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 both higher and more volatile in the first three months of 2018 than in the first three months of 2017. The result was higher margins for all unit types.
- In the first three months of 2018, average energy market net revenues increased by 324 percent for a new CT, 61 percent for a new CC, 650 percent for a new CP, 70 percent for a new nuclear plant, 4,429 percent for a new DS, 43 percent for a new wind installation, and 57 percent for a new solar installation compared to the first three months of 2017.
- The relative prices of fuel varied during the first three months of 2018. The marginal cost of the new CC and CT was above that of the new CP during periods of high gas costs in January.
- Using public data, the net revenue results show that there are four nuclear plants at risk of not covering their going forward costs: Oyster Creek, Three Mile Island, Davis Besse and Perry. Oyster Creek and Three Mile Island are scheduled to retire in 2019. In March 2018, Davis Besse and Perry requested retirement in 2021.

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 March 2018, although a new CC in the BGE zone was very close. 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 alone were not sufficient to cover total costs in any scenario, 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 March 2018 in the ComEd Zone and in the PSEG Zone and were very close 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 March 2018, and have not covered their total costs in the ComEd Zone through March 2018.

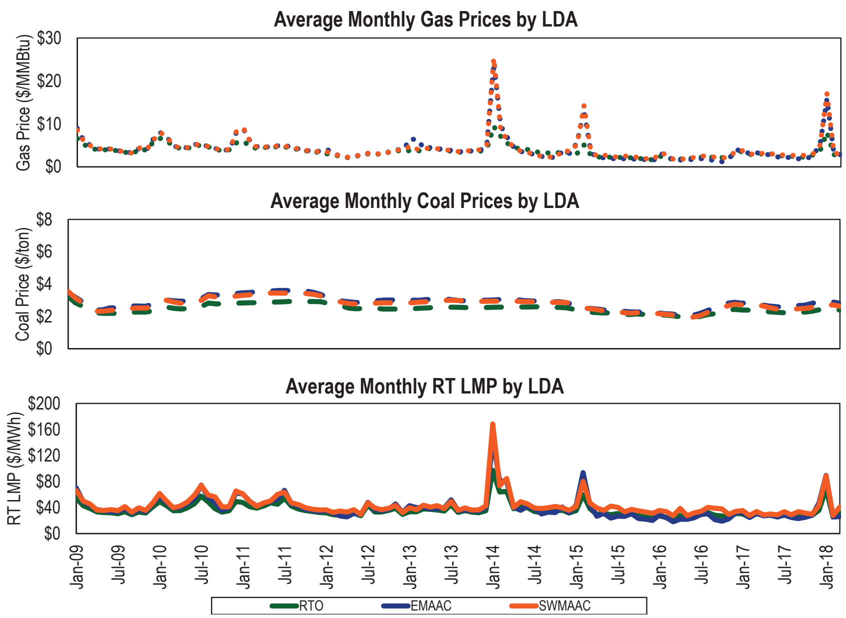
Net Revenue

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 load-weighted average real-time LMP was 63.3 percent higher in the first three months of 2018 than in the first three months of 2017, $49.45 per MWh versus $30.28 per MWh. Eastern natural gas prices and coal prices increased in the first three months of 2018. The price of Northern Appalachian coal was 1.2 percent higher; the price of Central Appalachian coal was 9.0 percent higher; the price of Powder River Basin coal was 4.5 percent higher; the price of eastern natural gas was 135.6 percent higher; and the price of western natural gas was 1.5 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through March 2018



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. While both energy prices and gas prices increased in early January 2018, hourly energy prices did not increase as much as gas prices, which lead to negative spark spreads during those high LMP hours. As a result, the average spark spreads are well below historical average spark spreads and the volatility of the spark spreads is significantly higher than in previous years.

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): 2011 through March 2018

	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	$16.77	$18.41	$33.20	$11.81	$25.40	$28.19	$12.80	$10.89	$29.97	$16.30	$15.71	$30.50
2018 (Jan-Mar)	$1.16	$35.31	$52.27	$11.14	$24.98	$29.02	($10.32)	$22.18	$44.63	$5.45	$28.10	$45.06

Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through March 2018

	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	$23.5	$25.0	$25.0	$19.8	$19.9	$19.9	$19.9	$22.9	$23.0	$23.2	$22.5	$22.6
2018 (Jan-Mar)	$88.5	$57.5	$57.2	$18.3	$21.9	$21.6	$95.7	$55.9	$55.5	$74.8	$47.7	$47.4

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

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): January 2017 through March 2018[1]

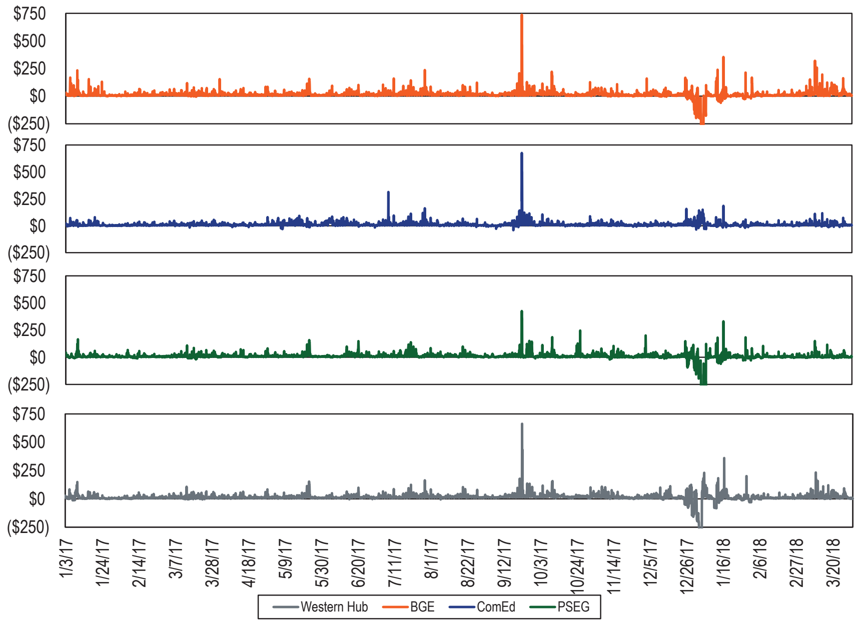
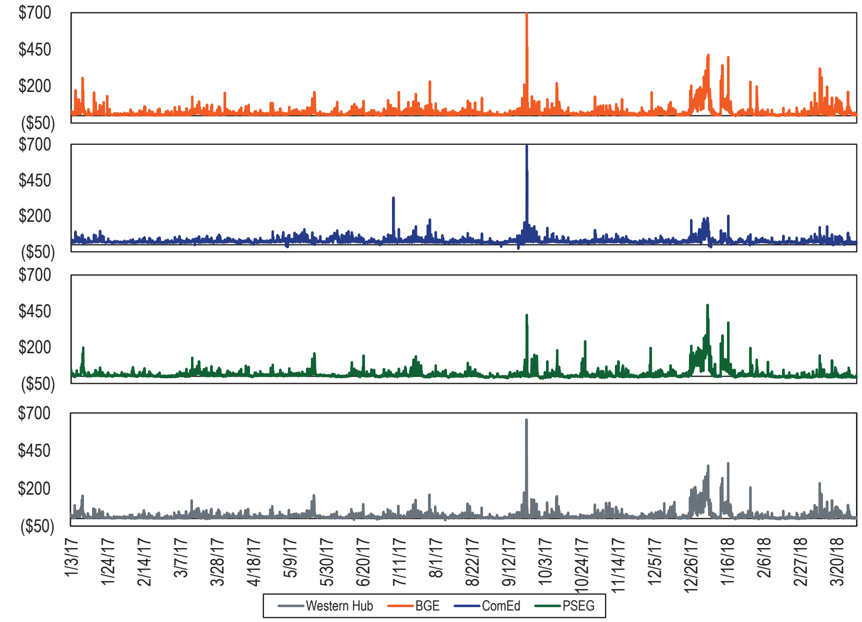


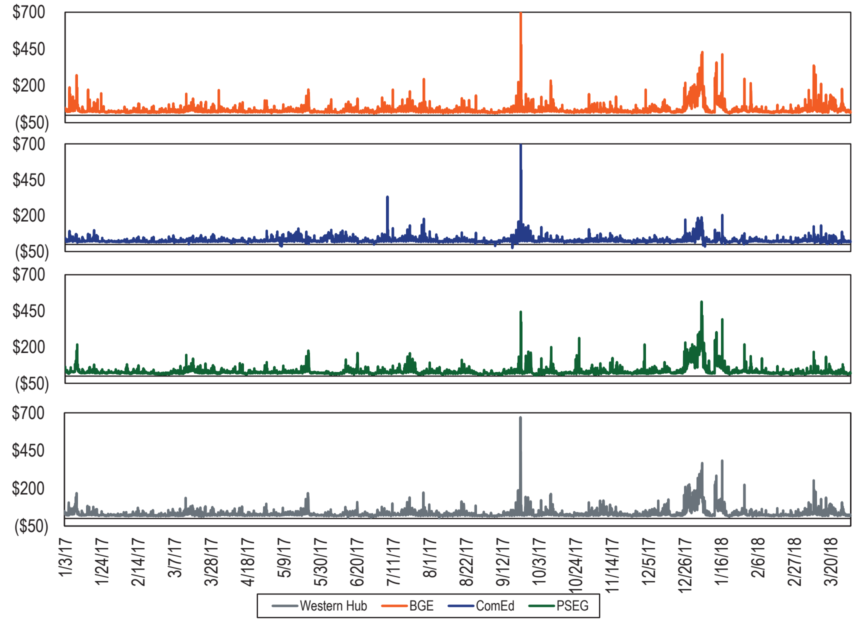
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): January 2017 through March 2018[2]



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 2017 through March 2018[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.

The analysis in this report includes only energy revenues unless explicitly stated. The analysis in the annual state of the market report includes revenues from all PJM markets.

3 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 747.9 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 1,137.2 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 21 Siemens 2.625 MW wind turbines totaling 55.1 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.

4 The duct burner firing dispatch rate is developed using the same method as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
5 Hourly ambient conditions supplied by DTN.
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, including all components, in Table 7-3 and the VOM component is also shown separately.

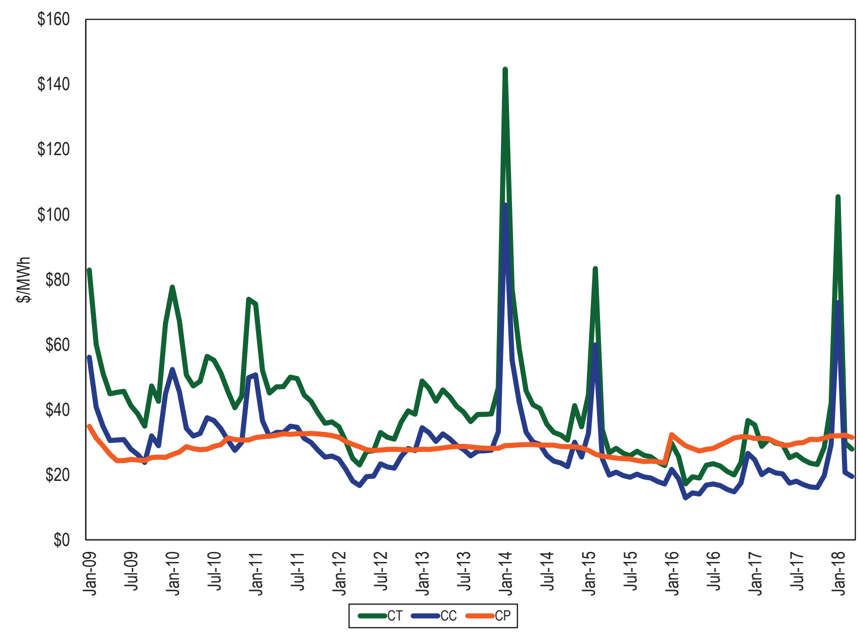
Table 7-3 Average short run marginal costs: January through March, 2018

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$54.41	9,437	$0.25
CC	$37.74	6,679	$1.00
CP	$31.87	9,250	$4.00
DS	$163.91	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 monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2009, shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant since 2011 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: 2009 through March 2018



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 through March, 2009 through 2018

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009 (Jan-Mar)	215	1,286	2,160	34	2,160		
2010 (Jan-Mar)	79	971	2,160	14	2,160		
2011 (Jan-Mar)	469	1,665	2,160	17	2,160		
2012 (Jan-Mar)	1,298	2,104	2,184	3	2,184	1,782	269
2013 (Jan-Mar)	429	1,743	2,160	5	2,160	1,735	340
2014 (Jan-Mar)	875	1,721	2,160	165	2,160	1,822	255
2015 (Jan-Mar)	952	1,742	2,160	118	2,160	1,704	296
2016 (Jan-Mar)	1,218	1,956	600	23	2,184	1,782	376
2017 (Jan-Mar)	390	1,990	847	5	2,160	1,882	305
2018 (Jan-Mar)	637	1,821	1,063	97	2,160	1,893	303

New Entrant Combustion Turbine

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.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher across all zones except DPL in the first three months of 2018 than in the first three months of 2017 (Table 7-5). The increase in energy margins and run hours over the full period more than offset the increase in gas prices and lower margins in early January.

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2009 through 2018 (Dollars per installed MW-year)[14 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)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
AECO	$2,728	$836	$9,202	$7,517	$3,214	$30,264	$13,722	$7,789	$1,115	$3,599	223%
AEP	$1,901	$621	$3,123	$8,528	$3,199	$48,084	$19,634	$9,440	$3,267	$21,435	556%
APS	$6,017	$2,409	$12,201	$11,591	$4,730	$65,810	$36,706	$13,928	$2,133	$6,752	216%
ATSI	NA	NA	$0	$8,891	$3,653	$54,456	$19,993	$6,737	$3,325	$26,172	687%
BGE	$3,358	$1,204	$5,747	$15,513	$5,058	$32,712	$9,300	$22,228	$4,780	$8,898	86%
ComEd	$683	$194	$857	$3,157	$1,116	$19,735	$6,229	$2,237	$910	$3,294	262%
DAY	$1,047	$331	$3,039	$9,388	$3,194	$47,524	$17,257	$6,209	$2,388	$21,780	812%
DEOK	NA	NA	NA	$6,331	$2,085	$44,695	$24,316	$7,194	$2,252	$25,013	1,011%
DLCO	$456	$2,513	$3,104	$9,158	$2,266	$41,566	$12,491	$11,236	$1,679	$3,281	95%
Dominion	$5,632	$5,929	$5,031	$10,436	$6,543	$26,374	$11,232	$9,791	$2,354	$7,424	215%
DPL	$3,661	$779	$5,614	$12,059	$2,838	$32,143	$13,114	$12,338	$3,560	$3,450	(3%)
EKPC	NA	NA	NA	NA	$0	$45,421	$23,459	$6,887	$2,066	$12,476	504%
JCPL	$2,577	$1,719	$10,060	$7,622	$5,970	$34,426	$15,452	$5,117	$1,701	$4,006	136%
Met-Ed	$2,371	$710	$7,093	$6,542	$3,058	$28,211	$13,333	$5,498	$2,059	$4,313	110%
PECO	$2,452	$881	$8,652	$6,738	$2,386	$28,475	$13,131	$4,502	$1,440	$3,324	131%
PENELEC	$3,650	$1,326	$10,947	$10,488	$7,549	$79,708	$59,869	$14,548	$3,618	$26,227	625%
Pepco	$3,268	$2,062	$5,965	$13,821	$5,302	$32,626	$7,748	$12,181	$3,198	$7,239	126%
PPL	$2,204	$880	$10,269	$6,045	$2,517	$34,732	$13,827	$5,592	$1,655	$2,804	69%
PSEG	$919	$328	$3,851	$4,562	$1,946	$17,568	$6,992	$2,292	$1,217	$1,535	26%
RECO	$461	$298	$2,296	$3,872	$3,442	$18,173	$9,147	$2,788	$1,331	$2,023	52%
PJM	$2,552	$1,354	$5,947	$8,540	$3,503	$38,135	$17,348	$8,427	$2,302	$9,752	324%

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
15 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

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.[16] 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 higher in all but three of 20 zones in the first three months of 2018 than in the first three months of 2017 (Table 7-6). The increase in energy margins and sustained high level of run hours over the full period more than offset the increase in gas prices and lower margins in early January.

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2009 through 2018 (Dollars per installed MW-year)[17] [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)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
AECO	$12,504	$7,650	$23,944	$20,898	$13,647	$56,633	$29,158	$15,981	$13,348	$19,143	43%
AEP	$5,215	$3,277	$13,838	$22,216	$15,740	$65,957	$32,327	$19,723	$16,833	$39,469	134%
APS	$17,657	$8,782	$29,151	$25,351	$19,220	$88,769	$51,238	$22,863	$15,794	$20,260	28%
ATSI	NA	NA	$0	$22,945	$17,203	$75,316	$33,610	$17,043	$16,337	$44,149	170%
BGE	$13,494	$9,004	$17,981	$29,349	$19,030	$61,497	$18,447	$33,294	$21,390	$23,371	9%
ComEd	$2,565	$456	$3,135	$13,158	$5,354	$24,423	$11,231	$9,726	$8,190	$11,246	37%
DAY	$3,506	$1,934	$13,084	$23,184	$16,421	$65,549	$30,270	$16,941	$15,176	$39,467	160%
DEOK	NA	NA	NA	$19,654	$12,964	$62,412	$37,950	$17,534	$14,095	$42,847	204%
DLCO	$2,172	$4,036	$11,553	$22,591	$12,417	$55,522	$22,933	$19,253	$14,605	$16,578	14%
Dominion	$19,787	$15,018	$18,479	$24,097	$18,064	$47,378	$20,917	$21,692	$15,689	$18,750	20%
DPL	$13,710	$5,448	$19,168	$25,392	$14,206	$58,992	$26,208	$21,594	$16,999	$15,305	(10%)
EKPC	NA	NA	NA	NA	$0	$62,362	$36,811	$16,795	$13,558	$29,156	115%
JCPL	$12,929	$7,674	$25,248	$21,166	$17,261	$64,421	$31,063	$13,416	$14,948	$19,317	29%
Met-Ed	$10,131	$6,078	$19,322	$19,502	$12,766	$54,369	$24,758	$13,449	$14,679	$19,558	33%
PECO	$10,974	$6,713	$23,065	$19,889	$11,677	$54,796	$28,134	$12,357	$12,853	$19,042	48%
PENELEC	$13,226	$6,336	$27,396	$24,519	$23,697	$106,773	$70,517	$23,233	$17,709	$44,638	152%
Pepco	$12,033	$9,781	$17,384	$27,686	$19,412	$57,616	$15,827	$25,144	$17,767	$19,832	12%
PPL	$9,837	$5,769	$21,396	$18,699	$11,602	$55,366	$26,697	$13,701	$14,160	$16,257	15%
PSEG	$8,516	$5,996	$13,942	$14,952	$9,112	$38,580	$14,493	$6,579	$10,693	$9,783	(9%)
RECO	$6,018	$4,820	$8,026	$13,976	$11,276	$40,300	$14,856	$7,289	$11,220	$8,935	(20%)
PJM	$10,251	$6,398	$17,006	$21,538	$14,053	$59,852	$28,872	$17,380	$14,802	$23,855	61%

16 All starts associated with combined cycle units are assumed to be hot starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
18 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

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 all zones as a result of higher gas prices and associated higher LMPs (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2009 through 2018 (Dollars per installed MW-year)[19 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)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
AECO	$43,215	$41,590	$36,063	$2,675	$13,783	$143,988	$58,708	$5,058	$3,111	$36,604	1,077%
AEP	$16,803	$29,638	$21,699	$3,597	$16,892	$82,244	$27,081	$2,332	$4,382	$24,318	455%
APS	$35,826	$40,552	$33,649	$5,402	$19,131	$102,926	$45,528	$3,116	$5,338	$32,050	500%
ATSI	NA	NA	$0	$3,649	$17,503	$90,714	$29,110	$1,819	$5,091	$26,249	416%
BGE	$46,577	$51,492	$40,197	$9,897	$23,506	$156,913	$62,899	$12,595	$6,930	$39,740	473%
ComEd	$36,166	$40,706	$34,460	$25,552	$31,957	$87,058	$35,291	$1,549	$3,644	$8,548	135%
DAY	$14,485	$27,375	$20,446	$1,419	$17,757	$82,450	$27,073	$1,480	$3,922	$21,465	447%
DEOK	NA	NA	NA	$619	$14,454	$76,026	$23,975	$1,372	$3,373	$27,596	718%
DLCO	$9,716	$23,675	$10,308	$1,926	$9,653	$66,530	$17,819	$1,869	$4,581	$25,300	452%
Dominion	$41,068	$50,166	$36,153	$5,034	$20,582	$127,290	$58,725	$6,801	$4,679	$38,541	724%
DPL	$47,268	$46,314	$42,948	$7,948	$19,736	$159,791	$72,097	$8,204	$4,793	$41,271	761%
EKPC	NA	NA	NA	NA	$0	$75,988	$22,964	$1,966	$3,160	$15,768	399%
JCPL	$43,327	$41,795	$36,913	$2,664	$16,833	$150,288	$59,850	$2,794	$3,677	$36,800	901%
Met-Ed	$43,283	$44,209	$37,718	$3,371	$17,543	$143,912	$57,928	$2,427	$4,116	$37,418	809%
PECO	$41,572	$40,698	$35,350	$2,336	$12,341	$141,628	$57,588	$2,626	$3,419	$36,515	968%
PENELEC	$30,086	$33,010	$25,545	$2,745	$17,876	$107,488	$44,858	$2,044	$2,787	$26,447	849%
Pepco	$42,835	$47,934	$33,287	$5,135	$19,073	$149,835	$57,241	$7,800	$5,245	$37,896	623%
PPL	$39,552	$39,126	$33,557	$1,684	$12,376	$140,691	$56,463	$2,710	$3,561	$35,437	895%
PSEG	$46,936	$43,883	$37,602	$3,241	$24,438	$163,942	$69,545	$3,179	$3,402	$36,220	965%
RECO	$43,612	$40,865	$30,456	$2,816	$30,378	$161,280	$70,870	$3,402	$3,214	$33,874	954%
PJM	$36,607	$40,178	$30,353	$4,827	$17,791	$120,549	$47,781	$3,757	$4,121	$30,903	650%

19 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
20 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

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.[21]

New entrant nuclear plant energy market net revenues were higher in all zones in the first three months of 2018 as a result of higher gas prices and associated higher LMPs (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2009 through 2018 (Dollars per installed MW-year)[22 23]

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)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
AECO	$101,789	$91,719	$95,005	$49,465	$62,135	$209,062	$105,885	$33,950	$43,518	$82,111	89%
AEP	$69,992	$68,828	$63,740	$45,781	$55,242	$130,923	$67,640	$38,437	$44,046	$68,182	55%
APS	$85,930	$79,042	$76,989	$48,737	$58,231	$153,609	$86,634	$41,297	$46,009	$79,446	73%
ATSI	NA	NA	$0	$46,380	$56,419	$140,042	$68,786	$38,237	$46,213	$72,445	57%
BGE	$102,425	$98,153	$92,808	$57,792	$68,082	$219,233	$107,545	$59,830	$53,199	$93,177	75%
ComEd	$57,229	$58,837	$54,172	$40,561	$48,679	$112,295	$54,074	$32,423	$40,093	$42,746	7%
DAY	$66,782	$66,322	$63,005	$46,714	$55,805	$130,464	$65,467	$38,133	$44,904	$67,314	50%
DEOK	NA	NA	NA	$43,474	$52,104	$123,359	$62,074	$37,014	$42,715	$73,430	72%
DLCO	$60,313	$67,382	$59,001	$46,158	$52,319	$118,934	$57,909	$37,464	$44,605	$71,071	59%
Dominion	$96,423	$96,719	$88,445	$51,477	$64,809	$186,500	$103,011	$48,565	$48,611	$90,456	86%
DPL	$103,176	$92,441	$95,787	$53,757	$63,861	$222,427	$117,363	$47,167	$49,012	$88,668	81%
EKPC	NA	NA	NA	NA	$0	$123,312	$60,945	$36,237	$42,216	$58,953	40%
JCPL	$101,904	$91,945	$95,926	$49,706	$65,740	$216,025	$106,900	$31,139	$45,076	$82,146	82%
Met-Ed	$98,776	$90,099	$90,065	$47,971	$61,337	$204,718	$101,495	$31,266	$44,916	$82,662	84%
PECO	$99,985	$90,734	$94,229	$48,462	$60,336	$206,442	$104,527	$30,136	$42,920	$81,886	91%
PENELEC	$84,307	$77,735	$76,824	$48,205	$61,776	$164,320	$87,695	$36,238	$44,250	$73,969	67%
Pepco	$101,387	$98,734	$91,988	$56,101	$68,248	$215,636	$105,010	$52,225	$50,713	$90,802	79%
PPL	$97,737	$88,977	$92,223	$47,319	$60,379	$205,302	$103,167	$31,552	$44,410	$78,907	78%
PSEG	$103,610	$94,408	$98,713	$50,323	$77,497	$232,843	$114,967	$33,622	$45,824	$84,879	85%
RECO	$99,961	$91,080	$90,901	$49,349	$84,198	$229,734	$116,341	$32,633	$46,163	$82,138	78%
PJM	$90,102	$84,891	$78,879	$48,828	$58,860	$177,259	$89,872	$38,378	$45,471	$77,269	70%

21 The class average forced outage rate was applied to total energy market net revenues.
22 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
23 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report for PJM.

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 zones in 2018 (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2009 through 2018[24] (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)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
AECO	$1,555	$780	$928	$8	$262	$36,066	$11,926	$1,252	$98	$11,532	11,649%
AEP	$100	$94	$9	$0	$99	$15,382	$3,059	$217	$16	$3,849	24,722%
APS	$808	$224	$13	$0	$127	$20,072	$6,840	$316	$63	$7,331	11,551%
ATSI	NA	NA	$0	$0	$97	$15,092	$2,727	$167	$63	$2,876	4,447%
BGE	$2,596	$1,572	$975	$136	$592	$53,670	$11,187	$1,796	$808	$13,135	1,526%
ComEd	$7	$73	$0	$0	$74	$12,076	$1,747	$92	$0	$757	NA
DAY	$174	$92	$97	$0	$87	$15,130	$2,559	$200	$14	$1,710	12,042%
DEOK	NA	NA	NA	$0	$74	$14,306	$2,105	$273	$0	$3,350	NA
DLCO	$65	$1,547	$8	$0	$78	$13,813	$2,489	$174	$63	$3,292	5,142%
Dominion	$2,696	$2,149	$1,062	$134	$468	$46,239	$10,055	$969	$350	$14,816	4,129%
DPL	$2,442	$1,175	$898	$19	$290	$40,857	$14,788	$1,569	$703	$13,493	1,819%
EKPC	NA	NA	NA	NA	$0	$15,363	$2,304	$171	$0	$1,872	NA
JCPL	$1,348	$732	$1,192	$22	$453	$36,332	$12,736	$289	$181	$12,564	6,838%
Met-Ed	$1,424	$758	$782	$4	$251	$35,247	$11,621	$265	$143	$12,422	8,579%
PECO	$1,402	$755	$847	$9	$252	$35,496	$11,794	$255	$148	$11,336	7,571%
PENELEC	$203	$109	$11	$0	$123	$17,773	$5,626	$168	$71	$5,590	7,722%
Pepco	$2,925	$1,882	$1,215	$137	$667	$55,675	$10,096	$943	$372	$13,030	3,401%
PPL	$1,297	$706	$920	$48	$255	$36,173	$12,432	$253	$179	$10,048	5,516%
PSEG	$1,210	$672	$847	$9	$325	$35,956	$12,238	$316	$186	$11,559	6,109%
RECO	$940	$530	$524	$0	$1,466	$33,335	$13,957	$310	$185	$10,483	5,557%
PJM	$1,247	$815	$574	$28	$302	$29,203	$8,114	$500	$182	$8,252	4,429%

24 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report for PJM.

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd Zone and in the PENELEC Zone were calculated hourly assuming the unit generated 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.[25] 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).[26]

Wind energy market net revenues were higher in both zones in the first three months of 2018 as a result of higher gas prices and associated higher LMPs (Table 7-10).

Table 7-10 Net revenue for a wind installation (Dollars per installed MW-year): January through March, 2012 through 2018

Zone	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
ComEd	$23,562	$25,808	$43,705	$28,043	$21,027	$23,254	$28,023	21%
PENELEC	$22,592	$30,532	$64,324	$42,418	$20,792	$25,299	$41,879	66%

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).[27]

Solar energy market net revenues were higher in the first three months of 2018 as a result of higher gas prices and associated higher LMPs (Table 7-11).

Table 7-11 PSEG net revenue for a solar installation (Dollars per installed MW-year): January through March, 2012 through 2018

Zone	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	2017 (Jan-Mar)	2018 (Jan-Mar)	Change in 2018 from 2017
PSEG	$3,832	$10,800	$20,037	$14,764	$6,116	$5,854	$9,189	57%

25 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.
26 The 1603 payment is a direct payment of 30 percent of the project cost.
27 The 1603 payment is a direct payment of 30 percent of the project cost.

Historical New Entrant CT and CC Revenue Adequacy

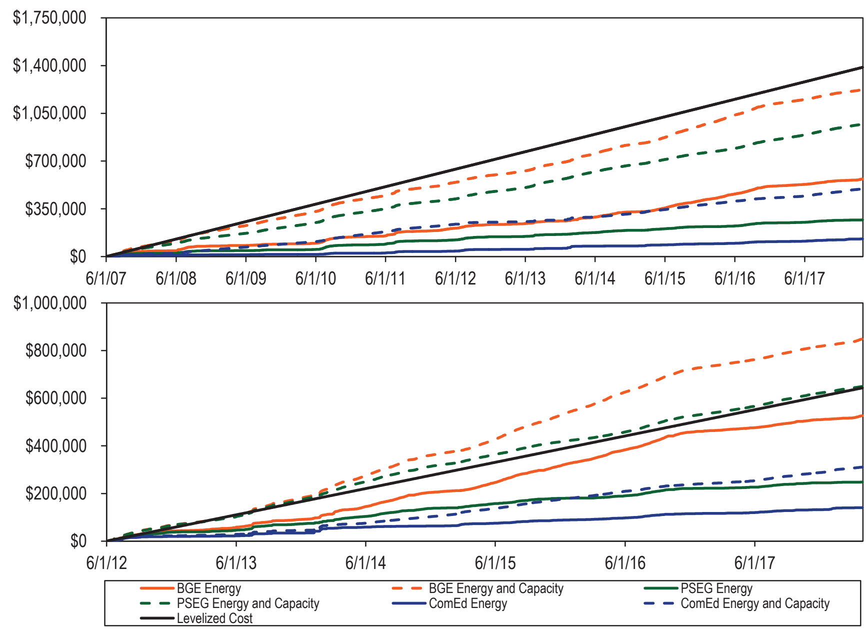
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through March 2018, although a new CC in the BGE zone was very close. 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, 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, 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.

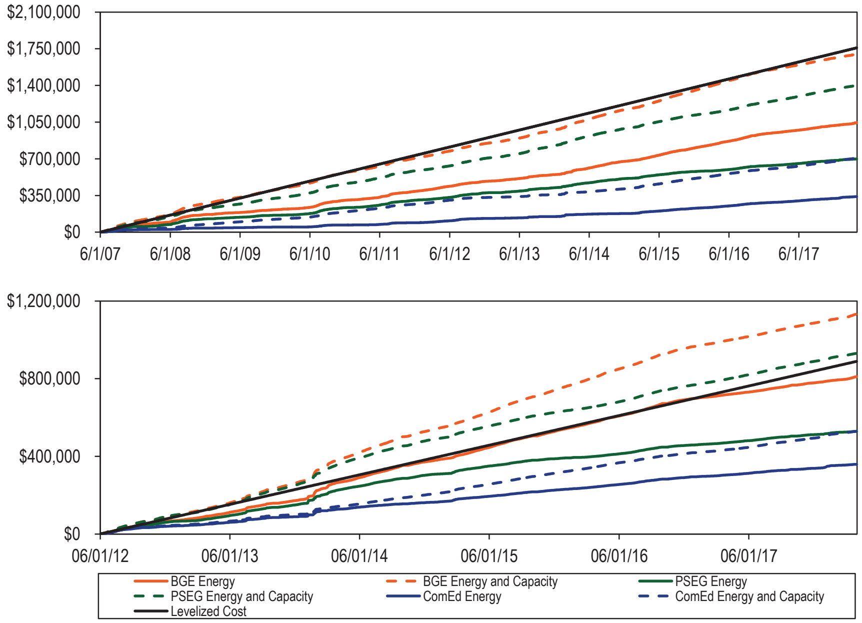
Figure 7-6 Historical new entrant CT revenue adequacy: June 1, 2007 through March 31, 2018 and June 1, 2012 through March 31, 2018



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, although a new CC in the BGE zone was very close to covering cumulative total costs. Cumulative total market net revenues through March

2018, 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 March 31, 2018 and June 1, 2012 through March 31, 2018



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

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations for a sample of nuclear plants.[28] [29] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2016. This is likely to result in conservatively high costs for the forward looking analysis. NEI operating costs have been decreasing annually since 2012 (6.2 percent decrease from 2012 through 2016). NEI's incremental capital expenditures include historical expenditures to meet regulatory requirements that resulted from reviews based on the accident at the Fukushima nuclear plant in Japan. NEI incremental capital expenditures have been decreasing annually since 2012 (38.2 percent decrease from 2012 through 2016) and decreased 16.5 percent from 2015 to 2016. For that reason, the analysis compares revenues to 100 percent, two thirds, and one third of NEI's 2016 annual capital expenditures.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices.[30] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs.[31] In the first part of January 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. The results for nuclear plants are also sensitive to changes in costs and whether unit costs are less than or greater than the benchmark NEI data. The results for nuclear plants are also sensitive to forward prices and the extent to which the owners of the plants sell the output forward.

Table 7-13 includes the publicly available data on energy market prices, capacity market prices and nuclear cost data for the nineteen nuclear plants in PJM.[32]

28 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>.

29 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

30 A change in the capacity market price of $24 per MW-day translates into a change in market revenue of $1.00 per MWh for a nuclear power plant operating in every hour.

31 The IMM submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program.* Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*

32 For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price. .

Table 7-13 Nuclear unit public data: 2013 through 2017

	ICAP	Average DA LMP ($/MWh)					BRA Capacity Price ($/MWh)					2016 NEI Costs ($/MWh)		
	(MW)	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	Fuel	Operating	Capital
Beaver Valley	1,777	$34.24	$41.86	$30.35	$27.07	$29.11	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Braidwood	2,330	$30.26	$37.34	$25.97	$24.30	$24.99	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Byron	2,300	$29.22	$35.05	$21.00	$17.94	$23.79	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Calvert Cliffs	1,716	$40.27	$57.88	$40.30	$32.64	$31.57	$7.81	$7.24	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
Cook	2,071	$34.14	$40.49	$29.94	$26.93	$28.03	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Davis Besse	894	$36.10	$47.21	$31.94	$27.80	$28.85	$0.96	$3.54	$10.86	$8.97	$4.90	$6.77	$25.95	$8.67
Dresden	1,787	$31.82	$39.22	$27.45	$25.89	$26.35	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Hope Creek	1,161	$37.43	$51.99	$32.41	$23.20	$26.78	$8.38	$7.57	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
LaSalle	2,238	$30.94	$37.88	$26.28	$23.95	$24.71	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Limerick	2,296	$37.28	$51.71	$32.65	$23.37	$26.99	$8.38	$7.57	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
North Anna	1,891	$38.55	$53.37	$38.05	$30.50	$31.27	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Oyster Creek	615	$38.62	$52.85	$33.10	$23.79	$27.52	$8.38	$7.57	$6.44	$5.80	$4.98	$6.77	$25.95	$8.67
Quad Cities	1,819	$25.94	$30.71	$19.47	$18.04	$23.09	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Peach Bottom	2,251	$37.37	$51.52	$31.98	$23.07	$26.76	$8.38	$7.57	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
Perry	1,240	$36.69	$46.14	$32.77	$27.84	$29.91	$0.96	$3.54	$10.86	$8.97	$4.90	$6.77	$25.95	$8.67
Salem	2,332	$37.40	$51.96	$32.37	$23.18	$26.76	$8.38	$7.57	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
Surry	1,690	$37.98	$51.75	$37.91	$30.08	$31.08	$0.96	$3.54	$5.49	$3.80	$3.95	$6.75	$18.73	$6.15
Susquehanna	2,520	$36.76	$50.93	$32.47	$23.66	$27.14	$7.81	$7.24	$6.44	$5.80	$4.98	$6.75	$18.73	$6.15
Three Mile Island	805	$36.83	$50.47	$30.94	$22.96	$27.12	$7.81	$7.24	$6.44	$5.80	$4.98	$6.77	$25.95	$8.67

Table 7-14 shows the surplus or shortfall in $/MWh for the nineteen nuclear plants in PJM calculated using this data.[33] In Table 7-14, six nuclear plants with a total capacity of 7,673 MW did not recover fuel costs, operating costs, and 50 percent of incremental capital expenditures in two of the last three years. In Table 7-14, nine nuclear plants with a total capacity of 14,027 MW did not recover fuel costs, operating costs, and 100 percent of incremental capital expenditures in two of the last three years.

Some nuclear plants did not clear the capacity market as a result of the interaction between the demand for capacity, the offers of other capacity resources, and the offers of the unit owners. Three Mile Island did not clear the

33 Analysis excludes Catawba 1 which is pseudo tied to PJM.

2018/2019 Auction[34] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[35] Three Mile Island and Quad Cities also did not clear the 2020/2021 Auction.[36]

Table 7-14 Nuclear unit surplus (shortfall) based on public data: 2013 through 2017

		Surplus (Shortfall) ($/MWh)														
	ICAP	100% of NEI Capital Costs					2/3 of NEI Capital Costs					1/3 of NEI Capital Costs				
	(MW)	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Beaver Valley	1,777	$3.6	$13.8	$4.2	($0.8)	$1.4	$5.6	$15.8	$6.3	$1.3	$3.5	$7.7	$17.9	$8.3	$3.3	$5.5
Braidwood	2,330	($0.4)	$9.3	($0.2)	($3.5)	($2.7)	$1.6	$11.3	$1.9	($1.5)	($0.6)	$3.7	$13.4	$3.9	$0.6	$1.4
Byron	2,300	($1.5)	$7.0	($5.1)	($9.9)	($3.9)	$0.6	$9.0	($3.1)	($7.8)	($1.8)	$2.6	$11.1	($1.0)	($5.8)	$0.2
Calvert Cliffs	1,716	$16.4	$33.5	$15.1	$6.8	$4.9	$18.5	$35.5	$17.2	$8.9	$7.0	$20.5	$37.6	$19.2	$10.9	$9.0
Cook	2,071	$3.5	$12.4	$3.8	($0.9)	$0.3	$5.5	$14.5	$5.8	$1.2	$2.4	$7.6	$16.5	$7.9	$3.2	$4.4
Davis Besse	894	($4.3)	$9.4	$1.4	($4.6)	($7.6)	($1.4)	$12.2	$4.3	($1.7)	($4.8)	$1.5	$15.1	$7.2	$1.2	($1.9)
Dresden	1,787	$1.2	$11.1	$1.3	($1.9)	($1.3)	$3.2	$13.2	$3.4	$0.1	$0.7	$5.3	$15.2	$5.4	$2.2	$2.8
Hope Creek	1,161	$14.2	$27.9	$7.2	($2.6)	$0.1	$16.2	$30.0	$9.3	($0.6)	$2.2	$18.3	$32.0	$11.3	$1.5	$4.2
LaSalle	2,238	$0.3	$9.8	$0.1	($3.9)	($3.0)	$2.3	$11.8	$2.2	($1.8)	($0.9)	$4.4	$13.9	$4.2	$0.2	$1.1
Limerick	2,296	$14.0	$27.7	$7.5	($2.5)	$0.3	$16.1	$29.7	$9.5	($0.4)	$2.4	$18.1	$31.8	$11.6	$1.6	$4.4
North Anna	1,891	$7.9	$25.3	$11.9	$2.7	$3.6	$9.9	$27.3	$14.0	$4.7	$5.6	$12.0	$29.4	$16.0	$6.8	$7.7
Oyster Creek	615	$5.6	$19.0	($1.9)	($11.8)	($8.9)	$8.5	$21.9	$1.0	($8.9)	($6.0)	$11.4	$24.8	$3.9	($6.0)	($3.1)
Quad Cities	1,819	($4.7)	$2.6	($6.7)	($9.8)	($4.6)	($2.7)	$4.7	($4.6)	($7.7)	($2.5)	($0.6)	$6.7	($2.6)	($5.7)	($0.5)
Peach Bottom	2,251	$14.1	$27.5	$6.8	($2.8)	$0.1	$16.2	$29.5	$8.8	($0.7)	$2.2	$18.2	$31.6	$10.9	$1.3	$4.2
Perry	1,240	($3.7)	$8.3	$2.2	($4.6)	($6.6)	($0.8)	$11.2	$5.1	($1.7)	($3.7)	$2.0	$14.1	$8.0	$1.2	($0.8)
Salem	2,332	$14.1	$27.9	$7.2	($2.6)	$0.1	$16.2	$29.9	$9.2	($0.6)	$2.2	$18.2	$32.0	$11.3	$1.5	$4.2
Surry	1,690	$7.3	$23.7	$11.8	$2.3	$3.4	$9.4	$25.7	$13.8	$4.3	$5.5	$11.4	$27.8	$15.9	$6.4	$7.5
Susquehanna	2,520	$12.9	$26.5	$7.3	($2.2)	$0.5	$15.0	$28.6	$9.3	($0.1)	$2.5	$17.0	$30.6	$11.4	$1.9	$4.6
Three Mile Island	805	$3.3	$16.3	($4.0)	($12.6)	($9.3)	$6.1	$19.2	($1.1)	($9.7)	($6.4)	$9.0	$22.1	$1.8	($6.8)	($3.5)

In order to further evaluate the viability of nuclear plants, analysis was performed based on forward energy market prices for 2018, 2019 and 2020 and known capacity market prices for 2018, 2019 and 2020. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values.

Table 7-15 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2018 through 2020 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[37] The 2018 LMPs include DA prices through March 2018 and forward prices for April through December 2018. The capacity prices are known based on PJM capacity auction results.

34 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
35 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction" (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
36 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
37 Forward prices on April 2, 2018. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2017 data.

Table 7-15 Forward prices in PJM energy and capacity markets and annual costs

	ICAP	Average Forward LMP ($/MWh)			BRA Capacity Price ($/MWh)			2016 NEI Costs ($/MWh)		
	(MW)	2018	2019	2020	2018	2019	2020	Fuel	Operating	Capital
Beaver Valley	1,777	$32.32	$30.33	$30.15	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Braidwood	2,330	$24.43	$25.59	$25.47	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Byron	2,300	$25.63	$25.39	$25.26	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Calvert Cliffs	1,716	$35.73	$32.13	$31.94	$6.09	$5.30	$3.83	$6.75	$18.73	$6.15
Cook	2,071	$29.51	$29.71	$29.53	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Davis Besse	894	$31.57	$30.52	$30.35	$6.09	$5.29	$3.60	$6.77	$25.95	$8.67
Dresden	1,787	$27.10	$27.92	$27.78	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Hope Creek	1,161	$31.42	$28.13	$27.95	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
LaSalle	2,238	$24.58	$25.65	$25.52	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Limerick	2,296	$31.74	$28.55	$28.37	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
North Anna	1,891	$35.55	$31.82	$31.61	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Oyster Creek	615	$32.03	$28.87	$28.69	$7.56	$6.82	$6.65	$6.77	$25.95	$8.67
Quad Cities	1,819	$25.07	$25.08	$24.94	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Peach Bottom	2,251	$31.18	$28.16	$27.98	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
Perry	1,240	$33.29	$31.19	$31.01	$6.09	$5.29	$3.60	$6.77	$25.95	$8.67
Salem	2,332	$31.39	$28.11	$27.93	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
Surry	1,690	$35.28	$31.42	$31.22	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Susquehanna	2,520	$31.38	$28.31	$28.14	$6.09	$5.29	$3.83	$6.75	$18.73	$6.15
Three Mile Island	805	$30.69	$28.06	$27.90	$6.09	$5.29	$3.83	$6.77	$25.95	$8.67

Table 7-16 and Table 7-17 show the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, for the 2018 through 2020 period, on a per MWh basis and a total dollar basis. The fuel and operating costs are the 2016 NEI fuel and operating costs and the capital expenditures are 100 percent of the NEI 2016 incremental capital expenditures. Based on forward prices for energy and the known forward prices for capacity, all but four nuclear plants would cover their annual avoidable costs on average over the next three years (2018 through 2020) when 100 percent of NEI's incremental capital expenditures are included. The four plants are Oyster Creek, Three Mile Island, Davis Besse, and Perry. Oyster Creek and Three Mile Island are scheduled to retire in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All four plants are single nuclear unit sites which have higher operating costs per MWh than multiple unit sites. The four plants together are 3,554 MW, of which 615 MW (Oyster Creek) have a definitive retirement plan and 2,939 MW (Three Mile Island, Davis Besse and Perry) have requested deactivation.

Table 7-16 Nuclear unit forward annual surplus (shortfall) in $/MWh

	Surplus (Shortfall) ($/MWh)								
	100% of NEI Capital Costs			2/3 of NEI Capital Costs			1/3 of NEI Capital Costs		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Beaver Valley	$6.77	$3.99	$2.11	$8.82	$6.04	$4.16	$10.87	$8.09	$6.21
Braidwood	$0.11	$2.63	$1.93	$2.16	$4.68	$3.98	$4.21	$6.73	$6.03
Byron	$1.31	$2.42	$1.72	$3.36	$4.47	$3.77	$5.41	$6.52	$5.82
Calvert Cliffs	$10.18	$5.79	$4.14	$12.23	$7.84	$6.19	$14.28	$9.89	$8.24
Cook	$3.96	$3.37	$1.50	$6.01	$5.42	$3.55	$8.06	$7.47	$5.60
Davis Besse	($3.73)	($5.57)	($7.44)	($0.84)	($2.68)	($4.55)	$2.05	$0.21	($1.66)
Dresden	$2.78	$4.95	$4.25	$4.83	$7.00	$6.30	$6.88	$9.05	$8.35
Hope Creek	$7.35	$3.32	$2.96	$9.40	$5.37	$5.01	$11.45	$7.42	$7.06
LaSalle	$0.26	$2.68	$1.98	$2.31	$4.73	$4.03	$4.36	$6.78	$6.08
Limerick	$7.67	$3.74	$3.39	$9.72	$5.79	$5.44	$11.77	$7.84	$7.49
North Anna	$10.01	$5.48	$3.58	$12.06	$7.53	$5.63	$14.11	$9.58	$7.68
Oyster Creek	($1.80)	($5.70)	($6.05)	$1.09	($2.81)	($3.16)	$3.98	$0.08	($0.27)
Quad Cities	$0.75	$2.11	$1.40	$2.80	$4.16	$3.45	$4.85	$6.21	$5.50
Peach Bottom	$7.11	$3.35	$3.00	$9.16	$5.40	$5.05	$11.21	$7.45	$7.10
Perry	($2.01)	($4.91)	($6.79)	$0.88	($2.02)	($3.90)	$3.77	$0.87	($1.01)
Salem	$7.33	$3.30	$2.94	$9.38	$5.35	$4.99	$11.43	$7.40	$7.04
Surry	$9.74	$5.08	$3.18	$11.79	$7.13	$5.23	$13.84	$9.18	$7.28
Susquehanna	$5.83	$1.97	$0.34	$7.88	$4.02	$2.39	$9.93	$6.07	$4.44
Three Mile Island	($4.61)	($8.04)	($9.66)	($1.72)	($5.15)	($6.77)	$1.17	($2.26)	($3.88)

Table 7-17 Nuclear unit forward annual surplus (shortfall) ($ in millions)

	Surplus (Shortfall) ($ in millions)								
	100% of NEI Capital Costs			2/3 of NEI Capital Costs			1/3 of NEI Capital Costs		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Beaver Valley	$105.5	$62.1	$32.9	$137.4	$94.0	$64.8	$169.3	$125.9	$96.7
Braidwood	$2.2	$53.6	$39.4	$44.1	$95.4	$81.2	$85.9	$137.3	$123.1
Byron	$26.3	$48.7	$34.7	$67.6	$90.0	$76.0	$108.9	$131.3	$117.3
Calvert Cliffs	$153.1	$87.1	$62.2	$183.9	$117.9	$93.0	$214.7	$148.7	$123.8
Cook	$71.9	$61.1	$27.2	$109.1	$98.3	$64.4	$146.3	$135.5	$101.6
Davis Besse	($29.2)	($43.7)	($58.3)	($6.6)	($21.0)	($35.7)	$16.0	$1.6	($13.0)
Dresden	$43.5	$77.4	$66.5	$75.6	$109.5	$98.5	$107.7	$141.6	$130.6
Hope Creek	$74.7	$33.8	$30.1	$95.6	$54.6	$51.0	$116.4	$75.5	$71.8
LaSalle	$5.0	$52.5	$38.8	$45.2	$92.7	$79.0	$85.4	$132.9	$119.2
Limerick	$154.3	$75.3	$68.1	$195.5	$116.5	$109.4	$236.7	$157.7	$150.6
North Anna	$165.8	$90.8	$59.3	$199.7	$124.7	$93.3	$233.7	$158.7	$127.2
Oyster Creek	($9.7)	($30.7)	($32.6)	$5.9	($15.1)	($17.0)	$21.4	$0.4	($1.5)
Quad Cities	$12.0	$33.6	$22.3	$44.6	$66.3	$55.0	$77.3	$99.0	$87.6
Peach Bottom	$140.2	$66.1	$59.1	$180.6	$106.5	$99.6	$221.1	$146.9	$140.0
Perry	($21.8)	($53.3)	($73.7)	$9.6	($21.9)	($42.3)	$41.0	$9.5	($10.9)
Salem	$149.6	$67.4	$60.1	$191.5	$109.3	$102.0	$233.4	$151.2	$143.9
Surry	$144.3	$75.2	$47.2	$174.6	$105.6	$77.5	$205.0	$135.9	$107.9
Susquehanna	$128.8	$43.6	$7.5	$174.0	$88.8	$52.8	$219.3	$134.1	$98.0
Three Mile Island	($32.5)	($56.7)	($68.1)	($12.1)	($36.3)	($47.8)	$8.3	($15.9)	($27.4)

The surplus levels over the recovery of avoidable costs decreased or became shortfalls in 2016 and 2017 as a result of low energy market prices. Surplus levels over the recovery of avoidable costs are somewhat higher looking forward, but decline to an average of $2.56 per MWh in 2020 using 100 percent of NEI incremental capital expenditures, excluding the four units that are currently planning to retire.