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 nine months of 2018 than in the first nine months of 2017. The result was higher margins for all unit types.
- In the first nine months of 2018, average energy market net revenues increased by 70 percent for a new CT, 39 percent for a new CC, 202 percent for a new coal plant (CP), 37 percent for a new nuclear plant (NP), 461 percent for a new diesel (DS), 22 percent for a new wind installation, and 10 percent for a new solar installation compared to the first nine months of 2017.
- The relative prices of fuel varied during the first nine 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.
- Based on forward prices for energy, known forward prices for capacity, and public data on costs, there are three nuclear plants in PJM at risk of not covering their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,939 MW, all of which have requested deactivation.

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 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 September 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 September 2018, and have not covered their total costs in the ComEd Zone.

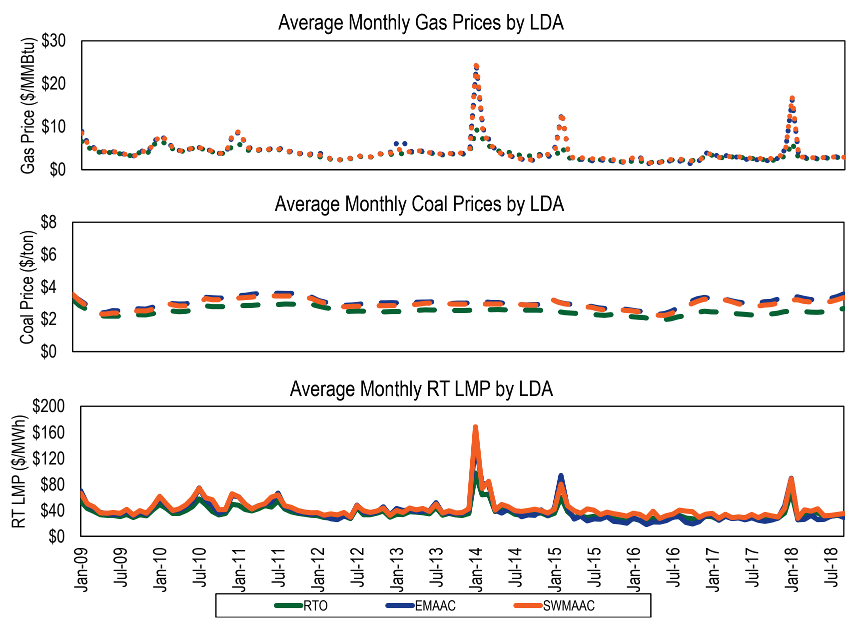
Net Revenue

When compared to annualized fixed costs and avoidable 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 short run marginal 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. Net revenues cover fixed costs, which include a return on investment, depreciation and income taxes and avoidable costs, which include long term and intermediate term operation and maintenance expenses. Net revenue is the contribution to total fixed and avoidable 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 and avoidable 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 and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable 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 and avoidable 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 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh. Eastern natural gas prices and coal prices increased in the first nine months of 2018. The price of Northern Appalachian coal was 7.8 percent higher; the price of Central Appalachian coal was 10.4 percent higher; the price of Powder River Basin coal was 3.8 percent higher; the price of eastern natural gas was 57.7 percent higher; and the price of western natural gas was 0.6 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through September 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 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 September 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-Sep)	$16.35	$27.79	$43.62	$13.69	$26.35	$29.38	$6.67	$13.96	$35.27	$16.94	$22.82	$38.66

Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through September 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-Sep)	$57.4	$41.1	$41.1	$18.0	$19.3	$19.2	$59.3	$37.3	$37.3	$48.1	$33.9	$33.8

Figure 7-2 shows the hourly spark spread, Figure 7-3 shows the hourly dark spread, and Figure 7-4 shows the hourly quark 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 September 2018[1]

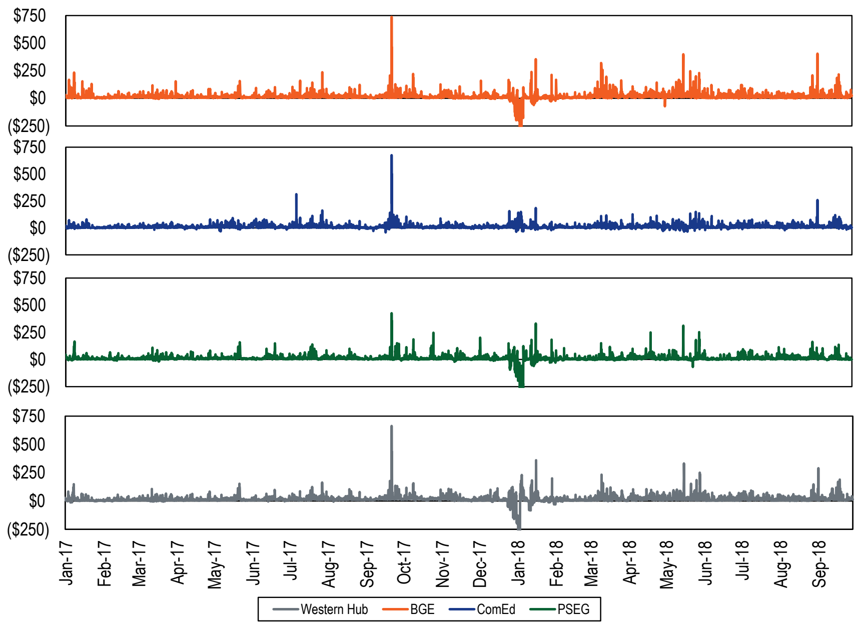
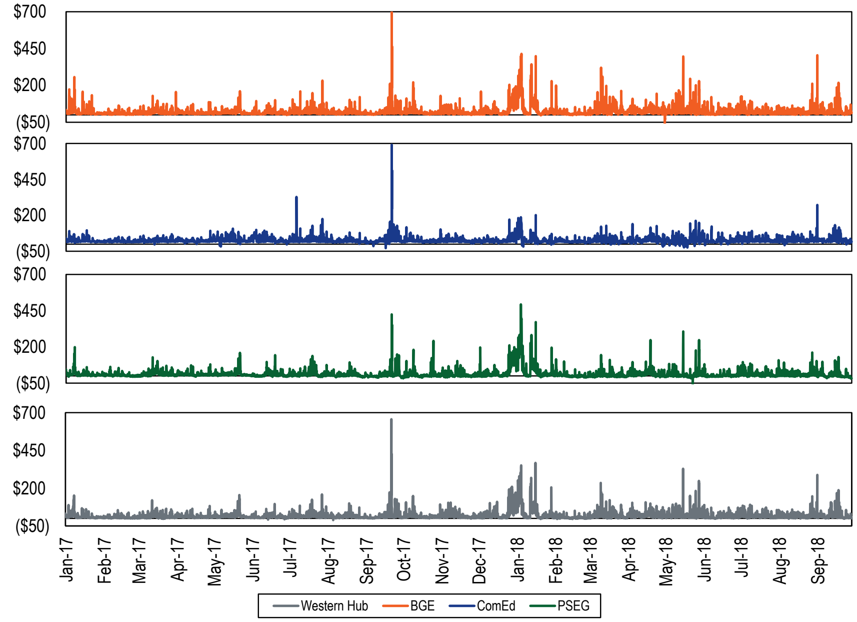


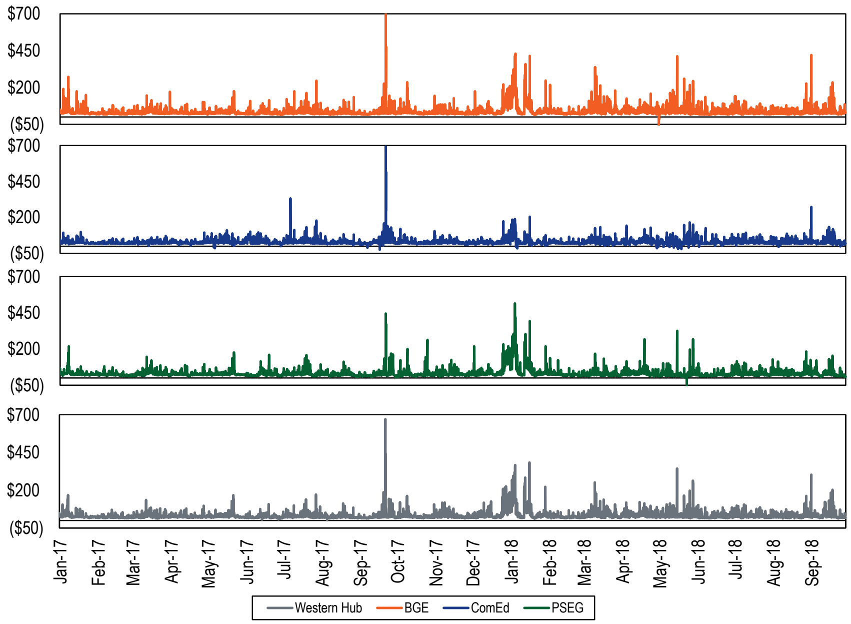
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): January 2017 through September 2018[2]



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 September 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 712.6 MW and consists of two GE Frame 7HA.02 CTs, equipped with evaporative coolers 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.
- 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.[4 5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

4 Hourly ambient conditions supplied by DTN.
5 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.[6]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[7] 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.[8] 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.[9] 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.[10]

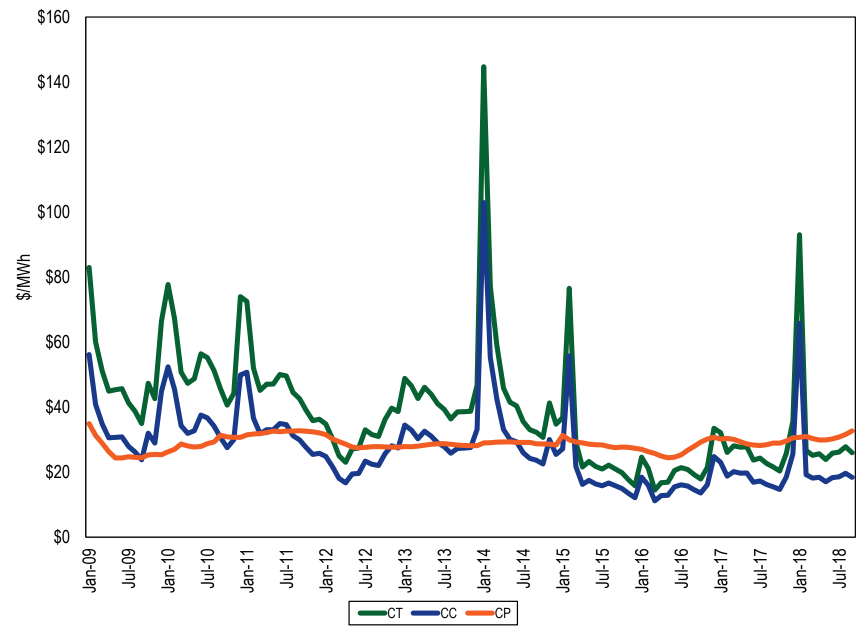
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[11] [12] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

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

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$33.33	9,241	$0.38
CC	$23.72	6,296	$1.09
CP	$30.77	9,250	$4.03
DS	$166.51	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the 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 September 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.

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

Table 7-4 Average run hours: January through September, 2009 through 2018

Jan-Sep	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		
2013	1,765	5,052	6,552	19	6,552	4,845	1,503
2014	2,834	5,167	6,552	171	6,552	4,920	1,462
2015	4,870	6,297	4,796	128	6,552	4,730	1,563
2016	5,310	6,458	4,143	39	6,576	4,474	1,528
2017	3,870	6,456	3,596	25	6,552	4,896	1,377
2018	4,238	6,365	3,870	110	6,552	4,843	1,283

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 Met-Ed in the first nine months of 2018 than in the first nine months of 2017 (Table 7-5). The increase in energy prices more than offset the increase in gas prices except in Met-Ed. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2009 through 2018 (Dollars per installed MW-year)[13]

	Jan-Sep										
Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$10,044	$37,036	$58,032	$43,904	$27,441	$54,259	$51,252	$51,995	$26,791	$31,885	19%
AEP	$3,625	$9,376	$25,847	$36,762	$17,232	$55,328	$62,810	$53,988	$30,834	$73,367	138%
APS	$11,768	$25,272	$44,348	$45,910	$22,546	$75,153	$119,290	$78,716	$44,017	$84,597	92%
ATSI	NA	NA	$0	$39,144	$21,931	$64,352	$55,747	$52,293	$32,361	$86,427	167%
BGE	$13,048	$47,046	$56,522	$64,182	$37,242	$79,650	$87,477	$107,937	$45,472	$64,715	42%
ComEd	$2,228	$9,034	$17,923	$24,184	$12,714	$25,196	$31,764	$34,658	$22,460	$35,681	59%
DAY	$2,880	$9,782	$25,834	$40,286	$17,846	$56,021	$51,627	$50,458	$31,599	$82,538	161%
DEOK	NA	NA	NA	$32,943	$17,096	$68,978	$48,697	$48,053	$30,331	$91,690	202%
DLCO	$2,992	$14,229	$28,062	$39,464	$17,795	$48,396	$71,731	$68,381	$39,847	$59,013	48%
Dominion	$13,837	$41,776	$43,998	$48,374	$28,992	$39,654	$62,221	$62,168	$33,535	$60,086	79%
DPL	$11,042	$37,029	$51,739	$55,149	$30,953	$65,039	$41,994	$35,659	$15,699	$31,280	99%
EKPC	NA	NA	NA	NA	$0	$66,992	$50,161	$47,005	$26,115	$56,373	116%
JCPL	$9,053	$34,187	$53,702	$42,224	$33,097	$56,246	$50,166	$47,010	$30,535	$32,758	7%
Met-Ed	$7,839	$34,791	$46,245	$40,916	$26,299	$47,331	$83,266	$68,073	$48,471	$45,100	(7%)
PECO	$8,417	$33,519	$54,247	$42,750	$24,846	$49,001	$82,478	$64,331	$39,113	$41,484	6%
PENELEC	$7,120	$18,964	$42,948	$46,886	$31,855	$108,799	$132,131	$84,595	$46,301	$82,628	78%
Pepco	$15,392	$44,270	$50,876	$58,419	$34,308	$71,683	$61,091	$61,544	$30,632	$54,164	77%
PPL	$7,250	$29,100	$48,836	$37,116	$24,819	$53,872	$152,168	$69,513	$43,372	$84,471	95%
PSEG	$6,902	$32,803	$43,946	$40,227	$26,161	$41,398	$94,738	$69,091	$44,993	$46,260	3%
RECO	$5,653	$30,775	$34,876	$36,485	$27,128	$40,277	$57,008	$51,366	$32,247	$35,610	10%
PJM	$8,182	$28,764	$40,443	$42,912	$24,015	$58,381	$72,391	$60,342	$34,736	$59,006	70%

13 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.[14] 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 zones except Met-Ed in the first nine months of 2018 than in the first nine months of 2017 (Table 7-6). The increase in energy prices offset the increase in gas prices except in Met-Ed. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: 2009 through 2018 (Dollars per installed MW-year)[15]

	Jan-Sep										
Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$34,530	$65,409	$93,684	$74,365	$55,749	$104,160	$66,328	$59,250	$54,402	$59,186	9%
AEP	$14,702	$23,155	$52,355	$68,103	$43,575	$84,646	$81,602	$64,716	$61,389	$104,904	71%
APS	$37,258	$48,836	$81,838	$77,472	$52,720	$110,774	$123,928	$83,031	$74,425	$116,090	56%
ATSI	NA	NA	$0	$71,769	$51,346	$98,438	$74,931	$63,589	$62,270	$116,398	87%
BGE	$37,714	$76,019	$89,251	$94,619	$69,981	$138,411	$101,060	$109,642	$77,704	$94,436	22%
ComEd	$9,094	$19,005	$28,907	$49,354	$26,127	$36,024	$45,062	$45,879	$43,599	$54,892	26%
DAY	$12,805	$22,975	$51,109	$72,126	$45,823	$86,948	$71,827	$62,711	$62,589	$113,598	81%
DEOK	NA	NA	NA	$63,256	$42,917	$110,828	$67,387	$59,989	$59,319	$120,715	104%
DLCO	$12,435	$27,135	$51,343	$69,956	$39,755	$70,587	$78,722	$74,436	$68,055	$88,786	30%
Dominion	$42,474	$72,788	$78,375	$79,191	$57,136	$76,359	$80,920	$73,606	$64,301	$88,484	38%
DPL	$35,834	$64,538	$86,932	$85,471	$60,938	$116,347	$47,973	$41,717	$27,411	$42,851	56%
EKPC	NA	NA	NA	NA	$0	$107,076	$69,827	$58,115	$55,191	$87,415	58%
JCPL	$34,167	$62,903	$90,596	$73,317	$62,129	$109,303	$66,020	$54,973	$58,508	$60,144	3%
Met-Ed	$28,494	$59,799	$77,701	$70,542	$52,733	$94,591	$92,015	$70,938	$75,080	$73,734	(2%)
PECO	$30,369	$60,474	$88,715	$72,715	$50,899	$97,271	$92,657	$67,978	$66,099	$71,777	9%
PENELEC	$28,349	$40,838	$78,814	$79,145	$68,494	$163,972	$130,927	$84,652	$74,991	$112,909	51%
Pepco	$37,685	$74,053	$82,407	$88,933	$66,461	$125,072	$78,507	$73,108	$59,891	$81,863	37%
PPL	$26,890	$52,570	$78,871	$66,913	$50,520	$95,882	$143,274	$71,700	$70,669	$109,756	55%
PSEG	$30,159	$62,435	$76,859	$68,867	$53,069	$87,551	$105,573	$72,389	$72,538	$77,990	8%
RECO	$25,325	$57,752	$60,375	$64,666	$54,169	$86,288	$69,359	$58,626	$60,265	$61,945	3%
PJM	$28,134	$52,393	$69,341	$73,199	$50,227	$100,026	$84,395	$67,552	$62,435	$86,894	39%

14 All starts associated with combined cycle units are assumed to be warm starts.
15 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 all zones as a result of more run hours, higher gas prices and associated higher energy prices (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: 2009 through 2018 (Dollars per installed MW-year)[16]

					Jan-Sep						
Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$82,808	$123,363	$91,942	$23,558	$47,414	$170,151	$56,357	$12,724	$4,443	$38,063	757%
AEP	$33,143	$79,883	$76,083	$22,674	$54,899	$118,501	$53,079	$37,072	$32,268	$64,870	101%
APS	$78,625	$118,182	$98,223	$33,229	$61,669	$142,636	$48,683	$15,705	$15,402	$48,837	217%
ATSI	NA	NA	$0	$28,570	$60,636	$131,340	$55,482	$32,673	$32,650	$66,941	105%
BGE	$92,204	$154,092	$112,530	$46,712	$73,505	$212,972	$89,639	$50,549	$16,551	$59,681	261%
ComEd	$83,265	$115,961	$112,618	$87,516	$104,250	$154,747	$41,750	$25,864	$26,044	$32,962	27%
DAY	$32,977	$77,240	$73,913	$19,587	$58,948	$122,202	$52,453	$31,114	$30,883	$64,808	110%
DEOK	NA	NA	NA	$15,351	$50,838	$111,478	$47,869	$28,524	$28,087	$71,993	156%
DLCO	$32,002	$63,403	$46,321	$20,302	$35,451	$88,804	$43,229	$28,656	$29,490	$66,778	126%
Dominion	$82,093	$139,673	$95,725	$32,457	$59,955	$167,681	$95,044	$47,070	$22,424	$70,423	214%
DPL	$90,353	$138,575	$111,741	$41,698	$65,687	$200,422	$80,573	$24,927	$11,249	$56,158	399%
EKPC	NA	NA	NA	NA	$0	$108,041	$40,870	$24,178	$22,880	$43,642	91%
JCPL	$81,909	$120,447	$88,735	$21,794	$53,056	$174,143	$55,336	$9,955	$5,624	$38,739	589%
Met-Ed	$81,157	$130,268	$96,673	$29,075	$55,790	$168,801	$74,657	$21,615	$17,417	$54,054	210%
PECO	$78,182	$118,089	$87,642	$22,952	$43,595	$164,314	$52,701	$10,690	$4,516	$37,638	733%
PENELEC	$60,807	$93,660	$73,609	$26,685	$53,893	$140,148	$66,747	$25,345	$13,178	$47,426	260%
Pepco	$87,267	$137,857	$85,838	$28,765	$58,786	$192,026	$48,570	$14,377	$4,546	$37,676	729%
PPL	$72,859	$107,497	$78,079	$17,797	$43,190	$161,459	$51,879	$9,005	$4,782	$37,029	674%
PSEG	$77,583	$123,112	$88,770	$23,924	$62,776	$191,011	$83,685	$15,395	$9,110	$45,287	397%
RECO	$71,409	$116,130	$71,479	$21,468	$67,841	$185,603	$84,158	$14,754	$8,940	$44,337	396%
PJM	$71,685	$115,143	$82,773	$29,690	$55,609	$155,324	$61,138	$24,010	$17,024	$51,367	202%

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

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.[17]

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

Table 7-8 Energy net revenue for a new entrant nuclear plant: 2009 through 2018 (Dollars per installed MW-year)[18]

	Jan-Sep										
Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$220,444	$283,596	$275,481	$160,586	$198,641	$332,216	$190,727	$108,018	$119,881	$170,395	42%
AEP	$165,079	$199,798	$205,599	$144,556	$174,656	$252,952	$164,054	$124,262	$133,854	$176,072	32%
APS	$195,683	$240,187	$234,187	$153,584	$183,795	$279,391	$187,270	$129,462	$135,090	$188,374	39%
ATSI	NA	NA	$0	$147,800	$182,629	$266,784	$168,226	$126,330	$137,617	$187,949	37%
BGE	$224,368	$302,330	$276,074	$180,658	$215,476	$374,646	$244,221	$183,793	$152,747	$215,435	41%
ComEd	$132,962	$175,483	$172,796	$131,406	$157,272	$222,150	$133,450	$112,155	$120,868	$127,412	5%
DAY	$160,936	$198,821	$204,683	$148,590	$177,043	$256,115	$164,680	$125,439	$138,011	$185,007	34%
DEOK	NA	NA	NA	$139,704	$167,933	$244,094	$159,469	$122,250	$134,587	$192,714	43%
DLCO	$155,568	$199,157	$201,501	$146,126	$170,938	$234,864	$154,508	$121,731	$133,880	$187,546	40%
Dominion	$213,382	$286,412	$257,755	$163,557	$200,179	$324,381	$214,263	$143,885	$144,634	$206,360	43%
DPL	$222,294	$285,118	$275,071	$171,153	$206,621	$357,351	$211,908	$131,519	$129,337	$191,066	48%
EKPC	NA	NA	NA	NA	$0	$240,126	$151,693	$117,443	$128,610	$160,514	25%
JCPL	$219,404	$280,306	$271,918	$159,284	$205,141	$336,396	$189,411	$102,496	$124,351	$171,216	38%
Met-Ed	$212,079	$275,729	$258,451	$156,059	$195,208	$320,029	$182,397	$104,070	$129,052	$170,454	32%
PECO	$215,347	$277,735	$270,547	$158,845	$193,881	$324,425	$184,521	$100,980	$119,553	$168,418	41%
PENELEC	$189,728	$235,110	$233,235	$155,445	$193,062	$292,097	$181,285	$117,280	$127,969	$175,506	37%
Pepco	$225,419	$299,684	$268,964	$175,051	$211,746	$361,650	$226,209	$157,421	$147,579	$208,084	41%
PPL	$209,319	$265,668	$259,612	$152,507	$193,155	$321,046	$182,826	$101,365	$122,279	$163,463	34%
PSEG	$223,101	$285,232	$276,936	$162,490	$220,267	$358,194	$200,258	$106,067	$126,357	$175,699	39%
RECO	$216,226	$277,469	$257,121	$158,052	$225,932	$352,042	$201,547	$105,844	$127,269	$176,473	39%
PJM	$200,079	$256,932	$233,330	$156,077	$183,679	$302,547	$184,646	$122,091	$131,676	$179,908	37%

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

New Entrant Diesel

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

New entrant DS plant energy market net revenues were higher in all zones except ComEd in 2018 (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: 2009 through 2018 (Dollars per installed MW-year)[19]

	Jan-Sep										
Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$1,623	$10,048	$6,708	$1,392	$1,082	$36,616	$12,155	$2,340	$796	$10,347	1,200%
AEP	$100	$495	$1,717	$786	$484	$15,803	$3,668	$802	$1,341	$4,207	214%
APS	$832	$1,394	$2,007	$1,022	$741	$20,496	$7,175	$868	$1,198	$6,792	467%
ATSI	NA	NA	$0	$1,033	$23,643	$15,523	$3,435	$1,946	$1,667	$7,105	326%
BGE	$3,061	$12,069	$7,815	$2,460	$2,551	$55,146	$15,645	$7,024	$2,315	$13,075	465%
ComEd	$7	$480	$811	$909	$384	$12,411	$2,131	$610	$1,279	$718	(44%)
DAY	$174	$548	$1,894	$904	$517	$15,611	$3,403	$876	$1,579	$3,860	145%
DEOK	NA	NA	NA	$664	$462	$14,743	$2,856	$1,259	$3,020	$6,621	119%
DLCO	$605	$2,839	$2,165	$885	$1,163	$14,261	$2,908	$2,254	$1,407	$8,104	476%
Dominion	$3,055	$9,142	$3,983	$1,611	$1,509	$46,858	$11,170	$2,108	$1,798	$14,985	733%
DPL	$2,576	$8,689	$5,769	$2,210	$1,083	$42,831	$16,156	$3,370	$1,973	$14,391	629%
EKPC	NA	NA	NA	NA	$0	$15,767	$2,703	$803	$900	$1,897	111%
JCPL	$1,626	$7,110	$6,610	$1,557	$2,014	$36,731	$13,108	$832	$1,094	$11,521	953%
Met-Ed	$1,477	$7,655	$5,032	$1,681	$1,254	$35,603	$12,968	$837	$2,597	$11,363	337%
PECO	$1,425	$7,600	$5,379	$1,787	$985	$35,981	$12,458	$820	$1,045	$10,172	873%
PENELEC	$203	$930	$2,642	$2,066	$1,104	$18,141	$6,417	$840	$1,245	$5,591	349%
Pepco	$3,253	$10,922	$5,961	$1,945	$2,134	$56,581	$11,432	$2,834	$1,763	$12,720	621%
PPL	$1,303	$6,814	$5,305	$1,611	$1,054	$36,526	$13,115	$735	$1,649	$9,082	451%
PSEG	$1,249	$6,534	$5,447	$1,549	$1,257	$36,377	$12,695	$885	$1,096	$10,668	873%
RECO	$1,068	$5,431	$4,255	$1,619	$2,387	$33,728	$13,749	$929	$1,110	$9,877	789%
PJM	$1,390	$5,806	$4,083	$1,457	$2,290	$29,787	$8,967	$1,649	$1,544	$8,655	461%

19 Percent change is NA when 2017 net revenue was zero.

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.[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 the first nine months of 2018 as a result of higher energy prices (Table 7-10).

Table 7-10 Net revenue for a wind installation (Dollars per installed MW-year): 2013 through 2018

	Jan-Sep						
Zone	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
ComEd	$59,854	$81,514	$55,721	$47,166	$51,225	$53,632	5%
PENELEC	$63,471	$99,658	$65,072	$39,808	$49,857	$68,969	38%

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 higher in the first nine months of 2018 as a result of higher energy prices (Table 7-11).

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.

22 The 1603 payment is a direct payment of 30 percent of the project cost.

Table 7-11 PSEG net revenue for a solar installation (Dollars per installed MW-year): 2013 through 2018

	Jan-Sep						
Zone	2013	2014	2015	2016	2017	2018	Change in 2018 from 2017
PSEG	$69,202	$87,522	$47,298	$32,585	$30,013	$33,019	10%

Historical New Entrant CT and CC Revenue Adequacy

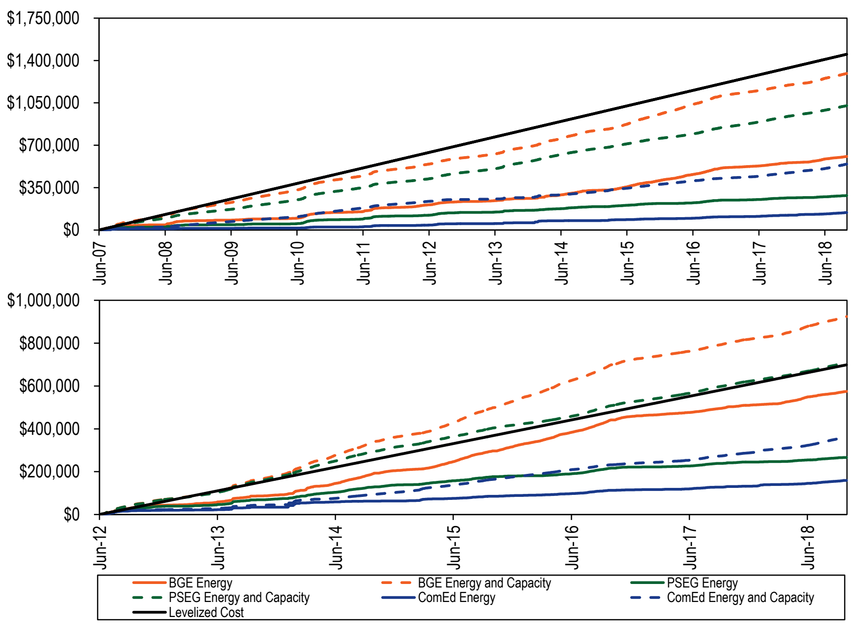
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital,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

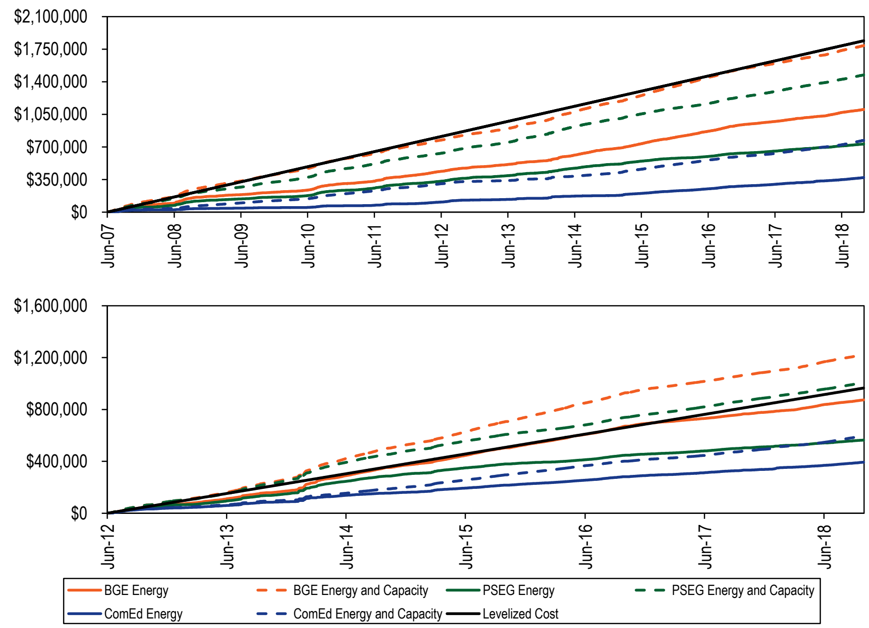
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-6 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007, and for a new CT that began operation on June 1, 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 2007 through September 2018 and June 2012 through September 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 September 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 2007 through September 2018 and June 2012 through September 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 of average costs for all U.S. nuclear plants.[23] [24] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2017. This is likely to result in conservatively high costs for the forward looking analysis. NEI operating costs have decreased for multiple unit plants since their peak in 2012 (8.7 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI's incremental capital expenditures include historical expenditures to meet regulatory requirements that resulted from reviews based on the 2011 accident at the Fukushima nuclear plant in Japan. NEI incremental capital expenditures have decreased since their peak in 2012 (40.8 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants).

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices.[25] 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.[26] 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. Energy prices in the first nine months of 2018 were significantly higher than in the first nine months of 2017 and forward prices are higher now than earlier in 2018. The result is that nuclear plant net revenues have continued to increase during 2018 and for the three year forward period. 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.[27]

23 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors.

24 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.

25 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.

26 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*

27 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 unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

Table 7-13 Nuclear unit day ahead LMP: 2008 through 2017

	ICAP	Average DA LMP ($/MWh)									
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Beaver Valley	1,777	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11
Braidwood	2,330	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79
Calvert Cliffs	1,716	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57
Cook	2,071	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85
Dresden	1,787	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35
Hope Creek	1,161	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78
LaSalle	2,238	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71
Limerick	2,296	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99
North Anna	1,891	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27
Oyster Creek	615	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52
Peach Bottom	2,251	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09
Salem	2,332	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76
Surry	1,690	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14
Three Mile Island	805	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12

Table 7-14 Nuclear unit capacity market data: 2008 through 2021[28] [29]

	ICAP	BRA Capacity Price ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,777	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.05	$5.26	$3.58	$4.70
Braidwood	2,330	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.27	$8.61	$8.05	$7.97
Byron	2,300	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.27	$8.61	$8.05	$7.97
Calvert Cliffs	1,716	$8.22	$9.03	$8.15	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.05	$5.27	$3.81	$4.87
Cook	2,071	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.05	$5.26	$3.58	$4.70
Davis Besse	894	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.05	$5.26	$3.58	$5.46
Dresden	1,787	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.27	$8.61	$8.05	$7.97
Hope Creek	1,161	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.52	$6.79	$6.61	$7.25
LaSalle	2,238	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.27	$8.61	$8.05	$7.97
Limerick	2,296	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.52	$6.79	$6.61	$7.25
North Anna	1,891	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.05	$5.26	$3.58	$4.70
Oyster Creek	615	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.52	NA	NA	NA
Peach Bottom	2,251	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.52	$6.79	$6.61	$7.25
Perry	1,240	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.05	$5.26	$3.58	$5.46
Quad Cities	1,819	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.27	$8.61	$8.05	$7.97
Salem	2,332	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.52	$6.79	$6.61	$7.25
Surry	1,690	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.05	$5.26	$3.58	$4.70
Susquehanna	2,520	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.05	$5.26	$3.81	$4.87
Three Mile Island	805	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.05	$5.26	$3.81	$4.87

28 Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.
29 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

Table 7-15 Nuclear unit costs: 2008 through 2017

		NEI Costs ($/MWh)									
	ICAP (MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Beaver Valley	1,777	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Braidwood	2,330	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Calvert Cliffs	1,716	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Cook	2,071	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66
Dresden	1,787	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Hope Creek	1,161	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
LaSalle	2,238	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Limerick	2,296	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
North Anna	1,891	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Oyster Creek	615	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66
Peach Bottom	2,251	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Salem	2,332	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Surry	1,690	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89
Three Mile Island	805	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66

Table 7-16 shows the surplus or shortfall in $/MWh for the nineteen nuclear plants in PJM calculated using this data.[30] In Table 7-16, 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 2018/2019 Auction[31] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[32] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[33] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[34] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[35]

30 Analysis excludes Catawba 1 which is pseudo tied to PJM.
31 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
32 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction" (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
33 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
34 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
35 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.

Table 7-16 Nuclear unit surplus (shortfall) based on public data: 2008 through 2017

	ICAP	Surplus (Shortfall) ($/MWh)									
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Beaver Valley	1,777	$26.1	$6.0	$10.1	$8.5	($3.4)	$1.4	$11.5	$2.9	($0.8)	$2.1
Braidwood	2,330	$24.7	$2.2	$6.0	$3.0	($6.3)	($2.6)	$7.0	($1.5)	($3.6)	($2.0)
Byron	2,300	$24.2	($1.5)	$3.0	($0.9)	($9.5)	($3.7)	$4.7	($6.5)	($10.0)	($3.2)
Calvert Cliffs	1,716	$60.1	$20.3	$28.1	$17.6	$4.2	$14.1	$31.1	$13.7	$6.7	$5.6
Cook	2,071	$28.9	$6.7	$11.0	$8.4	($3.7)	$1.3	$10.1	$2.4	($1.0)	$1.1
Davis Besse	894	NA	NA	NA	NA	($13.4)	($7.0)	$6.4	($1.9)	($4.8)	($8.9)
Dresden	1,787	$25.4	$2.8	$7.2	$4.1	($5.4)	($1.1)	$8.9	($0.0)	($2.0)	($0.6)
Hope Creek	1,161	$53.5	$16.6	$24.1	$16.5	$2.2	$11.9	$25.6	$5.9	($2.7)	$0.9
LaSalle	2,238	$24.6	$2.2	$6.0	$3.0	($6.2)	($1.9)	$7.5	($1.2)	($3.9)	($2.3)
Limerick	2,296	$53.7	$16.7	$24.3	$16.3	$2.3	$11.7	$25.3	$6.1	($2.6)	$1.1
North Anna	1,891	$51.8	$14.4	$25.1	$16.5	$0.1	$5.7	$23.0	$10.6	$2.6	$4.3
Oyster Creek	615	$47.1	$8.0	$15.4	$6.8	($8.5)	$2.7	$16.0	($5.1)	($11.9)	($10.2)
Peach Bottom	2,251	$53.3	$16.5	$23.7	$15.8	$2.0	$11.8	$25.1	$5.4	($2.9)	$0.8
Perry	1,240	NA	NA	NA	NA	($13.4)	($6.4)	$5.3	($1.0)	($4.7)	($7.9)
Quad Cities	1,819	$23.9	($0.7)	$2.0	($2.2)	($13.4)	($7.0)	$0.3	($8.0)	($9.9)	($3.9)
Salem	2,332	$53.6	$16.7	$24.0	$16.5	$2.2	$11.8	$25.5	$5.8	($2.8)	$0.8
Surry	1,690	$48.6	$13.5	$23.8	$16.0	($0.2)	$5.1	$21.4	$10.4	$2.2	$4.1
Susquehanna	2,520	$46.6	$14.8	$22.0	$15.8	$1.1	$10.6	$24.2	$5.9	($2.3)	$1.2
Three Mile Island	805	$40.5	$6.1	$12.9	$4.2	($9.9)	$0.4	$13.3	($7.2)	($12.7)	($10.6)

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 7-17 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2018 through 2021 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[36] The 2018 LMPs include DA prices through September 2018 and forward prices for October through December 2018. The capacity prices are known based on PJM capacity auction results.

36 Forward prices on October 1, 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 7-17 Forward prices in PJM energy and capacity markets and annual costs[37]

	ICAP	Average Forward LMP ($/MWh)				BRA Capacity Price ($/MWh)				2017 NEI Costs ($/MWh)		
	(MW)	2018	2019	2020	2021	2018	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,777	$35.45	$33.23	$31.29	$29.61	$6.05	$5.26	$3.58	$4.70	$6.44	$18.46	$5.99
Braidwood	2,330	$27.02	$28.06	$26.48	$25.05	$7.27	$8.61	$8.05	$7.97	$6.44	$18.46	$5.99
Byron	2,300	$26.55	$27.78	$26.20	$24.82	$7.27	$8.61	$8.05	$7.97	$6.44	$18.46	$5.99
Calvert Cliffs	1,716	$38.56	$35.21	$33.15	$31.37	$6.05	$5.27	$3.81	$4.87	$6.44	$18.46	$5.99
Cook	2,071	$31.01	$32.55	$30.65	$29.00	$6.05	$5.26	$3.58	$4.70	$6.44	$18.46	$5.99
Davis Besse	894	$33.81	$33.45	$31.50	$29.81	$6.05	$5.26	$3.58	$5.46	$6.42	$27.32	$8.92
Dresden	1,787	$27.99	$30.60	$28.87	$27.31	$7.27	$8.61	$8.05	$7.97	$6.44	$18.46	$5.99
Hope Creek	1,161	$32.74	$30.83	$29.01	$27.46	$7.52	$6.79	$6.61	$7.25	$6.44	$18.46	$5.99
LaSalle	2,238	$26.99	$28.12	$26.53	$25.09	$7.27	$8.61	$8.05	$7.97	$6.44	$18.46	$5.99
Limerick	2,296	$32.98	$31.29	$29.45	$27.88	$7.52	$6.79	$6.61	$7.25	$6.44	$18.46	$5.99
North Anna	1,891	$38.18	$34.87	$32.82	$31.06	$6.05	$5.26	$3.58	$4.70	$6.44	$18.46	$5.99
Peach Bottom	2,251	$32.46	$30.86	$29.05	$27.50	$6.05	$5.26	$3.58	$5.46	$6.44	$18.46	$5.99
Perry	1,240	$36.28	$34.18	$32.18	$30.46	$7.27	$8.61	$8.05	$7.97	$6.42	$27.32	$8.92
Quad Cities	1,819	$25.51	$27.46	$25.89	$24.52	$7.52	$6.79	$6.61	$7.25	$6.44	$18.46	$5.99
Salem	2,332	$32.71	$30.80	$28.99	$27.44	$7.52	$6.79	$6.61	$7.25	$6.44	$18.46	$5.99
Surry	1,690	$38.22	$34.43	$32.41	$30.67	$6.05	$5.26	$3.58	$4.70	$6.44	$18.46	$5.99
Susquehanna	2,520	$32.62	$31.03	$29.21	$27.65	$6.05	$5.26	$3.81	$4.87	$6.44	$18.46	$5.99
Three Mile Island	805	$31.36	$30.76	$28.96	$27.41	$6.05	$5.26	$3.81	$4.87	$6.42	$27.32	$8.92

Table 7-18 and Table 7-19 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 2021 period, on a per MWh basis and a total dollar basis. The fuel and operating costs are the 2017 NEI fuel and operating costs and the capital expenditures are 100 percent of the NEI 2017 incremental capital expenditures. Based on forward prices for energy and the known forward prices for capacity, all but three nuclear plants would cover their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,939 MW, all of which have requested deactivation.

37 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

Table 7-18 Nuclear unit forward annual surplus (shortfall) in $/MWh[38]

	Surplus (Shortfall) ($/MWh)			
	2018	2019	2020	2021
Beaver Valley	$10.61	$7.60	$3.97	$3.43
Braidwood	$3.40	$5.78	$3.64	$2.13
Byron	$2.93	$5.51	$3.35	$1.90
Calvert Cliffs	$13.72	$9.58	$6.07	$5.35
Cook	$6.17	$6.93	$3.33	$2.81
Davis Besse	($2.79)	($3.94)	($7.58)	($7.39)
Dresden	$4.37	$8.32	$6.02	$4.40
Hope Creek	$9.37	$6.72	$4.73	$3.82
LaSalle	$3.37	$5.84	$3.69	$2.18
Limerick	$9.61	$7.18	$5.17	$4.23
North Anna	$13.34	$9.24	$5.51	$4.87
Peach Bottom	$7.62	$5.23	$1.74	$2.07
Perry	$0.89	$0.14	($2.43)	($4.23)
Quad Cities	$2.14	$3.36	$1.61	$0.87
Salem	$9.33	$6.70	$4.71	$3.80
Surry	$13.39	$8.80	$5.10	$4.48
Susquehanna	$7.78	$5.40	$2.13	$1.63
Three Mile Island	($5.24)	($6.64)	($9.89)	($10.38)

Table 7-19 Nuclear unit forward annual surplus (shortfall) ($ in millions)[39]

	Surplus (Shortfall) ($ in millions)			
	2018	2019	2020	2021
Beaver Valley	$165.2	$118.4	$61.9	$53.4
Braidwood	$69.4	$118.1	$74.3	$43.5
Byron	$59.1	$110.9	$67.6	$38.3
Calvert Cliffs	$206.3	$144.1	$91.3	$80.4
Cook	$111.9	$125.6	$60.4	$51.0
Davis Besse	($21.9)	($30.9)	($59.4)	($57.9)
Dresden	$68.4	$130.2	$94.2	$68.8
Hope Creek	$95.3	$68.4	$48.1	$38.8
LaSalle	$66.1	$114.5	$72.3	$42.7
Limerick	$193.3	$144.5	$104.0	$85.2
North Anna	$221.0	$153.1	$91.2	$80.7
Peach Bottom	$150.2	$103.2	$34.3	$40.8
Perry	$9.7	$1.5	($26.4)	($45.9)
Quad Cities	$34.1	$53.5	$25.7	$13.9
Salem	$190.7	$136.9	$96.3	$77.6
Surry	$198.2	$130.4	$75.4	$66.3
Susquehanna	$171.8	$119.3	$47.0	$36.0
Three Mile Island	($37.0)	($46.8)	($69.8)	($73.2)

38 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

39 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.