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. Coal and natural gas prices and energy prices were lower in 2015 than in 2014. Net revenues from the energy market for all plant types were affected by the lower prices. Capacity prices for calendar year 2015 were higher than in 2014 in the western zones and helped some of the new entrant gas units fully recover levelized total costs.
- In 2015, average energy market net revenues decreased by 23 percent for a new CT, 27 percent for a new CC, 53 percent for a new CP, 59 percent for a new DS, 38 percent for a new nuclear plant, 30 percent for a new wind installation, and 31 percent for a new solar installation. The comparison to 2014 reflects, in part, the very high net revenues in January 2014.
- Capacity revenues for calendar year 2015 increased over 2014 in the western zones and decreased in the eastern zones. Capacity revenue accounted for 49 percent of total net revenues for a new CT, 38 percent for a new CC, 49 percent for a new CP, 81 percent for a new DS, and 6 percent for a new nuclear plant.
- In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones.
- In 2015, 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 four zones.
- In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2015, net revenues covered more than 82 percent of the annual levelized total costs of a new entrant wind installation and 175 percent of the annual levelized total costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation and 78 percent of the total net revenue of a solar installation.
- In 2015, a substantial portion of 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 2015, 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 some coal and oil or gas steam units.
- The actual net revenue results show that 28 units with 11,908 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 28 units, 23 are coal units and account for 99 percent of the capacity at risk.

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.

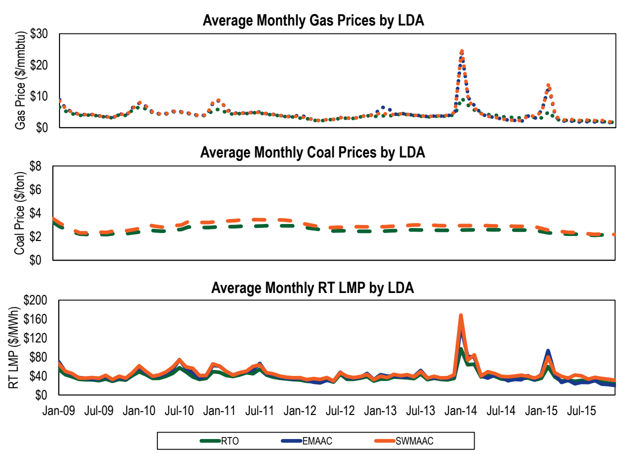
Net Revenue

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 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower (Figure 7-1). In western zones, capacity prices for calendar year 2015 were higher than in 2014.

Figure 7-1 Energy market net revenue factor trends: 2009 through 2015



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference in 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.

Figure 7-2 shows the hourly spark spread for peak hours since January 2011 for BGE, ComEd, PSEG, and Western Hub.[1]

Figure 7-2 Hourly spark spread for peak hours: 2011 through 2015

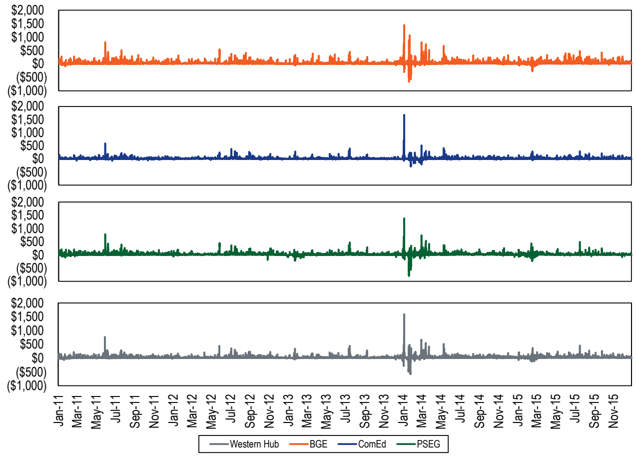


Figure 7-3 Hourly dark spread for peak hours: 2011 through 2015[2]

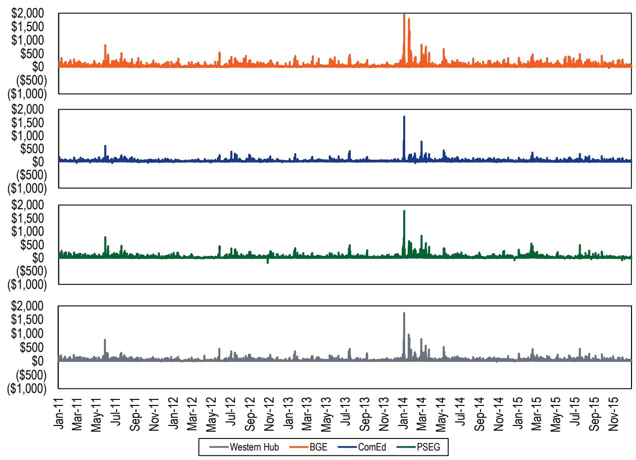
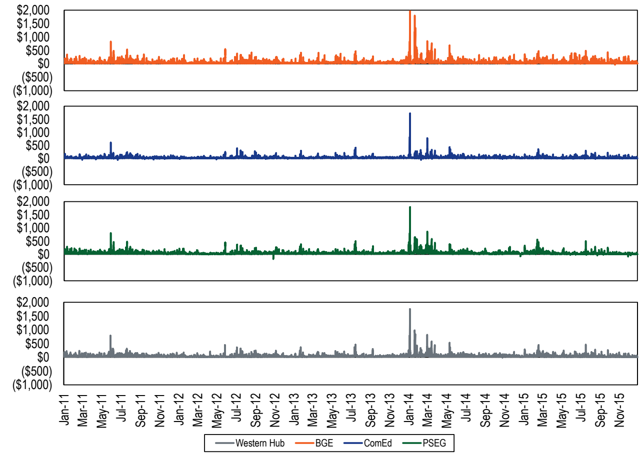


Figure 7-4 Quark spread for selected zones: 2011 through 2015[3]



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. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

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

1 Spark spreads use a combined cycle heat rate of 7,500 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.

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 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 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] 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 synchronized reserve service for all four plant types were set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. 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 7-1 New entrant ancillary service revenue (Dollars per MW-year)

	Reactive			Regulation
	CT	CC	CP	CP
2009	$923	$1,641	$613	$38
2010	$4,415	$930	$630	$6
2011	$3,675	$1,188	$3,403	$2
2012	$911	$2,715	$2,866	$20
2013	$1,358	$136	$263	$53
2014	$362	$695	$151	$168
2015	$323	$1,561	$36	$65

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[11]

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[12,13] Average short run marginal costs are shown in Table 7-2.

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.

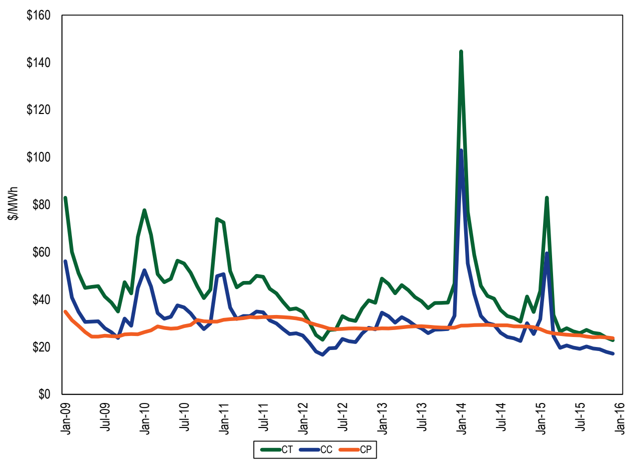
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

Table 7-2 Average short run marginal costs: 2015

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$32.69	9,437	$0.25
CC	$24.05	6,679	$1.00
CP	$25.03	9,250	$4.00
DS	$109.36	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 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). A significant increase in gas prices on cold days resulted in a corresponding increase in the average short run marginal cost of CTs and CCs in January 2014 and February 2015 (Figure 7-5).

Figure 7-5 Average short run marginal costs: 2009 through 2015



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.

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 2015 includes five months of the 2014/2015 RPM auction clearing price and seven months of the 2015/2016 RPM auction clearing price.[14]

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

Table 7-3 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2015[15]

Zone	2009	2010	2011	2012	2013	2014	2015	Average
AECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
AEP	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
AP	$57,842	$66,187	$49,858	$20,242	$8,420	$31,149	$48,128	$40,261
ATSI	NA	NA	NA	NA	NA	$31,149	$95,422	$63,286
BGE	$82,515	$73,135	$49,858	$45,261	$68,535	$63,360	$56,448	$62,730
ComEd	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DAY	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DEOK	NA	NA	NA	NA	$8,420	$31,149	$48,128	$29,232
DLCO	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
Dominion	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DPL	$63,411	$67,098	$50,501	$52,309	$77,542	$66,206	$56,448	$61,931
EKPC	NA	NA	NA	NA	NA	$31,149	$48,128	$39,639
JCPL	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
Met-Ed	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$58,213
PECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
PENELEC	$57,842	$66,187	$49,858	$45,216	$68,503	$63,360	$56,448	$58,202
Pepco	$82,515	$73,135	$49,858	$45,261	$73,027	$66,529	$56,448	$63,825
PPL	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$58,213
PSEG	$63,411	$66,187	$49,858	$49,957	$75,882	$72,567	$60,936	$62,686
RECO	NA	NA	NA	NA	NA	NA	NA	NA
PJM	$52,370	$60,604	$49,878	$32,806	$36,601	$46,247	$54,646	$47,593

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 7-4 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies increase in 2015 over 2014 with the exception of combined cycle which was unchanged.

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

Levelized Total Costs

Table 7-4 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[16,17]

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

15 See the *2015 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint. ATSI was integrated on June 1, 2011.

16 Levelized total costs provided by Pasteris Energy, Inc.

17 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 Combustion Turbine

Energy market net revenue was calculated for a CT plant economically dispatched by PJM. It was assumed that the CT 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. 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 CT plant energy market net revenues were lower in all zones but DEOK in 2015 (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[18]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$10,270	$41,776	$63,064	$50,716	$31,431	$62,488	$51,404	(18%)
AEP	$3,798	$12,246	$29,569	$39,768	$19,169	$58,738	$37,225	(37%)
AP	$12,211	$34,656	$49,411	$49,941	$26,767	$78,655	$58,192	(26%)
ATSI	NA	NA	$23,275	$43,763	$25,509	$67,762	$40,147	(41%)
BGE	$14,738	$52,514	$63,755	$71,707	$42,986	$89,712	$80,641	(10%)
ComEd	$2,253	$9,555	$18,515	$25,156	$12,992	$26,298	$13,595	(48%)
DAY	$3,011	$11,984	$30,125	$44,423	$19,910	$59,033	$37,710	(36%)
DEOK	NA	NA	NA	$36,426	$19,775	$78,150	$84,960	9%
DLCO	$3,247	$16,803	$33,064	$42,347	$20,903	$52,608	$31,438	(40%)
Dominion	$14,746	$47,122	$49,223	$53,638	$31,175	$43,721	$37,802	(14%)
DPL	$11,306	$40,871	$57,501	$62,542	$35,129	$78,702	$41,079	(48%)
EKPC	NA	NA	NA	NA	$15,244	$75,630	$75,433	(0%)
JCPL	$9,267	$39,408	$59,820	$49,343	$37,511	$64,876	$49,777	(23%)
Met-Ed	$8,092	$38,275	$50,960	$47,325	$29,546	$55,100	$47,292	(14%)
PECO	$8,598	$37,178	$59,087	$49,037	$27,857	$56,752	$45,876	(19%)
PENELEC	$7,418	$26,960	$47,419	$53,552	$40,971	$120,385	$112,826	(6%)
Pepco	$17,071	$49,586	$56,858	$64,640	$39,789	$80,268	$59,478	(26%)
PPL	$7,426	$31,826	$52,511	$43,024	$28,268	$61,271	$46,193	(25%)
PSEG	$7,067	$35,863	$49,340	$46,919	$30,673	$47,870	$23,810	(50%)
RECO	$5,805	$32,934	$39,366	$42,708	$32,271	$47,536	$25,602	(46%)
PJM	$8,607	$32,915	$46,270	$48,262	$28,394	$65,278	$50,024	(23%)

In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones (Table 7-6). A CT in the zones in which a new CT covered more than 90 percent of levelized total costs in 2014 also covered more than 90 percent of levelized total costs in 2015 with two exceptions. The net revenue results for a new CT reflect a number of factors, including substantially higher capacity market revenues in ATSI and a decline in both capacity and energy revenues in PSEG and DPL. Eastern zones continued to have generally higher net revenues but the net revenues in the western zones increased as a result of higher capacity market prices. Net revenues covered less than 75 percent of levelized total costs in only two zones, ComEd and DLCO.

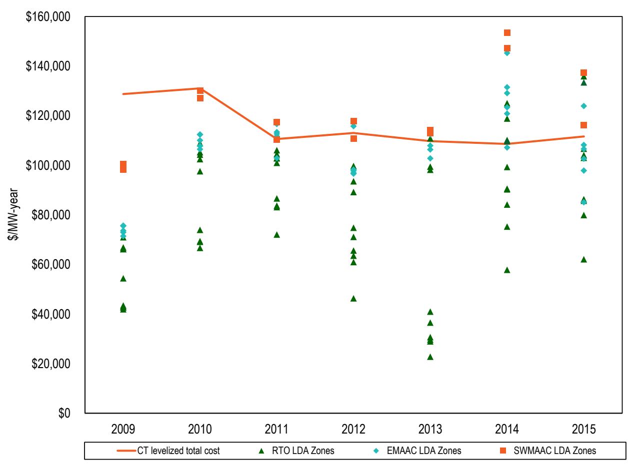
18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-6 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	59%	86%	105%	87%	97%	119%	97%
AEP	34%	53%	75%	54%	26%	83%	77%
AP	55%	80%	93%	63%	33%	101%	96%
ATSI	NA	NA	NA	NA	NA	91%	122%
BGE	76%	99%	106%	104%	103%	141%	123%
ComEd	33%	51%	65%	41%	21%	53%	56%
DAY	33%	53%	76%	58%	27%	83%	77%
DEOK	NA	NA	NA	NA	NA	101%	120%
DLCO	33%	56%	78%	56%	28%	77%	72%
Dominion	42%	80%	93%	66%	37%	69%	77%
DPL	59%	86%	101%	102%	104%	134%	88%
EKPC	NA	NA	NA	NA	NA	99%	111%
JCPL	57%	84%	102%	86%	102%	121%	95%
Met-Ed	52%	83%	94%	83%	91%	109%	93%
PECO	57%	82%	102%	85%	94%	114%	92%
PENELEC	51%	74%	91%	88%	101%	170%	152%
Pepco	78%	97%	100%	98%	104%	135%	104%
PPL	51%	78%	96%	79%	89%	115%	92%
PSEG	55%	81%	93%	87%	98%	111%	76%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	52%	76%	92%	77%	72%	107%	96%

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 2015



New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant economically dispatched by PJM. It was assumed that the CC 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.[19] 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.

New entrant CC plant energy market net revenues were lower in all zones in 2015 (Table 7-7).

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

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$37,852	$79,328	$111,306	$92,466	$70,012	$123,761	$90,646	(27%)
AEP	$15,920	$32,720	$70,273	$81,290	$52,898	$94,541	$73,584	(22%)
AP	$41,013	$70,232	$101,830	$93,060	$66,602	$121,059	$97,044	(20%)
ATSI	NA	NA	$47,083	$87,078	$64,344	$108,904	$77,638	(29%)
BGE	$46,193	$91,219	$111,996	$113,212	$86,520	$160,024	$123,490	(23%)
ComEd	$9,224	$20,318	$31,890	$53,616	$28,188	$38,964	$30,984	(20%)
DAY	$14,063	$30,879	$69,799	$86,887	$56,071	$96,827	$75,212	(22%)
DEOK	NA	NA	NA	$75,534	$55,985	$131,815	$126,326	(4%)
DLCO	$14,210	$35,028	$69,664	$81,852	$49,647	$80,373	$63,351	(21%)
Dominion	$48,720	$88,838	$98,117	$94,554	$67,136	$87,913	$74,747	(15%)
DPL	$39,572	$76,906	$105,344	$104,125	$73,857	$144,248	$75,044	(48%)
EKPC	NA	NA	NA	NA	$34,714	$127,207	$116,344	(9%)
JCPL	$37,944	$77,772	$109,562	$92,010	$77,489	$128,858	$89,489	(31%)
Met-Ed	$31,635	$70,703	$95,417	$87,492	$65,530	$112,744	$82,109	(27%)
PECO	$33,551	$73,009	$105,795	$89,597	$63,132	$115,652	$83,816	(28%)
PENELEC	$31,352	$61,287	$97,938	$98,591	$91,135	$188,435	$149,842	(20%)
Pepco	$45,176	$89,540	$103,337	$105,910	$82,294	$144,086	$99,510	(31%)
PPL	$29,740	$62,518	$94,143	$83,418	$62,900	$113,566	$82,866	(27%)
PSEG	$33,366	$73,323	$94,698	$85,877	$67,412	$103,746	$48,489	(53%)
RECO	$28,128	$67,511	$76,967	$80,214	$68,794	$103,181	$48,869	(53%)
PJM	$31,627	$64,772	$88,620	$88,778	$64,233	$116,295	$85,470	(27%)

In 2015, 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 four zones (Table 7-8). A CC in the zones in which a new CC covered more than 90 percent of levelized total costs in 2014 also covered more than 90 percent of levelized total costs in 2015 with one exception. The net revenue results for a new CC reflect a number of factors, including substantially higher capacity market revenues in ATSI and a decline in both capacity and energy revenues in PSEG. Eastern zones continued to have generally higher net revenues but the net revenues in the western zones increased as a result of higher capacity market prices. Net revenues covered less than 75 percent of levelized total costs in one zone and that result was 55 percent in ComEd.

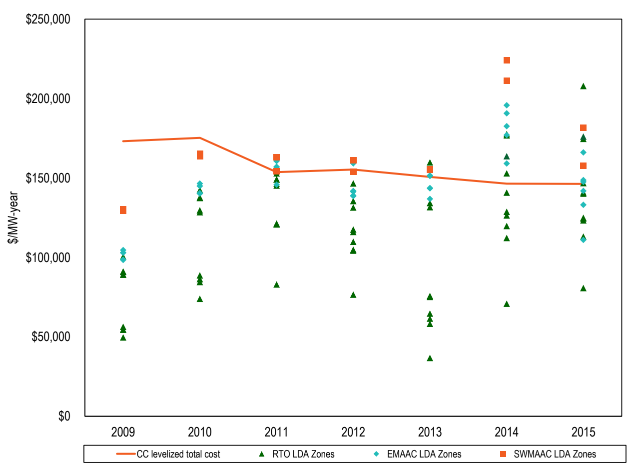
19 All starts associated with combined cycle units are assumed to be warm starts.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-8 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	59%	84%	106%	91%	95%	130%	102%
AEP	33%	49%	79%	67%	41%	86%	84%
AP	58%	78%	99%	75%	50%	104%	100%
ATSI	NA	NA	NA	NA	NA	96%	119%
BGE	75%	94%	106%	104%	103%	153%	124%
ComEd	29%	42%	54%	49%	24%	48%	55%
DAY	31%	48%	79%	71%	43%	88%	85%
DEOK	NA	NA	NA	NA	NA	112%	120%
DLCO	32%	51%	79%	67%	39%	77%	77%
Dominion	51%	81%	97%	76%	50%	82%	85%
DPL	60%	83%	102%	102%	101%	144%	91%
EKPC	NA	NA	NA	NA	NA	109%	113%
JCPL	59%	83%	105%	91%	100%	134%	101%
Met-Ed	53%	79%	95%	87%	89%	121%	96%
PECO	57%	80%	102%	89%	91%	125%	97%
PENELEC	52%	73%	97%	94%	106%	172%	142%
Pepco	75%	93%	100%	99%	103%	144%	108%
PPL	52%	74%	94%	85%	87%	121%	96%
PSEG	57%	80%	95%	89%	95%	121%	76%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	52%	73%	93%	84%	76%	114%	99%

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 2015



New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is at the direction of PJM. 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 2015 (Table 7-9).

Table 7-9 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[21]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$103,766	$146,624	$92,802	$34,149	$57,755	$177,470	$73,776	(58%)
AEP	$46,160	$94,385	$85,512	$34,944	$66,604	$130,312	$60,723	(53%)
AP	$99,655	$145,822	$105,988	$47,572	$76,645	$154,779	$79,952	(48%)
ATSI	NA	NA	$41,354	$42,673	$74,835	$143,552	$61,397	(57%)
BGE	$121,146	$184,563	$121,183	$62,567	$91,820	$228,990	$145,506	(36%)
ComEd	$109,938	$135,212	$129,279	$111,542	$130,283	$178,450	$97,010	(46%)
DAY	$44,900	$89,635	$81,825	$33,023	$72,665	$135,377	$59,299	(56%)
DEOK	NA	NA	NA	$26,451	$62,130	$122,282	$54,717	(55%)
DLCO	$43,907	$68,504	$49,251	$27,035	$43,321	$97,572	$47,474	(51%)
Dominion	$105,884	$167,920	$101,391	$44,651	$72,880	$180,306	$106,299	(41%)
DPL	$114,738	$166,793	$117,229	$57,505	$81,303	$222,872	$103,772	(53%)
EKPC	NA	NA	NA	NA	$32,626	$118,063	$45,675	(61%)
JCPL	$103,162	$144,597	$90,057	$32,724	$64,305	$181,578	$73,488	(60%)
Met-Ed	$104,285	$152,922	$101,258	$43,092	$68,531	$177,954	$74,648	(58%)
PECO	$98,600	$139,859	$88,317	$32,534	$52,526	$170,974	$70,211	(59%)
PENELEC	$78,821	$113,244	$77,113	$39,044	$67,118	$149,924	$70,797	(53%)
Pepco	$111,966	$164,693	$88,212	$38,656	$73,063	$202,767	$114,025	(44%)
PPL	$92,013	$125,723	$77,783	$26,866	$52,125	$167,421	$68,996	(59%)
PSEG	$96,099	$146,842	$89,665	$31,754	$77,582	$201,663	$83,728	(58%)
RECO	$89,060	$137,591	$71,676	$28,196	$83,010	$196,735	$84,679	(57%)
PJM	$92,006	$136,761	$89,439	$41,841	$70,056	$166,952	$78,809	(53%)

In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-8). The improved results in 2014 were reversed in 2015 and were relatively close to 2013 results. Zonal energy market net revenues decreased by from 49 percent to 77 percent which was not offset by the increase in some locational capacity market revenues.

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

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

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	38%	46%	31%	17%	27%	48%	25%
AEP	19%	32%	29%	12%	15%	32%	21%
AP	35%	46%	34%	15%	17%	37%	25%
ATSI	NA	NA	NA	NA	NA	35%	30%
BGE	46%	56%	37%	23%	33%	58%	39%
ComEd	33%	41%	39%	28%	28%	42%	28%
DAY	19%	31%	29%	12%	17%	33%	21%
DEOK	NA	NA	NA	NA	NA	31%	20%
DLCO	19%	26%	22%	10%	11%	26%	19%
Dominion	33%	48%	33%	14%	17%	42%	30%
DPL	40%	50%	36%	23%	32%	57%	31%
EKPC	NA	NA	NA	NA	NA	30%	18%
JCPL	37%	45%	30%	17%	28%	49%	25%
Met-Ed	36%	47%	33%	19%	28%	48%	25%
PECO	36%	44%	30%	17%	26%	47%	25%
PENELEC	31%	39%	28%	18%	28%	42%	25%
Pepco	44%	51%	30%	18%	30%	53%	33%
PPL	34%	41%	28%	16%	25%	46%	24%
PSEG	36%	46%	30%	18%	31%	54%	28%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	33%	43%	31%	17%	24%	43%	26%

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 2015

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 2015 (Table 7-11).

Table 7-11 Energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$1,763	$11,217	$6,708	$1,552	$1,082	$37,123	$15,506	(58%)
AEP	$112	$499	$1,717	$820	$484	$15,855	$6,002	(62%)
AP	$886	$1,771	$2,007	$1,061	$741	$20,542	$10,490	(49%)
ATSI	NA	NA	$308	$1,083	$23,643	$15,553	$5,777	(63%)
BGE	$3,712	$14,147	$7,870	$2,577	$2,654	$55,866	$27,241	(51%)
ComEd	$11	$480	$811	$909	$384	$12,427	$3,720	(70%)
DAY	$186	$554	$1,894	$946	$517	$15,671	$6,083	(61%)
DEOK	NA	NA	NA	$689	$462	$14,814	$5,829	(61%)
DLCO	$674	$2,987	$2,165	$914	$1,231	$14,403	$5,428	(62%)
Dominion	$3,639	$10,967	$4,108	$1,664	$1,545	$46,961	$15,836	(66%)
DPL	$2,721	$9,892	$5,769	$2,381	$1,083	$43,946	$25,593	(42%)
EKPC	NA	NA	NA	NA	$289	$15,816	$4,856	(69%)
JCPL	$1,895	$8,673	$6,610	$1,704	$2,016	$37,086	$15,065	(59%)
Met-Ed	$1,620	$8,711	$5,032	$1,833	$1,254	$35,789	$15,174	(58%)
PECO	$1,558	$8,570	$5,379	$1,936	$1,004	$36,186	$14,033	(61%)
PENELEC	$240	$1,124	$2,642	$2,141	$1,104	$18,141	$8,154	(55%)
Pepco	$4,036	$13,277	$6,077	$2,009	$2,249	$56,830	$18,222	(68%)
PPL	$1,428	$7,704	$5,317	$1,747	$1,054	$36,712	$14,906	(59%)
PSEG	$1,394	$7,394	$5,447	$1,695	$1,257	$36,629	$14,566	(60%)
RECO	$1,201	$6,241	$4,255	$1,737	$2,387	$34,756	$16,108	(54%)
PJM	$1,593	$6,718	$4,118	$1,547	$2,322	$30,055	$12,429	(59%)

In 2015, a new DS would not have received sufficient net revenue to cover levelized total costs in any zone. The marginal cost of the DS was relatively high compared to clearing prices in the energy market.

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

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

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.[22]

New entrant nuclear plant energy market net revenues were lower in all zones in 2015 (Table 7-13).

Table 7-13 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[23]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$288,632	$367,483	$335,035	$223,539	$262,810	$387,883	$220,023	(43%)
AEP	$218,504	$261,098	$262,335	$198,385	$230,716	$311,569	$204,723	(34%)
AP	$256,721	$314,729	$293,355	$210,232	$244,428	$337,998	$228,936	(32%)
ATSI	NA	NA	$153,888	$204,058	$242,705	$325,433	$208,372	(36%)
BGE	$298,473	$391,960	$341,862	$245,538	$285,910	$444,433	$304,148	(32%)
ComEd	$179,104	$217,838	$212,423	$175,450	$206,746	$272,321	$168,496	(38%)
DAY	$214,090	$258,210	$262,111	$203,992	$234,102	$314,747	$206,825	(34%)
DEOK	NA	NA	NA	$192,158	$221,863	$299,618	$201,391	(33%)
DLCO	$208,801	$257,065	$258,686	$199,094	$227,732	$291,888	$193,791	(34%)
Dominion	$281,069	$373,737	$319,215	$223,740	$263,891	$388,295	$260,516	(33%)
DPL	$291,154	$370,565	$335,597	$236,441	$272,775	$428,044	$250,192	(42%)
EKPC	NA	NA	NA	NA	$127,631	$294,606	$190,936	(35%)
JCPL	$287,875	$365,408	$332,717	$222,496	$271,028	$392,479	$218,452	(44%)
Met-Ed	$279,022	$354,677	$317,652	$217,622	$257,748	$374,408	$211,003	(44%)
PECO	$282,937	$359,927	$329,530	$220,535	$256,201	$378,894	$212,675	(44%)
PENELEC	$250,469	$310,481	$291,867	$215,338	$256,535	$349,950	$217,124	(38%)
Pepco	$298,215	$389,389	$332,675	$238,119	$281,722	$427,666	$279,006	(35%)
PPL	$275,067	$343,190	$316,501	$213,393	$255,433	$374,962	$211,595	(44%)
PSEG	$292,089	$371,365	$338,912	$226,944	$289,418	$416,439	$230,273	(45%)
RECO	$284,023	$360,820	$317,521	$221,087	$295,509	$411,345	$232,025	(44%)
PJM	$263,897	$333,408	$297,327	$215,166	$249,245	$361,149	$222,525	(38%)

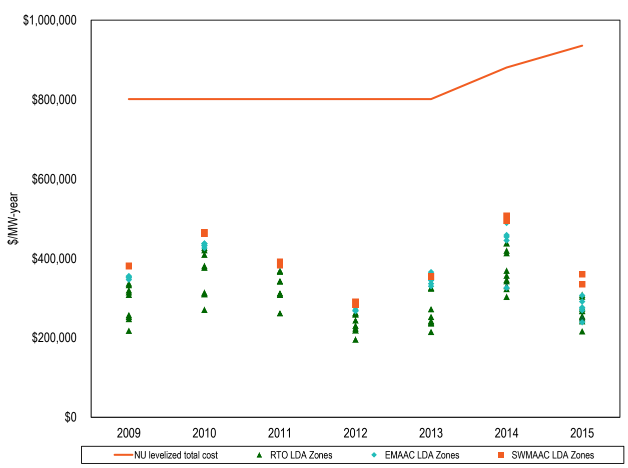
In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). The improved results in 2014 were reversed in 2015 and were relatively close to 2013 results. Zonal energy market net revenues decreased by from 32 percent to 45 percent which was not offset by the increase in some locational capacity market revenues.

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

Table 7-14 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2015

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

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



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 if 75 percent of existing wind units in the zone were generating power in that hour. Energy market net revenues for a wind installation include revenue from the Production Tax Credit (PTC) of $23 per MWh, from the Investment Tax Credit of $1 per MWh, and from Renewable Energy Certificates (RECs) of $0.81/MWh in ComEd and $14.80/MWh in PENELEC.[24]

Wind energy market net revenues were lower in 2015 (Table 7-15).

24 REC prices provided by Evolution Markets.

Table 7-15 Net revenue for a wind installation (Dollars per installed MW-year)

	2012				2013				2014				2015				2015 Total
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Change
ComEd	68,086	-	2,632	70,717	83,764	-	1,095	84,859	108,420	75,325	4,049	187,795	81,650	78,533	6,257	166,439	(11%)
PENELEC	69,632	56,622	5,878	132,132	88,401	78,900	8,905	176,206	127,839	96,234	8,237	232,310	83,937	95,617	7,338	186,892	(20%)

In 2015, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation.

Table 7-16 Percent of 20-year levelized total costs recovered by wind energy and capacity net revenue (Dollars per installed MW-year): 2012 through 2015

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

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 if 75 percent of existing solar units in the zone were generating power in that hour. Energy market net revenues for a solar installation in New Jersey include revenue from Solar Renewable Energy Certificates (SRECs) of $174.23/MWh.[25]

Solar energy market net revenues were slightly higher in 2015 (Table 7-17).

Table 7-17 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

	2012				2013				2014				2015				2015 Total
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Change
PSEG	48,501	312,580	18,984	380,065	81,122	287,853	28,835	397,811	98,182	281,386	27,575	407,144	67,807	319,866	23,156	410,828	1%

In 2015, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Production tax credits and renewable energy credits accounted for 78 percent of the total net revenue of a solar installation.

Table 7-18 Percent of 20-year levelized total costs recovered by solar energy and capacity net revenue (Dollars per installed MW-year)

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

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 2015, the average operating cost of the CC was lower than the average operating costs of the CP for the ten months from March through December, as a result of the relative cost of gas versus coal, compared to only five months in 2014 and 2013. (See Figure 7-5)

25 SREC prices provided by Evolution Markets.

Table 7-19 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	$119,139	13.9%	$156,300	13.9%	$547,017	13.6%
Base Case	$111,639	12.0%	$146,300	12.0%	$517,017	12.0%
Sensitivity 2	$104,139	10.0%	$136,300	10.0%	$487,017	10.4%
Sensitivity 3	$96,639	7.8%	$126,300	7.8%	$457,017	8.7%
Sensitivity 4	$89,139	5.4%	$116,300	5.6%	$427,017	7.0%
Sensitivity 5	$81,639	2.7%	$106,300	3.0%	$397,017	5.1%
Sensitivity 6	$74,139	(0.8%)	$96,300	0.0%	$367,017	3.1%

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market, when load requires them, and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. 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 2015, zonal energy net revenues decreased across all units, while capacity market prices increased over 2014 in the western zones.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. The same is true when efficient CCs are on the margin. However, when CTs or less efficient coal units are on the margin net revenues are higher for more efficient coal units.

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 7-4 The results are shown in Table 7-19.[26]

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 7-20 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 7-20 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%	$118,155	$154,644
Sensitivity 2	55%	$114,897	$150,472
Base Case	50%	$111,639	$146,300
Sensitivity 3	45%	$108,382	$142,128
Sensitivity 4	40%	$105,125	$137,956
Sensitivity 5	35%	$101,867	$133,785
Sensitivity 6	30%	$98,610	$129,612

26 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 7-21 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	$101,440	$133,239
Sensitivity 2	25	$105,294	$138,174
Base Case	20	$111,639	$146,300
Sensitivity 3	15	$116,985	$153,135
Sensitivity 4	10	$124,078	$162,197

Table 7-22 Interconnection cost sensitivity for 2015 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%	$108,017	$0	0.0%	$142,383
Sensitivity 2	$8,321	1.8%	$109,828	$12,738	1.4%	$144,341
Base Case	$16,643	3.6%	$111,639	$25,477	2.8%	$146,300
Sensitivity 3	$24,964	5.4%	$113,451	$38,215	4.2%	$148,259
Sensitivity 4	$33,286	7.3%	$115,262	$50,953	5.7%	$150,218
Sensitivity 5	$41,607	9.1%	$117,074	$63,692	7.1%	$152,177
Sensitivity 6	$50,000	10.9%	$118,901	$76,430	8.5%	$154,136
Sensitivity 7	$75,000	16.3%	$124,343	$100,000	11.1%	$157,760
Sensitivity 8	$100,000	21.8%	$129,785	$150,000	16.7%	$165,449

Table 7-21 shows the levelized annual revenue requirements 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 7-22 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.

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 and black start service, in addition to 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 2014/2015 and 2015/2016 RPM Auctions.[27] For units that did not submit ACR data, the default ACR was used.

Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[28] 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. Table 7-23 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed. Net revenues in Table 7-23 are calculated using units' cost-based offers. A more accurate method would be to use the lower of the unit's price-based or cost-based offers.[29]

Table 7-23 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs: 2015

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,032	$53,405	$109,826	$50,677
CC - Two or Three on One Frame F Technology	17,524	$56,828	$108,290	$19,030
CT - First & Second Generation Aero (P&W FT 4)	3,155	$5,173	$43,679	$10,661
CT - First & Second Generation Frame B	3,242	$891	$54,081	$11,446
CT - Second Generation Frame E	8,783	$12,296	$64,884	$10,170
CT - Third Generation Aero	3,696	$20,699	$75,356	$20,853
CT - Third Generation Frame F	9,691	$11,588	$58,922	$10,219
Diesel	461	$14,539	$64,782	$10,799
Hydro	7,363	$101,458	$152,650	$27,124
Nuclear	31,661	$177,868	$230,829	NA
Oil or Gas Steam	9,096	$9,552	$60,189	$40,230
Sub-Critical Coal	27,253	$21,044	$59,416	$59,215
Super Critical Coal	23,408	$21,660	$277,188	$129,569

The RPM 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 2014/2015 and 2015/2016 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 2015.

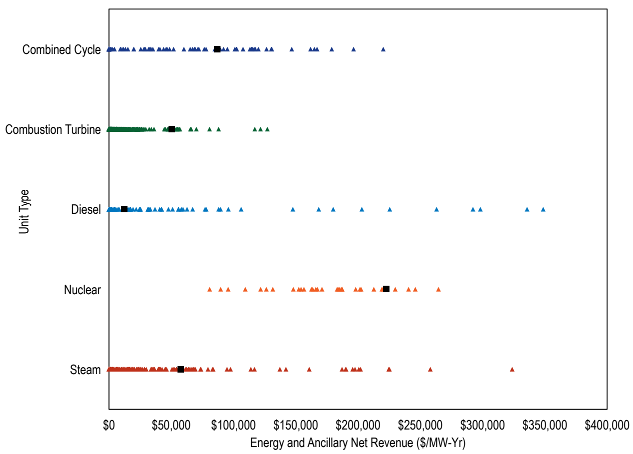
27 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

28 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.

29 *See* 148 FERC ¶ 61,140 (2014).

The average net revenue results do not show the underlying distribution of actual net revenues by unit type. This underlying distribution of energy and ancillary net revenues by unit type is shown in Figure 7-10. Each generating unit is represented by a single point, and the new entrant PJM average theoretical energy and ancillary net revenue is represented by a solid square.

Figure 7-10 PJM distribution of energy and ancillary net revenue by unit type (Dollars per installed MW-year): 2015



The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-23 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. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are used to present the range of data. The three break points between the four quartiles are presented. Table 7-24 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 average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographic distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus average energy net revenue for that technology class.

Table 7-24 Energy and ancillary service net revenue by quartile for select technologies: 2015

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$9,096	$19,623	$51,533
CC - Two or Three on One Frame F Technology	$8,218	$33,652	$93,539
CT - First & Second Generation Aero (P&W FT 4)	$363	$2,123	$4,069
CT - First & Second Generation Frame B	($1,053)	$673	$2,587
CT - Second Generation Frame E	$208	$3,069	$10,670
CT - Third Generation Aero	$5,693	$11,717	$26,596
CT - Third Generation Frame F	$1,458	$7,910	$17,308
Diesel	($332)	$0	$17,449
Hydro	$44,478	$79,978	$112,523
Nuclear	$154,267	$184,035	$212,658
Oil or Gas Steam	($593)	$2	$6,528
Sub-Critical Coal	($18)	$15,649	$40,826
Super Critical Coal	($1,459)	$11,498	$39,603

Table 7-25 shows capacity market net revenues by quartile for select technology classes.

Table 7-25 Capacity revenue by quartile for select technologies: 2015

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$55,002	$55,434	$60,591
CC - Two or Three on One Frame F Technology	$46,671	$48,748	$55,877
CT - First & Second Generation Aero (P&W FT 4)	$19,775	$35,468	$53,884
CT - First & Second Generation Frame B	$41,348	$49,536	$54,559
CT - Second Generation Frame E	$47,174	$48,065	$54,929
CT - Third Generation Aero	$47,883	$49,829	$54,058
CT - Third Generation Frame F	$45,698	$47,307	$48,262
Diesel	$45,475	$50,020	$56,447
Hydro	$47,734	$56,365	$57,179
Nuclear	$47,398	$47,901	$55,961
Oil or Gas Steam	$46,907	$53,626	$54,864
Sub-Critical Coal	$17,154	$45,032	$51,046
Super Critical Coal	$44,834	$52,087	$55,239

Table 7-26 shows total net revenues by quartile for select technology classes.

Table 7-26 Combined revenue from all markets by quartile for select technologies: 2015

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$64,098	$75,057	$112,124
CC - Two or Three on One Frame F Technology	$54,889	$82,400	$149,416
CT - First & Second Generation Aero (P&W FT 4)	$20,139	$37,591	$57,953
CT - First & Second Generation Frame B	$40,295	$50,209	$57,146
CT - Second Generation Frame E	$47,381	$51,134	$65,599
CT - Third Generation Aero	$53,576	$61,545	$80,653
CT - Third Generation Frame F	$47,156	$55,217	$65,570
Diesel	$45,143	$50,020	$73,896
Hydro	$92,212	$136,343	$169,703
Nuclear	$201,665	$231,936	$268,618
Oil or Gas Steam	$46,314	$53,628	$61,392
Sub-Critical Coal	$17,137	$60,681	$91,873
Super Critical Coal	$43,375	$63,586	$94,841

Table 7-27 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2015, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. The results do not include nuclear power plants because there is not good public data on nuclear unit avoidable costs.

Table 7-27 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies: 2015

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	11%	33%	56%
CC - Two or Three on One Frame F Technology	73%	126%	376%
CT - First & Second Generation Aero (P&W FT 4)	5%	25%	44%
CT - First & Second Generation Frame B	NA	11%	26%
CT - Second Generation Frame E	5%	18%	78%
CT - Third Generation Aero	25%	46%	102%
CT - Third Generation Frame F	14%	64%	168%
Diesel	NA	101%	534%
Hydro	167%	292%	399%
Nuclear	NA	NA	NA
Oil or Gas Steam	NA	2%	18%
Sub-Critical Coal	NA	21%	65%
Super Critical Coal	5%	14%	43%

Table 7-28 shows the avoidable cost recovery from all PJM markets by quartiles. The net revenues from all markets cover avoidable costs for even the first quartile of most technology types but this is not the case for every individual unit.

Table 7-28 Avoidable cost recovery by quartile from all PJM Markets for select technologies: 2015

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	132%	158%	183%
CC - Two or Three on One Frame F Technology	448%	529%	1,021%
CT - First & Second Generation Aero (P&W FT 4)	258%	405%	495%
CT - First & Second Generation Frame B	383%	470%	587%
CT - Second Generation Frame E	474%	523%	608%
CT - Third Generation Aero	227%	385%	421%
CT - Third Generation Frame F	453%	533%	676%
Diesel	409%	630%	1,298%
Hydro	348%	493%	778%
Nuclear	NA	NA	NA
Oil or Gas Steam	150%	193%	263%
Sub-Critical Coal	39%	88%	129%
Super Critical Coal	27%	88%	115%

Table 7-29 and Table 7-30 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2015, 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 and oil or gas steam units.

Table 7-29 Proportion of units recovering avoidable costs from energy and ancillary markets: 2009 through 2015

	Units with full recovery from energy and ancillary services markets						
Technology	2009	2010	2011	2012	2013	2014	2015
CC - NUG Cogeneration Frame B or E Technology	41%	39%	56%	45%	63%	53%	50%
CC - Two or Three on One Frame F Technology	22%	34%	54%	55%	56%	53%	66%
CT - First & Second Generation Aero (P&W FT 4)	27%	47%	14%	10%	14%	68%	8%
CT - First & Second Generation Frame B	28%	43%	27%	19%	9%	48%	9%
CT - Second Generation Frame E	52%	60%	41%	41%	35%	63%	51%
CT - Third Generation Aero	20%	35%	35%	43%	28%	48%	42%
CT - Third Generation Frame F	32%	47%	33%	63%	56%	52%	44%
Diesel	62%	73%	63%	51%	52%	71%	66%
Hydro and Pumped Storage	60%	53%	95%	99%	99%	99%	96%
Nuclear	NA	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	42%	52%	48%	44%	46%	55%	36%
Sub-Critical Coal	28%	38%	51%	30%	41%	67%	38%
Super Critical Coal	37%	40%	53%	24%	29%	75%	27%

Table 7-30 Proportion of units recovering avoidable costs from all markets: 2009 through 2015

	Units with full recovery from all markets						
Technology	2009	2010	2011	2012	2013	2014	2015
CC - NUG Cogeneration Frame B or E Technology	91%	96%	96%	90%	100%	100%	94%
CC - Two or Three on One Frame F Technology	100%	100%	81%	85%	74%	82%	100%
CT - First & Second Generation Aero (P&W FT 4)	98%	100%	100%	100%	94%	100%	100%
CT - First & Second Generation Frame B	99%	99%	93%	90%	88%	97%	97%
CT - Second Generation Frame E	100%	99%	93%	94%	99%	100%	100%
CT - Third Generation Aero	74%	99%	99%	90%	75%	96%	100%
CT - Third Generation Frame F	100%	100%	93%	93%	91%	97%	100%
Diesel	100%	98%	90%	84%	76%	93%	94%
Hydro and Pumped Storage	100%	100%	100%	100%	100%	100%	100%
Nuclear	NA	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	95%	89%	82%	75%	83%	93%	87%
Sub-Critical Coal	80%	85%	76%	46%	57%	79%	62%
Super Critical Coal	77%	94%	82%	41%	59%	89%	50%

Units At Risk

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at risk analysis.[30]

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 2016/2017 or the 2017/2018 capacity auctions is shown in Table 7-31.[31] These units are considered at risk of retirement.

These results mean that 11,908 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 that did not recover avoidable costs from total market revenues in two of the last three years or did not clear the 16/17 BRA or 17/18 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2015 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	3	139	403	11,295	21
Coal	23	11,736	5,697	10,291	47
Diesel	1	4	191	10,550	46
Oil or Gas Steam	1	30	4,765	14,226	28
Total	28	11,908	3,197	11,391	34

30 This analysis excludes nuclear units due to a lack of data.
31 Avoidable costs are ACR values and exclude APIR.