Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- Energy net revenues are significantly affected by fuel prices and energy prices. Coal and natural gas prices and energy prices were lower in the first three months of 2016 than in the first three months of 2015. Net revenues from the energy market for all plant types were affected by the lower prices.
- In the first three months of 2016, average energy market net revenues decreased from the first three months of 2015 by 62 percent for a new CT, 51 percent for a new CC, 82 percent for a new CP, 85 percent for a new DS, 56 percent for a new nuclear plant, 38 percent for a new wind installation, and 62 percent for a new solar installation.

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. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

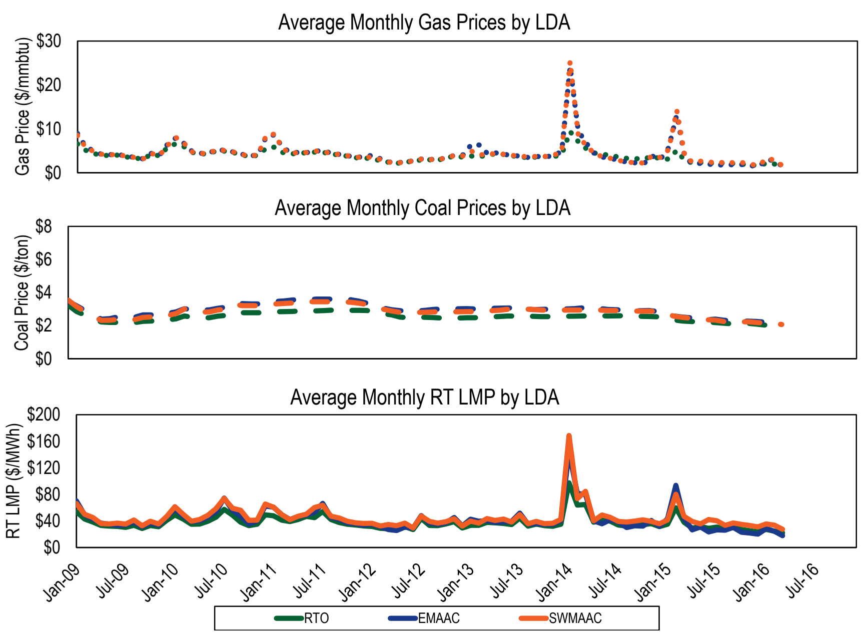
Net Revenue

When compared to annualized 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 to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover the fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 47.4 percent lower in the first three months of 2016 than in the first three months of 2015, $26.80 per MWh versus $50.91 per MWh. Coal and natural gas prices decreased in 2016. Comparing fuel prices in the first three months of 2016 to the first three months of 2015, the price of Northern Appalachian coal was 22.7 percent lower; the price of Central Appalachian coal was 15.5 percent lower; the price of Powder River Basin coal was 11.0 percent lower; the price of eastern natural gas was 67.2 percent lower; and the price of western natural gas was 32.1 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through March 2016



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power converted to a cost per MWh. The spark spread compares power prices to the cost of gas, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{mmBtu}\right) * Heat\ Rate\left(\frac{mmBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

Figure 7-2 shows the hourly spark spread for peak hours since January 2011 for BGE, ComEd, PSEG, and Western Hub.[1]

1 Spark spreads use a combined cycle heat rate of 7,500 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 Non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours: 2011 through March 2016[2]

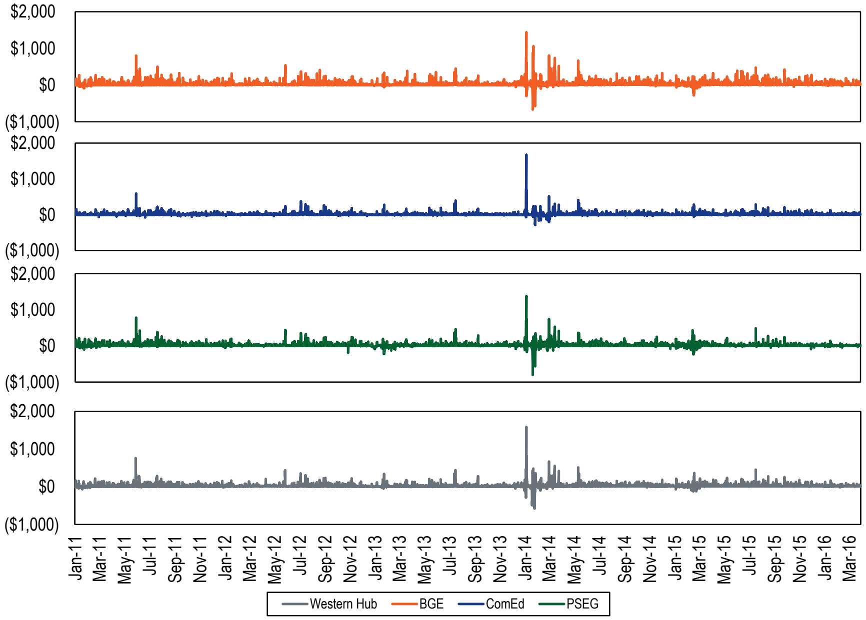
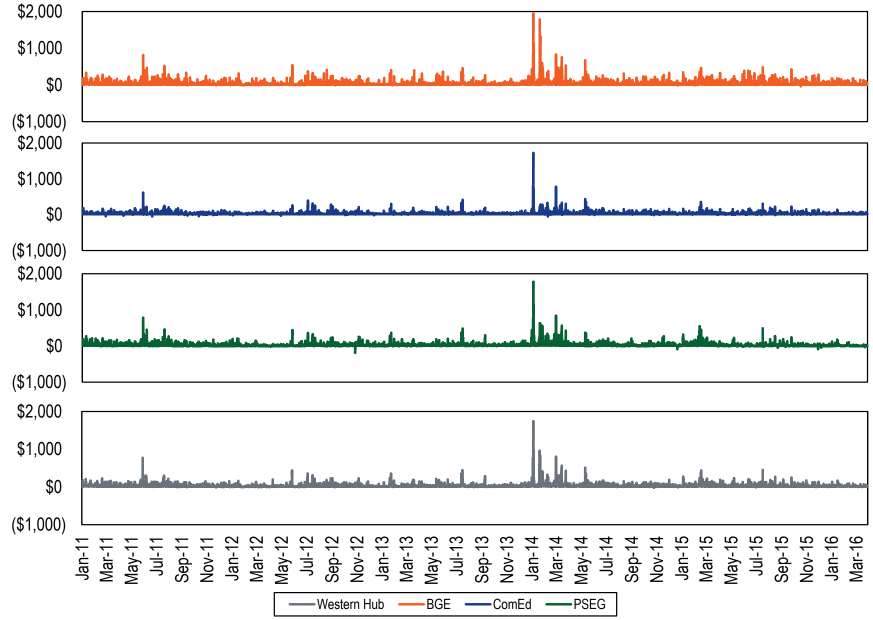


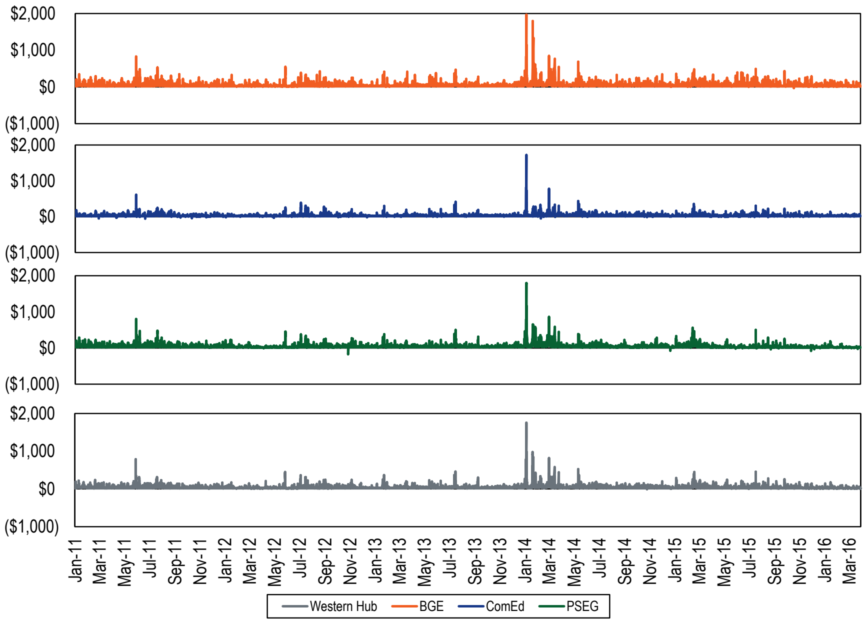
Figure 7-3 Hourly dark spread (coal) for peak hours: 2011 through March 2016[3]



2 The maximum peak hour spark spread for ComEd and Western Hub extends beyond the axis and was $1,674.45 and $1,590.66.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Figure 7-4 Hourly quark spread (uranium) for selected zones: 2011 through March 2016[4]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

4 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant has an installed capacity of 641.2 MW and consists of two GE Frame 7HA.02 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 971.4 MW and consists of two GE Frame 7HA.02 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[5]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty two Siemens 2.3 MW wind turbines totaling 50.6 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[6] [7] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

5 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
6 Hourly ambient conditions supplied by Schneider Electric.
7 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[8]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[9] Each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[10] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[12]

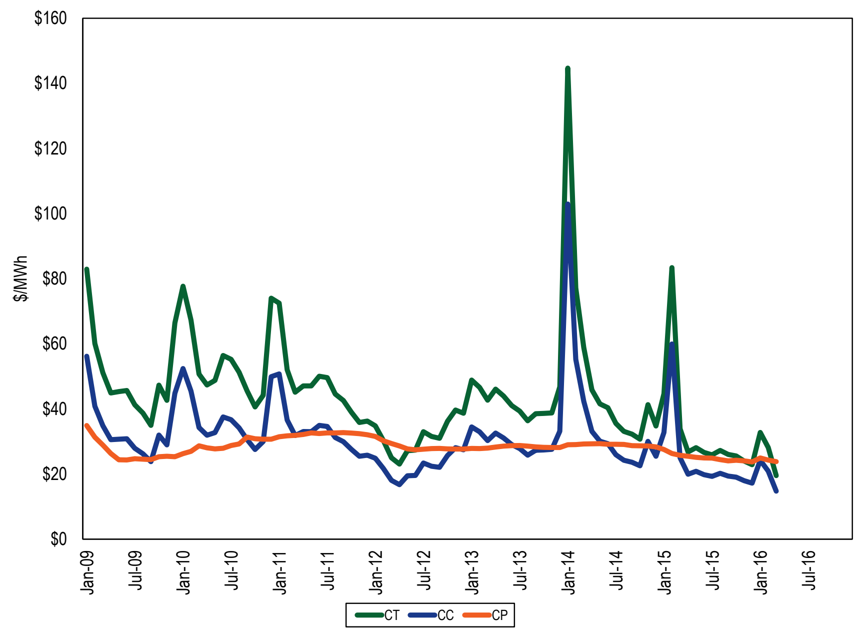
Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[13] [14] Average short run marginal costs are shown in Table 7-1.

Table 7-1 Average short run marginal costs: 2016

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$26.79	9,437	$0.25
CC	$19.94	6,679	$1.00
CP	$24.34	9,250	$4.00
DS	$80.48	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the short run marginal cost of the theoretical CT, CC and CP plants since January 2009 shows that the CC plant has been competitive with the CP plant but that the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-5). A significant increase in gas prices on cold days resulted in a corresponding increase in the average short run marginal cost of CTs and CCs in January 2014 and February 2015 (Figure 7-5).

Figure 7-5 Average short run marginal costs: 2009 through March 2016



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

8 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
9 Outage figures obtained from the PJM eGADS database.
10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt prices obtained from Platts.
13 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CT plant energy market net revenues were lower in all zones except BGE and Pepco in the first three months of 2016 (Table 7-2). In BGE and Pepco the new entrant CT ran for more than twice as many hours in the first three months of 2016 than in the first three months of 2015 as a result of lower gas costs.

Table 7-2 Energy net revenue for a new entrant gas fired CT under economic dispatch (Dollars per installed MW-year)[15]

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	Change in 2016 from 2015
AECO	$2,728	$836	$9,202	$7,517	$3,214	$30,264	$13,722	$5,005	(64%)
AEP	$1,901	$621	$3,123	$8,528	$3,199	$48,084	$19,634	$5,771	(71%)
AP	$6,017	$2,409	$12,201	$11,591	$4,730	$65,810	$36,706	$8,092	(78%)
ATSI	NA	NA	$0	$8,891	$3,653	$54,456	$19,993	$5,756	(71%)
BGE	$3,358	$1,204	$5,747	$15,513	$5,058	$32,712	$9,300	$18,204	96%
ComEd	$683	$194	$857	$3,157	$1,116	$19,735	$6,229	$1,180	(81%)
DAY	$1,047	$331	$3,039	$9,388	$3,194	$47,524	$17,257	$5,136	(70%)
DEOK	NA	NA	NA	$6,331	$2,085	$44,695	$24,316	$11,439	(53%)
DLCO	$456	$2,513	$3,104	$9,158	$2,266	$41,566	$12,491	$5,471	(56%)
Dominion	$5,632	$5,929	$5,031	$10,436	$6,543	$26,374	$11,232	$7,977	(29%)
DPL	$3,661	$779	$5,614	$12,059	$2,838	$32,143	$13,114	$9,476	(28%)
EKPC	NA	NA	NA	NA	$0	$45,421	$23,459	$10,693	(54%)
JCPL	$2,577	$1,719	$10,060	$7,622	$5,970	$34,426	$15,452	$2,566	(83%)
Met-Ed	$2,371	$710	$7,093	$6,542	$3,058	$28,211	$13,333	$2,958	(78%)
PECO	$2,452	$881	$8,652	$6,738	$2,386	$28,475	$13,131	$2,340	(82%)
PENELEC	$3,650	$1,326	$10,947	$10,488	$7,549	$79,708	$59,869	$12,109	(80%)
Pepco	$3,268	$2,062	$5,965	$13,821	$5,302	$32,626	$7,748	$12,071	56%
PPL	$2,204	$880	$10,269	$6,045	$2,517	$34,732	$13,827	$2,740	(80%)
PSEG	$919	$328	$3,851	$4,562	$1,946	$17,568	$6,992	$812	(88%)
RECO	$461	$298	$2,296	$3,872	$3,442	$18,173	$9,147	$1,129	(88%)
PJM	$2,552	$1,354	$5,947	$8,540	$3,503	$38,135	$17,348	$6,546	(62%)

15 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day-ahead in profitable blocks of at least eight hours, including start costs.[16] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were lower in all zones except BGE and Pepco in the first three months of 2016 (Table 7-3). In BGE and Pepco the new entrant CC ran for more hours in the first three months of 2016 than in the first three months of 2015 as a result of lower gas costs.

Table 7-3 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[17]

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	Change in 2016 from 2015
AECO	$12,504	$7,650	$23,944	$20,898	$13,647	$56,633	$29,158	$11,317	(61%)
AEP	$5,215	$3,277	$13,838	$22,216	$15,740	$65,957	$32,327	$14,302	(56%)
AP	$17,657	$8,782	$29,151	$25,351	$19,220	$88,769	$51,238	$17,210	(66%)
ATSI	NA	NA	$0	$22,945	$17,203	$75,316	$33,610	$14,189	(58%)
BGE	$13,494	$9,004	$17,981	$29,349	$19,030	$61,497	$18,447	$29,746	61%
ComEd	$2,565	$456	$3,135	$13,158	$5,354	$24,423	$11,231	$6,171	(45%)
DAY	$3,506	$1,934	$13,084	$23,184	$16,421	$65,549	$30,270	$14,125	(53%)
DEOK	NA	NA	NA	$19,654	$12,964	$62,412	$37,950	$21,571	(43%)
DLCO	$2,172	$4,036	$11,553	$22,591	$12,417	$55,522	$22,933	$13,448	(41%)
Dominion	$19,787	$15,018	$18,479	$24,097	$18,064	$47,378	$20,917	$16,657	(20%)
DPL	$13,710	$5,448	$19,168	$25,392	$14,206	$58,992	$26,208	$17,888	(32%)
EKPC	NA	NA	NA	NA	$0	$62,362	$36,811	$20,764	(44%)
JCPL	$12,929	$7,674	$25,248	$21,166	$17,261	$64,421	$31,063	$8,505	(73%)
Met-Ed	$10,131	$6,078	$19,322	$19,502	$12,766	$54,369	$24,758	$8,569	(65%)
PECO	$10,974	$6,713	$23,065	$19,889	$11,677	$54,796	$28,134	$7,544	(73%)
PENELEC	$13,226	$6,336	$27,396	$24,519	$23,697	$106,773	$70,517	$21,708	(69%)
Pepco	$12,033	$9,781	$17,384	$27,686	$19,412	$57,616	$15,827	$22,337	41%
PPL	$9,837	$5,769	$21,396	$18,699	$11,602	$55,366	$26,697	$8,872	(67%)
PSEG	$8,516	$5,996	$13,942	$14,952	$9,112	$38,580	$14,493	$3,070	(79%)
RECO	$6,018	$4,820	$8,026	$13,976	$11,276	$40,300	$14,856	$3,950	(73%)
PJM	$10,251	$6,398	$17,006	$21,538	$14,053	$59,852	$28,872	$14,097	(51%)

16 All starts associated with combined cycle units are assumed to be warm starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is at the direction of PJM. The regulation clearing price was compared to the day ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

New entrant CP plant energy market net revenues were lower in all zones in the first three months of 2016 (Table 7-4).

Table 7-4 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[18]

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	Change in 2016 from 2015
AECO	$43,215	$41,590	$36,063	$2,675	$13,783	$143,988	$58,708	$6,896	(88%)
AEP	$16,803	$29,638	$21,699	$3,597	$16,892	$82,244	$27,081	$10,291	(62%)
AP	$35,826	$40,552	$33,649	$5,402	$19,131	$102,926	$45,528	$3,261	(93%)
ATSI	NA	NA	$0	$3,649	$17,503	$90,714	$29,110	$7,939	(73%)
BGE	$46,577	$51,492	$40,197	$9,897	$23,506	$156,913	$62,899	$15,396	(76%)
ComEd	$36,166	$40,706	$34,460	$25,552	$31,957	$87,058	$35,291	$18,715	(47%)
DAY	$14,485	$27,375	$20,446	$1,419	$17,757	$82,450	$27,073	$7,647	(72%)
DEOK	NA	NA	NA	$619	$14,454	$76,026	$23,975	$6,783	(72%)
DLCO	$9,716	$23,675	$10,308	$1,926	$9,653	$66,530	$17,819	$7,638	(57%)
Dominion	$41,068	$50,166	$36,153	$5,034	$20,582	$127,290	$58,725	$18,205	(69%)
DPL	$47,268	$46,314	$42,948	$7,948	$19,736	$159,791	$72,097	$8,635	(88%)
EKPC	NA	NA	NA	NA	$0	$75,988	$22,964	$6,066	(74%)
JCPL	$43,327	$41,795	$36,913	$2,664	$16,833	$150,288	$59,850	$6,110	(90%)
Met-Ed	$43,283	$44,209	$37,718	$3,371	$17,543	$143,912	$57,928	$6,470	(89%)
PECO	$41,572	$40,698	$35,350	$2,336	$12,341	$141,628	$57,588	$5,821	(90%)
PENELEC	$30,086	$33,010	$25,545	$2,745	$17,876	$107,488	$44,858	$7,531	(83%)
Pepco	$42,835	$47,934	$33,287	$5,135	$19,073	$149,835	$57,241	$8,921	(84%)
PPL	$39,552	$39,126	$33,557	$1,684	$12,376	$140,691	$56,463	$6,000	(89%)
PSEG	$46,936	$43,883	$37,602	$3,241	$24,438	$163,942	$69,545	$7,539	(89%)
RECO	$43,612	$40,865	$30,456	$2,816	$30,378	$161,280	$70,870	$6,292	(91%)
PJM	$36,607	$40,178	$30,353	$4,827	$17,791	$120,549	$47,781	$8,608	(82%)

18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all zones in the first three months of 2016 (Table 7-5).

Table 7-5 Energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	Change in 2016 from 2015
AECO	$1,555	$780	$928	$8	$262	$36,066	$11,926	$2,843	(76%)
AEP	$100	$94	$9	$0	$99	$15,382	$3,059	$603	(80%)
AP	$808	$224	$13	$0	$127	$20,072	$6,840	$860	(87%)
ATSI	NA	NA	$0	$0	$97	$15,092	$2,727	$484	(82%)
BGE	$2,596	$1,572	$975	$136	$592	$53,670	$11,187	$3,937	(65%)
ComEd	$7	$73	$0	$0	$74	$12,076	$1,747	$266	(85%)
DAY	$174	$92	$97	$0	$87	$15,130	$2,559	$440	(83%)
DEOK	NA	NA	NA	$0	$74	$14,306	$2,105	$609	(71%)
DLCO	$65	$1,547	$8	$0	$78	$13,813	$2,489	$501	(80%)
Dominion	$2,696	$2,149	$1,062	$134	$468	$46,239	$10,055	$2,192	(78%)
DPL	$2,442	$1,175	$898	$19	$290	$40,857	$14,788	$3,104	(79%)
EKPC	NA	NA	NA	NA	$0	$15,363	$2,304	$871	(62%)
JCPL	$1,348	$732	$1,192	$22	$453	$36,332	$12,736	$799	(94%)
Met-Ed	$1,424	$758	$782	$4	$251	$35,247	$11,621	$746	(94%)
PECO	$1,402	$755	$847	$9	$252	$35,496	$11,794	$728	(94%)
PENELEC	$203	$109	$11	$0	$123	$17,773	$5,626	$542	(90%)
Pepco	$2,925	$1,882	$1,215	$137	$667	$55,675	$10,096	$2,212	(78%)
PPL	$1,297	$706	$920	$48	$255	$36,173	$12,432	$702	(94%)
PSEG	$1,210	$672	$847	$9	$325	$35,956	$12,238	$910	(93%)
RECO	$940	$530	$524	$0	$1,466	$33,335	$13,957	$887	(94%)
PJM	$1,247	$815	$574	$28	$302	$29,203	$8,114	$1,212	(85%)

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours of the year other than forced outage hours.[19]

New entrant nuclear plant energy market net revenues were lower in all zones in the first three months of 2016 (Table 7-6).

Table 7-6 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[20]

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	Change in 2016 from 2015
AECO	$101,789	$91,719	$95,005	$49,465	$62,135	$209,062	$105,885	$34,600	(67%)
AEP	$69,992	$68,828	$63,740	$45,781	$55,242	$130,923	$67,640	$39,173	(42%)
AP	$85,930	$79,042	$76,989	$48,737	$58,231	$153,609	$86,634	$42,088	(51%)
ATSI	NA	NA	$0	$46,380	$56,419	$140,042	$68,786	$38,969	(43%)
BGE	$102,425	$98,153	$92,808	$57,792	$68,082	$219,233	$107,545	$60,976	(43%)
ComEd	$57,229	$58,837	$54,172	$40,561	$48,679	$112,295	$54,074	$33,044	(39%)
DAY	$66,782	$66,322	$63,005	$46,714	$55,805	$130,464	$65,467	$38,864	(41%)
DEOK	NA	NA	NA	$43,474	$52,104	$123,359	$62,074	$37,723	(39%)
DLCO	$60,313	$67,382	$59,001	$46,158	$52,319	$118,934	$57,909	$38,182	(34%)
Dominion	$96,423	$96,719	$88,445	$51,477	$64,809	$186,500	$103,011	$49,495	(52%)
DPL	$103,176	$92,441	$95,787	$53,757	$63,861	$222,427	$117,363	$48,071	(59%)
EKPC	NA	NA	NA	NA	$0	$123,312	$60,945	$36,931	(39%)
JCPL	$101,904	$91,945	$95,926	$49,706	$65,740	$216,025	$106,900	$31,736	(70%)
Met-Ed	$98,776	$90,099	$90,065	$47,971	$61,337	$204,718	$101,495	$31,864	(69%)
PECO	$99,985	$90,734	$94,229	$48,462	$60,336	$206,442	$104,527	$30,713	(71%)
PENELEC	$84,307	$77,735	$76,824	$48,205	$61,776	$164,320	$87,695	$36,932	(58%)
Pepco	$101,387	$98,734	$91,988	$56,101	$68,248	$215,636	$105,010	$53,225	(49%)
PPL	$97,737	$88,977	$92,223	$47,319	$60,379	$205,302	$103,167	$32,157	(69%)
PSEG	$103,610	$94,408	$98,713	$50,323	$77,497	$232,843	$114,967	$34,266	(70%)
RECO	$99,961	$91,080	$90,901	$49,349	$84,198	$229,734	$116,341	$33,258	(71%)
PJM	$90,102	$84,891	$78,879	$48,828	$58,860	$177,259	$89,872	$39,113	(56%)

19 The class average forced outage rate was applied to total energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power in that hour. Energy market net revenues for a wind installation include revenue from the Production Tax Credit (PTC) of $23 per MWh and from Renewable Energy Certificates (RECs) of $0.88/MWh in ComEd and $16.42/MWh in PENELEC.[21]

Wind energy market net revenues were lower in the first three months of 2016 (Table 7-7).

Table 7-7 Net revenue for a wind installation (Dollars per installed MW-year)

	2012 (Jan-Mar)			2013 (Jan-Mar)			2014 (Jan-Mar)			2015 (Jan-Mar)			2016 (Jan-Mar)			Percent Change in 2016 Total
Zone	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Revenue
ComEd	23,623	-	23,623	25,851	-	25,851	43,854	24,996	68,851	28,135	22,067	50,203	21,040	24,674	45,714	(9%)
PENELEC	22,839	19,853	42,692	30,815	26,413	57,228	64,765	30,659	95,424	42,934	32,454	75,388	21,002	34,457	55,459	(26%)

New Entrant Solar Installation

Energy market net revenues for a solar installation located in the PSEG Zone were calculated hourly assuming the unit was generating at the average hourly capacity factor if 75 percent of existing solar units in the zone were generating power in that hour. Energy market net revenues for a solar installation in New Jersey include revenue from Solar Renewable Energy Certificates (SRECs) of $193.70/MWh.[22]

Solar energy market net revenues were slightly lower in the first three months of 2016 (Table 7-8).

Table 7-8 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

	2012 (Jan-Mar)			2013 (Jan-Mar)			2014 (Jan-Mar)			2015 (Jan-Mar)			2016 (Jan-Mar)			Percent Change in 2016 Total
Zone	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Energy	Credits	Total	Revenue
PSEG	6,525	55,616	62,141	14,810	54,369	69,179	38,446	55,267	93,713	22,335	63,337	85,672	8,396	75,965	84,361	(2%)

21 REC prices provided by Evolution Markets.
22 SREC prices provided by Evolution Markets.