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

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Natural gas prices and energy prices were lower in 2016 than in 2015 which affected energy market revenue for all plant types. Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG which affected capacity market revenues for all plant types.
- In 2016, average energy market net revenues increased by 21 percent for a new CT and 14 percent for a new CC. In 2016, average energy market net revenues decreased 54 percent for a new CP, 86 percent for a new DS, 26 percent for a new nuclear plant, 19 percent for a new wind installation, and 28 percent for a new solar installation.
- The results are very sensitive to the relative prices of fuel. For example, gas prices increased in December. While the marginal cost of the new CC was still below that of the new CP, the marginal cost of the new CT was above that of coal in December. As a result, CT hours dropped significantly and CP hours increased in all zones and substantially in some zones.
- Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG. Capacity revenue accounted for 43 percent of total net revenues for a new CT, 32 percent for a new CC, 55 percent for a new CP, 96 percent for a new DS, and 23 percent for a new nuclear plant.
- In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones. The zones in which a new CT would not have recovered levelized costs were western zones in which lower capacity prices were not offset by changes in energy net revenues.
- In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones.
- In 2016, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2016, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2016, net revenues covered more than 33 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 49 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 198 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for three 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 83 percent of the total net revenue of a solar installation in PSEG.
- In 2016, 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 2016, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most units and technology types in PJM, with the exception of some coal units.
- The actual net revenue results show that 96 units with 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 96 units, 55 are CTs and account for 1,408 MW and 25 are coal units and account for 11,282 MW.

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 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Conclusion

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

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through December 2016 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 December 2016 and have not covered their total costs in the ComEd Zone through December 2016.

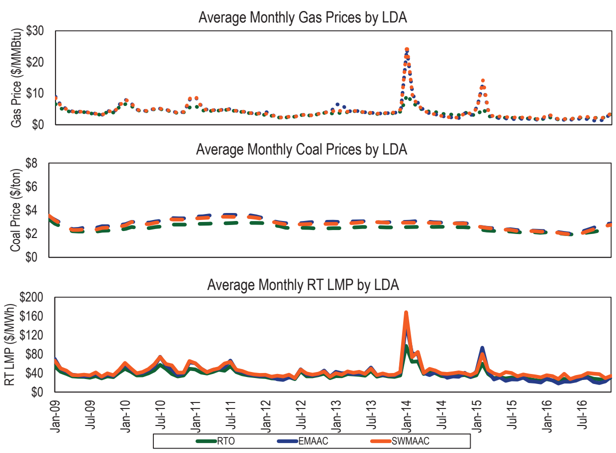
Net Revenue

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

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

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. Natural gas prices decreased in 2016 and coal prices decreased or remained flat. Comparing fuel prices in 2016 to 2015, the price of Northern Appalachian coal was 10.1 percent lower; the price of Central Appalachian coal was 0.1 percent higher; the price of Powder River Basin coal was 5.1 percent lower; the price of eastern natural gas was 35.6 percent lower; and the price of western natural gas was 4.2 percent lower (Figure 7-1).

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



Spark Spreads, Dark Spreads, and Quark Spreads

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

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

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

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 2016

	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

Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through 2016

	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

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

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2011 through 2016[1]

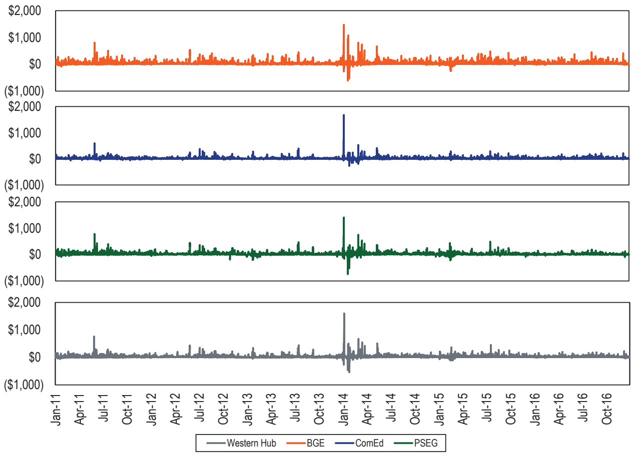


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2011 through 2016[2]

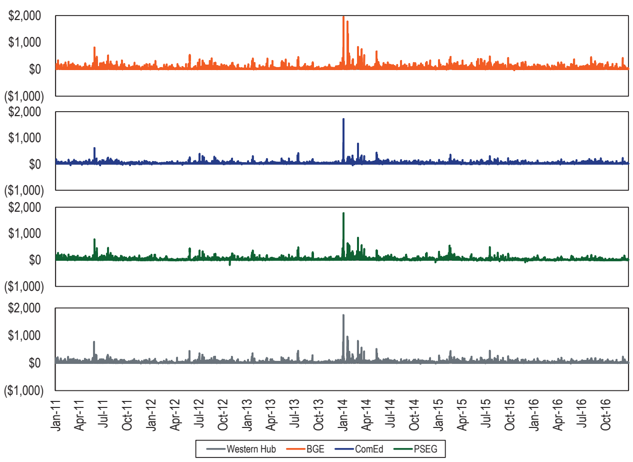
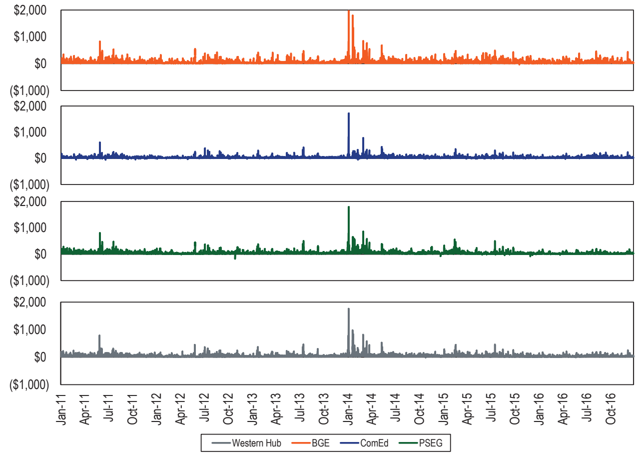


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2011 through 2016[3]



Theoretical Energy Market Net Revenue

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

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

- The CT plant has an installed capacity of 641.2 MW and consists of two GE Frame 7HA.02 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 971.4 MW and consists of two GE Frame 7HA.02 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[4]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NOx control, a flue gas desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.

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.

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

4 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.

- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty two Siemens 2.3 MW wind turbines totaling 50.6 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC installed capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[5 6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

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.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services 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 $3,500/MW-Yr.[9]

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	$24

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

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[13 14] Average short run marginal costs are shown in Table 7-4.

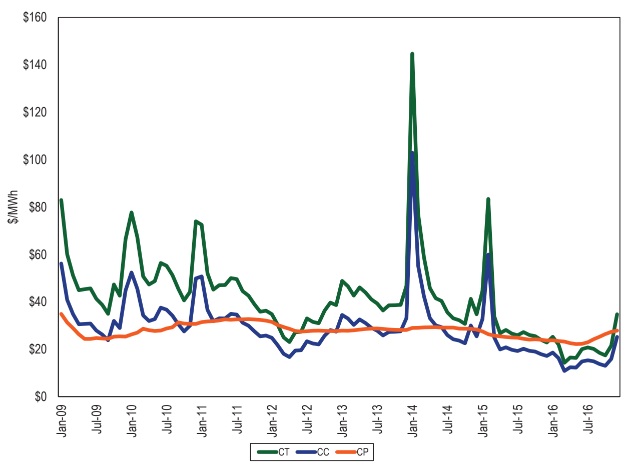
Table 7-4 Average short run marginal costs: 2016

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$20.62	9,437	$0.25
CC	$15.27	6,679	$1.00
CP	$24.29	9,250	$4.00
DS	$126.80	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

5 Hourly ambient conditions supplied by Schneider Electric.
6 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 $3,500/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt prices obtained from Platts.
13 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

A comparison of the short run marginal cost of the theoretical CT, CC and CP plants since January 2009 shows that the CC plant has been competitive with the CP plant but that the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-5). For much of 2016, the short run marginal costs of the CT and CC plant were below the short run marginal cost of the coal plant (Figure 7-5).

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



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

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.

Table 7-5 Average run hours: 2009 through 2016

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009	1,066	5,183	8,760	44	8,760		
2010	1,788	5,641	8,760	117	8,760		
2011	2,744	6,853	8,760	50	8,760		
2012	4,595	7,812	8,784	27	8,784	6,739	3,669
2013	2,243	6,558	8,760	20	8,760	6,873	3,755
2014	3,681	6,732	8,760	176	8,760	6,991	3,641
2015	4,345	7,013	8,760	210	8,760	6,884	3,741
2016	5,976	8,033	5,602	75	8,784	6,729	3,768

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 2016 includes five months of the 2015/2016 RPM auction clearing price and seven months of the 2016/2017 RPM auction clearing price.[15]

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2016[16]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Average
AECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
AEP	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
AP	$57,842	$66,187	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$39,401
ATSI	NA	NA	NA	NA	NA	$31,149	$95,422	$78,709	$68,427
BGE	$82,515	$73,135	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$61,257
ComEd	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DAY	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DEOK	NA	NA	NA	NA	$8,420	$31,149	$48,128	$33,377	$30,269
DLCO	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
Dominion	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DPL	$63,411	$67,098	$50,501	$52,309	$77,542	$66,206	$56,448	$50,948	$60,558
EKPC	NA	NA	NA	NA	NA	$31,149	$48,128	$33,377	$37,552
JCPL	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
Met-Ed	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$57,305
PECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
PENELEC	$57,842	$66,187	$49,858	$45,216	$68,503	$63,360	$56,448	$50,945	$57,295
Pepco	$82,515	$73,135	$49,858	$45,261	$73,027	$66,529	$56,448	$50,948	$62,215
PPL	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$57,305
PSEG	$63,411	$66,187	$49,858	$49,957	$75,882	$72,567	$60,936	$67,224	$63,253
RECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
PJM	$52,370	$60,604	$49,878	$32,806	$36,601	$46,247	$54,646	$48,568	$47,715

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 increase in 2016 over 2015 with the exception of the solar installation.

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

15 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

16 See the *2016 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))[17] [18]

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

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 capacity factor for the specified new entrant unit type. CCs had a low levelized cost of energy in 2016 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. Coal units had a relatively high levelized cost of energy in 2016 because coal units ran for fewer hours in 2016, which decreased the coal capacity factor, which decreased the MWh over which costs are spread.

Table 7-8 Levelized cost of energy: 2016

	CT	CC	CP	DS	Nuclear	Wind (ComEd)	Wind (PENELEC)	Solar (PSEG)
Levelized cost ($/MW-Yr)	$113,821	$148,327	$523,540	$173,182	$963,107	$231,310	$231,310	$218,937
Short run marginal costs ($/MWh)	$20.62	$15.27	$24.29	$126.80	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	68%	91%	64%	1%	98%	77%	77%	43%
Levelized cost of energy ($/MWh)	$40	$34	$118	$2,430	$120	$34	$34	$58

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM.[19] 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 applying to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

17 Levelized total costs provided by Pasteris Energy, Inc.

18 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.

19 The 2016 new entrant CT plant is modeled to incorporate the actual flexibility of a new CT. The 2016 CT is modeled with greater flexibility than in prior years.

New entrant CT plant energy market net revenues were higher in all but three zones in 2016 (Table 7-9). The decrease in energy prices was offset by the decrease in gas prices, resulting in higher energy net revenues in 17 of 20 zones. In DEOK, EKPC and PENELEC, the new entrant CT was economic for fewer hours than in 2015, resulting in lower energy net revenues.

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch (Dollars per installed MW-year)[20]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$10,270	$41,776	$63,064	$50,716	$31,431	$62,488	$51,404	$48,167	(6%)
AEP	$3,798	$12,246	$29,569	$39,768	$19,169	$58,738	$37,225	$31,391	(16%)
AP	$12,211	$34,656	$49,411	$49,941	$26,767	$78,655	$58,192	$73,765	27%
ATSI	NA	NA	$23,275	$43,763	$25,509	$67,762	$40,147	$28,048	(30%)
BGE	$14,738	$52,514	$63,755	$71,707	$42,986	$89,712	$80,641	$107,070	33%
ComEd	$2,253	$9,555	$18,515	$25,156	$12,992	$26,298	$13,595	$16,106	18%
DAY	$3,011	$11,984	$30,125	$44,423	$19,910	$59,033	$37,710	$26,092	(31%)
DEOK	NA	NA	NA	$36,426	$19,775	$78,150	$84,960	$28,275	(67%)
DLCO	$3,247	$16,803	$33,064	$42,347	$20,903	$52,608	$31,438	$66,431	111%
Dominion	$14,746	$47,122	$49,223	$53,638	$31,175	$43,721	$37,802	$37,027	(2%)
DPL	$11,306	$40,871	$57,501	$62,542	$35,129	$78,702	$41,079	$49,806	21%
EKPC	NA	NA	NA	NA	$15,244	$75,630	$75,433	$24,563	(67%)
JCPL	$9,267	$39,408	$59,820	$49,343	$37,511	$64,876	$49,777	$43,113	(13%)
Met-Ed	$8,092	$38,275	$50,960	$47,325	$29,546	$55,100	$47,292	$46,106	(3%)
PECO	$8,598	$37,178	$59,087	$49,037	$27,857	$56,752	$45,876	$41,989	(8%)
PENELEC	$7,418	$26,960	$47,419	$53,552	$40,971	$120,385	$112,826	$63,471	(44%)
Pepco	$17,071	$49,586	$56,858	$64,640	$39,789	$80,268	$59,478	$48,736	(18%)
PPL	$7,426	$31,826	$52,511	$43,024	$28,268	$61,271	$46,193	$42,792	(7%)
PSEG	$7,067	$35,863	$49,340	$46,919	$30,673	$47,870	$23,810	$30,019	26%
RECO	$5,805	$32,934	$39,366	$42,708	$32,271	$47,536	$25,602	$31,633	24%
PJM	$8,607	$32,915	$46,270	$48,262	$28,394	$65,278	$50,024	$44,230	(12%)

In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones (Table 7-10). For most zones, net revenue results for a new CT reflected increases in energy market net revenues which offset lower capacity market revenues. Net revenues covered 100 percent or more of levelized total costs for a CT in 13 zones and less than 80 percent in six of the western zones, AEP, ComEd, DAY, DEOK, Dominion, and EKPC.

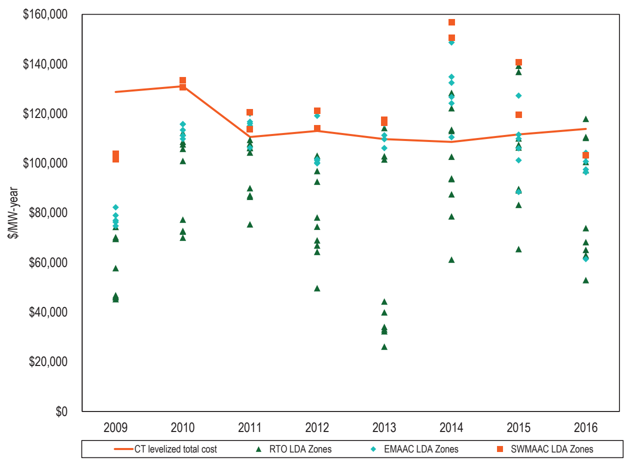
Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	64%	88%	108%	90%	100%	122%	100%	106%
AEP	36%	55%	78%	57%	29%	86%	80%	74%
AP	58%	83%	96%	66%	36%	105%	99%	114%
ATSI	NA	NA	NA	NA	NA	94%	125%	110%
BGE	79%	102%	109%	107%	106%	144%	126%	158%
ComEd	35%	53%	68%	44%	24%	56%	59%	56%
DAY	36%	55%	79%	61%	30%	86%	80%	68%
DEOK	NA	NA	NA	NA	NA	104%	123%	70%
DLCO	36%	59%	81%	59%	31%	81%	75%	107%
Dominion	45%	82%	96%	69%	40%	72%	80%	79%
DPL	61%	88%	104%	105%	107%	137%	91%	106%
EKPC	NA	NA	NA	NA	NA	102%	114%	66%
JCPL	60%	87%	106%	89%	105%	124%	98%	101%
Met-Ed	55%	86%	98%	86%	94%	112%	96%	104%
PECO	59%	85%	105%	88%	97%	117%	95%	100%
PENELEC	54%	77%	94%	91%	104%	173%	155%	122%
Pepco	81%	100%	103%	101%	107%	139%	107%	106%
PPL	54%	81%	99%	82%	93%	118%	95%	101%
PSEG	58%	84%	96%	89%	101%	114%	79%	101%
RECO	57%	82%	87%	83%	101%	108%	77%	88%
PJM	55%	79%	95%	80%	77%	110%	98%	97%

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

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 2016



New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM.[21] 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.[22] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all but three zones in 2016 (Table 7-11). The decrease in energy prices was offset by the decrease in gas prices, resulting in higher energy net revenues in 17 of 20 zones. In DEOK, EKPC and PENELEC, the new entrant CC was economic for fewer hours than in 2015, resulting in lower energy net revenues.

21 The 2016 new entrant CC plant is modeled to incorporate the actual flexibility of a new CC. The 2016 CC is modeled with greater flexibility than in prior years.

22 All starts associated with combined cycle units are assumed to be hot starts.

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[23]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$37,852	$79,328	$111,306	$92,466	$70,012	$123,761	$90,646	$78,013	(14%)
AEP	$15,920	$32,720	$70,273	$81,290	$52,898	$94,541	$73,584	$69,313	(6%)
AP	$41,013	$70,232	$101,830	$93,060	$66,602	$121,059	$97,044	$105,413	9%
ATSI	NA	NA	$47,083	$87,078	$64,344	$108,904	$77,638	$64,124	(17%)
BGE	$46,193	$91,219	$111,996	$113,212	$86,520	$160,024	$123,490	$145,186	18%
ComEd	$9,224	$20,318	$31,890	$53,616	$28,188	$38,964	$30,984	$43,630	41%
DAY	$14,063	$30,879	$69,799	$86,887	$56,071	$96,827	$75,212	$63,809	(15%)
DEOK	NA	NA	NA	$75,534	$55,985	$131,815	$126,326	$63,796	(49%)
DLCO	$14,210	$35,028	$69,664	$81,852	$49,647	$80,373	$63,351	$96,607	52%
Dominion	$48,720	$88,838	$98,117	$94,554	$67,136	$87,913	$74,747	$79,224	6%
DPL	$39,572	$76,906	$105,344	$104,125	$73,857	$144,248	$75,044	$82,446	10%
EKPC	NA	NA	NA	NA	$34,714	$127,207	$116,344	$58,759	(49%)
JCPL	$37,944	$77,772	$109,562	$92,010	$77,489	$128,858	$89,489	$72,909	(19%)
Met-Ed	$31,635	$70,703	$95,417	$87,492	$65,530	$112,744	$82,109	$75,696	(8%)
PECO	$33,551	$73,009	$105,795	$89,597	$63,132	$115,652	$83,816	$70,623	(16%)
PENELEC	$31,352	$61,287	$97,938	$98,591	$91,135	$188,435	$149,842	$96,217	(36%)
Pepco	$45,176	$89,540	$103,337	$105,910	$82,294	$144,086	$99,510	$94,523	(5%)
PPL	$29,740	$62,518	$94,143	$83,418	$62,900	$113,566	$82,866	$72,205	(13%)
PSEG	$33,366	$73,323	$94,698	$85,877	$67,412	$103,746	$48,489	$56,283	16%
RECO	$28,128	$67,511	$76,967	$80,214	$68,794	$103,181	$48,869	$58,456	20%
PJM	$31,627	$64,772	$88,620	$88,778	$64,233	$116,295	$85,470	$77,362	(9%)

In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones (Table 7-12). For most zones, net revenue results for a new CC reflected increases in energy market net revenues which offset lower capacity market revenues. Net revenues covered 90 percent or more of levelized total costs for a CC in 14 zones and less than 90 percent in six of the western zones, AEP, ComEd, DAY, DEOK, Dominion, and EKPC and RECO.

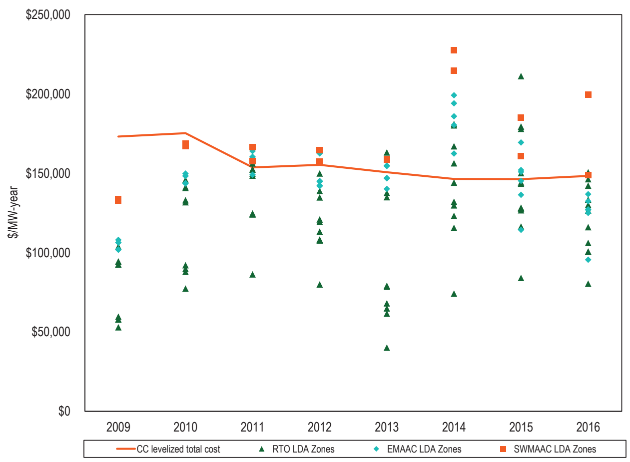
Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	61%	85%	108%	93%	98%	132%	104%	103%
AEP	34%	51%	81%	69%	43%	89%	87%	86%
AP	60%	80%	102%	77%	52%	107%	103%	110%
ATSI	NA	NA	NA	NA	NA	98%	122%	113%
BGE	77%	96%	108%	106%	105%	155%	126%	150%
ComEd	31%	44%	56%	51%	27%	51%	57%	68%
DAY	33%	50%	81%	73%	45%	90%	88%	82%
DEOK	NA	NA	NA	NA	NA	114%	123%	82%
DLCO	33%	53%	81%	70%	41%	79%	80%	104%
Dominion	53%	83%	99%	78%	52%	84%	87%	92%
DPL	62%	85%	104%	105%	103%	146%	93%	106%
EKPC	NA	NA	NA	NA	NA	111%	116%	78%
JCPL	61%	85%	107%	93%	103%	136%	103%	99%
Met-Ed	55%	81%	97%	89%	91%	123%	98%	101%
PECO	59%	82%	104%	92%	93%	127%	99%	97%
PENELEC	54%	75%	99%	97%	108%	175%	144%	115%
Pepco	77%	95%	103%	101%	105%	147%	110%	115%
PPL	53%	76%	97%	87%	90%	124%	99%	99%
PSEG	59%	82%	97%	91%	97%	123%	78%	98%
RECO	56%	79%	85%	86%	97%	118%	75%	89%
PJM	54%	75%	95%	86%	79%	116%	100%	99%

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

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 2016



New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM.[24] 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 lower in all zones in 2016 by an average of 54 percent (Table 7-13). The decrease in energy prices and the decrease in gas prices that exceeded the decrease in coal prices resulted in fewer run hours for the CP and smaller margins.

24 The 2016 new entrant CP plant is modeled to incorporate the actual flexibility of a new CP. The 2016 CP is modeled with greater flexibility than in prior years. In prior reports, the new entrant CP ran for the entire year and received uplift payments for unprofitable days.

Table 7-13 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[25]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$103,766	$146,624	$92,802	$34,149	$57,755	$177,470	$73,776	$28,825	(61%)
AEP	$46,160	$94,385	$85,512	$34,944	$66,604	$130,312	$60,723	$40,596	(33%)
AP	$99,655	$145,822	$105,988	$47,572	$76,645	$154,779	$79,952	$40,344	(50%)
ATSI	NA	NA	$41,354	$42,673	$74,835	$143,552	$61,397	$37,875	(38%)
BGE	$121,146	$184,563	$121,183	$62,567	$91,820	$228,990	$145,506	$86,749	(40%)
ComEd	$109,938	$135,212	$129,279	$111,542	$130,283	$178,450	$97,010	$33,128	(66%)
DAY	$44,900	$89,635	$81,825	$33,023	$72,665	$135,377	$59,299	$34,873	(41%)
DEOK	NA	NA	NA	$26,451	$62,130	$122,282	$54,717	$32,709	(40%)
DLCO	$43,907	$68,504	$49,251	$27,035	$43,321	$97,572	$47,474	$33,759	(29%)
Dominion	$105,884	$167,920	$101,391	$44,651	$72,880	$180,306	$106,299	$49,031	(54%)
DPL	$114,738	$166,793	$117,229	$57,505	$81,303	$222,872	$103,772	$44,431	(57%)
EKPC	NA	NA	NA	NA	$32,626	$118,063	$45,675	$28,789	(37%)
JCPL	$103,162	$144,597	$90,057	$32,724	$64,305	$181,578	$73,488	$23,852	(68%)
Met-Ed	$104,285	$152,922	$101,258	$43,092	$68,531	$177,954	$74,648	$26,920	(64%)
PECO	$98,600	$139,859	$88,317	$32,534	$52,526	$170,974	$70,211	$24,793	(65%)
PENELEC	$78,821	$113,244	$77,113	$39,044	$67,118	$149,924	$70,797	$29,521	(58%)
Pepco	$111,966	$164,693	$88,212	$38,656	$73,063	$202,767	$114,025	$57,753	(49%)
PPL	$92,013	$125,723	$77,783	$26,866	$52,125	$167,421	$68,996	$22,798	(67%)
PSEG	$96,099	$146,842	$89,665	$31,754	$77,582	$201,663	$83,728	$22,805	(73%)
RECO	$89,060	$137,591	$71,676	$28,196	$83,010	$196,735	$84,679	$22,506	(73%)
PJM	$92,006	$136,761	$89,439	$41,841	$70,056	$166,952	$78,809	$36,103	(54%)

In 2016, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-12). The combination of lower energy market net revenues and lower capacity market net revenues resulted in net revenues covering a smaller share of levelized total costs for the CP.

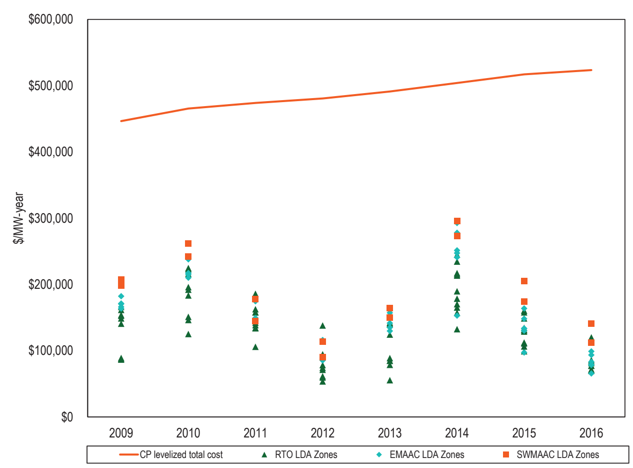
Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	38%	47%	32%	18%	27%	49%	26%	16%
AEP	20%	32%	30%	13%	16%	33%	22%	15%
AP	36%	46%	34%	15%	18%	38%	25%	15%
ATSI	NA	NA	NA	NA	NA	35%	31%	23%
BGE	47%	56%	38%	24%	33%	59%	40%	27%
ComEd	34%	41%	39%	29%	29%	42%	29%	13%
DAY	20%	31%	29%	12%	17%	34%	21%	14%
DEOK	NA	NA	NA	NA	NA	31%	21%	13%
DLCO	19%	27%	22%	11%	11%	26%	19%	13%
Dominion	33%	48%	33%	15%	17%	43%	31%	16%
DPL	41%	51%	37%	24%	33%	58%	32%	19%
EKPC	NA	NA	NA	NA	NA	30%	19%	13%
JCPL	38%	46%	31%	18%	29%	50%	26%	15%
Met-Ed	37%	48%	33%	20%	29%	49%	26%	16%
PECO	37%	45%	31%	18%	26%	48%	25%	15%
PENELEC	32%	39%	28%	19%	28%	43%	25%	16%
Pepco	44%	52%	31%	19%	30%	54%	34%	21%
PPL	34%	42%	28%	16%	25%	47%	25%	15%
PSEG	37%	47%	31%	18%	32%	55%	29%	18%
RECO	35%	45%	27%	17%	33%	53%	28%	15%
PJM	34%	44%	31%	18%	26%	44%	27%	16%

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

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 2016



New Entrant Diesel

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

New entrant DS plant energy market net revenues were lower in all zones in 2016 by an average of 86 percent (Table 7-15). As a result of relatively low energy market prices and the high short run marginal cost of the new entrant DS plant, there were relatively few hours in 2016 with positive margins.

Table 7-15 Energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$1,763	$11,217	$6,708	$1,552	$1,082	$37,123	$15,506	$1,894	(88%)
AEP	$112	$499	$1,717	$820	$484	$15,855	$6,002	$885	(85%)
AP	$886	$1,771	$2,007	$1,061	$741	$20,542	$10,490	$1,103	(89%)
ATSI	NA	NA	$308	$1,083	$23,643	$15,553	$5,777	$2,051	(64%)
BGE	$3,712	$14,147	$7,870	$2,577	$2,654	$55,866	$27,241	$8,395	(69%)
ComEd	$11	$480	$811	$909	$384	$12,427	$3,720	$702	(81%)
DAY	$186	$554	$1,894	$946	$517	$15,671	$6,083	$953	(84%)
DEOK	NA	NA	NA	$689	$462	$14,814	$5,829	$1,275	(78%)
DLCO	$674	$2,987	$2,165	$914	$1,231	$14,403	$5,428	$2,356	(57%)
Dominion	$3,639	$10,967	$4,108	$1,664	$1,545	$46,961	$15,836	$2,310	(85%)
DPL	$2,721	$9,892	$5,769	$2,381	$1,083	$43,946	$25,593	$3,912	(85%)
EKPC	NA	NA	NA	NA	$289	$15,816	$4,856	$725	(85%)
JCPL	$1,895	$8,673	$6,610	$1,704	$2,016	$37,086	$15,065	$800	(95%)
Met-Ed	$1,620	$8,711	$5,032	$1,833	$1,254	$35,789	$15,174	$762	(95%)
PECO	$1,558	$8,570	$5,379	$1,936	$1,004	$36,186	$14,033	$754	(95%)
PENELEC	$240	$1,124	$2,642	$2,141	$1,104	$18,141	$8,154	$884	(89%)
Pepco	$4,036	$13,277	$6,077	$2,009	$2,249	$56,830	$18,222	$3,512	(81%)
PPL	$1,428	$7,704	$5,317	$1,747	$1,054	$36,712	$14,906	$692	(95%)
PSEG	$1,394	$7,394	$5,447	$1,695	$1,257	$36,629	$14,566	$891	(94%)
RECO	$1,201	$6,241	$4,255	$1,737	$2,387	$34,756	$16,108	$1,083	(93%)
PJM	$1,593	$6,718	$4,118	$1,547	$2,322	$30,055	$12,429	$1,797	(86%)

In 2015, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone.

Table 7-16 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue

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

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.[26]

New entrant nuclear plant energy market net revenues were lower in all zones in 2016 by an average of 26 percent as a result of lower energy prices and constant short run marginal costs (Table 7-17).

26 The class average forced outage rate was applied to total energy market net revenues.

Table 7-17 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[27]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$288,632	$367,483	$335,035	$223,539	$262,810	$387,883	$220,023	$142,053	(35%)
AEP	$218,504	$261,098	$262,335	$198,385	$230,716	$311,569	$204,723	$170,459	(17%)
AP	$256,721	$314,729	$293,355	$210,232	$244,428	$337,998	$228,936	$175,687	(23%)
ATSI	NA	NA	$153,888	$204,058	$242,705	$325,433	$208,372	$171,884	(18%)
BGE	$298,473	$391,960	$341,862	$245,538	$285,910	$444,433	$304,148	$244,794	(20%)
ComEd	$179,104	$217,838	$212,423	$175,450	$206,746	$272,321	$168,496	$155,796	(8%)
DAY	$214,090	$258,210	$262,111	$203,992	$234,102	$314,747	$206,825	$171,657	(17%)
DEOK	NA	NA	NA	$192,158	$221,863	$299,618	$201,391	$166,942	(17%)
DLCO	$208,801	$257,065	$258,686	$199,094	$227,732	$291,888	$193,791	$165,526	(15%)
Dominion	$281,069	$373,737	$319,215	$223,740	$263,891	$388,295	$260,516	$195,475	(25%)
DPL	$291,154	$370,565	$335,597	$236,441	$272,775	$428,044	$250,192	$168,240	(33%)
EKPC	NA	NA	NA	NA	$127,631	$294,606	$190,936	$161,624	(15%)
JCPL	$287,875	$365,408	$332,717	$222,496	$271,028	$392,479	$218,452	$136,807	(37%)
Met-Ed	$279,022	$354,677	$317,652	$217,622	$257,748	$374,408	$211,003	$140,042	(34%)
PECO	$282,937	$359,927	$329,530	$220,535	$256,201	$378,894	$212,675	$134,306	(37%)
PENELEC	$250,469	$310,481	$291,867	$215,338	$256,535	$349,950	$217,124	$158,186	(27%)
Pepco	$298,215	$389,389	$332,675	$238,119	$281,722	$427,666	$279,006	$212,848	(24%)
PPL	$275,067	$343,190	$316,501	$213,393	$255,433	$374,962	$211,595	$136,296	(36%)
PSEG	$292,089	$371,365	$338,912	$226,944	$289,418	$416,439	$230,273	$141,701	(38%)
RECO	$284,023	$360,820	$317,521	$221,087	$295,509	$411,345	$232,025	$142,867	(38%)
PJM	$263,897	$333,408	$297,327	$215,166	$249,245	$361,149	$222,525	$164,660	(26%)

In 2016, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-18). The combination of lower energy market net revenues and lower capacity market net revenues resulted in net revenues covering a smaller share of levelized total costs for the new entrant nuclear plant.

Table 7-18 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2016

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

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2016

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly assuming the unit was generating at the average capacity factor of operating wind units in the zone if 75 percent of existing wind units in the zone were generating power in that hour. The unit is credited with wind RECs for its generation and is assumed to have

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

taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[28]

Wind energy market net revenues were lower in both zones in 2016 as a result of lower energy prices and lower RECs prices (Table 7-19).

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

	ComEd				PENELEC			
	Energy	RECs	Capacity	Total	Energy	RECs	Capacity	Total
2012	$68,086	-	$2,632	$70,717	$69,632	$56,622	$5,878	$132,132
2013	$83,764	-	$1,095	$84,859	$88,401	$78,900	$8,905	$176,206
2014	$108,420	$75,325	$4,049	$187,795	$127,839	$96,234	$8,237	$232,310
2015	$81,650	$78,533	$6,257	$166,439	$83,937	$95,617	$7,338	$186,892
2016	$69,487	$2,489	$4,339	$76,315	$64,649	$42,003	$6,623	$113,275
Change in 2016 from 2015	(15%)	(97%)	(31%)	(54%)	(23%)	(56%)	(10%)	(39%)

In 2016, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. Renewable energy credits accounted for three 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 2016

Zone	2012	2013	2014	2015	2016
ComEd	36%	43%	95%	82%	33%
PENELEC	67%	90%	117%	92%	49%

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 power 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).[29]

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

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

Solar energy market net revenues were lower in 2016 (Table 7-21) but total revenue was higher because of SRECs.

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

	PSEG			
	Energy	RECs	Capacity	Total
2012	$48,501	$312,580	$18,984	$380,065
2013	$81,122	$287,853	$28,835	$397,811
2014	$98,182	$281,386	$27,575	$407,144
2015	$67,807	$319,866	$23,156	$410,828
2016	$48,507	$360,487	$25,545	$434,539
Change in 2016 from 2015	(28%)	13%	10%	6%

In 2016, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Renewable energy credits accounted for 83 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)

Zone	2012	2013	2014	2015	2016
PSEG	96%	151%	172%	175%	198%

Historical New Entrant CT and CC Revenue Adequacy

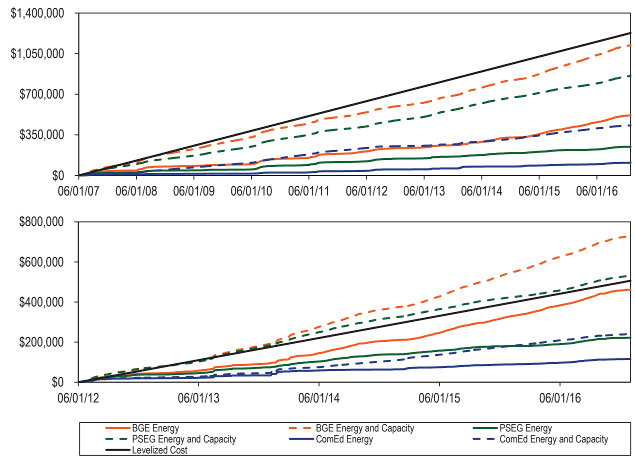
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. 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.

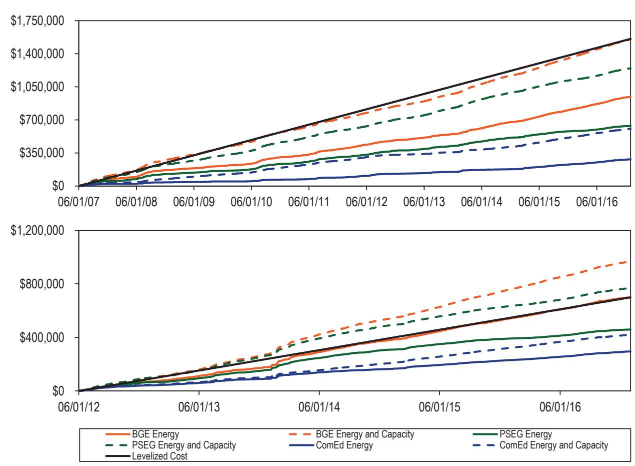
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007 and for a new CT that began operation on June 1, 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 2007 through December 2016 and June 2012 through December 2016



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 in 2016 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 2007 through December 2016



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 2016, 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 from February through November. (See Figure 7-5.)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Lower gas prices and relatively flat coal prices in 2016 meant that coal units (CP) ran fewer hours and with smaller margins than in prior years. 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, 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 2016, capacity market prices decreased across all zones.

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.[30]

30 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.

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	$121,321	13.9%	$158,327	13.9%	$553,540	13.5%
Base Case	$113,821	12.0%	$148,327	12.0%	$523,540	12.0%
Sensitivity 2	$106,321	10.0%	$138,327	10.0%	$493,540	10.4%
Sensitivity 3	$98,821	7.9%	$128,327	7.9%	$463,540	8.8%
Sensitivity 4	$91,321	5.5%	$118,327	5.6%	$433,540	7.0%
Sensitivity 5	$83,821	2.8%	$108,327	3.1%	$403,540	5.2%
Sensitivity 6	$76,321	(0.5%)	$98,327	0.1%	$373,540	3.2%

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%	$120,434	$156,726
Sensitivity 2	55%	$117,128	$152,527
Base Case	50%	$113,821	$148,327
Sensitivity 3	45%	$110,515	$144,128
Sensitivity 4	40%	$107,208	$139,929
Sensitivity 5	35%	$103,901	$135,730
Sensitivity 6	30%	$100,594	$131,531

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	$103,467	$135,181
Sensitivity 2	25	$107,379	$140,149
Base Case	20	$113,821	$148,327
Sensitivity 3	15	$119,247	$155,205
Sensitivity 4	10	$126,446	$164,327

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 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%	$110,123	$0	0.0%	$144,329
Sensitivity 2	$8,590	1.8%	$111,972	$13,060	1.4%	$146,328
Base Case	$17,181	3.6%	$113,821	$26,121	2.9%	$148,327
Sensitivity 3	$25,771	5.5%	$115,670	$39,181	4.3%	$150,327
Sensitivity 4	$34,361	7.3%	$117,519	$52,241	5.7%	$152,326
Sensitivity 5	$42,952	9.1%	$119,368	$65,302	7.2%	$154,326
Sensitivity 6	$51,616	10.9%	$120,885	$78,362	8.6%	$156,325
Sensitivity 7	$77,424	16.4%	$126,266	$102,528	11.3%	$159,637
Sensitivity 8	$103,233	21.9%	$131,647	$153,792	16.9%	$167,291

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 several 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 2015/2016 and 2016/2017 RPM Auctions.[31] 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 2015/2016 and 2016/2017 Delivery Years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets in 2016. Any unit with a significant portion of installed capacity

31 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.

designated as FRR committed was excluded from the analysis.[32] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The analysis was done 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. A more accurate method would be to use the lower of the unit's price-based or cost-based offers.[33]

Unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-28 and Table 7-29 represent 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.

comparable to existing unit CT net revenues, within the range of existing unit CP net revenues and at the low end of existing unit Diesel net revenues.

Table 7-29 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2016, 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. The results do not include nuclear power plants because there is not good public data on nuclear unit avoidable costs.

Table 7-28 Net revenue by quartile for select technologies: 2016

		($/MW-Yr)								
		Energy and ancillary service net revenue			Capacity revenue			Energy, ancillary, and capacity revenue		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	55,596	$1,811	$39,944	$65,299	$13,402	$25,360	$51,573	$50,022	$68,280	$100,461
CT - Aero Derivative	6,173	$1,095	$4,505	$8,457	$40,581	$49,364	$52,482	$46,189	$53,111	$59,397
CT - Industrial Frame	21,081	($538)	$1,397	$4,255	$42,786	$48,482	$51,646	$42,465	$50,054	$57,118
Coal Fired	61,317	$6,642	$17,122	$44,554	$40,834	$46,788	$51,273	$46,632	$66,180	$100,127
Diesel	439	($982)	$6,663	$38,870	$42,621	$48,633	$53,510	$47,915	$56,903	$82,162
Hydro	2,750	$40,482	$52,440	$74,257	$6,115	$51,064	$54,056	$56,942	$88,367	$112,738
Oil or Gas Steam	8,199	($2,636)	($467)	$5,710	$46,107	$51,669	$52,872	$44,187	$52,900	$59,616
Pumped Storage	4,721	$39,975	$46,880	$127,140	$6,243	$6,645	$52,917	$46,649	$102,416	$133,334

Table 7-28 shows average energy and ancillary service net revenues by quartile for select technology classes. 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 delivery costs associated with input fuels. The table also includes new entrant net revenue. The results show that the new entrant net revenues are at the high end of existing unit CC net revenues, not

32 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.

33 *See* 148 FERC ¶ 61,140 (2014).

Table 7-29 Avoidable cost recovery by quartile: 2016

		Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	55,596	12%	288%	535%	256%	487%	706%
CT - Aero Derivative	6,173	10%	27%	42%	243%	322%	434%
CT - Industrial Frame	21,081	0%	13%	38%	400%	472%	532%
Coal Fired	61,317	6%	21%	52%	61%	85%	131%
Diesel	439	0%	56%	329%	426%	490%	696%
Hydro	2,750	127%	164%	233%	179%	277%	354%
Oil or Gas Steam	8,199	0%	0%	16%	163%	183%	214%
Pumped Storage	4,721	214%	260%	681%	250%	561%	715%

Table 7-30 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2016, RPM 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 units.

Table 7-30 Proportion of units recovering avoidable costs: 2011 through 2016

	Units with full recovery from energy and ancillary net revenue						Units with full recovery from all markets					
Technology	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	85%	79%	79%	95%	88%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	100%	96%	76%	98%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	99%	98%	83%	100%	100%	100%
Coal Fired	31%	17%	27%	80%	16%	15%	82%	36%	54%	85%	64%	41%
Diesel	48%	42%	37%	69%	56%	33%	100%	100%	77%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	81%	77%	97%	98%	100%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	92%	78%	86%	85%	91%	91%
Pumped Storage	NA	100%	95%	100%	100%	100%	NA	100%	100%	100%	100%	100%

Units At Risk

Units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

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. In addition, units that failed to clear the most recent capacity auction(s) are at increased risk of retirement particularly if this result 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 2018/2019 or the 2019/2020 capacity auctions is shown in Table 7-31.[34] These units are considered at risk of retirement.[35]

These results mean that 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire.

Table 7-31 Profile of units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2016 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate
CC - Combined Cycle	4	915	1,002	28	9,523
CT - Aero Derivative	11	192	26	43	15,076
CT - Industrial Frame	44	1,217	123	39	14,542
Coal Fired	25	11,282	4,179	49	10,363
Diesel	4	30	330	25	10,999
Oil or Gas Steam	8	864	2,918	44	11,778
Total	96	14,500	3,197	34	11,391

34 Avoidable costs are ACR values and exclude APIR.
35 Units expected to continue operations are not considered at risk of retirement.