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 higher in 2014 than in 2013 and capacity market prices were slightly lower in 2014 in 10 eastern zones and substantially higher in six western zones. Net revenues for all plant types were significantly affected by the high prices and high demand in January 2014 which resulted in an increase in profitable run hours.
- In 2014, average net revenues increased by 74 percent for a new CT, 30 percent for a new CC, 113 percent for a new CP, 109 percent for a new DS, 43 percent for a new nuclear plant, 24 percent for a new wind installation, and 7 percent for a new solar installation. Increases in 2014 net revenues were primarily the result of higher energy net revenues in January 2014.
- In 2014, a new CT would have received sufficient net revenue to cover levelized total costs in 10 of the 19 zones. The net revenue results for a new CT bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 95 percent of levelized total costs. The relatively higher net revenues in these zones reflect higher capacity market revenues and generally higher energy market net revenues. In six of the remaining nine western zones net revenues cover less than 75 percent of levelized total costs with the lowest zone at 45 percent. The relatively lower net revenues in these zones result from lower net revenues from the capacity market and close to average net revenues in the energy markets with some exceptions. The net revenues in these zones increased by more than 200 percent from 2013. This is the same bifurcation that occurred in 2013, with the exception that net revenues in 2014 were higher in all zones.
- In 2014, the net revenue results for a new CC also bifurcate the zones into two groups with different results, although the results for CCs are overall higher coverage of levelized total costs than for CTs. There are ten eastern zones in which net revenues cover more than 105 percent of levelized total costs. These are the same ten zones with higher net revenues for CTs. The relatively higher net revenues in these zones reflect higher capacity market revenues and generally higher energy market net revenues. In the remaining nine western zones net revenues cover from 49 percent to 102 percent of levelized total costs. The relatively lower net revenues in these zones result from relatively lower capacity revenues and generally below average energy market revenues. The net revenues in these zones increased by more than 50 percent from 2013.
- In 2014, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone. The results for CPs vary from covering 22 percent of levelized total costs to 55 percent. Six zones were greater than or equal to 50 percent, the first time since 2009 that even a single zone equaled 50 percent or greater. The results for CPs in 2014 are better than they were in 2013 based on higher energy market net revenues in all zones and higher capacity market revenues in seven zones. All zones showed increases in the coverage of fixed costs by CPs in 2014.
- In 2014, a new DS would not have received sufficient net revenue to cover levelized total costs in any zone. The results for DS range from covering 26 percent of levelized total costs to 76 percent.
- In 2014, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone. The results for nuclear plants range from covering 35 percent of levelized total costs to 58 percent.
- In 2014, net revenues covered more than 90 percent of the annual levelized total costs of a new entrant wind installation and over 240 percent of the annual levelized total costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for a substantial portion

of the net revenue of a wind installation and a solar installation.

- In 2014, 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 2014, 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 mean that 22 units with 6,946 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire.

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.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of high price hours can significantly increase net revenues as shown by the results for January. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

Net Revenue

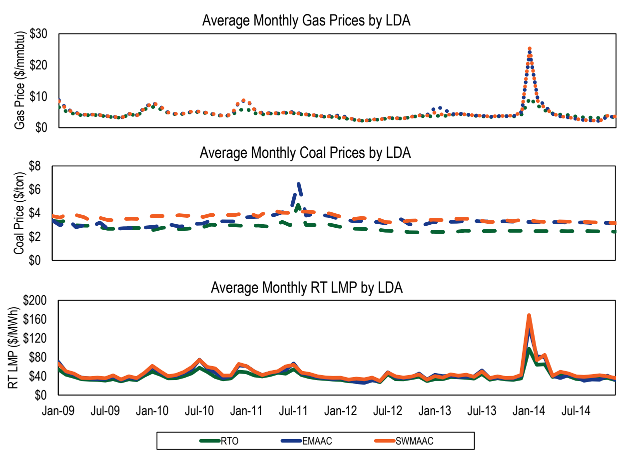
When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators 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 short run variable 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 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 payments, 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.

Operating reserve (uplift) payments are included when the analysis is based on the peak-hour, economic dispatch model and when the analysis uses actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 37.4 percent higher in 2014 than in 2013, $53.14 per MWh versus $38.66 per MWh. Natural gas prices increased in 2014, especially in the eastern part of PJM. Comparing fuel prices in 2014 to 2013, the price of Northern Appalachian coal remained constant; the price of Central Appalachian coal was 3.6 percent lower; the price of Powder River Basin coal was 9.3 percent higher; the price of eastern natural gas was 36.1 percent higher; and the price of western natural gas was 17.4 percent higher.

Figure 7-1 Energy Market net revenue factor trends: 2009 through 2014



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 eight 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. This is an upgrade from the CT plant technology used in the 2013 report.
- 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.[2] This is an upgrade from the CC plant technology used in the 2013 report.
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two nuclear power 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.[3,4] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

1 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

2 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.

3 Hourly ambient conditions supplied by Schneider Electric.

4 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. Therefore, there is a single offer point and no offer curve.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[5]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[6] Each CT, CC, CP, and DS plant was also given 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 offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. 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	$887	$1,641	$286	$2,213
2010	$4,320	$762	$601	$898
2011	$3,587	$964	$272	$1,025
2012	$891	$1,608	$117	$1,154
2013	$1,296	$269	$2,876	$2,187
2014	$362	$633	$151	$3,945

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] 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.[8] 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.[9]

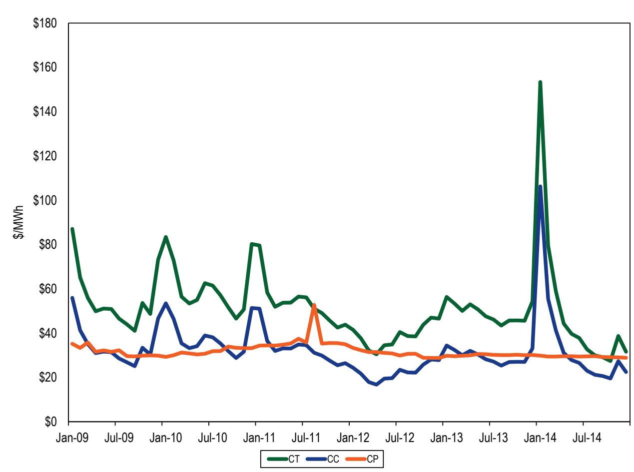
Operating costs are the short run marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[10,11] Average operating costs are shown in Table 7-2.

Table 7-2 Average operating costs

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$50.14	9,476	$0.25
CC	$35.13	6,667	$1.00
CP	$29.37	9,250	$4.00
DS	$193.77	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A significant increase in gas prices on cold days in January resulted in a corresponding increase in the average operating cost of CTs and CCs in January 2014 (Figure 7-2).

Figure 7-2 Average operating costs: 2009 through 2014



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

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 2014 includes five months of the 2013/2014 RPM auction clearing price and seven months of the 2014/2015 RPM auction clearing price.[12] These capacity revenues are adjusted for the yearly, system wide forced outage rate.

Table 7-3 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2014[13]

Zone	2009	2010	2011	2012	2013	2014	Average
AECO	$58,586	$61,406	$45,938	$43,138	$67,616	$60,012	$56,116
AEP	$35,789	$48,898	$45,938	$18,730	$7,743	$28,235	$30,889
AP	$53,440	$61,406	$45,938	$18,730	$7,743	$28,235	$35,915
ATSI	NA	NA	NA	NA	NA	$28,235	$28,235
BGE	$76,236	$67,851	$45,938	$41,878	$63,023	$57,432	$58,726
ComEd	$35,789	$48,898	$45,938	$18,730	$7,743	$28,235	$30,889
DAY	$35,789	$48,898	$45,938	$18,730	$7,743	$28,235	$30,889
DEOK	NA	NA	NA	NA	$7,743	$28,235	$17,989
DLCO	$35,789	$48,898	$45,938	$18,730	$7,743	$28,235	$30,889
Dominion	$35,789	$48,898	$45,938	$18,730	$7,743	$28,235	$30,889
DPL	$58,586	$62,251	$46,530	$48,399	$71,305	$60,012	$57,847
EKPC	NA	NA	NA	NA	NA	$28,235	$28,235
JCPL	$58,586	$61,406	$45,938	$43,138	$67,616	$60,012	$56,116
Met-Ed	$53,440	$61,406	$45,938	$41,878	$63,023	$57,432	$53,853
PECO	$58,586	$61,406	$45,938	$43,138	$67,616	$60,012	$56,116
PENELEC	$53,440	$61,406	$45,938	$41,837	$62,994	$57,432	$53,841
Pepco	$76,236	$67,851	$45,938	$41,878	$67,154	$60,305	$59,894
PPL	$53,440	$61,406	$45,938	$41,878	$63,023	$57,432	$53,853
PSEG	$58,586	$61,406	$45,938	$46,223	$69,779	$65,778	$57,952
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$30,354	$33,657	$41,920	$42,750

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 both the combined cycle and combustion turbine decreased in 2014 from 2013 as a result of upgraded CT technology from the GE Frame 7FA.05 to the GE Frame 7HA.02 which increased the capacity and provided associated economies of scale.

> 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.

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

13 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the EKPC or RECO zones.

Levelized Total Costs

Table 7-4 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[14,15]

	20-Year Levelized Total Cost					
	2009	2010	2011	2012	2013	2014
Combustion Turbine	$128,705	$131,044	$110,589	$113,027	$109,731	$108,613
Combined Cycle	$173,174	$175,250	$153,682	$155,294	$150,654	$146,443
Coal Plant	$446,550	$465,455	$474,692	$480,662	$491,240	$504,050
Diesel Plant	$153,143	$153,143	$153,143	$153,143	$153,143	$161,746
Nuclear Plant	$801,100	$801,100	$801,100	$801,100	$801,100	$880,770
Wind Installation (with 1603 grant)				$196,186	$196,148	$198,033
Solar Installation (with 1603 grant)				$394,855	$263,824	$236,289

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, 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 then 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.

Table 7-5 Energy net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2014[16]

Zone	January	Total	January as a Percent of Total
AECO	$12,281	$51,242	24%
AEP	$22,219	$43,081	52%
AP	$30,094	$57,460	52%
ATSI	$23,904	$49,706	48%
BGE	$13,485	$70,734	19%
ComEd	$10,325	$20,519	50%
DAY	$21,558	$43,498	50%
DEOK	$20,466	$60,698	34%
DLCO	$19,934	$39,799	50%
Dominion	$8,983	$36,074	25%
DPL	$9,932	$61,963	16%
EKPC	$21,281	$63,085	34%
JCPL	$13,899	$52,785	26%
Met-Ed	$12,367	$47,475	26%
PECO	$12,714	$48,641	26%
PENELEC	$34,613	$90,813	38%
Pepco	$13,390	$64,350	21%
PPL	$13,203	$48,159	27%
PSEG	$8,274	$42,603	19%
RECO	$7,767	$42,380	18%
PJM	$16,534	$51,753	32%

New entrant CT plant energy market net revenues were higher in 2014 in significant part as a result of higher energy market prices in January which more than offset the higher fuel prices. The net revenue increase in January was the result of an increase in profitable run hours and a number of very high price hours (Table 7-5).

Total market revenues (Total columns in Table 7-6) include energy, capacity and ancillary service revenues. Total market revenues increased for a new CT in all PJM zones in 2014.

14 Levelized total costs provided by Pasteris Energy, Inc.

15 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.

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

Table 7-6 Net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[17]

	2009		2010		2011		2012		2013		2014		Percent Change in
Zone	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	2014 Total Revenue
AECO	12,421	71,894	40,037	105,763	46,156	95,680	25,015	69,044	20,835	89,747	51,242	111,616	24%
AEP	3,696	40,371	11,575	64,793	20,838	70,363	16,262	35,882	12,535	21,573	43,081	71,677	232%
AP	11,136	65,464	32,494	98,220	32,958	82,483	21,028	40,648	17,091	26,129	57,460	86,057	229%
ATSI	NA	NA	NA	NA	NA	NA	18,295	NA	15,402	NA	49,706	78,303	NA
BGE	15,126	92,249	52,411	124,583	48,640	98,165	36,305	79,074	29,602	93,921	70,734	128,528	37%
ComEd	2,445	39,120	9,446	62,665	15,081	64,605	13,780	33,400	10,381	19,420	20,519	49,115	153%
DAY	3,313	39,989	11,701	64,919	21,704	71,229	18,572	38,193	12,559	21,597	43,498	72,095	234%
DEOK	NA	NA	NA	NA	NA	NA	16,003	NA	12,036	21,074	60,698	89,295	324%
DLCO	4,471	41,146	17,525	70,743	24,178	73,702	18,772	38,393	14,499	23,537	39,799	68,396	191%
Dominion	15,253	51,928	42,922	96,141	38,944	88,469	25,374	44,994	20,253	29,292	36,074	64,671	121%
DPL	13,886	73,358	40,530	107,101	44,338	94,455	32,585	81,876	24,545	97,146	61,963	122,336	26%
EKPC	NA	NA	NA	NA	NA	NA	NA	NA	10,507	NA	63,085	91,682	NA
JCPL	11,994	71,466	39,409	105,135	44,967	94,491	24,115	68,144	25,778	94,690	52,785	113,158	20%
Met-Ed	11,083	65,410	39,409	105,135	40,800	90,325	25,395	68,164	20,492	84,811	47,475	105,269	24%
PECO	10,611	70,083	38,311	104,037	45,852	95,377	25,882	69,911	19,688	88,599	48,641	109,015	23%
PENELEC	6,986	61,314	24,309	90,035	32,089	81,614	22,461	65,189	21,779	86,068	90,813	148,606	73%
Pepco	17,798	94,921	50,906	123,078	44,232	93,756	32,009	74,778	27,977	96,427	64,350	125,017	30%
PPL	10,045	64,372	33,649	99,375	42,870	92,395	22,816	65,585	19,895	84,214	48,159	105,952	26%
PSEG	10,079	69,552	37,626	103,352	37,927	87,452	24,080	71,194	20,872	91,948	42,603	108,743	18%
RECO	8,717	NA	35,022	NA	32,177	NA	22,807	NA	23,363	NA	42,380	NA	NA
PJM	9,945	59,216	32,781	93,327	36,103	85,647	23,240	54,485	19,004	53,958	51,753	94,035	74%

In 2014, a new CT would have received sufficient net revenue to cover levelized total costs in 10 of the 19 zones. The net revenue results for a new CT bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 95 percent of levelized total costs. The relatively higher net revenues in these zones reflect higher capacity market revenues and generally higher energy market net revenues. In six of the remaining nine western zones net revenues cover less than 75 percent of levelized total costs with the lowest zone at 45 percent. The relatively lower net revenues in these zones result from lower net revenues from the capacity market and close to average net revenues in the energy markets with some exceptions. The net revenues in these zones increased by more than 200 percent from 2013. This is the same bifurcation that occurred in 2013, with the exception that net revenues in 2014 were higher in all zones.

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

Zone	2009	2010	2011	2012	2013	2014
AECO	56%	81%	87%	61%	82%	103%
AEP	31%	49%	64%	32%	20%	66%
AP	51%	75%	75%	36%	24%	79%
ATSI	NA	NA	NA	NA	NA	72%
BGE	72%	95%	89%	70%	86%	118%
ComEd	30%	48%	58%	30%	18%	45%
DAY	31%	50%	64%	34%	20%	66%
DEOK	NA	NA	NA	NA	19%	82%
DLCO	32%	54%	67%	34%	21%	63%
Dominion	40%	73%	80%	40%	27%	60%
DPL	57%	82%	85%	72%	89%	113%
EKPC	NA	NA	NA	NA	NA	84%
JCPL	56%	80%	85%	60%	86%	104%
Met-Ed	51%	80%	82%	60%	77%	97%
PECO	54%	79%	86%	62%	81%	100%
PENELEC	48%	69%	74%	58%	78%	137%
Pepco	74%	94%	85%	66%	88%	115%
PPL	50%	76%	84%	58%	77%	98%
PSEG	54%	79%	79%	63%	84%	100%
RECO	NA	NA	NA	NA	NA	NA
PJM	46%	71%	77%	48%	49%	87%

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

Figure 7-3 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-3 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year)

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, 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.[18] If the unit was not already committed day ahead, it was then 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 higher in 2014 in significant part as a result of higher energy market prices in January which more than offset the higher fuel prices. The net revenue increase in January was the result of an increase in profitable run hours and a number of very high price hours (Table 7-8).

Table 7-8 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year): 2014[19]

Zone	January	Total	January as a Percent of Total
AECO	$18,273	$109,150	17%
AEP	$29,919	$87,474	34%
AP	$39,843	$106,662	37%
ATSI	$32,298	$97,567	33%
BGE	$26,853	$145,539	18%
ComEd	$15,371	$43,515	35%
DAY	$29,157	$88,806	33%
DEOK	$27,910	$119,057	23%
DLCO	$26,786	$75,160	36%
Dominion	$14,844	$84,615	18%
DPL	$21,508	$131,459	16%
EKPC	$29,397	$121,176	24%
JCPL	$21,808	$112,515	19%
Met-Ed	$17,436	$101,042	17%
PECO	$18,544	$103,847	18%
PENELEC	$45,892	$160,098	29%
Pepco	$25,516	$134,724	19%
PPL	$18,537	$102,133	18%
PSEG	$17,199	$102,296	17%
RECO	$13,954	$100,554	14%
PJM	$24,552	$106,370	23%

Total market revenues (Total columns in Table 7-9) include energy, capacity and ancillary service revenues. Total market revenues increased for a new CC in all PJM zones in 2014.

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

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

Table 7-9 Net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year)

	2009		2010		2011		2012		2013		2014		Percent Change in
Zone	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	2014 Total Revenue
AECO	62,063	122,290	106,643	168,811	126,866	173,768	101,147	145,892	87,580	155,464	109,150	169,795	9%
AEP	29,759	67,189	47,591	97,252	82,321	129,223	87,906	108,243	67,040	75,051	87,474	116,342	55%
AP	59,052	114,134	91,032	153,200	113,559	160,460	100,496	120,834	80,861	88,873	106,662	135,529	52%
ATSI	NA	NA	NA	NA	54,553	NA	94,384	NA	78,928	NA	97,567	126,435	NA
BGE	70,571	148,448	124,665	193,279	130,803	177,704	123,364	166,850	105,312	168,604	145,539	203,603	21%
ComEd	20,613	58,043	33,906	83,567	46,291	93,193	61,752	82,089	42,434	50,446	43,515	72,382	43%
DAY	27,904	65,333	46,647	96,308	82,064	128,966	93,514	113,852	70,151	78,163	88,806	117,674	51%
DEOK	NA	NA	NA	NA	NA	NA	82,041	NA	69,498	77,509	119,057	147,924	91%
DLCO	27,649	65,078	51,180	100,841	81,639	128,541	89,178	109,515	64,735	72,747	75,160	104,027	43%
Dominion	68,932	106,362	116,873	166,534	114,527	161,429	103,607	123,945	84,077	92,089	84,615	113,483	23%
DPL	64,321	124,547	106,245	169,258	123,597	171,090	114,805	164,812	93,469	165,043	131,459	192,103	16%
EKPC	NA	NA	NA	NA	NA	NA	NA	NA	47,065	NA	121,176	150,043	NA
JCPL	61,477	121,704	105,474	167,642	124,875	171,777	100,383	145,129	95,950	163,835	112,515	173,159	6%
Met-Ed	55,400	110,482	97,665	159,833	111,650	158,551	96,015	139,501	83,610	146,902	101,042	159,107	8%
PECO	57,843	118,069	99,951	162,119	121,801	168,703	98,148	142,894	81,262	149,146	103,847	164,491	10%
PENELEC	48,876	103,957	80,773	142,941	109,045	155,947	106,233	149,678	104,603	167,866	160,098	218,163	30%
Pepco	71,959	149,836	121,952	190,565	121,141	168,042	115,688	159,174	100,910	168,333	134,724	195,661	16%
PPL	52,285	107,366	87,314	149,481	111,108	158,010	91,724	135,211	81,294	144,586	102,133	160,197	11%
PSEG	57,910	118,137	101,819	163,986	114,948	161,850	96,614	144,446	88,596	158,645	102,296	168,706	6%
RECO	51,808	NA	93,724	NA	96,232	NA	90,921	NA	92,865	NA	100,554	NA	NA
PJM	52,260	102,286	89,027	146,014	103,723	150,644	97,259	129,221	81,012	114,939	106,370	148,923	30%

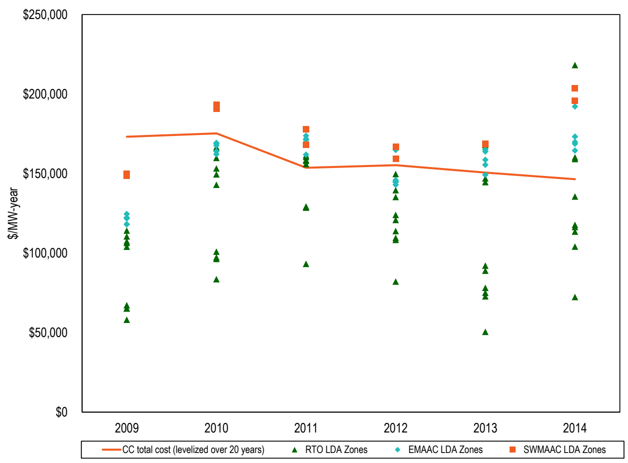
In 2014, the net revenue results for a new CC also bifurcate the zones into two groups with different results, although the results for CCs are overall higher coverage of levelized total costs than for CTs. There are ten eastern zones in which net revenues cover more than 105 percent of levelized total costs. These are the same ten zones with higher net revenues for CTs. The relatively higher net revenues in these zones reflect higher capacity market revenues and generally higher energy market net revenues. In the remaining nine western zones net revenues cover from 49 percent to 102 percent of levelized total costs. The relatively lower net revenues in these zones result from relatively lower capacity revenues and generally below average energy market revenues. The net revenues in these zones increased by more than 50 percent from 2013.

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

Zone	2009	2010	2011	2012	2013	2014
AECO	71%	96%	113%	94%	103%	116%
AEP	39%	55%	84%	70%	50%	79%
AP	66%	87%	104%	78%	59%	93%
ATSI	NA	NA	NA	NA	NA	86%
BGE	86%	110%	116%	107%	112%	139%
ComEd	34%	48%	61%	53%	33%	49%
DAY	38%	55%	84%	73%	52%	80%
DEOK	NA	NA	NA	NA	51%	101%
DLCO	38%	58%	84%	71%	48%	71%
Dominion	61%	95%	105%	80%	61%	77%
DPL	72%	97%	111%	106%	110%	131%
EKPC	NA	NA	NA	NA	NA	102%
JCPL	70%	96%	112%	93%	109%	118%
Met-Ed	64%	91%	103%	90%	98%	109%
PECO	68%	93%	110%	92%	99%	112%
PENELEC	60%	82%	101%	96%	111%	149%
Pepco	87%	109%	109%	102%	112%	134%
PPL	62%	85%	103%	87%	96%	109%
PSEG	68%	94%	105%	93%	105%	115%
RECO	NA	NA	NA	NA	NA	NA
PJM	59%	83%	98%	83%	76%	102%

Figure 7-4 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-4 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year)



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 under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

New entrant CP plant energy market net revenues were higher in 2014 in significant part as a result of higher energy market prices in January (Table 7-11). On average, January accounted for 41 percent of CP net revenues in 2014.

Table 7-11 Energy net revenue for a new entrant CP (Dollars per installed MW-year): 2014[20]

Zone	January	Total	January as a Percent of Total
AECO	$89,184	$163,818	54%
AEP	$41,897	$155,360	27%
AP	$54,038	$179,584	30%
ATSI	$45,576	$168,738	27%
BGE	$95,128	$200,813	47%
ComEd	$32,997	$121,218	27%
DAY	$42,031	$157,743	27%
DEOK	$39,092	$144,564	27%
DLCO	$32,561	$78,181	42%
Dominion	$74,977	$223,179	34%
DPL	$94,404	$212,647	44%
EKPC	$38,888	$126,098	31%
JCPL	$93,871	$170,253	55%
Met-Ed	$87,470	$158,799	55%
PECO	$88,597	$162,057	55%
PENELEC	$60,624	$190,213	32%
Pepco	$91,711	$187,740	49%
PPL	$87,962	$158,785	55%
PSEG	$99,125	$192,556	51%
RECO	$92,596	$185,588	50%
PJM	$69,136	$166,897	41%

Total market revenues (Total columns in Table 7-12) include energy, capacity and ancillary service revenues. Total market revenues increased for a new CP in all PJM zones in 2014.

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

Table 7-12 Net revenue for a new entrant CP (Dollars per installed MW-year)

	2009		2010		2011		2012		2013		2014		Percent Change in
Zone	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	2014 Total Revenue
AECO	87,901	148,766	149,022	211,834	75,325	122,803	23,302	68,057	41,305	114,314	163,818	228,065	100%
AEP	19,251	57,769	56,227	106,816	72,858	120,002	41,246	60,960	77,765	90,366	155,360	187,731	108%
AP	49,303	105,209	98,671	161,578	99,020	146,086	54,555	74,196	89,641	102,069	179,584	211,598	107%
ATSI	NA	NA	NA	NA	27,942	NA	47,276	NA	90,238	NA	168,738	200,935	NA
BGE	46,299	125,422	80,689	150,436	56,940	104,233	23,391	66,784	50,867	119,146	200,813	261,846	120%
ComEd	42,738	81,344	106,599	157,093	94,493	141,510	53,815	73,666	57,925	70,859	121,218	154,162	118%
DAY	27,905	66,301	77,082	127,524	65,842	112,974	43,029	62,727	91,857	104,310	157,743	190,099	82%
DEOK	NA	NA	NA	NA	NA	NA	36,521	NA	81,303	93,900	144,564	177,093	89%
DLCO	22,971	61,485	76,395	126,935	47,075	94,132	43,906	63,737	20,885	34,689	78,181	111,761	222%
Dominion	46,756	85,174	144,290	194,621	77,310	124,773	17,548	37,890	106,130	118,355	223,179	254,755	115%
DPL	38,833	100,379	147,279	210,936	94,908	142,910	29,103	78,990	42,291	119,042	212,647	276,273	132%
EKPC	NA	NA	NA	NA	NA	NA	NA	NA	32,142	NA	126,098	158,827	NA
JCPL	74,389	135,346	147,559	210,360	71,437	118,692	30,519	74,961	47,574	120,469	170,253	234,409	95%
Met-Ed	57,888	113,865	139,228	202,056	61,703	108,848	38,563	81,612	38,916	107,399	158,799	220,558	105%
PECO	78,602	139,510	142,542	205,362	74,834	121,945	24,475	69,115	37,354	110,468	162,057	226,345	105%
PENELEC	77,650	133,259	122,426	185,220	95,440	142,324	52,899	95,700	103,732	171,249	190,213	251,295	47%
Pepco	70,058	148,753	160,627	229,888	73,476	120,561	23,707	67,029	47,769	120,239	187,740	251,785	109%
PPL	71,601	127,425	114,549	177,453	76,697	123,816	18,080	61,532	37,379	105,906	158,785	220,534	108%
PSEG	171,879	232,222	124,533	187,396	47,550	95,621	22,590	70,346	63,026	137,820	192,556	262,192	90%
RECO	71,025	NA	143,410	NA	59,111	NA	29,259	NA	68,678	NA	185,588	NA	NA
PJM	62,062	112,945	119,478	177,203	70,665	117,918	34,410	66,034	61,339	100,059	166,897	212,912	113%

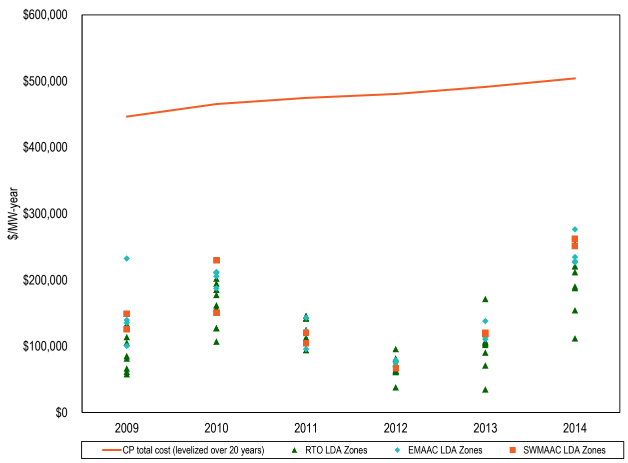
In 2014, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone. The results for CPs vary from covering 22 percent of levelized total costs to 55 percent. Six zones were greater than or equal to 50 percent, the first time since 2009 that even a single zone equaled 50 percent or greater. The results for CPs in 2014 are better than they were in 2013 based on higher energy market net revenues in all zones and higher capacity market revenues in seven zones. All zones showed increases in the coverage of fixed costs by CPs in 2014.

Table 7-13 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014
AECO	33%	46%	26%	14%	23%	45%
AEP	13%	23%	25%	13%	18%	37%
AP	24%	35%	31%	15%	21%	42%
ATSI	NA	NA	NA	NA	NA	40%
BGE	28%	32%	22%	14%	24%	52%
ComEd	18%	34%	30%	15%	14%	31%
DAY	15%	27%	24%	13%	21%	38%
DEOK	NA	NA	NA	NA	19%	35%
DLCO	14%	27%	20%	13%	7%	22%
Dominion	19%	42%	26%	8%	24%	51%
DPL	22%	45%	30%	16%	24%	55%
EKPC	NA	NA	NA	NA	NA	32%
JCPL	30%	45%	25%	16%	25%	47%
Met-Ed	25%	43%	23%	17%	22%	44%
PECO	31%	44%	26%	14%	22%	45%
PENELEC	30%	40%	30%	20%	35%	50%
Pepco	33%	49%	25%	14%	24%	50%
PPL	29%	38%	26%	13%	22%	44%
PSEG	52%	40%	20%	15%	28%	52%
RECO	NA	NA	NA	NA	NA	NA
PJM	25%	38%	25%	14%	20%	42%

Figure 7-5 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-5 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year)



New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

New entrant DS plant energy market net revenues were higher in 2014 in significant part as a result of higher energy market prices in January which more than offset the higher fuel prices. The net revenue increase in January was the result of an increase in profitable run hours and a number of very high price hours (Table 7-14).

Table 7-14 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): 2014

Zone	January	Total	January as a Percent of Total
AECO	$32,279	$41,497	78%
AEP	$13,946	$17,628	79%
AP	$17,537	$22,943	76%
ATSI	$13,182	$17,292	76%
BGE	$48,845	$61,978	79%
ComEd	$10,762	$13,804	78%
DAY	$13,550	$17,418	78%
DEOK	$12,942	$16,476	79%
DLCO	$12,409	$16,011	77%
Dominion	$39,254	$52,332	75%
DPL	$35,082	$49,131	71%
EKPC	$14,159	$17,570	81%
JCPL	$31,902	$41,430	77%
Met-Ed	$31,653	$39,978	79%
PECO	$32,082	$40,427	79%
PENELEC	$15,451	$20,298	76%
Pepco	$50,025	$63,237	79%
PPL	$33,187	$40,981	81%
PSEG	$32,353	$40,971	79%
RECO	$29,345	$38,965	75%
PJM	$25,997	$33,518	78%

Total market revenues (Total columns in Table 7-15) include energy, capacity and ancillary service revenues. Total market revenues increased for a new DS in all PJM zones in 2014.

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

	2009		2010		2011		2012		2013		2014		Percent Change in
Zone	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	2014 Total Revenue
AECO	3,778	62,363	10,802	72,207	6,783	52,721	1,586	44,724	1,122	68,738	41,497	101,509	48%
AEP	392	36,180	490	49,388	1,725	47,662	844	19,573	503	8,246	17,628	45,862	456%
AP	2,081	55,521	1,743	63,149	2,019	47,957	1,087	19,816	771	8,513	22,943	51,178	501%
ATSI	NA	NA	NA	NA	318	NA	1,109	NA	23,776	NA	17,292	45,526	NA
BGE	5,594	81,830	13,673	81,524	7,961	53,899	2,619	44,498	2,758	65,781	61,978	119,410	82%
ComEd	107	35,895	473	49,371	817	46,755	928	19,658	399	8,141	13,804	42,039	416%
DAY	375	36,163	545	49,443	1,906	47,844	971	19,700	535	8,277	17,418	45,653	452%
DEOK	NA	NA	NA	NA	NA	NA	708	NA	477	8,219	16,476	44,711	444%
DLCO	758	36,546	2,882	51,781	2,180	48,118	941	19,671	1,269	9,011	16,011	44,246	391%
Dominion	5,265	41,054	10,589	59,488	4,172	50,110	1,700	20,429	1,600	9,342	52,332	80,566	762%
DPL	4,926	63,511	9,548	71,799	5,842	52,372	2,431	50,830	1,125	72,431	49,131	109,142	51%
EKPC	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17,570	45,804	NA
JCPL	3,829	62,415	8,364	69,770	6,681	52,618	1,741	44,878	2,083	69,699	41,430	101,442	46%
Met-Ed	3,343	56,784	8,422	69,828	5,093	51,031	1,866	43,744	1,292	64,315	39,978	97,409	51%
PECO	3,300	61,885	8,266	69,672	5,446	51,384	1,967	45,105	1,024	68,639	40,427	100,439	46%
PENELEC	829	54,269	1,102	62,508	2,671	48,609	2,167	44,003	1,141	64,135	20,298	77,729	21%
Pepco	5,955	82,191	12,838	80,689	6,149	52,087	2,046	43,924	2,332	69,486	63,237	123,541	78%
PPL	3,079	56,519	7,428	68,834	5,380	51,317	1,782	43,660	1,088	64,111	40,981	98,413	54%
PSEG	3,187	61,772	7,142	68,547	5,519	51,456	1,730	47,953	1,302	71,081	40,971	106,748	50%
RECO	2,733	NA	6,038	NA	4,310	NA	1,771	NA	2,469	NA	38,965	NA	NA
PJM	2,914	51,298	6,491	62,716	4,165	50,122	1,579	31,932	2,477	36,135	33,518	75,439	109%

In 2014, a new 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
AECO	41%	47%	34%	29%	45%	63%
AEP	24%	32%	31%	13%	5%	28%
AP	36%	41%	31%	13%	6%	32%
ATSI	NA	NA	NA	NA	NA	28%
BGE	53%	53%	35%	29%	43%	74%
ComEd	23%	32%	31%	13%	5%	26%
DAY	24%	32%	31%	13%	5%	28%
DEOK	NA	NA	NA	NA	5%	28%
DLCO	24%	34%	31%	13%	6%	27%
Dominion	27%	39%	33%	13%	6%	50%
DPL	41%	47%	34%	33%	47%	67%
EKPC	NA	NA	NA	NA	NA	28%
JCPL	41%	46%	34%	29%	46%	63%
Met-Ed	37%	46%	33%	29%	42%	60%
PECO	40%	45%	34%	29%	45%	62%
PENELEC	35%	41%	32%	29%	42%	48%
Pepco	54%	53%	34%	29%	45%	76%
PPL	37%	45%	34%	29%	42%	61%
PSEG	40%	45%	34%	31%	46%	66%
RECO	NA	NA	NA	NA	NA	NA
PJM	33%	41%	33%	21%	24%	47%

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

New entrant CP plant energy market net revenues were higher in 2014 in significant part as a result of higher energy market prices in January (Table 7-17).

Table 7-17 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2014[21]

Zone	January	Total	January as a Percent of Total
AECO	$119,979	$395,429	30%
AEP	$59,863	$317,638	19%
AP	$73,607	$344,578	21%
ATSI	$63,174	$331,770	19%
BGE	$127,342	$453,074	28%
ComEd	$49,757	$277,615	18%
DAY	$58,908	$320,879	18%
DEOK	$55,592	$305,455	18%
DLCO	$55,595	$297,575	19%
Dominion	$97,271	$395,849	25%
DPL	$123,843	$436,382	28%
EKPC	$56,997	$300,307	19%
JCPL	$125,091	$400,115	31%
Met-Ed	$117,680	$381,693	31%
PECO	$119,005	$386,266	31%
PENELEC	$80,402	$356,762	23%
Pepco	$123,539	$435,983	28%
PPL	$118,216	$382,257	31%
PSEG	$130,878	$424,538	31%
RECO	$123,472	$419,345	29%
PJM	$94,011	$368,176	26%

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

Total market revenues (Total columns in Table 7-18) include energy, capacity and ancillary service revenues. Total market revenues increased for a new nuclear plant in all PJM zones in 2014 as a result of higher prices and low, stable fuel costs.

Table 7-18 Net revenue for a new entrant nuclear plant (Dollars per installed MW-year)

	2009		2010		2011		2012		2013		2014		Percent Change in
Zone	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	Energy	Total	2014 Total Revenue
AECO	288,632	347,217	367,483	428,889	344,843	390,781	227,226	270,363	265,982	333,597	395,429	455,441	37%
AEP	218,504	254,293	261,098	309,996	270,022	315,960	201,658	220,387	233,502	241,244	317,638	345,873	43%
AP	256,721	310,161	314,729	376,135	301,946	347,884	213,700	232,430	247,378	255,121	344,578	372,813	46%
ATSI	NA	NA	NA	NA	158,417	NA	207,425	NA	245,634	NA	331,770	360,005	NA
BGE	298,473	374,708	391,960	459,811	351,870	397,808	249,585	291,463	289,357	352,380	453,074	510,506	45%
ComEd	179,104	214,892	217,838	266,736	218,630	264,567	178,333	197,062	209,239	216,982	277,615	305,849	41%
DAY	214,090	249,878	258,210	307,108	269,794	315,732	207,356	226,086	236,929	244,671	320,879	349,114	43%
DEOK	NA	NA	NA	NA	NA	NA	195,327	NA	224,542	232,285	305,455	333,690	44%
DLCO	208,801	244,589	257,065	305,963	266,265	312,202	202,379	221,108	230,482	238,224	297,575	325,809	37%
Dominion	281,069	316,857	373,737	422,636	328,562	374,500	227,430	246,160	267,075	274,818	395,849	424,084	54%
DPL	291,154	349,739	370,565	432,816	345,422	391,952	240,338	288,737	276,066	347,371	436,382	496,394	43%
EKPC	NA	NA	NA	NA	NA	NA	NA	NA	129,152	NA	300,307	328,542	NA
JCPL	287,875	346,460	365,408	426,814	342,457	388,395	226,166	269,304	274,298	341,914	400,115	460,126	35%
Met-Ed	279,022	332,463	354,677	416,083	326,952	372,890	221,211	263,089	260,859	323,882	381,693	439,125	36%
PECO	282,937	341,523	359,927	421,333	339,177	385,115	224,172	267,310	259,293	326,909	386,266	446,278	37%
PENELEC	250,469	303,909	310,481	371,887	300,414	346,352	218,890	260,727	259,631	322,624	356,762	414,193	28%
Pepco	298,215	374,450	389,389	457,240	342,415	388,352	242,044	283,922	285,119	352,273	435,983	496,288	41%
PPL	275,067	328,507	343,190	404,596	325,767	371,704	216,913	258,792	258,516	321,539	382,257	439,689	37%
PSEG	292,089	350,674	371,365	432,771	348,834	394,771	230,686	276,909	292,907	362,687	424,538	490,316	35%
RECO	284,023	NA	360,820	NA	326,819	NA	224,733	NA	299,071	NA	419,345	NA	NA
PJM	263,897	312,281	333,408	389,634	306,034	351,990	218,714	249,068	252,252	285,909	368,176	410,096	43%

In 2014, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.

Table 7-19 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014
AECO	43%	54%	49%	34%	42%	52%
AEP	32%	39%	39%	28%	30%	39%
AP	39%	47%	43%	29%	32%	42%
ATSI	NA	NA	NA	NA	NA	41%
BGE	47%	57%	50%	36%	44%	58%
ComEd	27%	33%	33%	25%	27%	35%
DAY	31%	38%	39%	28%	31%	40%
DEOK	NA	NA	NA	NA	29%	38%
DLCO	31%	38%	39%	28%	30%	37%
Dominion	40%	53%	47%	31%	34%	48%
DPL	44%	54%	49%	36%	43%	56%
EKPC	NA	NA	NA	NA	NA	37%
JCPL	43%	53%	48%	34%	43%	52%
Met-Ed	42%	52%	47%	33%	40%	50%
PECO	43%	53%	48%	33%	41%	51%
PENELEC	38%	46%	43%	33%	40%	47%
Pepco	47%	57%	48%	35%	44%	56%
PPL	41%	51%	46%	32%	40%	50%
PSEG	44%	54%	49%	35%	45%	56%
RECO	NA	NA	NA	NA	NA	NA
PJM	39%	49%	44%	31%	36%	47%

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by 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.

Wind net revenues did not increase as much as other technology types because wind is not dispatchable in response to higher prices. The significant increase in annual revenue was in part a result of the fact that January was the highest wind output month in 2014.

Table 7-20 Energy Market net revenue for a wind installation (Dollars per installed MW-year)

	2012				2013				2014				Percent Change in
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	2014 Total Revenue
ComEd	67,781	60,971	2,435	131,186	83,453	66,324	1,007	150,783	107,998	71,840	3,671	183,508	22%
PENELEC	68,929	51,529	5,439	125,897	87,404	58,951	8,189	154,545	126,556	61,619	7,466	195,641	27%

In 2014, a new wind installation would have received sufficient net revenue to cover levelized total costs in PENELEC or ComEd.

Table 7-21 Percent of 20-year levelized total costs recovered by wind energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014
ComEd	67%	77%	93%
PENELEC	64%	79%	99%

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG Zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power in that hour.

Like wind, solar net revenues did not increase as much as other technology types because solar output in January was close to the lowest monthly solar output in 2014 and because solar is not dispatchable in response to higher prices.

Table 7-22 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

	2012				2013				2014				Percent Change in
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	2014 Total Revenue
PSEG	50,363	328,733	17,565	396,661	81,813	328,720	26,516	437,050	100,313	323,268	24,995	448,577	3%

In 2014, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG.

Table 7-23 Percent of 20-year levelized total costs recovered by solar energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014
PSEG	100%	166%	190%

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 2014, the average operating cost of the CC was lower than the average operating costs of the CP from May through December, as a result of the relative cost of gas versus coal. (See Figure 7-2.)

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 2014, zonal energy net revenues increased for CCs and CTs, while capacity market prices increased over 2013 in the western zones. The higher net revenues in the western zones resulted from increases in net revenues from both capacity and energy markets.

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 7-24.[22]

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	$116,113	13.9%	$156,443	13.9%	$534,050	13.6%
Base Case	$108,613	12.0%	$146,443	12.0%	$504,050	12.0%
Sensitivity 2	$101,113	10.0%	$136,443	10.0%	$474,050	10.4%
Sensitivity 3	$93,613	7.9%	$126,443	7.9%	$444,050	8.6%
Sensitivity 4	$86,113	5.5%	$116,443	5.6%	$414,050	6.8%
Sensitivity 5	$78,613	2.8%	$106,443	3.1%	$384,050	4.9%
Sensitivity 6	$71,113	(0.5%)	$96,443	0.1%	$354,050	2.8%

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%	$115,225	$154,823
Sensitivity 2	55%	$111,920	$150,633
Base Case	50%	$108,613	$146,443
Sensitivity 3	45%	$105,306	$142,253
Sensitivity 4	40%	$101,999	$138,063
Sensitivity 5	35%	$98,693	$133,873
Sensitivity 6	30%	$95,387	$129,683

Table 7-26 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.

22 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 financing 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 utilized in all calculations.

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	$98,259	$133,325
Sensitivity 2	25	$102,171	$138,282
Base Case	20	$108,613	$146,443
Sensitivity 3	15	$114,040	$153,307
Sensitivity 4	10	$121,234	$162,410

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 2014 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%	$105,051	$0	0.0%	$142,592
Sensitivity 2	$8,005	1.8%	$106,832	$12,127	1.4%	$144,518
Base Case	$16,010	3.5%	$108,613	$24,254	2.8%	$146,443
Sensitivity 3	$24,015	5.3%	$110,393	$36,381	4.2%	$148,368
Sensitivity 4	$32,019	7.0%	$112,173	$48,507	5.5%	$150,294
Sensitivity 5	$40,024	8.8%	$113,954	$60,634	6.9%	$152,219
Sensitivity 6	$50,000	11.0%	$116,173	$72,761	8.3%	$154,145
Sensitivity 7	$75,000	16.5%	$121,734	$100,000	11.4%	$158,470
Sensitivity 8	$100,000	22.0%	$127,295	$150,000	17.2%	$166,408

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 fixed 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 for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and 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 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 energy revenues, less submitted or estimated operating costs, as well as any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start service, in addition to actual or class average reactive revenues from actual FERC filings.

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 2013/2014 and 2014/2015 RPM Auctions.[23] For units that did not submit ACR data, the default ACR was used.

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 2013/2014 and 2014/2015 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 2014. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[24] 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 underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 7-28 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed. Net revenues in Table 7-28 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.

Table 7-28 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: 2014[25]

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	2,078	$76,130	$138,722	$48,810
CC - Two on Three on One Frame F Technology	10,789	$37,188	$85,377	$21,810
CT - First & Second Generation Aero (P&W FT 4)	3,505	$23,014	$78,718	$9,439
CT - First & Second Generation Frame B	3,282	$13,355	$69,202	$10,974
CT - Second Generation Frame E	9,826	$15,641	$58,708	$9,707
CT - Third Generation Aero	3,864	$26,031	$75,112	$19,799
CT - Third Generation Frame F	10,418	($5,350)	$30,746	$9,812
Diesel	480	$29,717	$78,206	$9,627
Hydro	6,869	$480,087	$529,312	$24,646
Nuclear	31,661	$302,462	$346,518	NA
Oil or Gas Steam	9,545	$38,120	$94,129	$40,223
Sub-Critical Coal	28,284	$69,316	$102,224	$68,463
Super Critical Coal	20,716	$89,723	$134,320	$117,933

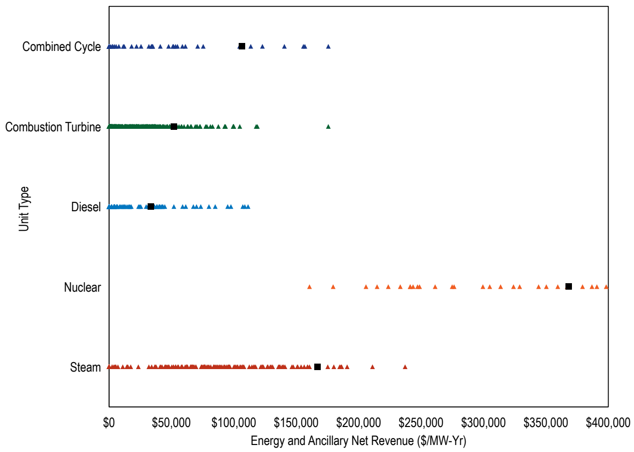
The average net revenue results do not show the underlying distribution of actual net revenues by unit type. This underlying distribution of energy and ancillary net revenues by unit type is shown in Figure 7-6. Each generating unit is represented by a single point, and the new entrant PJM average theoretical energy and ancillary net revenue is represented by a solid square.

23 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.

24 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.

25 20-year levelized total cost used in place of Nuclear ACR.

Figure 7-6 PJM distribution of energy and ancillary net revenue by unit type (Dollars per installed MW-year): 2014



The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-28 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 while avoiding the influence of outliers. The three break points between the four quartiles are presented. Table 7-29 shows average energy and ancillary service net revenues by quartile for select technology classes.

Table 7-29 Energy and ancillary service net revenue by quartile for select technologies: 2014

	Energy and ancillary net revenue ($/MW year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$1,361	$30,183	$58,759
CC - Two on Three on One Frame F Technology	$0	$18,086	$54,781
CT - First & Second Generation Aero (P&W FT 4)	$3,308	$19,905	$29,573
CT - First & Second Generation Frame B	($85)	$5,282	$25,226
CT - Second Generation Frame E	$5	$3,983	$22,338
CT - Third Generation Aero	$5,442	$16,208	$42,773
CT - Third Generation Frame F	$1,524	$7,982	$27,437
Diesel	$0	$6,812	$38,454
Hydro	$122,130	$276,798	$480,028
Nuclear	$241,331	$305,066	$367,972
Oil or Gas Steam	($329)	$4,049	$21,605
Sub-Critical Coal	$5,415	$67,627	$107,361
Super Critical Coal	$62,296	$89,513	$121,550

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 geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class.

Table 7-30 shows capacity market net revenues by quartile for select technology classes.

Table 7-30 Capacity revenue by quartile for select technologies: 2014

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$60,935	$64,267	$71,670
CC - Two on Three on One Frame F Technology	$31,002	$44,293	$65,237
CT - First & Second Generation Aero (P&W FT 4)	$45,618	$60,251	$65,814
CT - First & Second Generation Frame B	$30,058	$56,497	$62,248
CT - Second Generation Frame E	$29,725	$30,942	$63,375
CT - Third Generation Aero	$30,888	$31,203	$62,046
CT - Third Generation Frame F	$29,216	$30,675	$31,656
Diesel	$30,595	$56,286	$65,439
Hydro	$30,380	$60,641	$63,360
Nuclear	$30,472	$30,915	$63,055
Oil or Gas Steam	$55,401	$61,966	$64,931
Sub-Critical Coal	$27,629	$29,489	$45,831
Super Critical Coal	$29,541	$54,087	$60,806

Table 7-31 shows total net revenues by quartile for select technology classes.

Table 7-31 Combined revenue from all markets by quartile for select technologies: 2014

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$62,296	$94,451	$130,429
CC - Two on Three on One Frame F Technology	$31,002	$62,379	$120,018
CT - First & Second Generation Aero (P&W FT 4)	$48,926	$80,155	$95,387
CT - First & Second Generation Frame B	$29,973	$61,780	$87,474
CT - Second Generation Frame E	$29,730	$34,925	$85,712
CT - Third Generation Aero	$36,330	$47,411	$104,819
CT - Third Generation Frame F	$30,740	$38,657	$59,093
Diesel	$30,595	$63,098	$103,892
Hydro	$152,510	$337,440	$543,388
Nuclear	$271,803	$335,980	$431,027
Oil or Gas Steam	$55,071	$66,015	$86,536
Sub-Critical Coal	$33,044	$97,116	$153,193
Super Critical Coal	$91,837	$143,600	$182,356

Table 7-32 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2014, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 7-32 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies

	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	31%	72%	109%
CC - Two on Three on One Frame F Technology	0%	90%	140%
CT - First & Second Generation Aero (P&W FT 4)	32%	184%	319%
CT - First & Second Generation Frame B	NA	67%	240%
CT - Second Generation Frame E	NA	77%	225%
CT - Third Generation Aero	28%	61%	133%
CT - Third Generation Frame F	15%	79%	260%
Diesel	75%	536%	710%
Hydro	820%	1,039%	1,592%
Nuclear	NA	NA	NA
Oil or Gas Steam	NA	25%	87%
Sub-Critical Coal	10%	91%	143%
Super Critical Coal	83%	113%	172%

Table 7-33 shows the avoidable cost recovery from all PJM markets by quartiles. The net revenues from all markets cover avoidable costs for most technology types.

Table 7-33 Avoidable cost recovery by quartile from all PJM Markets for select technologies for 2014

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	179%	211%	276%
CC - Two on Three on One Frame F Technology	270%	378%	500%
CT - First & Second Generation Aero (P&W FT 4)	545%	783%	1,057%
CT - First & Second Generation Frame B	494%	611%	862%
CT - Second Generation Frame E	290%	415%	644%
CT - Third Generation Aero	165%	284%	368%
CT - Third Generation Frame F	303%	454%	704%
Diesel	554%	1,378%	1,570%
Hydro	1,037%	1,374%	1,808%
Nuclear	NA	NA	NA
Oil or Gas Steam	192%	259%	324%
Sub-Critical Coal	78%	134%	207%
Super Critical Coal	104%	173%	255%

Table 7-34 and Table 7-35 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2014, 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 7-34 Proportion of units recovering avoidable costs from energy and ancillary markets

	Units with full recovery from energy and ancillary services markets					
Technology	2009	2010	2011	2012	2013	2014
CC - NUG Cogeneration Frame B or E Technology	41%	81%	52%	40%	61%	50%
CC - Two on Three on One Frame F Technology	22%	54%	53%	52%	56%	59%
CT - First & Second Generation Aero (P&W FT 4)	27%	33%	16%	12%	19%	71%
CT - First & Second Generation Frame B	28%	27%	26%	20%	8%	50%
CT - Second Generation Frame E	52%	32%	40%	43%	38%	65%
CT - Third Generation Aero	20%	48%	51%	43%	23%	46%
CT - Third Generation Frame F	32%	29%	31%	62%	54%	51%
Diesel	62%	77%	68%	55%	53%	72%
Hydro and Pumped Storage	60%	99%	96%	99%	99%	99%
Nuclear	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	42%	52%	42%	39%	42%	48%
Sub-Critical Coal	28%	76%	53%	30%	44%	66%
Super Critical Coal	37%	80%	53%	28%	31%	79%

Table 7-35 Proportion of units recovering avoidable costs from all markets

	Units with full recovery from all markets					
Technology	2009	2010	2011	2012	2013	2014
CC - NUG Cogeneration Frame B or E Technology	91%	90%	92%	90%	100%	100%
CC - Two on Three on One Frame F Technology	100%	89%	87%	90%	85%	93%
CT - First & Second Generation Aero (P&W FT 4)	98%	90%	90%	90%	86%	97%
CT - First & Second Generation Frame B	99%	99%	95%	94%	90%	97%
CT - Second Generation Frame E	100%	91%	90%	94%	94%	100%
CT - Third Generation Aero	74%	99%	99%	90%	73%	96%
CT - Third Generation Frame F	100%	96%	93%	92%	90%	97%
Diesel	100%	98%	91%	85%	74%	93%
Hydro and Pumped Storage	100%	100%	100%	100%	100%	100%
Nuclear	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	95%	90%	68%	69%	77%	88%
Sub-Critical Coal	80%	94%	76%	48%	60%	80%
Super Critical Coal	77%	100%	80%	39%	64%	87%

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.[26]

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, may be at risk of retirement. In addition, units that failed to clear the most recent capacity auction(s) may be at risk of retirement. The profile of units falling into these categories is shown in Table 7-36. These units are considered at risk of retirement.

These results mean that 6,946 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire.

While the evidence is not complete on whether nuclear units are covering avoidable costs, total market revenues are not covering the total annualized costs of nuclear units in any part of PJM. Further analysis is required in order to determine whether any nuclear units are at risk in PJM.

Table 7-36 Profile of units that did not recover avoidable costs from total market revenues or did not clear the 16/17 BRA or 17/18 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2014 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	9	340	1,889	12,662	27
Coal	7	4,844	7,184	10,019	46
Diesel	3	33	3,261	11,267	23
Oil or Gas Steam	3	1,730	2,043	12,447	35
Total	22	6,946	3,197	11,391	34

26 This analysis excludes nuclear units due to a lack of data and is based in part on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits to the extent they were known and understood by generation owners following the issuance of the final MATS rule.