4,795	6%

Net Revenue Adequacy

Table 3-17 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)): Calendar years 2005 through 2010 (See 2010 SOM, Table 3-20)

	20-Year Levelized Fixed Cost					
	2005	2006	2007	2008	2009	2010
CT	$72,207	$80,315	$90,656	$123,640	$128,705	$131,044
CC	$93,549	$99,230	$143,600	$171,361	$173,174	$175,250
CP	$208,247	$267,792	$359,750	$492,780	$446,550	$465,455

New Entrant Combustion Turbine

Table 3-18 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-22)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$96,160	$89,131	$131,044	73%	68%
AEP	$45,786	$59,994	$131,044	35%	46%
AP	$76,092	$74,694	$131,044	58%	57%
ATSI	NA	NA	$131,044	NA	NA
BGE	$114,017	$94,639	$131,044	87%	72%
ComEd	$45,194	$55,155	$131,044	34%	42%
DAY	$46,355	$62,009	$131,044	35%	47%
DLCO	$51,254	$63,799	$131,044	39%	49%
Dominion	$98,544	$83,957	$131,044	75%	64%
DPL	$83,010	$84,119	$131,044	63%	64%
JCPL	$90,001	$87,722	$131,044	69%	67%
Met-Ed	$92,429	$81,982	$131,044	71%	63%
PECO	$89,258	$84,537	$131,044	68%	65%
PENELEC	$66,969	$74,329	$131,044	51%	57%
Pepco	$103,574	$85,026	$131,044	79%	65%
PPL	$85,999	$84,678	$131,044	66%	65%
PSEG	$93,485	$81,886	$131,044	71%	62%
RECO	NA	NA	$131,044	NA	NA
PJM	$78,027	$76,261	$131,044	60%	58%

Figure 3-1 New entrant CT real-time net revenue for January through September 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): (See 2010 SOM, Figure 3-3)

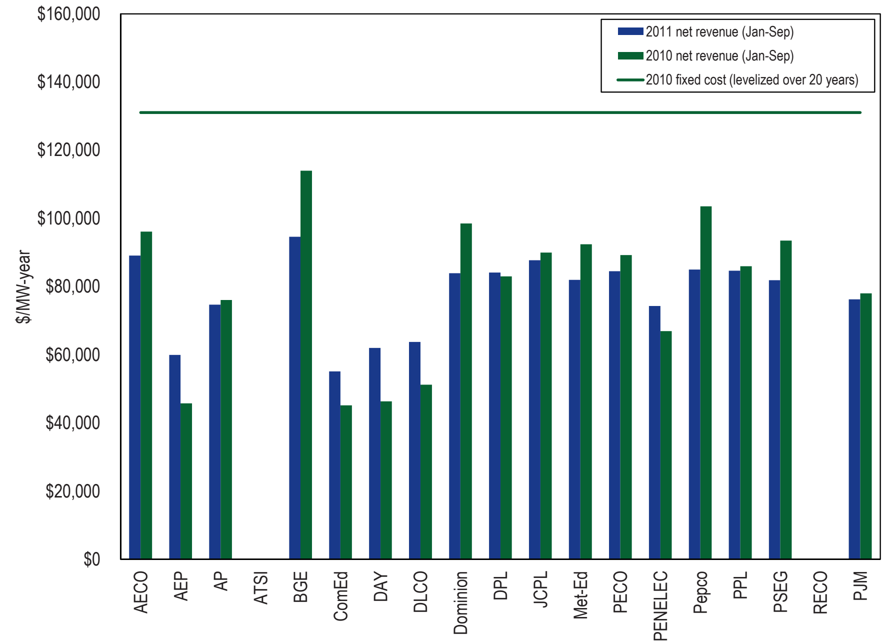
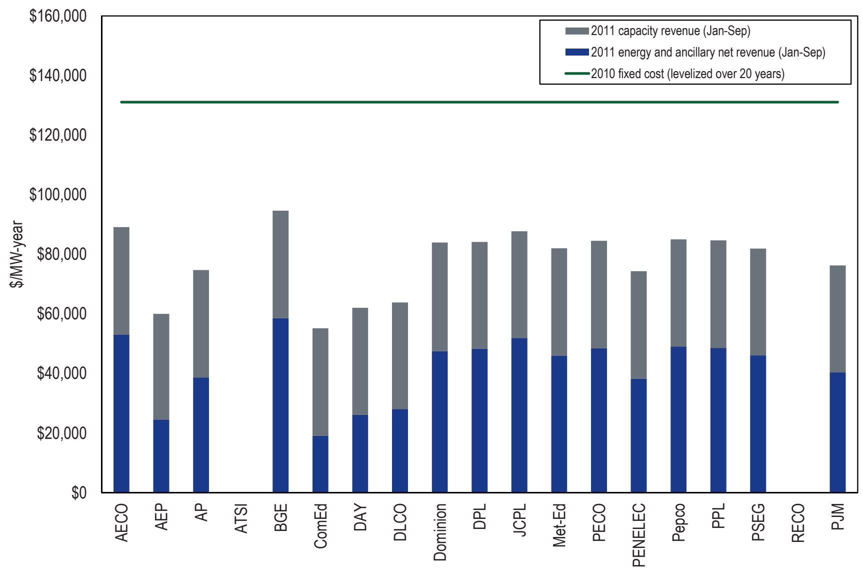


Figure 3-2 New entrant CT zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-4)



New Entrant Combined Cycle

Table 3-19 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-24)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$138,694	$129,227	$175,250	79%	74%
AEP	$70,807	$88,589	$175,250	40%	51%
AP	$112,215	$112,005	$175,250	64%	64%
ATSI	NA	NA	$175,250	NA	NA
BGE	$158,710	$133,295	$175,250	91%	76%
ComEd	$67,404	$76,972	$175,250	38%	44%
DAY	$72,275	$90,430	$175,250	41%	52%
DLCO	$74,736	$92,062	$175,250	43%	53%
Dominion	$139,021	$120,791	$175,250	79%	69%
DPL	$125,146	$122,926	$175,250	71%	70%
JCPL	$131,895	$126,554	$175,250	75%	72%
Met-Ed	$132,640	$117,790	$175,250	76%	67%
PECO	$129,769	$121,995	$175,250	74%	70%
PENELEC	$98,679	$110,927	$175,250	56%	63%
Pepco	$146,483	$121,097	$175,250	84%	69%
PPL	$124,229	$120,709	$175,250	71%	69%
PSEG	$136,625	$120,306	$175,250	78%	69%
RECO	NA	NA	$175,250	NA	NA
PJM	$114,448	$110,047	$175,250	65%	63%

Figure 3-3 New entrant CC real-time net revenue for January through September 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Figure 3-6)

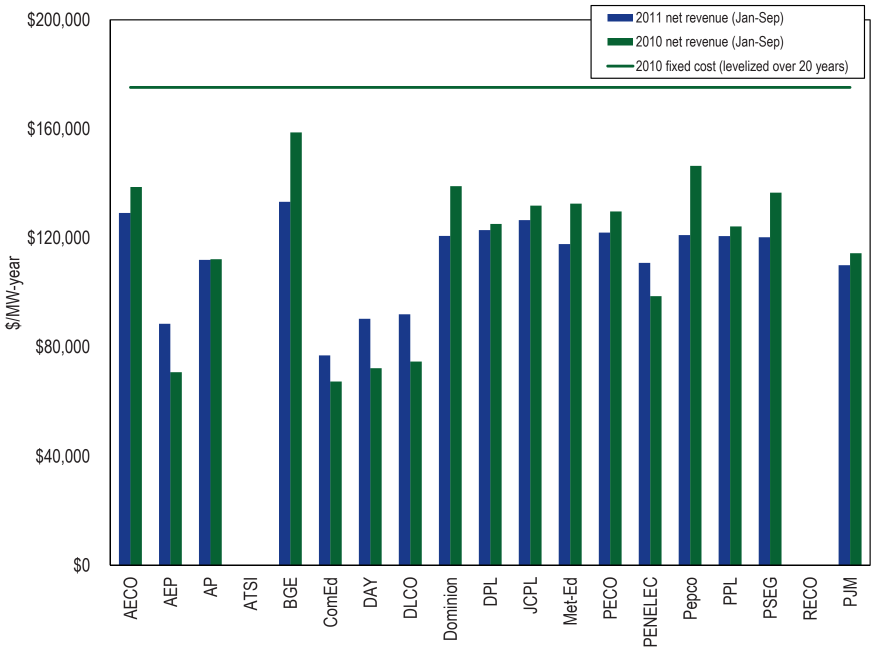
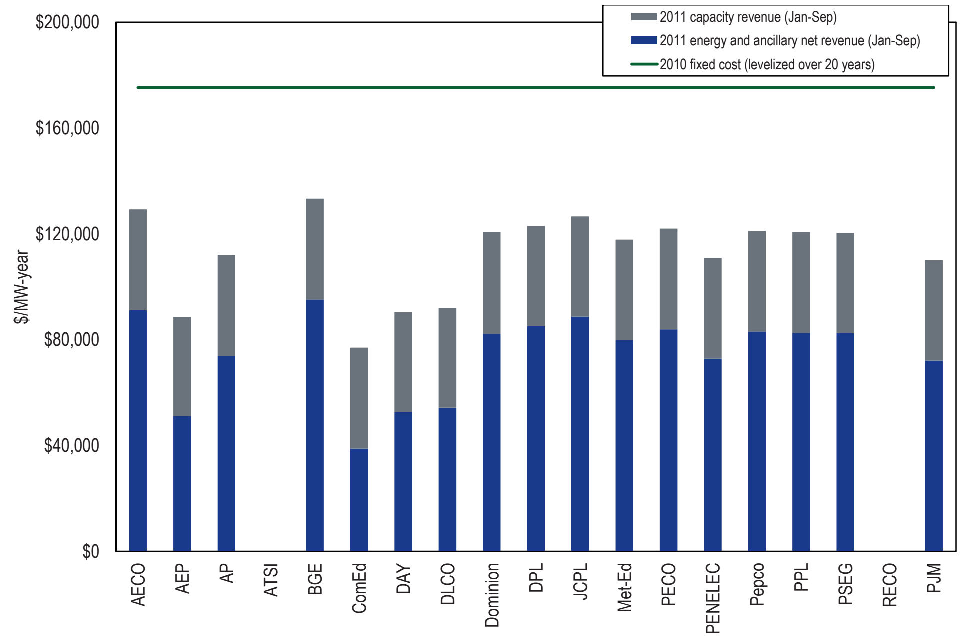


Figure 3-4 New entrant CC zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-7)



New Entrant Coal Plant

Table 3-20 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Table 3-26)

Zone	2010 (Jan - Sep)	2011 (Jan - Sep)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$180,624	$128,304	$465,455	39%	28%
AEP	$90,899	$116,589	$465,455	20%	25%
AP	$136,231	$144,923	$465,455	29%	31%
ATSI	NA	NA	$465,455	NA	NA
BGE	$132,335	$113,333	$465,455	28%	24%
ComEd	$135,488	$137,550	$465,455	29%	30%
DAY	$109,214	$111,168	$465,455	23%	24%
DLCO	$107,974	$99,620	$465,455	23%	21%
Dominion	$172,546	$127,185	$465,455	37%	27%
DPL	$166,491	$143,884	$465,455	36%	31%
JCPL	$173,938	$124,290	$465,455	37%	27%
Met-Ed	$172,915	$110,704	$465,455	37%	24%
PECO	$170,689	$119,060	$465,455	37%	26%
PENELEC	$146,864	$134,448	$465,455	32%	29%
Pepco	$185,614	$121,533	$465,455	40%	26%
PPL	$152,060	$127,737	$465,455	33%	27%
PSEG	$161,437	$100,292	$465,455	35%	22%
RECO	NA	NA	$465,455	NA	NA
PJM	$148,655	$118,617	$465,455	32%	25%

Figure 3-5 New entrant CP real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through September 2010 and 2011 (See 2010 SOM, Figure 3-9)

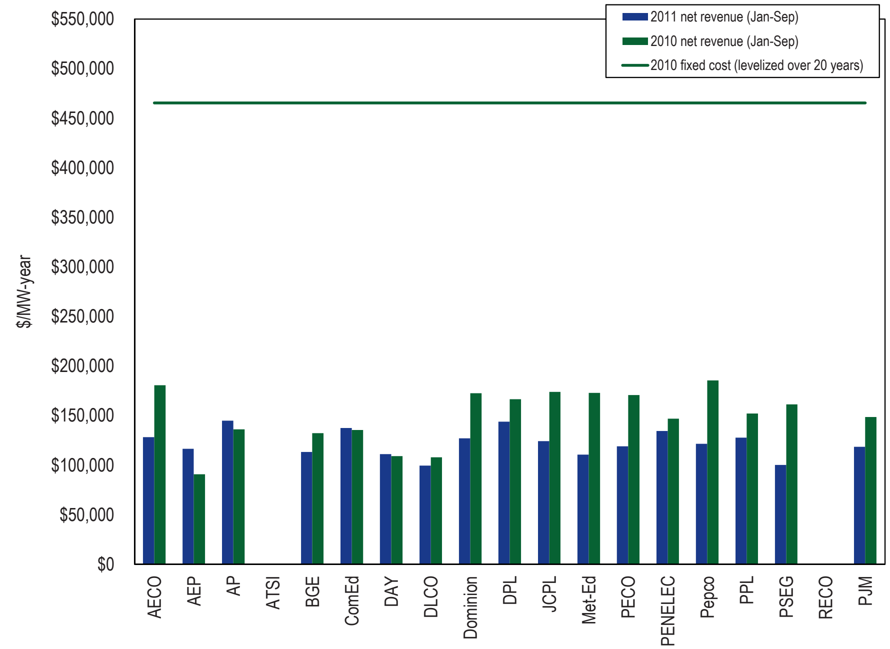
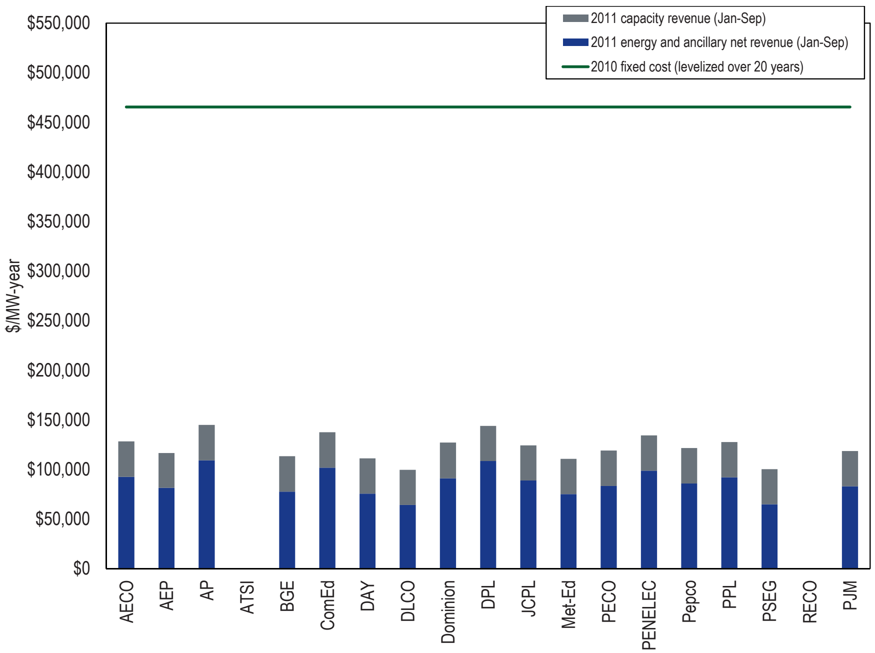


Figure 3-6 New entrant CP zonal real-time January through September 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-10)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-21 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2011 (See 2010 SOM, Table 3-42)

	1-Jan-11		31-May-11		1-Jun-11		30-Sep-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,879.4	40.7%	76,968.3	42.4%	75,267.3	41.9%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,524.5	28.1%
Hydroelectric	7,954.5	4.8%	7,991.8	4.8%	8,029.6	4.4%	8,047.0	4.5%
Nuclear	30,552.2	18.4%	30,822.2	18.5%	33,145.6	18.3%	33,145.6	18.5%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,217.3	6.2%
Solar	0.0	0.0%	1.9	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	633.5	0.3%	649.5	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	179,571.6	100.0%

Energy Production by Fuel Source

Table 3-22 PJM generation (By fuel source (GWh)): January through September 2010 and 2011[15] (See 2010 SOM, Table 3-43)

	2010 (Jan-Sep)		2011 (Jan-Sep)		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,800.6	49.3%	279,501.2	48.0%	(0.1%)
Standard Coal	270,693.3	47.7%	270,273.8	46.4%	(0.1%)
Waste Coal	9,107.3	1.6%	9,227.4	1.6%	0.0%
Nuclear	192,379.3	33.9%	195,196.7	33.5%	1.5%
Gas	69,803.0	12.3%	82,263.4	14.1%	17.9%
Natural Gas	68,566.0	12.1%	80,907.4	13.9%	18.0%
Landfill Gas	1,236.6	0.2%	1,355.9	0.2%	9.6%
Biomass Gas	0.4	0.0%	0.1	0.0%	(61.6%)
Hydroelectric	11,192.6	2.0%	11,379.8	2.0%	1.7%
Wind	6,173.6	1.1%	7,924.5	1.4%	28.4%
Waste	4,922.3	0.9%	4,254.8	0.7%	(13.6%)
Solid Waste	3,760.1	0.7%	3,318.0	0.6%	(11.8%)
Miscellaneous	1,162.2	0.2%	936.8	0.2%	(19.4%)
Oil	2,956.1	0.5%	2,074.8	0.4%	(29.8%)
Heavy Oil	2,506.1	0.4%	1,711.8	0.3%	(31.7%)
Light Oil	403.2	0.1%	334.3	0.1%	(17.1%)
Diesel	28.0	0.0%	15.9	0.0%	(43.2%)
Kerosene	18.8	0.0%	12.7	0.0%	(32.2%)
Jet Oil	0.1	0.0%	0.1	0.0%	(5.7%)
Solar	3.7	0.0%	37.9	0.0%	934.9%
Battery	0.3	0.0%	0.2	0.0%	(37.7%)
Total	567,231.4	100.0%	582,633.3	100.0%	2.7%

Table 3-23 PJM capacity factor (By unit type (GWh)); January through September 2010 and 2011[16, 17] (New table)

	2010 (Jan-Sep)		2011 (Jan-Sep)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.3	4.0%	0.2	1.3%
Combined Cycle	59,379.5	28.8%	74,151.5	46.7%
Combustion Turbine	6,987.2	3.8%	5,691.7	3.0%
Diesel	616.8	19.6%	542.5	16.7%
Diesel (Landfill gas)	501.9	40.4%	581.0	42.5%
Nuclear	192,379.3	93.3%	195,196.7	91.9%
Pumped Storage Hydro	6,246.5	17.4%	5,460.1	15.2%
Run of River Hydro	4,946.2	32.2%	5,919.8	38.6%
Solar	3.7	14.9%	37.9	12.7%
Steam	289,996.6	55.6%	287,127.5	52.2%
Wind	6,157.5	24.2%	7,924.5	27.2%
Total	567,215.4	49.6%	582,633.3	48.8%

15 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

16 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

17 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.

Planned Generation Additions

Table 3-24 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 30, 2011[18] (See 2010 SOM, Table 3-44)

	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	2,097
2011 (Jan-Sep)	3,639

PJM Generation Queues

Table 3-25 Queue comparison (MW): September 30, 2011 vs. December 31, 2010 (See 2010 SOM, Table 3-44)

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	15,913	(9,466)	(37%)
2012	13,261	16,478	3,217	24%
2013	11,244	12,999	1,755	16%
2014	13,888	17,009	3,121	22%
2015	5,960	15,563	9,603	161%
2016	1,350	4,009	2,659	197%
2017	2,140	1,700	(440)	(21%)
2018	3,194	3,194	0	0%
Total	76,415	86,864	10,449	14%

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

Table 3-26 Capacity in PJM queues (MW): At September 30, 2011[19, 20] (See 2010 SOM, Table 3-46)

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	4,646	0	15,833	20,478
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	1,086	555	21,461	23,102
H Expired 31-Jan-02	0	703	0	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	148	150	2,346	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	150	3,828	4,482
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,466	1,470	574	4,083	7,592
P Expired 31-Jan-06	513	2,625	655	4,908	8,701
Q Expired 31-Jul-06	1,759	1,384	2,778	8,693	14,614
R Expired 31-Jan-07	4,587	691	1,283	16,194	22,755
S Expired 31-Jul-07	2,357	2,618	925	14,993	20,893
T Expired 31-Jan-08	11,425	927	471	14,845	27,667
U Expired 31-Jan-09	6,295	222	815	26,116	33,447
V Expired 31-Jan-10	12,317	111	419	4,287	17,134
W Expired 31-Jan-11	16,275	10	617	7,605	24,507
X Expires 31-Jan-12	18,920	0	60	355	19,335
Total	77,310	30,020	9,624	218,358	335,311

19 The *2011 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.
20 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 3-27 Average project queue times (days): At September 30, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	812	656	0	4,420
In-Service	782	652	0	3,602
Suspended	2,307	897	704	4,103
Under Construction	1,214	841	0	4,370
Withdrawn	461	491	0	3,186

Distribution of Units in the Queues

Table 3-28 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2011 (See 2010 SOM, Table 3-48)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,255	762	9	0	0	797	665	0	2,191	5,680
AEP	4,325	0	21	170	0	143	2,416	0	14,136	21,210
AP	958	0	8	98	0	372	597	32	1,215	3,281
ATSI	268	72	22	0	0	14	135	0	1,047	1,558
BGE	0	0	29	0	1,640	0	132	0	0	1,801
ComEd	1,080	398	103	23	613	95	1,366	20	15,502	19,199
DAY	0	0	2	112	0	73	12	0	1,440	1,639
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	5,241	595	16	0	1,669	134	429	32	984	9,100
DPL	1,759	96	0	0	0	263	20	34	905	3,077
JCPL	1,995	27	30	0	0	1,178	0	0	0	3,230
Met-Ed	1,910	0	21	0	24	210	0	3	0	2,168
PECO	663	7	17	0	490	26	0	2	0	1,206
PENELEC	905	20	5	0	0	36	146	0	1,600	2,711
Pepco	2,309	0	6	0	0	10	0	0	0	2,325
PPL	1,354	13	10	3	1,600	144	33	20	420	3,597
PSEG	3,343	1,083	1	0	50	388	105	2	20	4,991
Total	27,365	3,073	301	406	6,177	3,883	6,055	145	39,459	86,864

Table 3-29 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2011[21] (See 2010 SOM, Table 3-49)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	9,015	1,975	57	0	540	2,652	790	38	3,116	18,183
SWMAAC	2,309	0	35	0	1,640	10	132	0	0	4,126
WMAAC	4,169	33	36	3	1,624	390	179	23	2,020	8,476
Non-MAAC	11,872	1,065	172	403	2,373	831	4,955	84	34,323	56,078
Total	27,365	3,073	301	406	6,177	3,883	6,055	145	39,459	86,864

21 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-30 Existing PJM capacity: At September 30, 2011[22] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	154	661	21	0	0	20	1,110	0	8	1,973
AEP	4,367	3,676	59	1,002	2,094	0	21,571	0	1,203	33,973
AP	1,129	1,180	36	80	0	0	8,451	27	663	11,566
ATSI	0	1,661	52	0	2,134	0	7,998	0	0	11,845
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,763	7,178	86	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	3,435	3,761	161	3,589	3,558	0	8,283	0	0	22,787
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	690	0	66	439	0	6,117	0	185	8,471
JCPL	1,693	1,225	33	400	615	0	15	0	0	3,980
Met-Ed	2,041	416	42	20	805	0	844	0	0	4,167
PECO	2,644	836	7	1,642	4,541	3	1,706	1	0	11,379
PENELEC	0	344	39	513	0	0	6,834	0	555	8,284
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,527	0	220	11,274
PSEG	2,960	2,863	5	5	3,493	47	2,447	0	0	11,820
Total	24,568	30,425	751	7,904	34,051	71	92,815	28	4,779	195,393

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

Table 3-31 PJM capacity (MW) by age: at September 30, 2011 (See 2010 SOM, Table 3-51)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,490	15,587	430	11	0	71	1,864	28	4,768	41,250
11 to 20	4,657	6,323	89	48	0	0	4,936	0	10	16,062
21 to 30	980	1,162	37	3,382	16,517	0	6,920	0	0	28,998
31 to 40	244	4,251	43	105	16,053	0	33,782	0	0	54,479
41 to 50	198	3,103	148	2,915	1,482	0	26,650	0	0	34,495
51 to 60	0	0	4	379	0	0	16,466	0	0	16,849
61 to 70	0	0	0	0	0	0	2,047	0	0	2,047
71 to 80	0	0	0	344	0	0	95	0	0	439
81 to 90	0	0	0	488	0	0	54	0	0	542
91 to 100	0	0	0	194	0	0	0	0	0	194
101 and over	0	0	0	37	0	0	0	0	0	37
Total	24,568	30,425	751	7,904	34,051	71	92,815	28	4,779	195,393

Table 3-32 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[23] (See 2010 SOM, Table 3-52)

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	Combined Cycle	198	2.4%	8,576	25.2%	9,015	17,392	39.0%
	Combustion Turbine	1,375	16.9%	7,358	21.7%	1,975	7,958	17.8%
	Diesel	53	0.7%	162	0.5%	57	166	0.4%
	Hydroelectric	2,042	25.1%	2,047	6.0%	0	5	0.0%
	Nuclear	615	7.6%	8,648	25.5%	540	9,188	20.6%
	Solar	0	0.0%	70	0.2%	2,652	2,722	6.1%
	Steam	3,841	47.3%	7,102	20.9%	790	4,051	9.1%
	Storage	0	0.0%	1	0.0%	38	39	0.1%
	Wind	0	0.0%	8	0.0%	3,116	3,124	7.0%
	EMAAC Total	8,124	100.0%	33,972	100.0%	18,183	44,645	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	2,309	2,539	22.4%
	Combustion Turbine	761	16.5%	2,162	18.3%	0	1,400	12.4%
	Diesel	0	0.0%	19	0.2%	35	54	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	29.5%
	Solar	0	0.0%	0	0.0%	10	10	0.1%

23 Percentages shown in Table 3-32 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-32 continued on next page.

Table 3-32 continued from previous page.

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
	Steam	3,840	83.5%	7,686	65.1%	132	3,978	35.1%
	SWMAAC Total	4,601	100.0%	11,801	100.0%	4,126	11,327	100.0%
WMAAC	Combined Cycle	0	0.0%	3,851	16.2%	4,169	8,020	50.0%
	Combustion Turbine	312	3.8%	1,377	5.8%	33	1,098	6.8%
	Diesel	46	0.6%	129	0.5%	36	120	0.7%
	Hydroelectric	887	10.9%	1,113	4.7%	3	229	1.4%
	Nuclear	0	0.0%	3,275	13.8%	1,624	4,899	30.5%
	Solar	0	0.0%	0	0.0%	390	390	2.4%
	Steam	6,887	84.7%	13,205	55.7%	179	6,496	40.5%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	775	3.3%	2,020	2,795	17.4%
	WMAAC Total	8,132	100.0%	23,725	100.0%	8,476	16,049	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,911	9.5%	11,872	23,783	16.0%
	Combustion Turbine	655	1.9%	19,529	15.5%	1,065	19,939	13.5%
	Diesel	53	0.2%	441	0.4%	172	560	0.4%
	Hydroelectric	1,429	4.2%	4,744	3.8%	403	3,718	2.5%
	Nuclear	867	2.6%	20,423	16.2%	2,373	21,929	14.8%
	Solar	0	0.0%	1	0.0%	831	832	0.6%
	Steam	30,744	91.1%	64,822	51.5%	4,955	39,033	26.3%
	Storage	0	0.0%	27	0.0%	84	111	0.1%
	Wind	0	0.0%	3,996	3.2%	34,323	38,320	25.9%
	Non-MAAC Total	33,747	100.0%	125,895	100.0%	56,078	148,226	100.0%
All Areas	Total	54,605		195,393		86,864	220,247	

Environmental Impact and Renewables

Characteristics of Wind Units

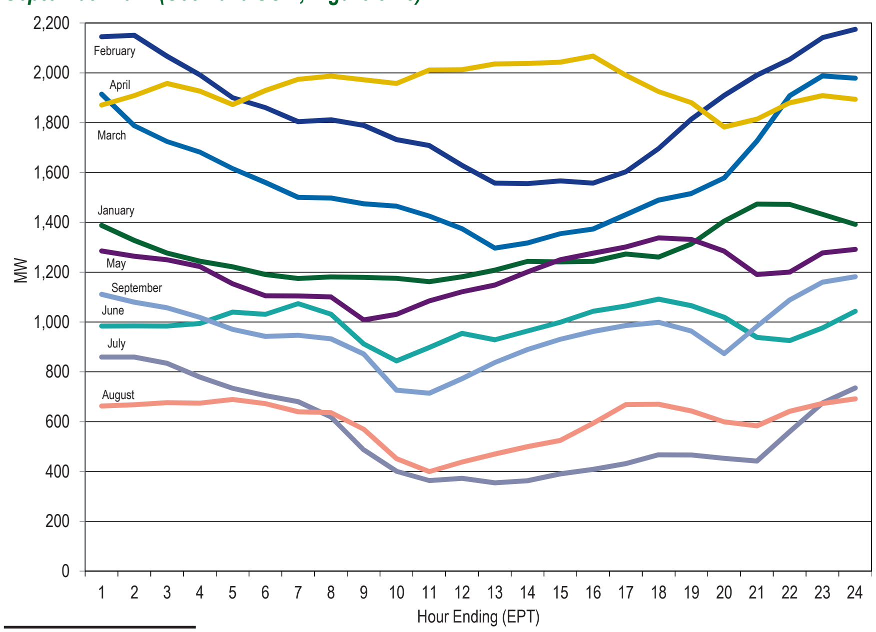
Table 3-33 Capacity factor[24] of wind units in PJM, January through September 2011 (See 2010 SOM, Table 3-53)

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.7%	NA	85,859	849
Capacity Resource	27.7%	169.2%	264,800	3,957
All Units	27.2%	169.2%	350,659	4,806

Table 3-34 Wind resources in real time offering at a negative price in PJM, January through September 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	908.0	1,987	2.53%
All Wind	2,136.4	4,071	5.18%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through September 2011 (See 2010 SOM, Figure 3-13)



24 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

Table 3-35 Capacity factor of wind units in PJM by month, 2010 and 2011[25] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	971,942.0	35.9%	950,441.9	29.7%
February	736,663.6	28.9%	1,237,813.0	42.4%
March	853,590.0	30.3%	1,175,567.0	36.4%
April	1,001,447.6	36.6%	1,399,217.0	44.7%
May	730,087.9	25.9%	893,485.1	27.6%
June	492,344.0	17.7%	713,713.8	21.9%
July	396,754.7	13.7%	416,695.8	12.1%
August	344,015.5	11.6%	447,575.2	13.0%
September	733,193.7	23.0%	689,962.6	20.7%
October	1,042,735.7	31.1%		
November	1,127,306.0	34.0%		
December	1,159,478.3	33.8%		
Annual	9,589,559.0	27.4%	7,924,471.5	27.2%

Table 3-36 Table 3-16 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): January through September 2011 (See 2010 SOM, Table 3-56)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	34.1%	43.1%	19.1%		26.5%
	Average Wind Generation	1,474.1	2,003.5	869.3		1,180.8
	Average Load	86,939.1	75,551.5	99,674.0		92,790.6
Off-Peak	Capacity Factor	37.7%	46.1%	18.8%		27.7%
	Average Wind Generation	1,633.8	1,874.6	853.7		1,235.1
	Average Load	75,243.8	62,156.7	78,079.9		75,397.1

25 Capacity factor shown in Table 3-35 is based on all hours in January through September, 2011.

Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through September 2011 (See 2010 SOM, Figure 3-14)

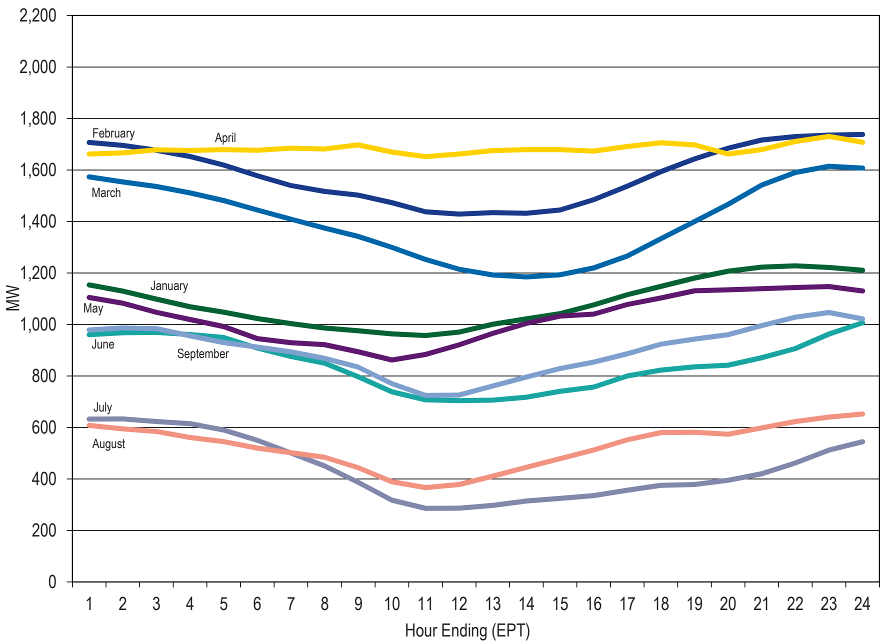
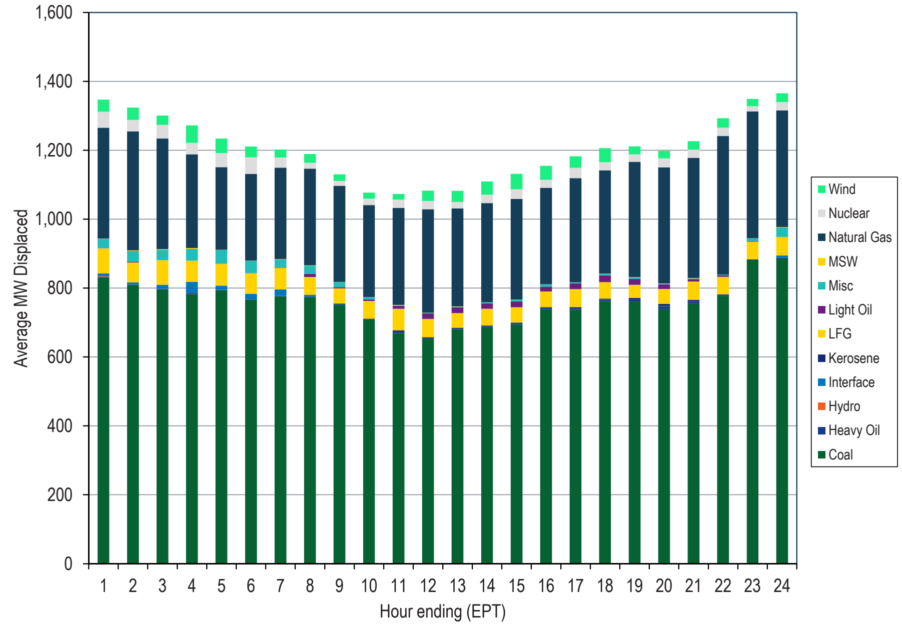


Figure 3-9 Marginal fuel at time of wind generation in PJM, January through September 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-10 Spot monthly average emission price comparison: 2010 and 2011 (See 2010 SOM, Figure 3-16)

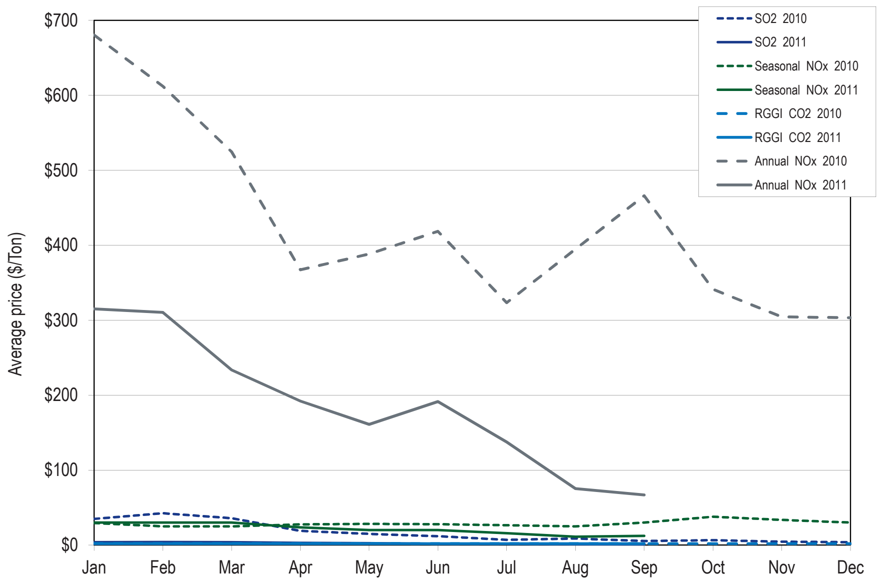


Table 3-37 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[26]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000

Emission Controlled Capacity in the PJM Region

Table 3-38 SO_2 emission controls (FGD) by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-58)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	51,991.2	29,924.6	81,915.8	63.5%
Combined Cycle	0.0	24,520.7	24,520.7	0.0%
Combustion Turbine	0.0	30,320.8	30,320.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	0.0	10,000.5	10,000.5	0.0%
Total	51,991.2	95,133.1	147,124.3	35.3%

26 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed October 1, 2011).

Table 3-39 NO_x emission controls by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-59)

	NO_x Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	79,293.0	2,622.8	81,915.8	96.8%
Combined Cycle	24,329.6	191.1	24,520.7	99.2%
Combustion Turbine	24,936.4	5,384.4	30,320.8	82.2%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	5,012.7	4,987.8	10,000.5	50.1%
Total	133,571.7	13,552.6	147,124.3	90.8%

Table 3-40 Particulate emission controls by unit type (MW), as of September 30, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	80,281.8	1,634.0	81,915.8	98.0%
Combined Cycle	0.0	24,520.7	24,520.7	0.0%
Combustion Turbine	0.0	30,320.8	30,320.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	3,047.0	6,953.5	10,000.5	30.5%
Total	83,328.8	63,795.5	147,124.3	56.6%

CSAPR and HEDD Limits

Table 3-41 2012 and 2014 assurance levels for SO_2[27], NO_x, and O_3 season NO_x[28] emissions (New table)

	SO_2		NO_x		O3 Season NO_x	
	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level
Illinois	277,169	146,465	56,489	56,489	25,662	25,662
Indiana	336,800	190,111	129,477	127,940	56,720	55,872
Kentucky	274,541	125,415	100,401	91,141	43,762	39,536
Maryland	35,542	33,280	19,627	19,557	8,687	8,687
Michigan	270,578	169,914	77,197	74,387	31,160	29,920
New Jersey	9,051	6,577	9,069	8,706	4,809	4,328
North Carolina	161,520	67,992	59,693	49,033	26,823	22,331
Ohio	366,071	161,751	109,390	103,242	48,476	45,728
Pennsylvania	328,808	132,185	141,583	140,649	63,163	62,814
Tennessee	174,817	69,423	42,130	22,818	18,039	9,699
Virginia	83,568	41,367	39,226	39,226	17,487	17,487
West Virginia	172,485	89,288	70,177	64,407	30,592	28,182

Table 3-42 HEDD maximum NO_x emission rates[29] (New table)

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

27 Annual NOX assurance levels for Michigan and Annual NO_x and SO_2 and Seasonal NOX for New Jersey are as adjusted in the Proposed Revised CSAPR II, as set forth in the Technical Revisions to State Budgets and New Unit Set-Asides, Docket No. EPA-HQ-2009-0491 (October 2011) at 5 (Table 1.208.b) & 38 (Table 10.h).
28 CSPAR at 48269–70 (Tables VI.F-1, F-2 & F-3); Proposed Revised CSAPR at 40666 (Table 1.C-2).
29 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

Renewable Portfolio Standards

Table 3-43 Renewable standards of PJM jurisdictions to 2021[30,31] (See 2010 SOM, Table 3-61)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana	No Standard										
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

30 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

31 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 3-44 Solar renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-62)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

Table 3-45 Additional renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-63)

Jurisdiction		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	3.75%	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)		306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste			0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)			170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	4.20%	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

Table 3-46 Renewable alternative compliance payments in PJM jurisdictions: 2011 (See 2010 SOM, Table 3-64)

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 3-47 Renewable generation by jurisdiction and renewable resource type (GWh): January through September 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	44.1	0.0	0.0	0.0	0.0	0.0	0.0	44.1	88.1
Indiana	0.0	0.0	32.1	0.0	0.0	0.0	1,856.4	1,888.5	1,888.5
Illinois	111.0	0.0	0.0	0.0	7.6	0.0	3,813.7	3,924.7	3,932.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	71.8	0.0	1,728.3	0.0	690.4	0.0	210.9	2,011.0	2,701.3
Michigan	20.9	0.0	46.6	0.0	0.0	0.0	0.0	67.5	67.5
New Jersey	233.8	456.3	20.5	34.1	1,056.0	0.0	6.8	295.1	1,807.5
North Carolina	0.0	0.0	289.9	0.0	0.0	0.0	0.0	289.9	289.9
Ohio	72.6	0.0	92.9	1.1	0.0	0.0	52.1	218.7	218.7
Pennsylvania	664.2	1,307.5	2,401.2	2.7	1,322.0	8,373.5	1,257.8	4,326.0	15,328.9
Tennessee	0.0	0.0	0.0	0.0	252.0	0.0	0.0	0.0	252.0
Virginia	134.1	3,696.2	541.1	0.0	926.8	0.0	0.0	675.3	5,298.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	3.4	0.0	767.1	0.0	0.0	786.3	726.9	1,497.4	2,283.8
Total	1,356.0	5,460.1	5,919.8	37.9	4,254.8	9,159.8	7,924.5	15,238.2	34,112.8

Table 3-48 PJM renewable capacity by jurisdiction (MW), on September 30, 2011 (See 2010 SOM, Table 3-66)

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	0.0	24.5	129.0	66.0	0.0	1,162.0	0.0	109.0	0.0	120.0	1,610.5
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	67.3	191.1	0.0	7.5	756.4
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	3,028.7	25.8	0.0	18.0	.	112.0	1.1	0.0	0.0	150.0	3,335.6
Pennsylvania	0.0	215.5	2,327.0	0.0	2,575.0	672.6	3.0	263.0	1,473.9	790.0	8,320.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	108.5	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,465.5
West Virginia	301.0	2.0	0.0	0.0	0.0	239.6	0.0	0.0	130.0	528.1	1,200.7
PJM Total	3,329.7	539.6	4,371.3	115.9	6,563.0	2,983.3	71.4	943.1	1,603.9	4,778.7	25,299.9

Table 3-49 Renewable capacity by jurisdiction, non-PJM units registered in GATS[32,33] (MW), on September 30, 2011 (See 2010 SOM, Table 3-67)

Jurisdiction	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	21.1	0.0	0.1	21.2
Illinois	4.0	97.8	0.0	0.0	0.0	10.6	0.0	302.5	415.0
Indiana	0.0	32.2	0.0	679.1	0.0	0.4	0.0	0.0	711.7
Kentucky	2.0	16.0	0.0	0.0	0.0	0.3	88.0	0.0	106.4
Maryland	0.0	7.0	0.0	0.0	0.0	29.8	0.0	0.0	36.8
Michigan	0.0	1.6	0.0	0.0	0.0	0.1	0.0	0.0	1.7
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	39.9	0.0	0.0	23.3	355.7	0.0	0.2	419.1
New York	141.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	142.1
North Carolina	225.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	227.1
Ohio	1.0	37.3	52.6	45.0	0.0	25.8	109.3	10.3	281.3
Pennsylvania	0.2	5.4	4.8	85.5	0.3	102.1	0.0	3.2	201.5
Virginia	12.5	14.8	0.0	0.0	0.0	3.9	318.1	0.0	349.4
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	2.4
West Virginia	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.4
Wisconsin	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Total	395.5	252.1	57.4	809.6	23.6	555.5	560.0	462.4	3,116.0

32 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
33 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed October 01, 2011).

Scarcity and Scarcity Pricing

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. These offers give the aggregate energy supply curve its steep upward sloping tail.[34] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This provides the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market. Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets.

PJM's current administrative scarcity pricing mechanism is designed to recognize real-time scarcity in the Energy Market and increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.

There is an issue with how the capacity market rules interact with the current scarcity pricing rules. While the capacity market rules create incentives to make capacity available during the highest load periods of the year, this capacity does not have to be made available as non-emergency MW. When scarcity conditions are a possibility, as in the case when PJM declares a Maximum Emergency Generation Alert or a Hot Weather Alert, PJM's current scarcity rules provide an incentive for some capacity MW to be made available as emergency MW, as the loading of maximum emergency generation for a Scarcity Constraint triggers scarcity pricing under the current rules. The tariff limits the classification of MW as emergency under scarcity conditions unless they meet four defined criteria, but this is a hard rule to enforce in practice.[35] The MMU recommends that the rules be clarified.

34 See *2011 Quarterly State of the Market Report for PJM: January through September*, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: July through September 2010 and 2011."

35 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations. See PJM. "Manual 13: Emergency Operations," Revision: 44 (Effective May 26, 2011), p. 68.

High-Load Events: January through September 2011

There were no scarcity pricing events in the January through September 2011 period under PJM's current emergency action based scarcity pricing rules.

In general, participant behavior in the summer of 2011 was consistent with the market incentives created by the Capacity and Energy Market. During the declared Hot Weather Alerts in 2011, declared outage MW were lower than the average declared outage MW in the May through August period. Maximum emergency generation declarations during maximum emergency generation periods were also lower than the monthly averages in the period. However, energy was produced from declared emergency segments during a number of Hot Weather Alert days, when energy prices were below $500 per MWh and in the absence of PJM specific instructions to load the maximum emergency generation. This behavior suggests that some emergency MW segments were incorrectly classified.

There were a total of 35 high-load hours in 2011.[36] There were eleven days with high load hours in June, July and July of 2011: two in June, six in July and three in August. There were eight high load hours in June, sixteen in July and eleven in August. In the May through September period, PJM declared twenty one Hot Weather Alerts.[37]

36 A high-load hour is defined to exist when hourly demand, including the day-ahead operating reserve target, equals 96 percent or more of total, within-30 minute supply in the absence of non market administrative intervention, on an hourly integrated basis. See PJM "Manual 13: Emergency Operations", Revision 44. Effective Date May 26, 2011. p 11.

37 "The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days."

Operating Reserve[38]

Credit and Charge Results

Overall Results

Table 3-50 Monthly operating reserve charges: Calendar years 2010 and 2011 (See SOM 2010, Table 3-72)

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,472,496	$50,803,869	$12,373,099	$110,095	$49,241,974	$61,725,168
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,504,113	$35,583,603
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$23,817,025	$30,720,775
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889	$4,405,102	$13,011	$18,454,339	$22,872,452
May	$5,127,307	$131,600	$39,144,404	$44,403,311	$7,064,934	$39,417	$45,834,527	$52,938,878
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415	$8,303,391	$9,056	$62,117,583	$70,430,030
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778	$4,993,311	$238,127	$106,125,466	$111,356,905
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817	$8,360,392	$104,982	$55,277,638	$63,743,012
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949	$6,249,240	$40,878	$36,357,847	$42,647,965
Oct	$7,719,744	$1,543	$30,433,986	$38,155,273				
Nov	$6,556,715	$29,674	$20,020,310	$26,606,698				
Dec	$12,951,879	$59,954	$83,021,125	$96,032,958				
Total	$63,473,794	$628,972	$344,164,993	$408,267,759	$67,527,391	$760,886	$423,730,511	$492,018,787
Share of Annual Charges	15.5%	0.2%	84.3%	100.0%	13.7%	0.2%	86.1%	100.0%

38 See the *2010 State of the Market Report for PJM,* Volume II, Section 3, "Energy Market, Part 2", Table 3-68 *Operating reserve credit and charges* and Table 3-69 *Operating reserve deviations* for details regarding operating reserve structure.

Table 3-51 Regional balancing operating reserve charges allocation: January through September 2011[39] (See SOM 2010, Table 3-73)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$45,657,166 9.5%	$1,851,929 0.4%	$47,509,095 9.9%	$79,832,680 16.6%	$23,993,384 5.0%	$206,001,417 42.9%	$309,827,481 64.5%	$357,336,576 74.4%
East	$9,755,946 2.0%	$583,122 0.1%	$10,339,068 2.2%	$23,528,097 4.9%	$6,123,664 1.3%	$59,588,642 12.4%	$89,240,403 18.6%	$99,579,471 20.7%
West	$16,011,130 3.3%	$874,280 0.2%	$16,885,410 3.5%	$3,418,605 0.7%	$1,224,749 0.3%	$2,033,089 0.4%	$6,676,443 1.4%	$23,561,853 4.9%
Total	$71,424,242 14.9%	$3,309,330 0.7%	$74,733,573 15.6%	$106,779,383 22.2%	$31,341,796 6.5%	$267,623,148 55.7%	$405,744,328 84.4%	$480,477,900 100%

Deviations

Allocation

Table 3-52 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011 (See SOM 2010, Table 3-74)

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,798,230	3,261,409	25,640,990	38,700,629
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	22,571,322	32,577,260
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	23,370,795	33,348,329
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,624,265	2,028,227	21,698,434	30,350,926
May	9,004,034	4,228,004	2,416,103	15,648,141	7,213,247	2,450,164	23,189,595	32,853,005
Jun	10,936,989	3,964,478	3,174,230	18,075,697	10,155,922	2,865,616	20,822,919	33,844,457
Jul	10,928,408	3,847,011	3,412,498	18,187,917	10,170,858	2,690,836	21,948,613	34,810,307
Aug	9,747,045	3,417,328	3,188,437	16,352,810	8,566,032	2,057,281	18,493,882	29,117,195
Sep	9,480,237	3,587,356	2,524,213	15,591,806	8,829,765	2,198,723	17,992,916	29,021,403
Oct	7,170,712	2,913,554	2,368,303	12,452,569				
Nov	7,606,971	2,860,054	2,485,153	12,952,178				
Dec	10,069,627	4,027,236	3,513,489	17,610,352				
Total	107,168,077	49,691,893	32,634,038	189,494,008	76,065,232	22,828,814	195,729,467	294,623,512
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	25.8%	7.7%	66.4%	100.0%

39 The total charges shown in Table 3-52 do not equal the total balancing charges shown in Table 3-50 because the totals in Table 3-50 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-52 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 3-53 R egional operating reserve charges determinants (MWh): January through September 2011 (See SOM 2010, Table 3-75)

	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	548,529,196	23,853,706	572,382,902	76,065,232	22,828,814	195,729,467	294,623,512	867,006,414
East	287,309,142	10,851,861	298,161,003	45,446,676	12,347,835	146,947,851	204,742,363	502,903,365
West	261,220,055	13,001,845	274,221,900	30,307,989	10,370,567	20,036,381	60,714,937	334,936,836

Operating Reserve Credits by Category

Figure 3-11 Operating reserve credits: January through September 2011 (See SOM 2010, Figure 3-22)

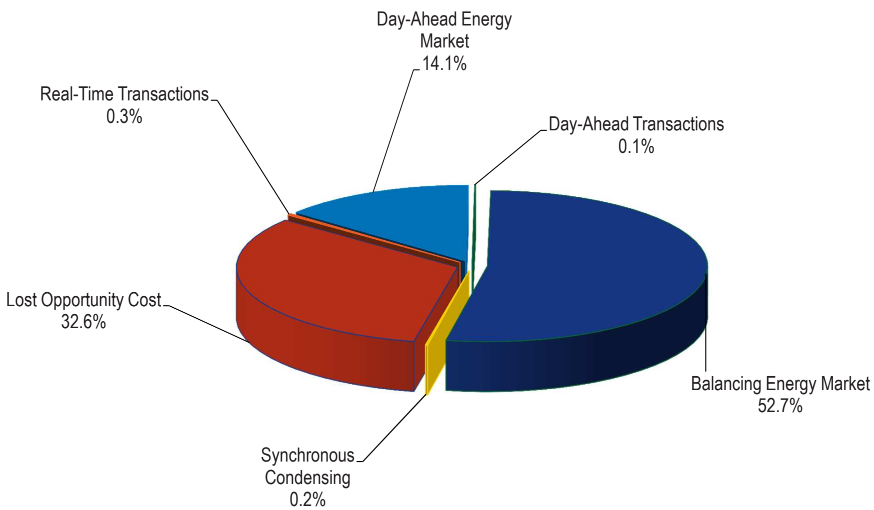


Table 3-54 Operating reserve credits by month (By operating reserve market): January through September 2011[40] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$43,536,900	$473,239	$2,946,513	$59,439,847
Feb	$8,844,162	$96,041	$139,287	$22,920,110	$378,056	$3,205,948	$35,583,604
Mar	$6,830,696	$7,024	$66,032	$15,312,266	$421,862	$7,091,141	$29,729,020
Apr	$4,395,461	$9,641	$13,011	$11,008,300	$215,816	$7,230,224	$22,872,452
May	$7,057,377	$7,557	$39,417	$22,772,231	$13,365	$20,364,971	$50,254,918
Jun	$8,158,879	$144,512	$9,056	$31,864,011	$20,077	$27,996,648	$68,193,183
Jul	$4,972,654	$20,657	$238,127	$56,725,590	$1,068	$45,972,367	$107,930,463
Aug	$8,355,563	$4,828	$104,982	$29,638,014	$4,774	$24,131,500	$62,239,661
Sep	$6,249,124	$116	$40,878	$18,099,540	$40,005	$16,897,975	$41,327,639
Oct							
Nov							
Dec							
Total	$67,216,527	$310,864	$760,885	$251,876,963	$1,568,263	$155,837,286	$477,570,788
Share of Credits	14.1%	0.1%	0.2%	52.7%	0.3%	32.6%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-55 Operating reserve credits by unit types (By operating reserve market): January through September 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	29.0%	0.0%	67.8%	3.2%	$92,661,071
Combustion Turbine	2.1%	0.4%	34.8%	62.6%	$186,099,392
Diesel	2.4%	0.0%	82.9%	14.7%	$299,174
Hydro	47.7%	0.0%	52.3%	0.0%	$252,916
Landfill	0.0%	0.0%	0.0%	100.0%	$16,217,096
Nuclear	0.0%	0.0%	0.0%	100.0%	$291,748
Steam	21.2%	0.0%	70.9%	7.9%	$167,676,815
Wind Farm	0.0%	0.0%	99.8%	0.2%	$3,439,734

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

Table 3-56 Credits by operating reserve market (By unit type): January through September 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	40.4%	0.0%	25.1%	2.0%
Combustion Turbine	5.9%	100.0%	25.9%	78.0%
Diesel	0.0%	0.0%	0.1%	0.0%
Hydro	0.2%	0.0%	0.1%	0.0%
Landfill	0.0%	0.0%	0.0%	10.9%
Nuclear	0.0%	0.0%	0.0%	0.2%
Steam	53.5%	0.0%	47.5%	8.9%
Wind Farm	0.0%	0.0%	1.4%	0.0%
Total	$66,473,554	$760,885	$250,324,547	$149,378,961

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-57 Regional balancing operating reserve credits: January through September 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$47,509,095	$309,827,481	$357,336,576
East	$10,339,068	$89,240,403	$99,579,471
West	$16,885,410	$6,676,443	$23,561,853
Total	$74,733,573	$405,744,328	$480,477,900

Table 3-58 Total deviations: January through September 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	76,065,232	22,828,814	195,729,467	294,623,512

Table 3-59 Actual regional credits, charges, rates and charge allocation (MWh): January through September 2011 (See SOM 2010, Table 3-89)

	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	$47,509,095	572,382,903	0.083	$47,509,095	$309,827,481	294,623,512	1.052	$309,827,481	$357,336,576
East	$10,339,068	298,161,003	0.035	$10,339,068	$89,240,403	204,742,363	0.436	$89,240,403	$99,579,471
West	$16,885,410	274,221,900	0.062	$16,885,410	$6,676,443	60,714,937	0.110	$6,676,443	$23,561,853
Total	$74,733,573	572,382,903	NA	$74,733,573	$405,744,328	294,623,512	NA	$405,744,328	$480,477,900

Impact on Decrement Bids and Incremental Offers

Table 3-60 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh[41]): Calendar years 2010 and 2011 (See SOM 2010, Table 3-91)

	2010				2011			
Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	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	6,054,214	8,284,810	1,548,295	3,162,842
Feb	8,323,844	11,828,781	2,004,162	2,234,045	5,732,202	7,440,032	1,376,811	2,271,323
Mar	8,032,429	11,159,303	2,150,898	2,594,826	5,372,006	7,753,370	1,152,805	2,548,787
Apr	7,568,471	9,989,951	2,214,314	2,066,270	5,200,154	7,351,597	957,164	2,050,911
May	8,306,597	11,573,314	2,250,271	3,437,786	5,537,880	7,609,897	1,174,272	2,217,049
Jun	8,304,139	12,735,819	2,223,204	4,058,044	6,367,269	8,938,210	1,200,432	2,709,247
Jul	8,389,094	12,813,573	1,840,017	3,503,722	6,393,392	9,072,394	1,120,299	2,734,062
Aug	7,862,123	11,648,289	1,465,333	2,676,901	5,622,097	8,184,829	909,703	2,007,437
Sep	8,188,967	11,532,284	2,103,152	3,105,498	5,287,621	8,950,589	1,157,069	3,242,434
Oct	7,777,616	10,423,935	1,564,871	2,163,717				
Nov	8,027,852	11,041,950	1,408,786	2,467,942				
Dec	9,416,187	12,320,592	1,920,956	3,451,929				
Total	98,488,750	140,097,307	23,609,817	35,212,727	51,566,835	73,585,727	10,596,850	22,944,092

41 Adjusted deviations refer to increment offers and decrement bids that were net out by real-time imports, exports, transactions, generation, or load.

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-61 Unit operating reserve credits (By zone): January through September 2011 (See SOM 2010, Table 3-100)

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	$409,727.39	$0.00	$4,430,442.94	$4,027,145.84	$8,867,316.17	1.9%
AEP	$2,388,192.09	$368.22	$33,790,330.36	$11,789,492.34	$47,968,383.01	10.1%
AP	$1,689,215.05	$0.00	$7,173,509.45	$11,376,236.71	$20,238,961.21	4.3%
ATSI	$686,850.33	$0.00	$801,390.25	$6,360,519.56	$7,848,760.14	1.6%
BGE	$8,440,411.63	$0.00	$9,647,240.77	$697,002.52	$18,784,654.92	3.9%
ComEd	$1,093,871.37	$0.00	$6,370,679.99	$16,562,749.55	$24,027,300.91	5.1%
DAY	$175,225.95	$0.00	$841,482.18	$713,149.48	$1,729,857.61	0.4%
Dominion	$5,595,544.83	$0.00	$43,697,947.29	$87,375,575.12	$136,669,067.24	28.7%
DLCO	$304,052.68	$0.00	$2,446,671.01	$5,453.81	$2,756,177.50	0.6%
DPL	$1,733,225.40	$0.00	$14,609,449.62	$4,480,898.32	$20,823,573.34	4.4%
JCPL	$1,563,596.70	$0.00	$6,339,948.63	$1,746,302.20	$9,649,847.53	2.0%
Met-Ed	$231,931.10	$0.00	$2,701,605.30	$456,040.87	$3,389,577.27	0.7%
PECO	$601,993.21	$4,691.56	$7,402,864.20	$394,817.43	$8,404,366.40	1.8%
PENELEC	$430,190.07	$0.00	$3,201,480.17	$3,592,925.25	$7,224,595.49	1.5%
Pepco	$3,531,212.34	$0.00	$38,825,588.16	$1,234,641.44	$43,591,441.94	9.2%
PPL	$653,774.02	$0.00	$7,690,558.74	$1,604,047.85	$9,948,380.61	2.1%
PSEG	$37,687,512.46	$755,825.69	$61,905,774.03	$3,420,287.89	$103,769,400.07	21.8%
External	$0.00	$0.00	$0.00	$0.00	$0.00	0.0%
Total	$67,216,526.62	$760,885.47	$251,876,963.09	$155,837,286.18	$475,691,661.36	100.0%

Table 3-62 Top 10 units and organizations receiving total operating reserve credits: January through September 2011 (See SOM 2010, Table 3-101)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$30,032,491	6.3%	6.3%	$107,930,853	22.7%	22.7%
2	$24,125,705	5.1%	11.4%	$102,987,596	21.7%	44.3%
3	$20,217,005	4.3%	15.6%	$31,705,644	6.7%	51.0%
4	$18,083,292	3.8%	19.4%	$29,565,668	6.2%	57.2%
5	$12,889,230	2.7%	22.1%	$25,977,869	5.5%	62.7%
6	$8,872,694	1.9%	24.0%	$24,271,927	5.1%	67.8%
7	$7,244,337	1.5%	25.5%	$18,251,590	3.8%	71.6%
8	$6,981,948	1.5%	27.0%	$17,559,600	3.7%	75.3%
9	$6,748,554	1.4%	28.4%	$16,253,488	3.4%	78.7%
10	$6,228,987	1.3%	29.7%	$14,688,384	3.1%	81.8%

Table 3-63 Top 10 units and organizations receiving day-ahead generator credits: January through September 2011 (See SOM 2010, Table 3-102)

	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	$13,407,979	19.9%	19.9%	$37,543,343	55.9%	55.9%
2	$12,897,002	19.2%	39.1%	$9,033,617	13.4%	69.3%
3	$6,149,535	9.1%	48.3%	$5,004,091	7.4%	76.7%
4	$3,373,898	5.0%	53.3%	$4,717,423	7.0%	83.8%
5	$2,965,345	4.4%	57.7%	$1,849,108	2.8%	86.5%
6	$2,216,457	3.3%	61.0%	$1,709,805	2.5%	89.1%
7	$1,635,635	2.4%	63.4%	$1,095,729	1.6%	90.7%
8	$1,095,729	1.6%	65.1%	$882,015	1.3%	92.0%
9	$746,226	1.1%	66.2%	$843,347	1.3%	93.2%
10	$673,817	1.0%	67.2%	$676,035	1.0%	94.3%

Table 3-64 Top 10 units and organizations receiving synchronous condensing credits: January through September 2011 (See SOM 2010, Table 3-103)

	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	$54,950	7.2%	7.2%	$755,826	99.3%	99.3%
2	$54,772	7.2%	14.4%	$4,692	0.6%	100.0%
3	$51,039	6.7%	21.1%	$368	0.0%	100.0%
4	$50,856	6.7%	27.8%			
5	$46,721	6.1%	34.0%			
6	$46,106	6.1%	40.0%			
7	$44,997	5.9%	45.9%			
8	$44,031	5.8%	51.7%			
9	$43,681	5.7%	57.5%			
10	$40,101	5.3%	62.7%			

Table 3-65 Top 10 units and organizations receiving balancing generator credits: January through September 2011 (See SOM 2010, Table 3-104)

	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	$23,856,521	9.5%	9.5%	$61,268,139	24.3%	24.3%
2	$18,061,887	7.2%	16.6%	$37,409,463	14.9%	39.2%
3	$12,215,413	4.8%	21.5%	$25,944,152	10.3%	49.5%
4	$10,695,913	4.2%	25.7%	$23,918,514	9.5%	59.0%
5	$8,872,694	3.5%	29.3%	$22,679,037	9.0%	68.0%
6	$7,316,331	2.9%	32.2%	$12,770,557	5.1%	73.0%
7	$7,244,337	2.9%	35.0%	$12,341,886	4.9%	77.9%
8	$4,705,627	1.9%	36.9%	$7,078,417	2.8%	80.8%
9	$3,508,780	1.4%	38.3%	$6,465,058	2.6%	83.3%
10	$3,254,072	1.3%	39.6%	$5,861,871	2.3%	85.7%

Table 3-66 Top 10 units and organizations receiving lost opportunity cost credits: January through September 2011 (See SOM 2010, Table 3-105)

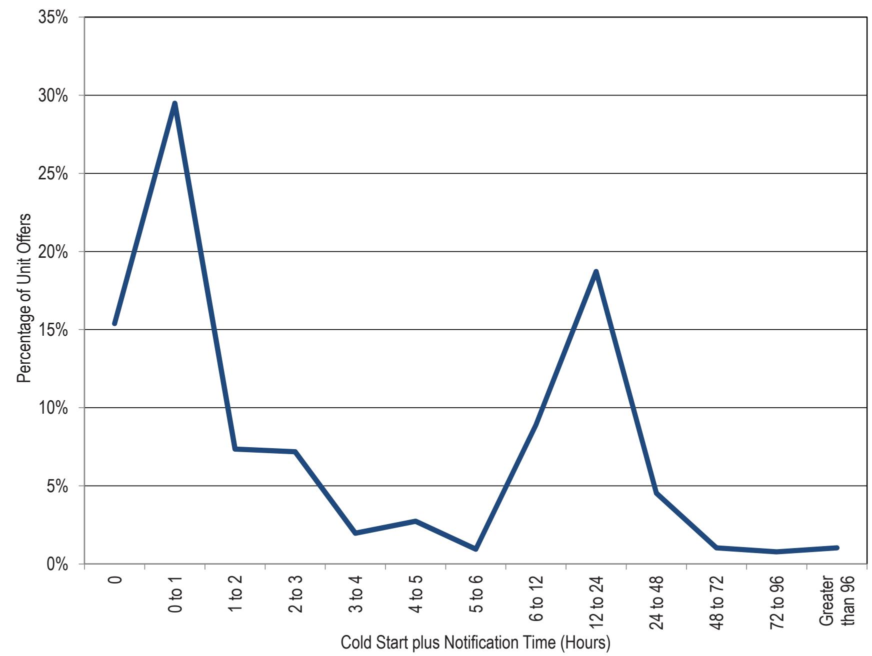
	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$6,621,926	4.2%	4.2%	$65,517,299	42.0%	42.0%
2	$6,013,853	3.9%	8.1%	$16,202,279	10.4%	52.4%
3	$5,322,286	3.4%	11.5%	$13,284,457	8.5%	61.0%
4	$5,301,680	3.4%	14.9%	$8,901,427	5.7%	66.7%
5	$4,468,104	2.9%	17.8%	$6,059,157	3.9%	70.6%
6	$4,376,201	2.8%	20.6%	$5,938,021	3.8%	74.4%
7	$4,197,395	2.7%	23.3%	$5,233,670	3.4%	77.7%
8	$3,906,302	2.5%	25.8%	$4,309,377	2.8%	80.5%
9	$3,643,638	2.3%	28.1%	$3,907,413	2.5%	83.0%
10	$2,926,531	1.9%	30.0%	$3,619,558	2.3%	85.3%

PLS (Parameter Limited Schedules) Recommendations

Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers. This issue is currently in discussion in the PJM stakeholder process. Figure 3-12 shows the distribution of start plus notification times for the first three quarters of 2011.

Figure 3-12 Average Cold Start plus Notification Time (Hours) of PJM offers: January through September 2011 (New Figure)



Parameter Limited Schedules

Currently, parameter limited schedules are only enforced for cost-based schedules, except for emergencies, permitting the use of price-based schedule parameters as a possible method to exercise market power. (Table 3-67 is the parameter limited schedule matrix.) The parameter limited schedule should reflect the most flexible physical parameters of the unit, and there are a number of potential issues that result when a unit is not offering its most flexible parameters. For example, a unit may temporarily extend a minimum down time parameter to avoid being turned off when not economic, although there is no physical change to the unit. The result is increased operating reserve credits to the unit and operating reserve charges paid by other market participants. One way to address this issue would be a more forward looking PJM dispatch process which could better capture the operation of baseload units that were not designed to cycle daily. A unit also may offer more flexible operating parameters on a price-based schedule than on a cost-based schedule. The result can be increased operating reserve credits to the unit and charges paid by other participants when the cost-based schedule is taken in place of the price-based schedule when offer capping is implemented. One way to address this issue would be require units to include their most flexible operating parameters in their cost-based offers. These and related issues are currently being discussed in the PJM stakeholder process.

Table 3-67 PJM Unit Parameter Limited Schedule Matrix (See SOM 2010, Table 3-97)

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