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 energy prices and fuel prices. Energy prices and fuel prices were higher in the first nine months of 2017 than in the first nine months of 2016. Gas prices increased more than LMP and CTs and CCs ran fewer hours with lower margins as a result. Coal prices increased more than LMP but less than gas prices and CPs ran for slightly more hours in the first nine months of 2017 than in the first nine months of 2016 and margins varied by zone.
- In the first nine months of 2017, average energy market net revenues decreased by 51 percent for a new CT, 28 percent for a new CC, 17 percent for a new CP, 6 percent for a new DS, and 9 percent for a new solar installation compared to the first nine months of 2016. Average energy market net revenues increased by 6 percent for a new nuclear plant, and 15 percent for a new wind installation compared to the first nine months of 2016.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through September 30, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

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.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through September 30, 2017 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through September 30, 2017, and have not covered their total costs in the ComEd Zone through September 30, 2017.

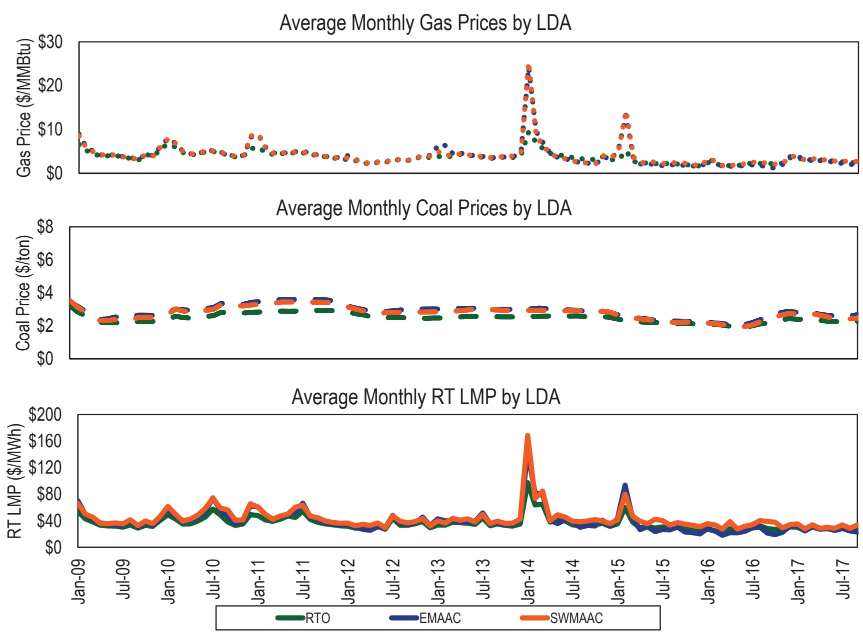
Net Revenue

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 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 3.5 percent higher in the first nine months of 2017 than in the first nine months of 2016, $30.36 per MWh versus $29.32 per MWh. Natural gas prices and coal prices increased in the first nine months of 2017 over the first nine months of 2016. The price of Northern Appalachian coal was 25.4 percent higher; the price of Central Appalachian coal was 33.2 percent higher; the price of Powder River Basin coal was 17.1 percent higher; the price of eastern natural gas was 35.9 percent higher; and the price of western natural gas was 37.0 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: January 1, 2009 through September 30, 2017



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

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviation.

Table 7-1 Peak hour spreads ($/MWh): January 1, 2011, through September 30, 2017

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$26.27	$33.76	$48.66	$12.47	$33.68	$30.85	$22.99	$28.15	$47.70	$19.50	$26.15	$41.06
2012	$24.29	$24.21	$36.25	$16.17	$30.87	$27.23	$19.51	$17.57	$33.01	$19.94	$19.86	$31.91
2013	$19.59	$26.45	$40.79	$10.70	$31.64	$30.44	$13.65	$25.09	$42.13	$16.16	$22.34	$36.68
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017 (Jan-Sep)	$17.33	$17.98	$32.72	$12.33	$26.06	$28.80	$13.17	$10.49	$28.82	$16.62	$14.76	$29.50

Table 7-2 Peak hour spread standard deviation ($/MWh): January 1, 2011, through September 30, 2017

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$50.7	$51.1	$51.1	$26.3	$26.9	$26.9	$43.6	$45.3	$45.3	$37.2	$37.5	$37.4
2012	$33.7	$33.9	$33.7	$23.6	$23.7	$23.7	$29.6	$29.7	$29.7	$27.6	$28.0	$27.8
2013	$32.6	$33.3	$33.3	$18.2	$18.3	$18.2	$32.4	$30.4	$30.4	$25.3	$25.5	$25.5
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017 (Jan-Sep)	$24.4	$25.0	$25.0	$21.8	$21.8	$21.9	$18.9	$19.8	$19.9	$21.3	$21.0	$21.0

Figure 7-2 shows the hourly spark spread for peak hours since January 1, 2017, for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): January 1 through September 30, 2017[1]

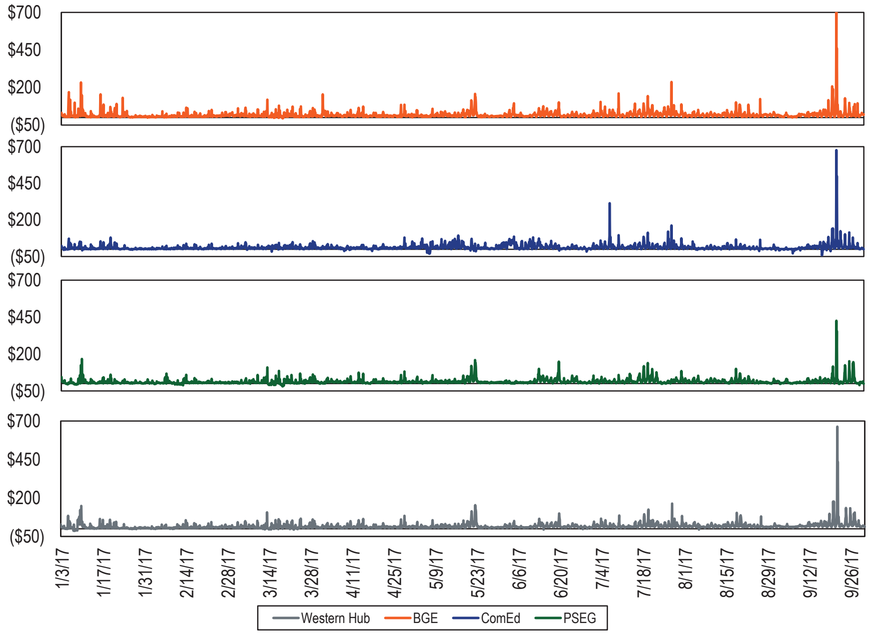
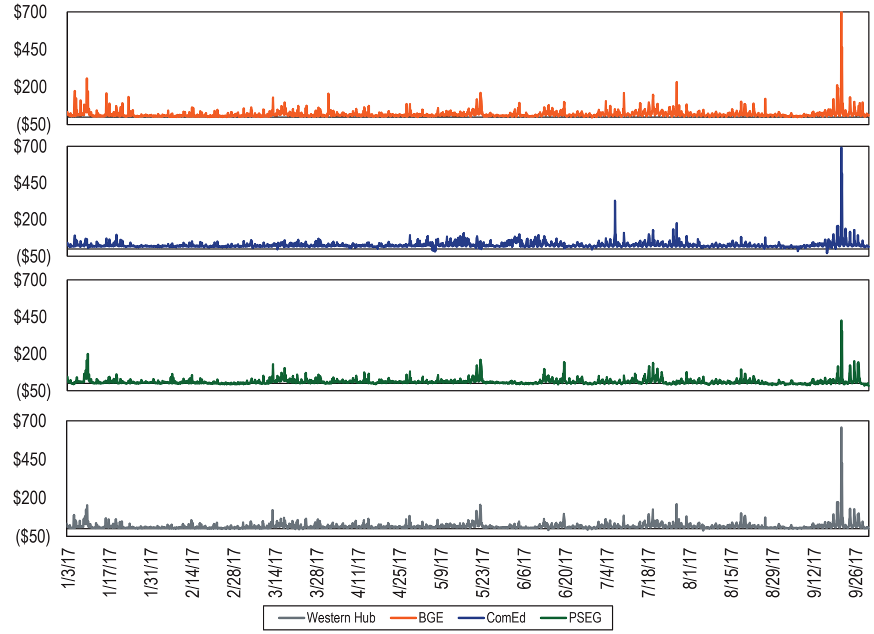


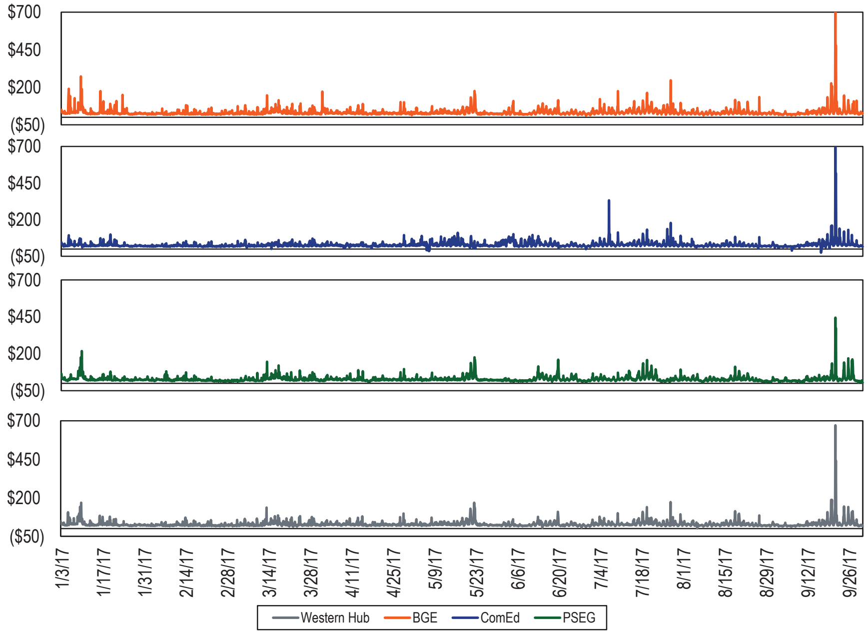
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): January 1 through September 30, 2017[2]



1 Spark spreads use a combined cycle heat rate of 7,000 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.

2 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 ($/MWh): January 1 through September 30, 2017[3]



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.

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.[4]
- 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 22 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 installed 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.[5][6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

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

4 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.
5 Hourly ambient conditions supplied by Schneider Electric.
6 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.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, 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.[9] 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.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month prices, adjusted for rail transportation costs.[11]

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[12] [13] Average short run marginal costs are shown in Table 7-3.

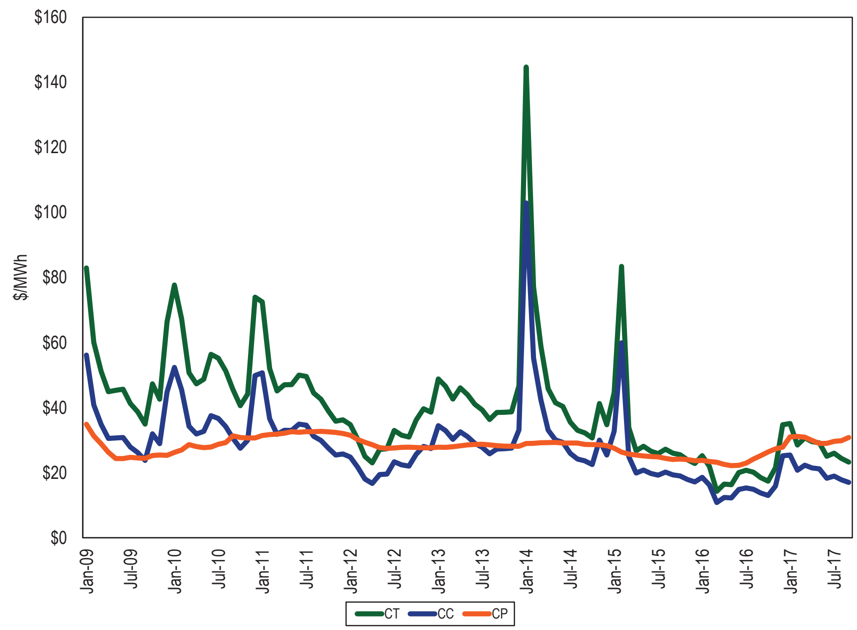
Table 7-3 Average short run marginal costs: January 1 through September 30, 2017

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$27.97	9,437	$0.25
CC	$20.37	6,679	$1.00
CP	$30.15	9,250	$4.00
DS	$134.64	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 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.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

A comparison of the short run marginal cost of the theoretical CT, CC and CP plants since January 1, 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).

Figure 7-5 Average short run marginal costs: January 1, 2009 through September 30, 2017



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.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January 1 through September 30, 2009 through 2017

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009	974	4,338	6,552	40	6,552		
2010	1,392	4,230	6,552	99	6,552		
2011	2,056	5,081	6,552	50	6,552		
2012	3,975	6,141	6,576	23	6,576	5,073	2,954
2013	1,765	5,052	6,552	19	6,552	5,040	3,013
2014	2,834	5,167	6,552	171	6,552	5,111	2,907
2015	3,446	5,420	6,552	174	6,552	4,948	2,975
2016	4,259	6,006	2,589	61	6,576	4,703	1,554
2017	2,598	5,687	2,691	18	6,552	4,960	1,380

New Entrant Combustion Turbine

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January 1 through September 30, 2009 through 2017 (Dollars per installed MW-year)[14]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$10,044	$37,036	$58,032	$43,904	$27,441	$54,259	$46,922	$46,038	$21,028	(54%)
AEP	$3,625	$9,376	$25,847	$36,762	$17,232	$55,328	$33,465	$30,773	$16,003	(48%)
AP	$11,768	$25,272	$44,348	$45,910	$22,546	$75,153	$53,727	$65,912	$32,572	(51%)
ATSI	NA	NA	$0	$39,144	$21,931	$64,352	$36,313	$28,383	$16,034	(44%)
BGE	$13,048	$47,046	$56,522	$64,182	$37,242	$79,650	$61,380	$94,974	$30,624	(68%)
ComEd	$2,228	$9,034	$17,923	$24,184	$12,714	$25,196	$12,614	$17,279	$11,379	(34%)
DAY	$2,880	$9,782	$25,834	$40,286	$17,846	$56,021	$32,672	$26,240	$15,802	(40%)
DEOK	NA	NA	NA	$32,943	$17,096	$68,978	$70,718	$28,320	$16,649	(41%)
DLCO	$2,992	$14,229	$28,062	$39,464	$17,795	$48,396	$28,110	$59,478	$32,526	(45%)
Dominion	$13,837	$41,776	$43,998	$48,374	$28,992	$39,654	$32,045	$36,578	$15,858	(57%)
DPL	$11,042	$37,029	$51,739	$55,149	$30,953	$65,039	$35,792	$47,931	$18,074	(62%)
EKPC	NA	NA	NA	NA	$0	$66,992	$63,599	$24,722	$11,642	(53%)
JCPL	$9,053	$34,187	$53,702	$42,224	$33,097	$56,246	$46,092	$40,903	$24,021	(41%)
Met-Ed	$7,839	$34,791	$46,245	$40,916	$26,299	$47,331	$43,478	$42,892	$29,070	(32%)
PECO	$8,417	$33,519	$54,247	$42,750	$24,846	$49,001	$41,991	$39,802	$21,215	(47%)
PENELEC	$7,120	$18,964	$42,948	$46,886	$31,855	$108,799	$103,662	$57,951	$25,499	(56%)
Pepco	$15,392	$44,270	$50,876	$58,419	$34,308	$71,683	$45,881	$47,022	$17,017	(64%)
PPL	$7,250	$29,100	$48,836	$37,116	$24,819	$53,872	$42,438	$39,968	$23,143	(42%)
PSEG	$6,902	$32,803	$43,946	$40,227	$26,161	$41,398	$22,482	$28,534	$14,533	(49%)
RECO	$5,653	$30,775	$34,876	$36,485	$27,128	$40,277	$24,224	$29,370	$14,545	(50%)
PJM	$8,182	$28,764	$40,443	$42,912	$24,015	$58,381	$43,880	$41,653	$20,362	(51%)

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two 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 two hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CT plant energy market net revenues were lower across all zones in the first nine months of 2017 than in the first nine months of 2016 (Table 7-5). The increase in gas prices caused average CT operating costs to be higher than the average LMP in January, February and April, resulting in a 40 percent reduction in run hours. In addition, there were fewer high LMP hours in the first nine months of 2017 than in 2016, which means that the CT had fewer hours to operate with high margins.

14 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 new CC plant economically dispatched by PJM. It was assumed that the CC 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.[15] 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 CC plant energy market net revenues were lower across all zones in the first nine months of 2017 than in the first nine months of 2016 (Table 7-6). In the first nine months of 2017, the new CC plant had a 6 percent reduction in run hours from the first nine months of 2016. Gas prices increased more than the LMP increased, resulting in lower margins and lower energy net revenues.

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January 1 through September 30, 2009 through 2017 (Dollars per installed MW-year)[16]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$34,530	$65,409	$93,684	$74,365	$55,749	$104,160	$79,564	$70,106	$50,790	(28%)
AEP	$14,702	$23,155	$52,355	$68,103	$43,575	$84,646	$60,851	$60,237	$45,295	(25%)
AP	$37,258	$48,836	$81,838	$77,472	$52,720	$110,774	$83,827	$91,181	$65,667	(28%)
ATSI	NA	NA	$0	$71,769	$51,346	$98,438	$65,546	$57,837	$43,811	(24%)
BGE	$37,714	$76,019	$89,251	$94,619	$69,981	$138,411	$93,406	$125,594	$68,726	(45%)
ComEd	$9,094	$19,005	$28,907	$49,354	$26,127	$36,024	$25,336	$41,306	$30,384	(26%)
DAY	$12,805	$22,975	$51,109	$72,126	$45,823	$86,948	$61,077	$56,525	$43,740	(23%)
DEOK	NA	NA	NA	$63,256	$42,917	$110,828	$103,503	$56,836	$42,441	(25%)
DLCO	$12,435	$27,135	$51,343	$69,956	$39,755	$70,587	$52,208	$83,612	$64,588	(23%)
Dominion	$42,474	$72,788	$78,375	$79,191	$57,136	$76,359	$59,199	$69,529	$44,710	(36%)
DPL	$35,834	$64,538	$86,932	$85,471	$60,938	$116,347	$63,402	$75,400	$46,160	(39%)
EKPC	NA	NA	NA	NA	$0	$107,076	$96,045	$52,186	$36,865	(29%)
JCPL	$34,167	$62,903	$90,596	$73,317	$62,129	$109,303	$79,225	$64,991	$55,117	(15%)
Met-Ed	$28,494	$59,799	$77,701	$70,542	$52,733	$94,591	$71,996	$66,637	$59,693	(10%)
PECO	$30,369	$60,474	$88,715	$72,715	$50,899	$97,271	$74,041	$63,245	$50,329	(20%)
PENELEC	$28,349	$40,838	$78,814	$79,145	$68,494	$163,972	$132,907	$83,581	$58,852	(30%)
Pepco	$37,685	$74,053	$82,407	$88,933	$66,461	$125,072	$75,669	$82,680	$47,452	(43%)
PPL	$26,890	$52,570	$78,871	$66,913	$50,520	$95,882	$72,592	$64,029	$53,115	(17%)
PSEG	$30,159	$62,435	$76,859	$68,867	$53,069	$87,551	$43,268	$50,652	$41,175	(19%)
RECO	$25,325	$57,752	$60,375	$64,666	$54,169	$86,288	$43,361	$51,824	$42,275	(18%)
PJM	$28,134	$52,393	$69,341	$73,199	$50,227	$100,026	$71,851	$68,399	$49,559	(28%)

15 All starts associated with combined cycle units are assumed to be hot starts.
16 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 for a new CP plant economically dispatched by PJM. It was assumed that the CP 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. 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. 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 higher in eight zones and lower in 12 zones in the first nine months of 2017 than in the first nine months of 2016 (Table 7-7). The increase in LMP was more than offset by the increase in coal prices, resulting in slightly more run hours at lower margins in most zones.

Table 7-7 Energy net revenue for a new entrant CP: January 1 through September 30, 2009 through 2017 (Dollars per installed MW-year)[17]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$82,808	$123,363	$91,942	$23,558	$47,414	$170,151	$74,429	$18,275	$11,002	(40%)
AEP	$33,143	$79,883	$76,083	$22,674	$54,899	$118,501	$53,883	$18,035	$19,577	9%
AP	$78,625	$118,182	$98,223	$33,229	$61,669	$142,636	$73,716	$19,246	$19,526	1%
ATSI	NA	NA	$0	$28,570	$60,636	$131,340	$56,385	$17,866	$20,979	17%
BGE	$92,204	$154,092	$112,530	$46,712	$73,505	$212,972	$122,859	$50,896	$22,382	(56%)
ComEd	$83,265	$115,961	$112,618	$87,516	$104,250	$154,747	$79,884	$15,521	$18,241	18%
DAY	$32,977	$77,240	$73,913	$19,587	$58,948	$122,202	$53,404	$16,849	$19,537	16%
DEOK	NA	NA	NA	$15,351	$50,838	$111,478	$48,858	$16,928	$19,017	12%
DLCO	$32,002	$63,403	$46,321	$20,302	$35,451	$88,804	$42,472	$17,200	$19,292	12%
Dominion	$82,093	$139,673	$95,725	$32,457	$59,955	$167,681	$95,683	$25,267	$19,072	(25%)
DPL	$90,353	$138,575	$111,741	$41,698	$65,687	$200,422	$98,199	$27,690	$15,614	(44%)
EKPC	NA	NA	NA	NA	$0	$108,041	$41,903	$15,094	$14,185	(6%)
JCPL	$81,909	$120,447	$88,735	$21,794	$53,056	$174,143	$73,931	$13,888	$12,938	(7%)
Met-Ed	$81,157	$130,268	$96,673	$29,075	$55,790	$168,801	$74,574	$16,258	$17,300	6%
PECO	$78,182	$118,089	$87,642	$22,952	$43,595	$164,314	$70,812	$15,669	$11,536	(26%)
PENELEC	$60,807	$93,660	$73,609	$26,685	$53,893	$140,148	$67,779	$15,239	$12,129	(20%)
Pepco	$87,267	$137,857	$85,838	$28,765	$58,786	$192,026	$99,191	$31,201	$19,195	(38%)
PPL	$72,859	$107,497	$78,079	$17,797	$43,190	$161,459	$69,464	$13,691	$12,321	(10%)
PSEG	$77,583	$123,112	$88,770	$23,924	$62,776	$191,011	$84,306	$13,820	$10,287	(26%)
RECO	$71,409	$116,130	$71,479	$21,468	$67,841	$185,603	$85,200	$13,308	$10,470	(21%)
PJM	$71,685	$115,143	$82,773	$29,690	$55,609	$155,324	$73,347	$19,597	$16,230	(17%)

17 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 higher in all but six zones in the first nine months of 2017 than in the first nine months of 2016 (Table 7-8). There were relatively few hours in 2017 with high LMPs and positive margins because prices were higher but less volatile than in the first nine months of 2016.

Table 7-8 Energy market net revenue for a new entrant DS: January 1 through September 30, 2009 through 2017 (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$1,623	$10,048	$6,708	$1,392	$1,082	$36,616	$13,733	$1,730	$677	(61%)
AEP	$100	$495	$1,717	$786	$484	$15,803	$4,905	$700	$1,248	78%
AP	$832	$1,394	$2,007	$1,022	$741	$20,496	$9,336	$875	$1,127	29%
ATSI	NA	NA	$0	$1,033	$23,643	$15,523	$4,843	$1,869	$1,528	(18%)
BGE	$3,061	$12,069	$7,815	$2,460	$2,551	$55,146	$21,485	$6,740	$2,168	(68%)
ComEd	$7	$480	$811	$909	$384	$12,411	$2,921	$555	$1,222	120%
DAY	$174	$548	$1,894	$904	$517	$15,611	$4,893	$797	$1,434	80%
DEOK	NA	NA	NA	$664	$462	$14,743	$4,397	$1,100	$2,605	137%
DLCO	$605	$2,839	$2,165	$885	$1,163	$14,261	$4,546	$2,182	$1,254	(43%)
Dominion	$3,055	$9,142	$3,983	$1,611	$1,509	$46,858	$13,517	$1,728	$1,618	(6%)
DPL	$2,576	$8,689	$5,769	$2,210	$1,083	$42,831	$20,342	$3,438	$1,817	(47%)
EKPC	NA	NA	NA	NA	$0	$15,767	$3,864	$473	$838	77%
JCPL	$1,626	$7,110	$6,610	$1,557	$2,014	$36,731	$14,956	$677	$919	36%
Met-Ed	$1,477	$7,655	$5,032	$1,681	$1,254	$35,603	$14,827	$662	$2,348	255%
PECO	$1,425	$7,600	$5,379	$1,787	$985	$35,981	$13,806	$666	$927	39%
PENELEC	$203	$930	$2,642	$2,066	$1,104	$18,141	$7,838	$777	$1,103	42%
Pepco	$3,253	$10,922	$5,961	$1,945	$2,134	$56,581	$14,869	$2,623	$1,655	(37%)
PPL	$1,303	$6,814	$5,305	$1,611	$1,054	$36,526	$14,711	$608	$1,494	146%
PSEG	$1,249	$6,534	$5,447	$1,549	$1,257	$36,377	$14,437	$692	$935	35%
RECO	$1,068	$5,431	$4,255	$1,619	$2,387	$33,728	$15,903	$730	$946	30%
PJM	$1,390	$5,806	$4,083	$1,457	$2,290	$29,787	$11,006	$1,481	$1,393	(6%)

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.[18]

New entrant nuclear plant energy market net revenues were higher in all but four zones in the first nine months of 2017 than in the first nine months of 2016 (Table 7-9). The increase in LMP resulted in higher margins and higher net revenues in most zones.

Table 7-9 Energy net revenue for a new entrant nuclear plant: January 1 through September 30, 2009 through 2017 (Dollars per installed MW-year)[19]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$220,444	$283,596	$275,481	$160,586	$198,641	$332,216	$190,727	$108,018	$118,299	10%
AEP	$165,079	$199,798	$205,599	$144,556	$174,656	$252,952	$164,054	$124,262	$132,088	6%
AP	$195,683	$240,187	$234,187	$153,584	$183,795	$279,391	$187,270	$129,462	$133,307	3%
ATSI	NA	NA	$0	$147,800	$182,629	$266,784	$168,226	$126,330	$135,801	7%
BGE	$224,368	$302,330	$276,074	$180,658	$215,476	$374,646	$244,221	$183,793	$150,731	(18%)
ComEd	$132,962	$175,483	$172,796	$131,406	$157,272	$222,150	$133,450	$112,155	$119,273	6%
DAY	$160,936	$198,821	$204,683	$148,590	$177,043	$256,115	$164,680	$125,439	$136,190	9%
DEOK	NA	NA	NA	$139,704	$167,933	$244,094	$159,469	$122,250	$132,812	9%
DLCO	$155,568	$199,157	$201,501	$146,126	$170,938	$234,864	$154,508	$121,731	$132,114	9%
Dominion	$213,382	$286,412	$257,755	$163,557	$200,179	$324,381	$214,263	$143,885	$142,726	(1%)
DPL	$222,294	$285,118	$275,071	$171,153	$206,621	$357,351	$211,908	$131,519	$127,631	(3%)
EKPC	NA	NA	NA	NA	$0	$240,126	$151,693	$117,443	$126,913	8%
JCPL	$219,404	$280,306	$271,918	$159,284	$205,141	$336,396	$189,411	$102,496	$122,710	20%
Met-Ed	$212,079	$275,729	$258,451	$156,059	$195,208	$320,029	$182,397	$104,070	$127,349	22%
PECO	$215,347	$277,735	$270,547	$158,845	$193,881	$324,425	$184,521	$100,980	$117,975	17%
PENELEC	$189,728	$235,110	$233,235	$155,445	$193,062	$292,097	$181,285	$117,280	$126,280	8%
Pepco	$225,419	$299,684	$268,964	$175,051	$211,746	$361,650	$226,209	$157,421	$145,632	(7%)
PPL	$209,319	$265,668	$259,612	$152,507	$193,155	$321,046	$182,826	$101,365	$120,666	19%
PSEG	$223,101	$285,232	$276,936	$162,490	$220,267	$358,194	$200,258	$106,067	$124,690	18%
RECO	$216,226	$277,469	$257,121	$158,052	$225,932	$352,042	$201,547	$105,844	$125,589	19%
PJM	$200,079	$256,932	$233,330	$156,077	$183,679	$302,547	$184,646	$122,091	$129,939	6%

18 The class average forced outage rate was applied to total energy market net revenues.
19 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 of operating wind units in the zone if 75 percent of existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour.[20] The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[21]

Wind energy market net revenues were higher in both zones in the first nine months of 2017 than in the first nine months of 2016 as a result of higher energy prices and higher margins (Table 7-10).

Table 7-10 Energy net revenue for a wind installation: January 1 through September 30, 2012 through 2017 (Dollars per installed MW-year)

Zone	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
ComEd	$52,229	$59,854	$81,514	$55,936	$48,119	$51,661	7%
PENELEC	$48,210	$63,471	$99,658	$66,444	$40,959	$49,857	22%

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 of operating solar units in the zone if 75 percent of existing solar units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[22]

Solar energy market net revenues were slightly lower in the first nine months of 2017 than in the first nine months of 2016 with higher LMPs not offsetting fewer run hours (Table 7-11).

Table 7-11 PSEG energy net revenue for a solar installation: January 1 through September 30, 2012 through 2017 (Dollars per installed MW-year)

Zone	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
PSEG	$39,831	$69,202	$87,522	$60,592	$32,882	$30,065	(9%)

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through September 30, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones, but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

The summary figures compare net revenues for a new entrant CT and CC that began operation on June 1, 2007, at the start of the RPM Capacity Market, and new entrant CT and CC that began operation on June 1, 2012. In each figure,

20 The condition that existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor was not included in prior analyses of wind unit net revenues.

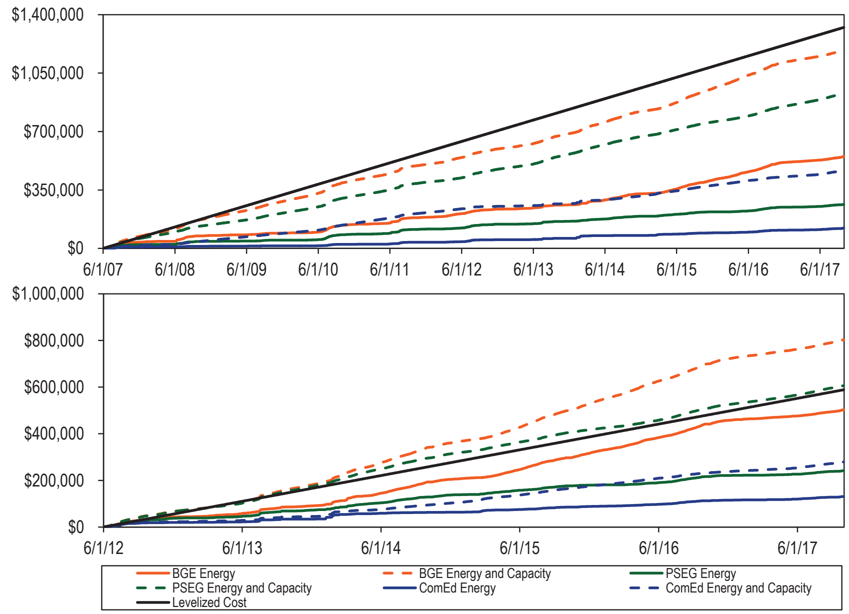
21 The 1603 payment is a direct payment of 30 percent of the project cost. REC related net revenues were overstated for the new entrant wind installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and were updated beginning with the *2016 State of the Market Report for PJM.*

22 The 1603 payment is a direct payment of 30 percent of the project cost. SREC related net revenues were overstated for the new entrant solar installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and have been updated as of the *2016 State of the Market Report for PJM.*

the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

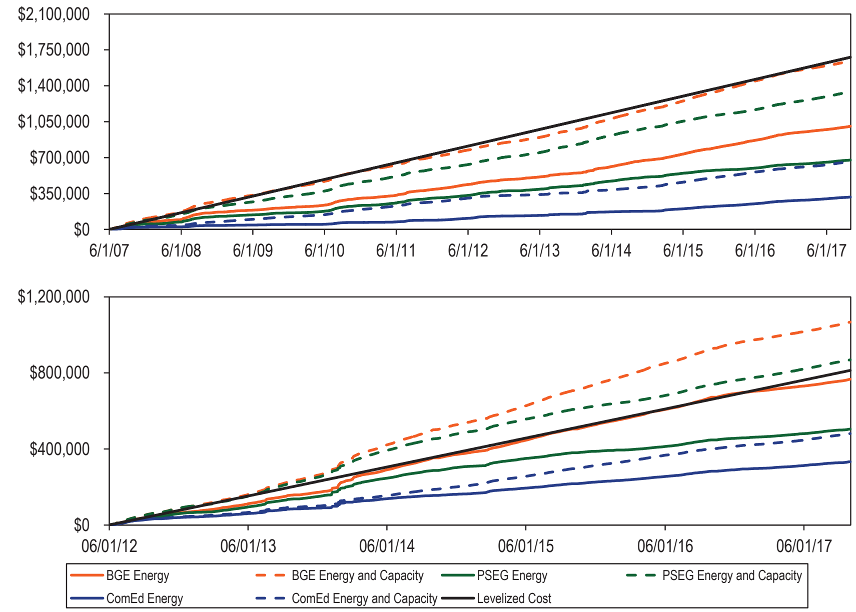
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-6 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007 and for a new CT that began operation on June 1, 2012. Cumulative energy market net revenues were less than cumulative total costs in all cases. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CT unit for each year in each of the three zones. Cumulative total market net revenues were greater than the cumulative total costs of the 2012 new entrant CT unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-6 Historical new entrant CT revenue adequacy: June 1, 2007 through September 30, 2017 and June 1, 2012 through September 30, 2017



For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-7 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on June 1, 2007 and for a new CC that began operation on June 1, 2012. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CC unit for each year in each of the three zones. Cumulative total market net revenues through September 30, 2017, were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-7 Historical new entrant CC revenue adequacy: June 1, 2007 through September 30, 2017 and June 1, 2012 through September 30, 2017



Assumptions used for this analysis are shown in Table 7-12.

Table 7-12 Assumptions for analysis of new entry

	2007 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA	GE Frame 7FA.05	GE Frame 7FA	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

Actual Net Revenue

The actual net revenue results for 2016 have been updated to include the results for nuclear plants.[23] [24]

Table 7-13 Avoidable cost recovery by quartile

	Total Installed	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
Nuclear (2016)	31,661	61%	88%	105%	91%	119%	135%
Nuclear (October 2016 through September 2017)	31,661	84%	97%	111%	109%	126%	143%

Table 7-13 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. The results have been updated using nuclear plant operating costs of $25.83 per MWh for single unit sites and $18.73 per MWh for multiunit sites as avoidable costs.[25] For the 12 months ended September 30, 2017, fewer than a quarter of nuclear units did not recover avoidable costs from energy and capacity revenues. The average DA LMP increase of 5.3 percent between the 12 months ended September 30, 2017, and 2016, resulted in all nuclear plants recovering more than 90 percent of avoidable costs for the 12 months ended September 30, 2017.

Capital expenditures are generally sunk costs and appropriately excluded from this analysis. To the extent that there are annual avoidable capital expenditures, the results could be affected. As a sensitivity analysis, the results were calculated with one third of the NEI capital expenditures added to the avoidable costs.[26] For the 12 months ended September 30, 2017, approximately a quarter of nuclear units did not recover the sum of avoidable costs plus one third of the NEI capital expenditures.

23 In prior reports the results did not include nuclear power plants in order not to reveal confidential data and because there was not good public data on nuclear unit avoidable costs.
24 The analysis of nuclear plants uses uniform fuel costs for all units. Net revenue is net of fuel costs.
25 Operating costs from: Nuclear Energy Institute (August, 2017) "*Nuclear Costs in Context*," <https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf>
26 *Id.*