Net Revenue

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

Overview

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in 2017 than in 2016. Gas prices increased more than energy prices and CTs and CCs ran with lower margins as a result. Coal prices increased more than energy prices but less than gas prices and CPs ran for slightly more hours in 2017 than in 2016 and margins varied by zone.
- In 2017, average energy market net revenues decreased by 54 percent for a new CT, 9 percent for a new CC, 2 percent for a new CP, and 4 percent for a new solar installation compared to 2016. Average energy market net revenues increased by 49 percent for a new DS, 11 percent for a new nuclear plant, and 11 percent for a new wind installation compared to 2016.
- The relative prices of fuel varied during 2017. While the marginal cost of the new CC was consistently below that of the new CP in 2017, the marginal cost of the new CT was above that of the new CP in January and December. As a result, CT hours dropped significantly and CP hours increased.
- Capacity revenue accounted for 65 percent of total net revenues for a new CT, 38 percent for a new CC, 62 percent for a new CP, 95 percent for a new DS, and 20 percent for a new nuclear plant.
- In 2017, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone but would have covered 95 percent of levelized costs in the PSEG Zone, as a result of higher locational capacity market prices.
- In 2017, a new CC would have received sufficient net revenue to cover levelized total costs in three of the twenty zones and to cover 90 percent or more of levelized costs in 11 zones.
- In 2017, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, net revenues covered more than 44 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 65 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 167 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for five percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 81 percent of the total net revenue of a solar installation in PSEG.
- In 2017, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2017, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- The net revenue results show that there are between 108 and 118 units with between 22,929 MW and 30,785 MW of capacity in PJM at risk of retirement in addition to the units that are currently planning to retire. Coal and nuclear units account for most of the MW at risk. There are between 38 and 46 coal units, with between 17,302 MW and 21,039 MW, at risk. There are between three and five nuclear plants at risk, with between 2,939 MW and 7,058 MW at risk.

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 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

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

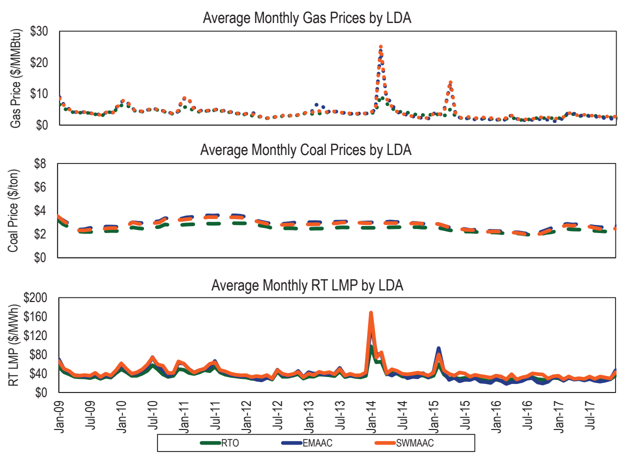
Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed received by generators from all PJM markets.

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

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The load-weighted average real-time LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 per MWh. Natural gas prices and coal prices increased in 2017. The price of Northern Appalachian coal was 17.4 percent higher; the price of Central Appalachian coal was 25.3 percent higher; the price of Powder River Basin coal was 12.7 percent higher; the price of eastern natural gas was 35.1 percent higher; and the price of western natural gas was 23.7 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through 2017



Spark Spreads, Dark Spreads, and Quark Spreads

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

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

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

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 2017

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$26.27	$33.76	$48.66	$12.47	$33.68	$30.85	$22.99	$28.15	$47.70	$19.50	$26.15	$41.06
2012	$24.29	$24.21	$36.25	$16.17	$30.87	$27.23	$19.51	$17.57	$33.01	$19.94	$19.86	$31.91
2013	$19.59	$26.45	$40.79	$10.70	$31.64	$30.44	$13.65	$25.09	$42.13	$16.16	$22.34	$36.68
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017	$16.77	$18.41	$33.20	$11.81	$25.40	$28.19	$12.80	$10.89	$29.97	$16.30	$15.71	$30.50

Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through 2017

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$50.7	$51.1	$51.1	$26.3	$26.9	$26.9	$43.6	$45.3	$45.3	$37.2	$37.5	$37.4
2012	$33.7	$33.9	$33.7	$23.6	$23.7	$23.7	$29.6	$29.7	$29.7	$27.6	$28.0	$27.8
2013	$32.6	$33.3	$33.3	$18.2	$18.3	$18.2	$32.4	$30.4	$30.4	$25.3	$25.5	$25.5
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017	$23.5	$25.0	$25.0	$19.8	$19.9	$19.9	$19.9	$22.9	$23.0	$23.2	$22.5	$22.6

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): 2017[1]

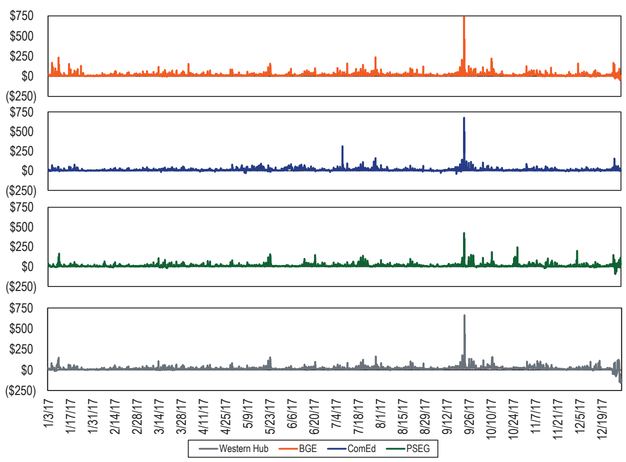
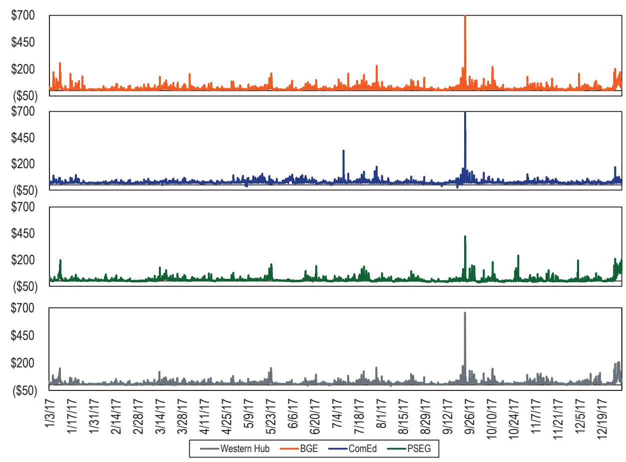


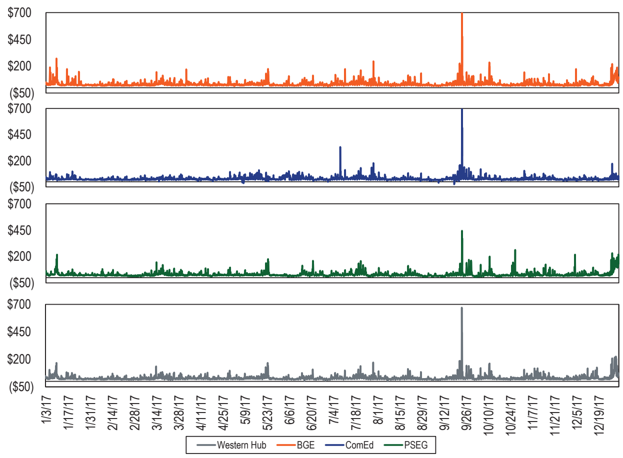
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2017[2]



1 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

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

Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2017[3]



Theoretical Energy Market Net Revenue

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

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

- The CT plant has an installed capacity of 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.[4]
- 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.[5] [6]
- 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.[7] [8] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

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.[9]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[10] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of regulation service were calculated for the CP. 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. No black start service capability is assumed for any of the unit types.

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.
4 GE Power, "7HA Power Plants," 7HA.02 unit capacity was updated based on GE unit specifications. (November 2017) <https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf>.
5 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.
6 GE Power, "7HA Power Plants," 7HA.02 unit capacity was updated based on GE unit specifications. (November 2017) <https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf>.
7 Hourly ambient conditions supplied by DTN.
8 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.
9 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
10 Outage figures obtained from the PJM eGADS database.

CT revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CTs with 20 or fewer operating years. CC revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive capability revenue of $3,350/MW-Yr.[11]

Table 7-3 New entrant ancillary service revenue (Dollars per MW-year)

	Reactive			Regulation
	CT	CC	CP	CP
2009	$4,273	$4,991	$3,963	$38
2010	$7,765	$4,280	$3,980	$6
2011	$7,025	$4,539	$6,753	$2
2012	$4,261	$6,065	$6,216	$20
2013	$4,708	$3,486	$3,614	$53
2014	$3,712	$4,046	$3,501	$168
2015	$3,673	$4,911	$3,386	$74
2016	$3,436	$4,573	$3,470	$19
2017	$3,885	$3,591	$3,415	$26

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[12] 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.[13] 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.[14]

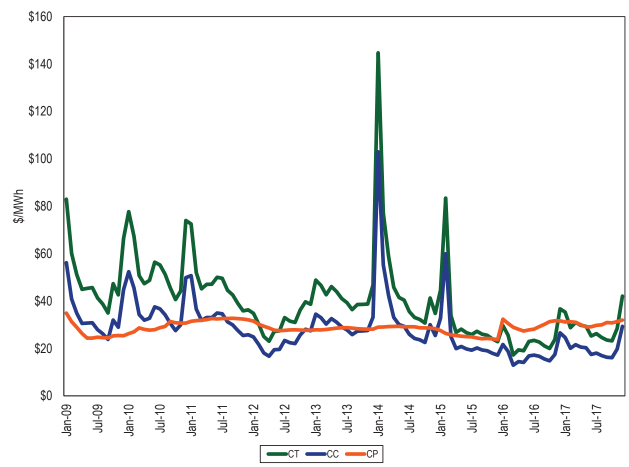
Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[15] [16] Average short run marginal costs are shown in Table 7-4.

Table 7-4 Average short run marginal costs: 2017

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$28.95	9,437	$0.25
CC	$20.07	6,679	$1.00
CP	$30.52	9,250	$4.00
DS	$142.62	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the short run marginal cost of the theoretical CT, CC and CP plants since 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 2017



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

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-5 shows the average run hours by a new entrant unit.

11 $3,350/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
12 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.
13 Gas daily cash prices obtained from Platts.
14 Coal prompt prices obtained from Platts.
15 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
16 VOM rates provided by Pasteris Energy, Inc.

Table 7-5 Average run hours: 2009 through 2017

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009	1,066	5,183	6,552	44	6,552		
2010	1,788	5,641	6,552	117	6,552		
2011	2,744	6,853	6,552	50	6,552		
2012	4,595	7,812	6,576	27	6,576	5,073	2,954
2013	2,243	6,558	6,552	20	6,552	5,040	3,013
2014	3,681	6,732	6,552	176	6,552	6,758	1,748
2015	4,345	7,013	6,552	210	6,552	6,625	1,890
2016	4,845	7,535	2,999	68	6,576	6,496	1,859
2017	2,952	7,664	3,229	33	6,552	6,726	1,690

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2017 includes five months of the 2016/2017 capacity market clearing price and seven months of the 2017/2018 RPM capacity market clearing price.[17]

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies decreased in 2017 over 2016 with the exception of the coal plant and nuclear plant.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2017[18]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Average
AECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$43,669	$57,431
AEP	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$35,251
APS	$57,842	$66,187	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$38,872
ATSI	NA	NA	NA	NA	NA	$31,149	$95,422	$78,709	$42,929	$62,052
BGE	$82,515	$73,135	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$43,669	$59,303
ComEd	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$35,251
DAY	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$35,251
DEOK	NA	NA	NA	NA	$8,420	$31,149	$48,128	$33,377	$34,645	$31,144
DLCO	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$35,251
Dominion	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$34,645	$35,251
DPL	$63,411	$67,098	$50,501	$52,309	$77,542	$66,206	$56,448	$50,948	$43,669	$58,681
EKPC	NA	NA	NA	NA	NA	$31,149	$48,128	$33,377	$34,645	$36,825
JCPL	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$43,669	$57,431
Met-Ed	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$43,669	$55,790
PECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$43,669	$57,431
PENELEC	$57,842	$66,187	$49,858	$45,216	$68,503	$63,360	$56,448	$50,945	$43,667	$55,781
Pepco	$82,515	$73,135	$49,858	$45,261	$73,027	$66,529	$56,448	$50,948	$43,669	$60,154
PPL	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$43,669	$55,790
PSEG	$63,411	$66,187	$49,858	$49,957	$75,882	$72,567	$60,936	$67,224	$73,401	$64,380
RECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$43,669	$57,431
PJM	$52,370	$60,604	$49,878	$32,806	$36,601	$46,247	$54,646	$48,568	$44,809	$47,392

17 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions.

18 See the *2017 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[19] [20]

	20-Year Levelized Total Cost								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
Combustion Turbine	$128,705	$131,044	$110,589	$113,027	$109,731	$108,613	$111,639	$113,821	$95,264
Combined Cycle	$173,174	$175,250	$153,682	$155,294	$150,654	$146,443	$146,300	$148,327	$129,731
Coal Plant	$446,550	$465,455	$473,835	$480,662	$491,240	$504,050	$517,017	$523,540	$528,701
Diesel Plant	$153,143	$153,143	$153,143	$153,143	$153,143	$161,746	$170,500	$173,182	$158,817
Nuclear Plant	$801,100	$801,100	$801,100	$801,100	$801,100	$880,770	$935,659	$963,107	$1,349,850
Wind Installation (with 1603 grant)				$196,186	$196,148	$198,033	$202,874	$231,310	$188,747
Solar Installation (with 1603 grant)				$394,855	$263,824	$236,289	$234,151	$218,937	$200,931

Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at a defined capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2017 because low gas prices resulted in low short run marginal costs which increased dispatch and the capacity factor, which increased the MWh over which costs are spread. DS units had a high levelized cost of energy in 2017 because DS units ran for extremely few hours in 2017, which decreased the capacity factor, which decreased the MWh over which costs are spread. The levelized cost of wind is comparable to or less than that of all other resources except CCs. The levelized cost of solar is high as a result of a low capacity factor.

Table 7-8 Levelized cost of energy: 2017

	CT	CC	CP	DS	Nuclear	Wind (ComEd)	Wind (PENELEC)	Solar (PSEG)
Levelized cost ($/MW-Yr)	$95,264	$129,731	$528,701	$158,817	$1,349,850	$188,747	$188,747	$200,931
Short run marginal costs ($/MWh)	$28.95	$20.07	$30.52	$142.62	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	34%	87%	37%	0%	99%	35%	30%	14%
Levelized cost of energy ($/MWh)	$61	$37	$194	$5,007	$163	$62	$73	$166

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.

19 Levelized total costs provided by Pasteris Energy, Inc.

20 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

New entrant CT plant energy market net revenues were lower across all zones in 2017 than in 2016 (Table 7-9). The increase in gas prices reduced both energy margins and run hours.

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2017[21 22]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$10,270	$41,776	$63,064	$50,716	$31,431	$62,488	$51,404	$48,167	$21,522	(55%)
AEP	$3,798	$12,246	$29,569	$39,768	$19,169	$58,738	$37,225	$31,391	$16,897	(46%)
APS	$12,211	$34,656	$49,411	$49,941	$26,767	$78,655	$58,192	$73,765	$33,728	(54%)
ATSI	NA	NA	$23,275	$43,763	$25,509	$67,762	$40,147	$28,048	$17,537	(37%)
BGE	$14,738	$52,514	$63,755	$71,707	$42,986	$89,712	$80,641	$107,070	$28,146	(74%)
ComEd	$2,253	$9,555	$18,515	$25,156	$12,992	$26,298	$13,595	$16,106	$9,330	(42%)
DAY	$3,011	$11,984	$30,125	$44,423	$19,910	$59,033	$37,710	$26,092	$16,375	(37%)
DEOK	NA	NA	NA	$36,426	$19,775	$78,150	$84,960	$28,275	$17,290	(39%)
DLCO	$3,247	$16,803	$33,064	$42,347	$20,903	$52,608	$31,438	$66,431	$33,309	(50%)
Dominion	$14,746	$47,122	$49,223	$53,638	$31,175	$43,721	$37,802	$37,027	$14,134	(62%)
DPL	$11,306	$40,871	$57,501	$62,542	$35,129	$78,702	$41,079	$49,806	$20,644	(59%)
EKPC	NA	NA	NA	NA	$15,244	$75,630	$75,433	$24,563	$11,472	(53%)
JCPL	$9,267	$39,408	$59,820	$49,343	$37,511	$64,876	$49,777	$43,113	$24,016	(44%)
Met-Ed	$8,092	$38,275	$50,960	$47,325	$29,546	$55,100	$47,292	$46,106	$28,324	(39%)
PECO	$8,598	$37,178	$59,087	$49,037	$27,857	$56,752	$45,876	$41,989	$22,027	(48%)
PENELEC	$7,418	$26,960	$47,419	$53,552	$40,971	$120,385	$112,826	$63,471	$28,929	(54%)
Pepco	$17,071	$49,586	$56,858	$64,640	$39,789	$80,268	$59,478	$48,736	$14,498	(70%)
PPL	$7,426	$31,826	$52,511	$43,024	$28,268	$61,271	$46,193	$42,792	$22,510	(47%)
PSEG	$7,067	$35,863	$49,340	$46,919	$30,673	$47,870	$23,810	$30,019	$13,512	(55%)
RECO	$5,805	$32,934	$39,366	$42,708	$32,271	$47,536	$25,602	$31,633	$13,080	(59%)
PJM	$8,607	$32,915	$46,270	$48,262	$28,394	$65,278	$50,024	$44,230	$20,364	(54%)

In 2017, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone but would have covered 95 percent of levelized costs in the PSEG Zone, primarily as a result of higher capacity revenue in PSEG (Table 7-10).

Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2009 through 2017

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	64%	88%	108%	90%	100%	122%	100%	90%	73%
AEP	36%	55%	78%	57%	29%	86%	80%	60%	58%
APS	58%	83%	96%	66%	36%	105%	99%	97%	76%
ATSI	NA	NA	NA	NA	NA	94%	125%	97%	68%
BGE	79%	102%	109%	107%	106%	144%	126%	142%	79%
ComEd	35%	53%	68%	44%	24%	56%	59%	46%	50%
DAY	36%	55%	79%	61%	30%	86%	80%	55%	58%
DEOK	NA	NA	NA	NA	NA	104%	123%	57%	59%
DLCO	36%	59%	81%	59%	31%	81%	75%	91%	75%
Dominion	45%	82%	96%	69%	40%	72%	80%	65%	55%
DPL	61%	88%	104%	105%	107%	137%	91%	92%	72%
EKPC	NA	NA	NA	NA	NA	102%	114%	54%	52%
JCPL	60%	87%	106%	89%	105%	124%	98%	86%	75%
Met-Ed	55%	86%	98%	86%	94%	112%	96%	88%	80%
PECO	59%	85%	105%	88%	97%	117%	95%	85%	73%
PENELEC	54%	77%	94%	91%	104%	173%	155%	104%	80%
Pepco	81%	100%	103%	101%	107%	139%	107%	91%	65%
PPL	54%	81%	99%	82%	93%	118%	95%	85%	74%
PSEG	58%	84%	96%	89%	101%	114%	79%	88%	95%
RECO	57%	82%	87%	83%	101%	108%	77%	76%	64%
PJM	55%	79%	95%	80%	77%	110%	98%	82%	69%

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

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017

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.[23] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were lower in 15 of 20 zones in 2017 than in 2016 (Table 7-11). Gas prices increased more than the LMP increased, resulting in lower margins and lower energy net revenues.

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year): 2009 through 2017[24 25]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$37,852	$79,328	$111,306	$92,466	$70,012	$123,761	$90,646	$78,013	$70,631	(9%)
AEP	$15,920	$32,720	$70,273	$81,290	$52,898	$94,541	$73,584	$69,313	$69,198	(0%)
APS	$41,013	$70,232	$101,830	$93,060	$66,602	$121,059	$97,044	$105,413	$89,818	(15%)
ATSI	NA	NA	$47,083	$87,078	$64,344	$108,904	$77,638	$64,124	$66,412	4%
BGE	$46,193	$91,219	$111,996	$113,212	$86,520	$160,024	$123,490	$145,186	$91,292	(37%)
ComEd	$9,224	$20,318	$31,890	$53,616	$28,188	$38,964	$30,984	$43,630	$40,484	(7%)
DAY	$14,063	$30,879	$69,799	$86,887	$56,071	$96,827	$75,212	$63,809	$67,072	5%
DEOK	NA	NA	NA	$75,534	$55,985	$131,815	$126,326	$63,796	$64,571	1%
DLCO	$14,210	$35,028	$69,664	$81,852	$49,647	$80,373	$63,351	$96,607	$88,010	(9%)
Dominion	$48,720	$88,838	$98,117	$94,554	$67,136	$87,913	$74,747	$79,224	$64,856	(18%)
DPL	$39,572	$76,906	$105,344	$104,125	$73,857	$144,248	$75,044	$82,446	$69,520	(16%)
EKPC	NA	NA	NA	NA	$34,714	$127,207	$116,344	$58,759	$56,372	(4%)
JCPL	$37,944	$77,772	$109,562	$92,010	$77,489	$128,858	$89,489	$72,909	$74,785	3%
Met-Ed	$31,635	$70,703	$95,417	$87,492	$65,530	$112,744	$82,109	$75,696	$80,021	6%
PECO	$33,551	$73,009	$105,795	$89,597	$63,132	$115,652	$83,816	$70,623	$70,541	(0%)
PENELEC	$31,352	$61,287	$97,938	$98,591	$91,135	$188,435	$149,842	$96,217	$86,626	(10%)
Pepco	$45,176	$89,540	$103,337	$105,910	$82,294	$144,086	$99,510	$94,523	$67,694	(28%)
PPL	$29,740	$62,518	$94,143	$83,418	$62,900	$113,566	$82,866	$72,205	$71,852	(0%)
PSEG	$33,366	$73,323	$94,698	$85,877	$67,412	$103,746	$48,489	$56,283	$56,257	(0%)
RECO	$28,128	$67,511	$76,967	$80,214	$68,794	$103,181	$48,869	$58,456	$56,867	(3%)
PJM	$31,627	$64,772	$88,620	$88,778	$64,233	$116,295	$85,470	$77,362	$70,144	(9%)

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

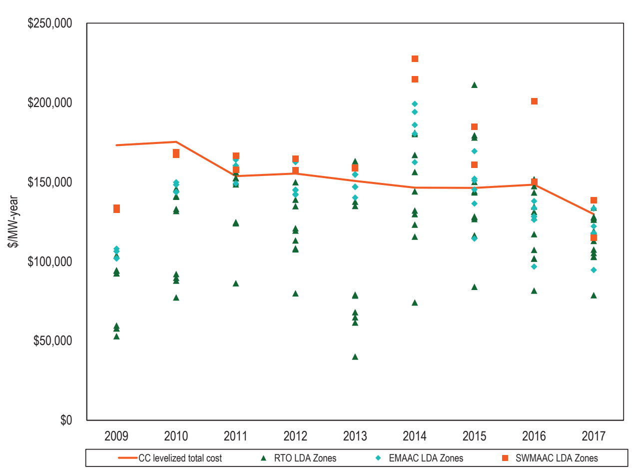
In 2017, a new CC would have received sufficient net revenue to cover levelized total costs in three zones and to cover 90 percent or more of levelized costs in 11 of 20 zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2009 through 2017

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	61%	85%	108%	93%	98%	132%	104%	90%	91%
AEP	34%	51%	81%	69%	43%	89%	87%	72%	83%
APS	60%	80%	102%	77%	52%	107%	103%	97%	99%
ATSI	NA	NA	NA	NA	NA	98%	122%	99%	87%
BGE	77%	96%	108%	106%	105%	155%	126%	135%	107%
ComEd	31%	44%	56%	51%	27%	51%	57%	55%	61%
DAY	33%	50%	81%	73%	45%	90%	88%	69%	81%
DEOK	NA	NA	NA	NA	NA	114%	123%	69%	79%
DLCO	33%	53%	81%	70%	41%	79%	80%	91%	97%
Dominion	53%	83%	99%	78%	52%	84%	87%	79%	79%
DPL	62%	85%	104%	105%	103%	146%	93%	93%	90%
EKPC	NA	NA	NA	NA	NA	111%	116%	65%	73%
JCPL	61%	85%	107%	93%	103%	136%	103%	87%	94%
Met-Ed	55%	81%	97%	89%	91%	123%	98%	88%	98%
PECO	59%	82%	104%	92%	93%	127%	99%	85%	91%
PENELEC	54%	75%	99%	97%	108%	175%	144%	102%	103%
Pepco	77%	95%	103%	101%	105%	147%	110%	101%	89%
PPL	53%	76%	97%	87%	90%	124%	99%	86%	92%
PSEG	59%	82%	97%	91%	97%	123%	78%	86%	103%
RECO	56%	79%	85%	86%	97%	118%	75%	77%	80%
PJM	54%	75%	95%	86%	79%	116%	100%	86%	89%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017



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 2017 in 12 of 20 zones (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2017[26 27]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$103,766	$146,624	$92,802	$34,149	$57,755	$177,470	$73,776	$21,635	$19,895	(8%)
AEP	$46,160	$94,385	$85,512	$34,944	$66,604	$130,312	$60,723	$24,173	$25,137	4%
APS	$99,655	$145,822	$105,988	$47,572	$76,645	$154,779	$79,952	$25,333	$27,170	7%
ATSI	NA	NA	$41,354	$42,673	$74,835	$143,552	$61,397	$24,503	$26,732	9%
BGE	$121,146	$184,563	$121,183	$62,567	$91,820	$228,990	$145,506	$56,405	$32,765	(42%)
ComEd	$109,938	$135,212	$129,279	$111,542	$130,283	$178,450	$97,010	$21,963	$21,851	(1%)
DAY	$44,900	$89,635	$81,825	$33,023	$72,665	$135,377	$59,299	$22,403	$25,111	12%
DEOK	NA	NA	NA	$26,451	$62,130	$122,282	$54,717	$21,493	$24,449	14%
DLCO	$43,907	$68,504	$49,251	$27,035	$43,321	$97,572	$47,474	$22,968	$25,003	9%
Dominion	$105,884	$167,920	$101,391	$44,651	$72,880	$180,306	$106,299	$31,704	$29,239	(8%)
DPL	$114,738	$166,793	$117,229	$57,505	$81,303	$222,872	$103,772	$32,950	$27,701	(16%)
EKPC	NA	NA	NA	NA	$32,626	$118,063	$45,675	$20,383	$18,934	(7%)
JCPL	$103,162	$144,597	$90,057	$32,724	$64,305	$181,578	$73,488	$17,593	$21,131	20%
Met-Ed	$104,285	$152,922	$101,258	$43,092	$68,531	$177,954	$74,648	$19,879	$25,961	31%
PECO	$98,600	$139,859	$88,317	$32,534	$52,526	$170,974	$70,211	$18,342	$20,229	10%
PENELEC	$78,821	$113,244	$77,113	$39,044	$67,118	$149,924	$70,797	$19,527	$19,212	(2%)
Pepco	$111,966	$164,693	$88,212	$38,656	$73,063	$202,767	$114,025	$37,737	$28,615	(24%)
PPL	$92,013	$125,723	$77,783	$26,866	$52,125	$167,421	$68,996	$17,010	$20,650	21%
PSEG	$96,099	$146,842	$89,665	$31,754	$77,582	$201,663	$83,728	$16,277	$21,056	29%
RECO	$89,060	$137,591	$71,676	$28,196	$83,010	$196,735	$84,679	$16,666	$20,176	21%
PJM	$92,006	$136,761	$89,439	$41,841	$70,056	$166,952	$78,809	$24,447	$24,051	(2%)

In 2017, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire nine year period of the analysis.

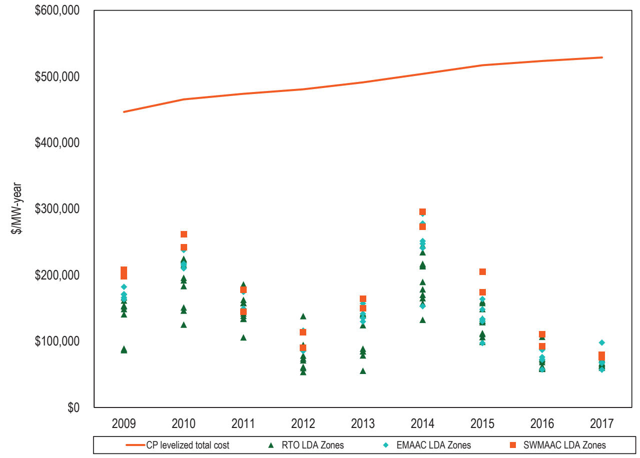
Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2009 through 2017

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	38%	47%	32%	18%	27%	49%	26%	15%	13%
AEP	20%	32%	30%	13%	16%	33%	22%	12%	12%
APS	36%	46%	34%	15%	18%	38%	25%	12%	12%
ATSI	NA	NA	NA	NA	NA	35%	31%	20%	14%
BGE	47%	56%	38%	24%	33%	59%	40%	21%	15%
ComEd	34%	41%	39%	29%	29%	42%	29%	11%	11%
DAY	20%	31%	29%	12%	17%	34%	21%	11%	12%
DEOK	NA	NA	NA	NA	NA	31%	21%	11%	12%
DLCO	19%	27%	22%	11%	11%	26%	19%	11%	12%
Dominion	33%	48%	33%	15%	17%	43%	31%	13%	13%
DPL	41%	51%	37%	24%	33%	58%	32%	17%	14%
EKPC	NA	NA	NA	NA	NA	30%	19%	11%	11%
JCPL	38%	46%	31%	18%	29%	50%	26%	14%	13%
Met-Ed	37%	48%	33%	20%	29%	49%	26%	14%	14%
PECO	37%	45%	31%	18%	26%	48%	25%	14%	13%
PENELEC	32%	39%	28%	19%	28%	43%	25%	14%	13%
Pepco	44%	52%	31%	19%	30%	54%	34%	18%	14%
PPL	34%	42%	28%	16%	25%	47%	25%	14%	13%
PSEG	37%	47%	31%	18%	32%	55%	29%	17%	19%
RECO	35%	45%	27%	17%	33%	53%	28%	14%	13%
PJM	34%	44%	31%	18%	26%	44%	27%	14%	13%

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

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017



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.[28]

New entrant nuclear plant energy market net revenues were higher in all but two zones in 2017 (Table 7-15). The increase in LMP resulted in higher margins and higher net revenues in 18 of 20 zones.

Table 7-15 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2009 through 2017[29 30]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$288,632	$367,483	$335,035	$223,539	$262,810	$387,883	$220,023	$141,415	$166,619	18%
AEP	$218,504	$261,098	$262,335	$198,385	$230,716	$311,569	$204,723	$169,693	$182,261	7%
APS	$256,721	$314,729	$293,355	$210,232	$244,428	$337,998	$228,936	$174,898	$186,514	7%
ATSI	NA	NA	$153,888	$204,058	$242,705	$325,433	$208,372	$171,111	$187,815	10%
BGE	$298,473	$391,960	$341,862	$245,538	$285,910	$444,433	$304,148	$243,694	$211,305	(13%)
ComEd	$179,104	$217,838	$212,423	$175,450	$206,746	$272,321	$168,496	$155,096	$160,622	4%
DAY	$214,090	$258,210	$262,111	$203,992	$234,102	$314,747	$206,825	$170,886	$187,977	10%
DEOK	NA	NA	NA	$192,158	$221,863	$299,618	$201,391	$166,192	$183,433	10%
DLCO	$208,801	$257,065	$258,686	$199,094	$227,732	$291,888	$193,791	$164,782	$182,956	11%
Dominion	$281,069	$373,737	$319,215	$223,740	$263,891	$388,295	$260,516	$194,597	$201,989	4%
DPL	$291,154	$370,565	$335,597	$236,441	$272,775	$428,044	$250,192	$167,484	$186,693	11%
EKPC	NA	NA	NA	NA	$127,631	$294,606	$190,936	$160,897	$174,511	8%
JCPL	$287,875	$365,408	$332,717	$222,496	$271,028	$392,479	$218,452	$136,192	$171,550	26%
Met-Ed	$279,022	$354,677	$317,652	$217,622	$257,748	$374,408	$211,003	$139,412	$177,070	27%
PECO	$282,937	$359,927	$329,530	$220,535	$256,201	$378,894	$212,675	$133,703	$166,558	25%
PENELEC	$250,469	$310,481	$291,867	$215,338	$256,535	$349,950	$217,124	$157,475	$177,336	13%
Pepco	$298,215	$389,389	$332,675	$238,119	$281,722	$427,666	$279,006	$211,892	$205,068	(3%)
PPL	$275,067	$343,190	$316,501	$213,393	$255,433	$374,962	$211,595	$135,684	$168,294	24%
PSEG	$292,089	$371,365	$338,912	$226,944	$289,418	$416,439	$230,273	$141,064	$177,559	26%
RECO	$284,023	$360,820	$317,521	$221,087	$295,509	$411,345	$232,025	$142,225	$178,340	25%
PJM	$263,897	$333,408	$297,327	$215,166	$249,245	$361,149	$222,525	$163,920	$181,724	11%

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

In 2017, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire nine year period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2017

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	44%	54%	48%	34%	42%	52%	30%	20%	16%
AEP	32%	39%	39%	27%	30%	39%	27%	21%	16%
APS	39%	48%	43%	29%	32%	42%	30%	22%	16%
ATSI	NA	NA	NA	NA	NA	40%	32%	26%	17%
BGE	48%	58%	49%	36%	44%	58%	39%	31%	19%
ComEd	27%	34%	33%	24%	27%	34%	23%	20%	14%
DAY	32%	39%	39%	28%	30%	39%	27%	21%	16%
DEOK	NA	NA	NA	NA	NA	38%	27%	21%	16%
DLCO	31%	39%	39%	27%	29%	37%	26%	21%	16%
Dominion	40%	53%	46%	30%	34%	48%	33%	24%	18%
DPL	44%	55%	48%	36%	44%	56%	33%	23%	17%
EKPC	NA	NA	NA	NA	NA	37%	26%	20%	15%
JCPL	44%	54%	48%	34%	43%	52%	29%	19%	16%
Met-Ed	42%	53%	46%	33%	41%	50%	29%	20%	16%
PECO	43%	53%	47%	33%	41%	51%	29%	19%	16%
PENELEC	38%	47%	43%	33%	41%	47%	29%	22%	16%
Pepco	48%	58%	48%	35%	44%	56%	36%	27%	18%
PPL	42%	51%	46%	32%	40%	50%	29%	19%	16%
PSEG	44%	55%	49%	35%	46%	56%	31%	22%	19%
RECO	43%	53%	46%	33%	46%	54%	31%	20%	16%
PJM	40%	49%	44%	32%	38%	47%	30%	22%	17%

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017

New Entrant Diesel

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

New entrant DS plant energy market net revenues were higher in all but four zones in 2017 (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS (Dollars per installed MW-year): 2009 through 2017[31]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$1,763	$11,217	$6,708	$1,552	$1,082	$37,123	$15,506	$1,730	$2,805	62%
AEP	$112	$499	$1,717	$820	$484	$15,855	$6,002	$807	$1,296	61%
APS	$886	$1,771	$2,007	$1,061	$741	$20,542	$10,490	$992	$1,317	33%
ATSI	NA	NA	$308	$1,083	$23,643	$15,553	$5,777	$1,959	$1,607	(18%)
BGE	$3,712	$14,147	$7,870	$2,577	$2,654	$55,866	$27,241	$7,924	$3,131	(60%)
ComEd	$11	$480	$811	$909	$384	$12,427	$3,720	$652	$1,276	96%
DAY	$186	$554	$1,894	$946	$517	$15,671	$6,083	$905	$1,494	65%
DEOK	NA	NA	NA	$689	$462	$14,814	$5,829	$1,200	$2,509	109%
DLCO	$674	$2,987	$2,165	$914	$1,231	$14,403	$5,428	$2,279	$1,382	(39%)
Dominion	$3,639	$10,967	$4,108	$1,664	$1,545	$46,961	$15,836	$2,120	$2,636	24%
DPL	$2,721	$9,892	$5,769	$2,381	$1,083	$43,946	$25,593	$3,690	$5,798	57%
EKPC	NA	NA	NA	NA	$289	$15,816	$4,856	$646	$926	43%
JCPL	$1,895	$8,673	$6,610	$1,704	$2,016	$37,086	$15,065	$718	$2,974	314%
Met-Ed	$1,620	$8,711	$5,032	$1,833	$1,254	$35,789	$15,174	$679	$3,673	441%
PECO	$1,558	$8,570	$5,379	$1,936	$1,004	$36,186	$14,033	$666	$3,083	363%
PENELEC	$240	$1,124	$2,642	$2,141	$1,104	$18,141	$8,154	$791	$1,684	113%
Pepco	$4,036	$13,277	$6,077	$2,009	$2,249	$56,830	$18,222	$3,256	$2,489	(24%)
PPL	$1,428	$7,704	$5,317	$1,747	$1,054	$36,712	$14,906	$626	$3,022	383%
PSEG	$1,394	$7,394	$5,447	$1,695	$1,257	$36,629	$14,566	$803	$3,479	333%
RECO	$1,201	$6,241	$4,255	$1,737	$2,387	$34,756	$16,108	$970	$3,155	225%
PJM	$1,593	$6,718	$4,118	$1,547	$2,322	$30,055	$12,429	$1,671	$2,487	49%

In 2017, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire nine year period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2009 through 2017

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	43%	51%	37%	31%	49%	64%	42%	30%	29%
AEP	25%	35%	34%	14%	6%	29%	32%	20%	23%
APS	38%	44%	34%	14%	6%	32%	34%	20%	23%
ATSI	NA	NA	NA	NA	NA	29%	59%	47%	28%
BGE	56%	57%	38%	31%	46%	74%	49%	34%	29%
ComEd	25%	35%	33%	14%	6%	27%	30%	20%	23%
DAY	25%	35%	34%	14%	6%	29%	32%	20%	23%
DEOK	NA	NA	NA	NA	NA	28%	32%	20%	23%
DLCO	26%	36%	34%	14%	6%	28%	31%	21%	23%
Dominion	28%	42%	35%	14%	7%	48%	38%	20%	23%
DPL	43%	50%	37%	36%	51%	68%	48%	32%	31%
EKPC	NA	NA	NA	NA	NA	29%	31%	20%	22%
JCPL	43%	49%	37%	32%	49%	64%	42%	30%	29%
Met-Ed	39%	49%	36%	31%	46%	61%	42%	30%	30%
PECO	42%	49%	36%	32%	49%	63%	41%	30%	29%
PENELEC	38%	44%	34%	31%	45%	50%	38%	30%	29%
Pepco	57%	56%	37%	31%	49%	76%	44%	31%	29%
PPL	39%	48%	36%	31%	45%	62%	42%	30%	29%
PSEG	42%	48%	36%	34%	50%	68%	44%	39%	48%
RECO	42%	47%	35%	32%	50%	62%	43%	30%	29%
PJM	38%	46%	35%	26%	33%	50%	40%	28%	28%

31 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.[32] 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).[33]

Wind energy market net revenues were higher in both zones in 2017 as a result of higher energy prices.

Table 7-19 Net revenue for a wind installation (Dollars per installed MW-year): 2012 through 2017

	ComEd				PENELEC			
	Energy	RECs	Capacity	Total	Energy	RECs	Capacity	Total
2012	$52,229	-	$2,632	$54,860	$48,210	$3,271	$5,878	$57,359
2013	$59,854	-	$1,095	$60,948	$63,471	$13,686	$8,905	$86,063
2014	$108,044	$3,233	$4,049	$115,326	$125,923	$33,337	$8,237	$167,497
2015	$81,393	$2,080	$6,257	$89,730	$82,385	$35,739	$7,338	$125,463
2016	$69,319	$2,621	$4,339	$76,279	$63,327	$41,221	$6,623	$111,172
2017	$74,413	$4,247	$4,504	$83,164	$72,282	$44,870	$5,677	$122,829
Change in 2017 from 2016	7%	62%	4%	9%	14%	9%	(14%)	10%

In 2017, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. This has been the consistent result for a new wind installation for the entire six year period of the analysis. Renewable energy credits accounted for five percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC.

Table 7-20 Percent of 20-year levelized total costs recovered by wind net revenue (Dollars per installed MW-year): 2012 through 2017

Zone	2012	2013	2014	2015	2016	2017
ComEd	28%	31%	58%	44%	33%	44%
PENELEC	29%	44%	85%	62%	48%	65%

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).[34]

Solar energy market net revenues were slightly lower in 2017 than in 2016 with higher LMPs not offsetting fewer run hours.

Table 7-21 PSEG net revenue for a solar installation (Dollars per installed MW-year): 2012 through 2017

	PSEG			
	Energy	RECs	Capacity	Total
2012	$39,831	$255,001	$18,984	$313,815
2013	$69,202	$234,868	$28,835	$332,905
2014	$68,341	$212,315	$27,575	$308,231
2015	$52,679	$272,943	$23,156	$348,778
2016	$38,225	$284,155	$25,545	$347,926
2017	$36,722	$271,908	$27,892	$336,522
Change in 2017 from 2016	(4%)	(4%)	9%	(3%)

In 2017, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Renewable energy credits accounted for 81 percent of the total net revenue of a solar installation.

Table 7-22 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2012 through 2017

Zone	2012	2013	2014	2015	2016	2017
PSEG	79%	126%	130%	149%	159%	167%

32 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.

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

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

Historical New Entrant CT and CC Revenue Adequacy

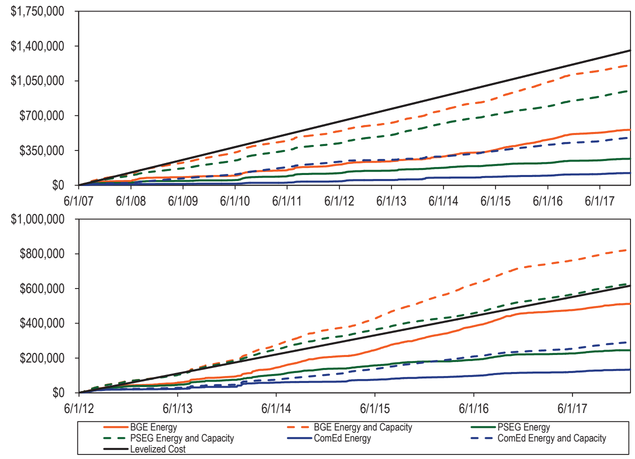
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital,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

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

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

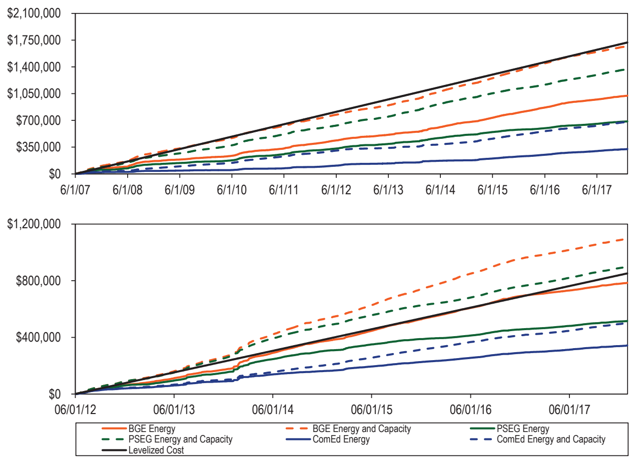
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007, and for a new CT that began operation on June 1, 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 7-10 Historical new entrant CT revenue adequacy: June 1, 2007 through December 31, 2017 and June 1, 2012 through December 31, 2017



For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-11 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on June 1, 2007, and for a new CC that began operation on June 1, 2012. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CC unit for each year in each of the three zones. Cumulative total market net revenues through 2017, were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-11 Historical new entrant CC revenue adequacy: June 1, 2007 through December 31, 2017 and June 1, 2012 through December 31, 2017



Assumptions used for this analysis are shown in Table 7-23.

Table 7-23 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

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2017, the average short run marginal cost of the CC was lower than the average short run marginal cost of the CP in every month and the operating cost of the CT was lower than the CP all months except January, May, and December. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher energy prices, higher gas prices, and higher coal prices meant that gas units ran with smaller margins than in prior year and results for coal units were mixed. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2017, capacity market prices decreased in some zones and increased in others.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7 . The results are shown in Table 7-24.[35]

Table 7-24 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$102,764	14.2%	$139,731	14.2%	$558,701	13.5%
Base Case	$95,264	12.0%	$129,731	12.0%	$528,701	12.0%
Sensitivity 2	$87,764	9.7%	$119,731	9.7%	$498,701	10.4%
Sensitivity 3	$80,264	7.2%	$109,731	7.2%	$468,701	8.8%
Sensitivity 4	$72,764	4.4%	$99,731	4.5%	$438,701	7.1%
Sensitivity 5	$65,264	1.0%	$89,731	1.4%	$408,701	5.3%
Sensitivity 6	$57,764	(4.0%)	$79,731	(2.5%)	$378,701	3.3%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-25 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-25 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$101,039	$137,070
Sensitivity 2	55%	$98,151	$133,400
Base Case	50%	$95,264	$129,731
Sensitivity 3	45%	$92,376	$126,063
Sensitivity 4	40%	$89,489	$122,394
Sensitivity 5	35%	$86,601	$118,725
Sensitivity 6	30%	$83,713	$115,057

Table 7-26 shows the levelized annual revenue requirement associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 7-26 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$86,222	$118,245
Sensitivity 2	25	$89,638	$122,585
Base Case	20	$95,264	$129,731
Sensitivity 3	15	$100,004	$135,740
Sensitivity 4	10	$106,294	$143,710

Table 7-27 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant

35 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-27 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$91,531	$0	0.0%	$125,727
Sensitivity 2	$9,834	2.1%	$93,398	$14,954	1.7%	$127,729
Base Case	$19,669	4.2%	$95,264	$29,908	3.3%	$129,731
Sensitivity 3	$29,503	6.4%	$97,130	$44,861	5.0%	$131,733
Sensitivity 4	$39,338	8.5%	$98,996	$59,815	6.7%	$133,735
Sensitivity 5	$49,172	10.6%	$100,862	$74,769	8.3%	$135,737
Sensitivity 6	$59,091	12.7%	$101,019	$89,723	10.0%	$137,739
Sensitivity 7	$88,637	19.1%	$105,762	$117,392	13.1%	$139,115
Sensitivity 8	$118,182	25.5%	$110,506	$176,088	19.6%	$145,810

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2016/2017 and 2017/2018 RPM Auctions.[36] For units that did not submit ACR data, the default ACR was used.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2016/2017 and 2017/2018 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental

36 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the base residual auction.

auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2017. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[37] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Net revenues are calculated using units' price-based offers for technologies other than coal and nuclear. For coal units, net revenues are calculated using the lower of the unit's price-based or cost-based offer. For nuclear units, public data on revenues and costs are used.[38]

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-28 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-28 shows energy and ancillary service net revenues by quartile for select technology classes.[39] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price.

Table 7-28 also includes new entrant net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. The new entrant net revenues are at the high end of existing unit CC net revenues, are not comparable to existing unit CT net revenues, are within the range of existing unit coal plant and nuclear plant net revenues and are at the low end of existing unit diesel net revenues.

Table 7-28 Net revenue by quartile for select technologies: 2017

		($/MW-Yr)									
	Total Installed	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue		
Technology	Capacity (ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	56,286	$70,144	$96	$27,121	$47,120	$13,886	$22,265	$46,672	$44,468	$55,014	$71,718
CT - Aero Derivative	5,997	$20,364	($771)	$1,371	$5,893	$38,273	$45,964	$50,371	$41,187	$47,832	$53,162
CT - Industrial Frame	21,317	-	($965)	$1,094	$3,078	$36,208	$43,859	$49,862	$36,694	$45,074	$50,927
Coal Fired	52,495	$24,051	($1,469)	$7,067	$23,949	$42,546	$45,689	$48,955	$43,470	$52,944	$67,864
Diesel	412	$2,487	($854)	$2,803	$23,702	$39,596	$43,668	$49,099	$41,896	$48,685	$65,270
Hydro	2,750	-	$68,168	$96,524	$124,393	$4,950	$42,702	$46,271	$100,176	$121,108	$169,918
Nuclear	33,732	$181,724	$171,676	$178,304	$195,883	$34,579	$42,922	$43,668	$206,255	$221,011	$236,337
Oil or Gas Steam	8,178	-	($2,571)	($773)	$1,919	$33,438	$42,754	$47,424	$34,829	$43,621	$49,002
Pumped Storage	4,721	-	$49,623	$49,623	$121,759	$5,432	$6,265	$42,640	$55,055	$80,528	$127,934

37 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

38 *See* 148 FERC ¶ 61,140 (2014). FERC directed that price based offers be used in the calculation of net revenues used in calculating capacity market offer caps. It is more accurate to use the lower of the unit's price-based or cost-based offers. Coal is the only technology for which there is a significant impact.

39 The quartile numbers in the table are the dividing line between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-29 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2017, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit and it is not the case for coal units or for nuclear units.

Table 7-29 Avoidable cost recovery by quartile: 2017

Technology	Total Installed Capacity (ICAP)	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
		First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	56,286	1%	182%	362%	283%	424%	545%
CT - Aero Derivative	5,997	0%	10%	41%	295%	341%	386%
CT - Industrial Frame	21,317	0%	11%	27%	340%	427%	481%
Coal Fired	52,495	0%	10%	38%	74%	87%	117%
Diesel	412	0%	25%	212%	386%	443%	583%
Hydro	2,750	225%	319%	411%	331%	400%	561%
Nuclear	33,732	73%	85%	89%	85%	100%	102%
Oil or Gas Steam	8,178	0%	0%	6%	139%	161%	183%
Pumped Storage	4,721	397%	397%	973%	440%	749%	1,023%

Table 7-30 Proportion of units recovering avoidable costs: 2011 through 2017

Technology	Units with full recovery fromenergy and ancillary net revenue							Units with full recovery from all markets						
	2011	2012	2013	2014	2015	2016	2017	2011	2012	2013	2014	2015	2016	2017
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	62%	85%	79%	79%	95%	88%	93%	86%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	23%	100%	96%	76%	98%	100%	99%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	18%	99%	98%	83%	100%	100%	100%	99%
Coal Fired	-	-	25%	78%	18%	19%	19%	-	-	54%	83%	69%	40%	52%
Diesel	48%	42%	37%	69%	56%	33%	46%	100%	100%	77%	100%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	95%	81%	77%	97%	98%	100%	100%	97%
Nuclear	-	-	79%	100%	53%	16%	21%	-	-	95%	100%	89%	58%	68%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	9%	92%	78%	86%	85%	91%	88%	88%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

The analysis of nuclear plants includes an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations for a sample of nuclear plants.[40] [41] The NEI annual avoidable costs used in the analysis are for 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. For that reason, the analysis includes 50 percent of NEI's 2016 annual capital expenditures. For reference, the data including 100 percent of the NEI capital expenditures are included in Table 7-31. 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. The analysis includes the most recent operating cost data published by NEI, for 2016. This is likely to be conservatively high given that NEI operating costs have been decreasing annually since 2012 (6.2 percent decrease from 2012 through 2016).

Table 7-30 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2017, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and nuclear units.[42] [43] [44]

40 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>.

41 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

42 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>.

43 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

44 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

Nuclear Net Revenue Analysis

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices.[45] 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.[46]

Table 7-31 includes the publicly available data on energy market prices, capacity market prices and nuclear cost data for nineteen nuclear plants in PJM.

Table 7-31 Nuclear unit public data: 2013 through 2017[47]

		Average DA LMP ($/MWh)					BRA Capacity Price ($/MWh)					2016 NEI Costs ($/MWh)		
	ICAP	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 7-32 shows the surplus or shortfall for nineteen nuclear plants in PJM calculated using this data.[48] In Table 7-32, six nuclear plants with a total capacity of 7,673 MW did not recover their avoidable costs in two of the last three years assuming avoidable costs are equal to fuel costs, operating costs, and 50 percent of capital expenditures. If it is assumed that nuclear plants incurred 100 percent of their 2016 NEI incremental capital expenditures and that these costs are appropriately considered avoidable costs, nine plants with a total capacity of 14,027 MW did not recover their avoidable costs 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[49] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 auction.[50] Three Mile Island and Quad Cities also did not clear the 2020/2021 auction.[51]

45 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.

46 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*

47 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

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

49 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

50 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction" (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

51 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

Table 7-32 Nuclear unit surplus (shortfall) based on public data: 2013 through 2017[52]

		Surplus (Shortfall) ($/MWh)														
		100% of NEI Capital Costs					2/3 of NEI Capital Costs					1/3 of NEI Capital Costs				
	ICAP	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 7-33 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.[53] The 2018 LMPs include DA prices through January 2018 and forward prices for February through December 2018. The capacity prices are known based on PJM capacity auction results.

52 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

53 Forward prices on February 1, 2018. Forward prices are reported for PJM trading hubs which must be 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 7-33 Forward prices in PJM energy and capacity markets and annual costs[54]

		Average Forward LMP ($/MWh)			BRA Capacity Price ($/MWh)			2016 NEI Costs ($/MWh)		
	ICAP	2018	2019	2020	2018	2019	2020	Fuel	Operating	Capital
Beaver Valley	1,777	$33.18	$29.80	$29.63	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Braidwood	2,330	$26.19	$25.16	$24.99	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Byron	2,300	$26.37	$24.95	$24.84	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Calvert Cliffs	1,716	$36.28	$31.57	$31.37	$6.09	$5.30	$3.83	$6.75	$18.73	$6.15
Cook	2,071	$30.82	$29.19	$29.03	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Davis Besse	894	$32.33	$30.00	$29.83	$6.09	$5.29	$3.60	$6.77	$25.95	$8.67
Dresden	1,787	$28.68	$27.44	$27.29	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Hope Creek	1,161	$32.53	$27.64	$27.45	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
LaSalle	2,238	$26.25	$25.21	$25.04	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Limerick	2,296	$32.97	$28.06	$27.87	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
North Anna	1,891	$36.08	$31.26	$31.06	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Oyster Creek	615	$33.31	$28.37	$28.18	$7.56	$6.82	$6.65	$6.77	$25.95	$8.67
Quad Cities	1,819	$25.79	$24.65	$24.52	$7.31	$8.66	$8.09	$6.75	$18.73	$6.15
Peach Bottom	2,251	$32.41	$27.67	$27.48	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
Perry	1,240	$34.29	$30.65	$30.47	$6.09	$5.29	$3.60	$6.77	$25.95	$8.67
Salem	2,332	$32.51	$27.62	$27.43	$7.56	$6.82	$6.65	$6.75	$18.73	$6.15
Surry	1,690	$35.71	$30.87	$30.67	$6.09	$5.29	$3.60	$6.75	$18.73	$6.15
Susquehanna	2,520	$32.62	$27.83	$27.64	$6.09	$5.29	$3.83	$6.75	$18.73	$6.15
Three Mile Island	805	$32.28	$27.58	$27.41	$6.09	$5.29	$3.83	$6.77	$25.95	$8.67

Table 7-34 and Table 7-35 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) even when 100 percent of NEI's capital expenditures are included. The four plants are Davis Besse, Oyster Creek, Perry and Three Mile Island. Oyster Creek has been scheduled to retire since 2015, so there are three nuclear plants that would not cover avoidable costs on this basis.[55] These three plants are all single site nuclear plants which have higher costs than multiple unit sites.

Table 7-34 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	$7.64	$3.46	$1.59	$9.69	$5.51	$3.64	$11.74	$7.56	$5.69
Braidwood	$1.87	$2.19	$1.45	$3.92	$4.24	$3.50	$5.97	$6.29	$5.55
Byron	$2.04	$1.98	$1.30	$4.09	$4.03	$3.35	$6.14	$6.08	$5.40
Calvert Cliffs	$10.73	$5.24	$3.58	$12.78	$7.29	$5.63	$14.83	$9.34	$7.68
Cook	$5.28	$2.85	$0.99	$7.33	$4.90	$3.04	$9.38	$6.95	$5.09
Davis Besse	($2.97)	($6.10)	($7.97)	($0.08)	($3.21)	($5.08)	$2.81	($0.32)	($2.19)
Dresden	$4.36	$4.47	$3.75	$6.41	$6.52	$5.80	$8.46	$8.57	$7.85
Hope Creek	$8.46	$2.84	$2.46	$10.51	$4.89	$4.51	$12.56	$6.94	$6.56
LaSalle	$1.93	$2.24	$1.50	$3.98	$4.29	$3.55	$6.03	$6.34	$5.60
Limerick	$8.91	$3.25	$2.88	$10.96	$5.30	$4.93	$13.01	$7.35	$6.98
North Anna	$10.54	$4.92	$3.03	$12.59	$6.97	$5.08	$14.64	$9.02	$7.13
Oyster Creek	($0.52)	($6.19)	($6.56)	$2.37	($3.30)	($3.67)	$5.26	($0.41)	($0.78)
Quad Cities	$1.47	$1.68	$0.98	$3.52	$3.73	$3.03	$5.57	$5.78	$5.08
Peach Bottom	$8.35	$2.87	$2.50	$10.40	$4.92	$4.55	$12.45	$6.97	$6.60
Perry	($1.02)	($5.45)	($7.32)	$1.87	($2.56)	($4.43)	$4.76	$0.33	($1.54)
Salem	$8.44	$2.82	$2.44	$10.49	$4.87	$4.49	$12.54	$6.92	$6.54
Surry	$10.17	$4.53	$2.64	$12.22	$6.58	$4.69	$14.27	$8.63	$6.74
Susquehanna	$7.08	$1.49	($0.16)	$9.13	$3.54	$1.89	$11.18	$5.59	$3.94
Three Mile Island	($3.02)	($8.52)	($10.16)	($0.13)	($5.63)	($7.27)	$2.76	($2.74)	($4.38)

54 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

55 PJM. Generator Deactivation Summary Sheets, "Future Deactivation Requests," (February 26, 2018) <https://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests.ashx>.

Table 7-35 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	$118.9	$53.9	$24.8	$150.8	$85.8	$56.7	$182.7	$117.7	$88.6
Braidwood	$38.1	$44.7	$29.6	$80.0	$86.5	$71.4	$121.8	$128.3	$113.2
Byron	$41.2	$39.9	$26.3	$82.5	$81.2	$67.6	$123.8	$122.5	$108.9
Calvert Cliffs	$161.4	$78.7	$53.8	$192.2	$109.5	$84.6	$223.0	$140.4	$115.4
Cook	$95.8	$51.8	$18.0	$133.0	$89.0	$55.2	$170.2	$126.1	$92.4
Davis Besse	($23.3)	($47.8)	($62.4)	($0.6)	($25.2)	($39.8)	$22.0	($2.5)	($17.1)
Dresden	$68.3	$70.0	$58.8	$100.4	$102.1	$90.8	$132.5	$134.1	$122.9
Hope Creek	$86.1	$28.9	$25.0	$106.9	$49.7	$45.9	$127.8	$70.6	$66.7
LaSalle	$37.8	$43.9	$29.4	$78.0	$84.1	$69.6	$118.2	$124.3	$109.8
Limerick	$179.1	$65.4	$57.9	$220.4	$106.6	$99.2	$261.6	$147.9	$140.4
North Anna	$174.6	$81.6	$50.1	$208.6	$115.5	$84.1	$242.5	$149.5	$118.0
Oyster Creek	($2.8)	($33.3)	($35.3)	$12.8	($17.8)	($19.8)	$28.3	($2.2)	($4.2)
Quad Cities	$23.4	$26.8	$15.6	$56.1	$59.4	$48.3	$88.7	$92.1	$80.9
Peach Bottom	$164.6	$56.6	$49.2	$205.0	$97.0	$89.7	$245.4	$137.4	$130.1
Perry	($11.0)	($59.2)	($79.5)	$20.4	($27.8)	($48.1)	$51.7	$3.6	($16.7)
Salem	$172.5	$57.6	$49.9	$214.3	$99.4	$91.8	$256.2	$141.3	$133.7
Surry	$150.6	$67.1	$39.1	$180.9	$97.4	$69.4	$211.3	$127.8	$99.8
Susquehanna	$156.2	$32.8	($3.6)	$201.5	$78.1	$41.7	$246.7	$123.3	$86.9
Three Mile Island	($21.3)	($60.1)	($71.6)	($0.9)	($39.7)	($51.2)	$19.5	($19.3)	($30.9)

Units At Risk

The definition of units at risk of retirement incorporates judgment. Alternative definitions are included in order to provide more clarity about the significance of the results.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue.[56] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2019/2020 or the 2020/2021 capacity auctions is shown in Table 7-36.[57] [58] These units are considered at risk of retirement.[59] The nuclear results are based only on the recovery of avoidable costs and not on capacity market clearing status.

Based on these criteria, 30,785 MW of capacity in PJM are at risk of retirement, in addition to the units that are currently planning to retire, primarily coal and nuclear units. If the coal units at risk are defined to be units receiving less than 90 percent of their avoidable costs, the total coal MW at risk would be 17,302 MW. If nuclear plants at risk are defined to be plants that cover avoidable costs based on forward prices, then the nuclear MW at risk would be 2,939 MW. Based on these criteria, 22,929 MW of capacity in PJM are at risk of retirement, in addition to the units that are currently planning to retire, primarily coal and nuclear units.

56 Units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.
57 Avoidable costs for non-nuclear units are ACR values and exclude APIR.
58 For nuclear units, avoidable costs consist of fuel costs, operating costs, and 50 percent of NEI capital expenditures.
59 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

Table 7-36 Profile of units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2017 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
CC - Combined Cycle	5	590	497	33	11,302
CT - Aero Derivative	10	254	137	41	13,724
CT - Industrial Frame	40	955	94	41	14,434
Coal Fired (high)	46	21,039	3,346	46	10,428
Coal Fired (low) (90% ACR recovery)	38	17,302	3,304	46	10,390
Diesel or Oil or Gas Steam	12	889	968	36	11,701
Nuclear (high)	5	7,058	-	38	-
Nuclear (low) (forward looking)	3	2,939	-	38	-
Total (high)	118	30,785	1,560	42	12,312
Total (low)	108	22,929	1,404	42	12,441