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. Fuel prices and energy prices were higher in 2013 than in 2012 and capacity market prices were higher in 2013 in 10 eastern zones and lower in six western zones, AEP, AP, ComEd, DAY, DLCO, and Dominion.
- In 2013, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone. But 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 75 percent of levelized fixed costs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 30 percent of levelized fixed costs with the lowest zone at 18 percent. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets. Covering 75 percent of levelized fixed costs would result in a rate of return slightly less than half the rate of return included in the calculation of levelized fixed costs.
- In 2013, the net revenue results for a new CC also 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 fixed costs. These are the same ten zones with higher net revenues for CTs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 65 but more than 33 percent of levelized fixed costs. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets.
- In 2013, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for CPs in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013.
- In 2013, a new nuclear plant in the western AEP zone would not have received sufficient net revenue to cover levelized fixed costs. The combination of lower energy market revenues and lower capacity market revenues in the AEP zone, similar to the other western zones, than in the eastern zones resulted in a covering only 30 percent of the annual fixed costs for a nuclear power plant.
- In 2013, actual net revenues covered more than 75 percent of the annual levelized fixed costs of a new entrant wind installation and over 200 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 75 percent of the net revenue of a solar installation.
- In 2013, 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. Capacity market revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of some coal units and some oil or gas steam units.
- The actual net revenue results mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW 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.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. The actual net revenue results illustrate that a significant amount of generation in PJM relies on the capacity market to cover the gap between energy market net revenues and avoidable costs. Capacity market revenues are critical to covering total costs including fixed costs.

The net revenue results also demonstrate the significance of capacity market design. Capacity market prices have been suppressed by a number of market design factors. These factors, including an inappropriate definition of capacity imports has led to especially low capacity market prices in the western part of the system. The impacts of this are clearly shown in the bifurcation of net revenue results between the eastern and western zones in PJM.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low 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 and other inframarginal units.

Net Revenue

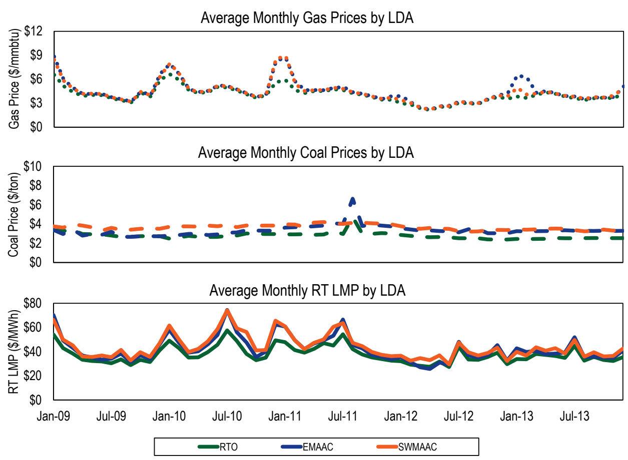
When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators 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 9.7 percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh. Comparing fuel prices in 2013 to 2012, the price of Northern Appalachian coal was 1.0 percent higher; the price of Central Appalachian coal was 0.3 percent higher; the price of Powder River Basin coal was 20.0 percent higher; the price of eastern natural gas was 40.0 percent higher; and the price of western natural gas was 32.0 percent higher.

Figure 7-1 Energy Market net revenue factor trends: 2009 through 2013



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 410.2 MW and consists of two GE Frame 7FA.05 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 655.7 MW and consists of two GE Frame 7FA.05 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]
- 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 GE 2.5 MW wind turbines totaling 50 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.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included

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 heat rate and subsequently 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.

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 are 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 30 or fewer operating years.

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]

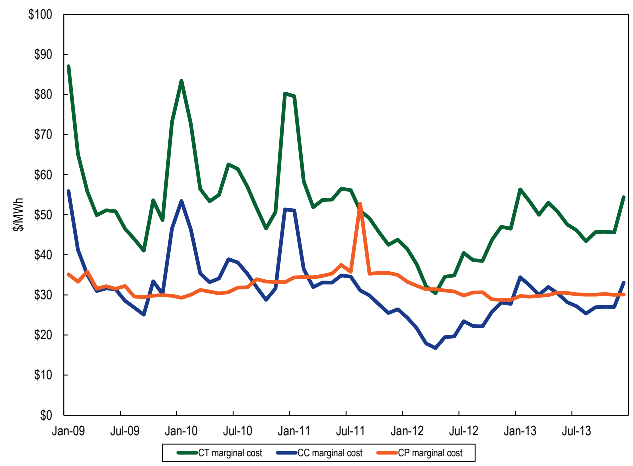
Operating costs are the marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[10] Average zonal operating costs in 2013 are shown in Table 7-1.

Table 7-1 Average zonal operating costs

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$49.10	10,241	$8.59
CC	$29.34	7,127	$1.50
CP	$29.98	9,250	$3.32
DS	$220.21	9,660	$12.50

Increasing gas prices caused the average zonal operating cost of a CC to rise above the average zonal operating cost of a CP by the end of the 2013 as shown in Figure 7-2.

Figure 7-2 Average zonal operating costs: 2009 through 2013



The net revenue measure does not include the potentially significant contribution to fixed cost 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.

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 VOM rates provided by Pasteris Energy, Inc.

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 2013 includes five months of the 2012/2013 RPM auction clearing price and seven months of the 2013/2014 RPM auction clearing price.[11] These capacity revenues are adjusted for the yearly, system wide forced outage rate.

Table 7-2 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2013[12]

Zone	2009	2010	2011	2012	2013	Average
AECO	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
AEP	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
AP	$53,440	$61,406	$45,938	$18,730	$7,743	$37,451
ATSI	NA	NA	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$41,878	$63,023	$58,985
ComEd	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DAY	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DEOK	NA	NA	NA	NA	$7,743	$7,743
DLCO	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
Dominion	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DPL	$58,586	$62,251	$46,530	$48,399	$71,305	$57,414
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
Met-Ed	$53,440	$61,406	$45,938	$41,878	$63,023	$53,137
PECO	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
PENELEC	$53,440	$61,406	$45,938	$41,837	$62,994	$53,123
Pepco	$76,236	$67,851	$45,938	$41,878	$67,154	$59,811
PPL	$53,440	$61,406	$45,938	$41,878	$63,023	$53,137
PSEG	$58,586	$61,406	$45,938	$46,223	$69,779	$56,386
RECO	NA	NA	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$30,354	$33,657	$42,916

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 7-3 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$9,945	$48,385	$0	$0	$887	$59,216
2010	$32,781	$56,226	$0	$0	$4,320	$93,327
2011	$36,103	$45,956	$0	$0	$3,587	$85,647
2012	$23,240	$30,354	$0	$0	$891	$54,485
2013	$19,004	$33,657	$0	$0	$1,296	$53,958

Table 7-4 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2013[13]

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$12,421	$40,037	$46,156	$25,015	$20,835	(17%)
AEP	$3,696	$11,575	$20,838	$16,262	$12,535	(23%)
AP	$11,136	$32,494	$32,958	$21,028	$17,091	(19%)
ATSI	NA	NA	NA	$18,295	$15,402	(16%)
BGE	$15,126	$52,411	$48,640	$36,305	$29,602	(18%)
ComEd	$2,445	$9,446	$15,081	$13,780	$10,381	(25%)
DAY	$3,313	$11,701	$21,704	$18,572	$12,559	(32%)
DEOK	NA	NA	NA	$16,003	$12,036	(25%)
DLCO	$4,471	$17,525	$24,178	$18,772	$14,499	(23%)
Dominion	$15,253	$42,922	$38,944	$25,374	$20,253	(20%)
DPL	$13,886	$40,530	$44,338	$32,585	$24,545	(25%)
EKPC	NA	NA	NA	NA	$10,507	NA
JCPL	$11,994	$39,409	$44,967	$24,115	$25,778	7%
Met-Ed	$11,083	$39,409	$40,800	$25,395	$20,492	(19%)
PECO	$10,611	$38,311	$45,852	$25,882	$19,688	(24%)
PENELEC	$6,986	$24,309	$32,089	$22,461	$21,779	(3%)
Pepco	$17,798	$50,906	$44,232	$32,009	$27,977	(13%)
PPL	$10,045	$33,649	$42,870	$22,816	$19,895	(13%)
PSEG	$10,079	$37,626	$37,927	$24,080	$20,872	(13%)
RECO	$8,717	$35,022	$32,177	$22,807	$23,363	2%
PJM	$9,945	$32,781	$36,103	$23,240	$19,004	(18%)

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

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

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

Table 7-5 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$71,894	$105,763	$95,680	$69,044	$89,747	30%
AEP	$40,371	$64,793	$70,363	$35,882	$21,573	(40%)
AP	$65,464	$98,220	$82,483	$40,648	$26,129	(36%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$92,249	$124,583	$98,165	$79,074	$93,921	19%
ComEd	$39,120	$62,665	$64,605	$33,400	$19,420	(42%)
DAY	$39,989	$64,919	$71,229	$38,193	$21,597	(43%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$41,146	$70,743	$73,702	$38,393	$23,537	(39%)
Dominion	$51,928	$96,141	$88,469	$44,994	$29,292	(35%)
DPL	$73,358	$107,101	$94,455	$81,876	$97,146	19%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$71,466	$105,135	$94,491	$68,144	$94,690	39%
Met-Ed	$65,410	$105,135	$90,325	$68,164	$84,811	24%
PECO	$70,083	$104,037	$95,377	$69,911	$88,599	27%
PENELEC	$61,314	$90,035	$81,614	$65,189	$86,068	32%
Pepco	$94,921	$123,078	$93,756	$74,778	$96,427	29%
PPL	$64,372	$99,375	$92,395	$65,585	$84,214	28%
PSEG	$69,552	$103,352	$87,452	$71,194	$91,948	29%
RECO	NA	NA	NA	NA	NA	NA
PJM	$59,216	$93,327	$85,647	$54,485	$53,958	(1%)

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.[14] 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 generally lower in 2013 as a result of the interaction between the relative costs of gas and coal and energy market prices.

Table 7-6 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$52,260	$48,385	$0	$0	$1,641	$102,286
2010	$89,027	$56,226	$0	$0	$762	$146,014
2011	$106,616	$45,956	$0	$0	$964	$153,536
2012	$97,259	$30,354	$0	$0	$1,608	$129,221
2013	$81,012	$33,657	$0	$0	$269	$114,939

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

Table 7-7 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$62,063	$106,643	$126,866	$101,147	$87,580	(13%)
AEP	$29,759	$47,591	$82,321	$87,906	$67,040	(24%)
AP	$59,052	$91,032	$113,559	$100,496	$80,861	(20%)
ATSI	NA	NA	NA	$94,384	$78,928	(16%)
BGE	$70,571	$124,665	$130,803	$123,364	$105,312	(15%)
ComEd	$20,613	$33,906	$46,291	$61,752	$42,434	(31%)
DAY	$27,904	$46,647	$82,064	$93,514	$70,151	(25%)
DEOK	NA	NA	NA	$82,041	$69,498	(15%)
DLCO	$27,649	$51,180	$81,639	$89,178	$64,735	(27%)
Dominion	$68,932	$116,873	$114,527	$103,607	$84,077	(19%)
DPL	$64,321	$106,245	$123,597	$114,805	$93,469	(19%)
EKPC	NA	NA	NA	NA	$47,065	NA
JCPL	$61,477	$105,474	$124,875	$100,383	$95,950	(4%)
Met-Ed	$55,400	$97,665	$111,650	$96,015	$83,610	(13%)
PECO	$57,843	$99,951	$121,801	$98,148	$81,262	(17%)
PENELEC	$48,876	$80,773	$109,045	$106,233	$104,603	(2%)
Pepco	$71,959	$121,952	$121,141	$115,688	$100,910	(13%)
PPL	$52,285	$87,314	$111,108	$91,724	$81,294	(11%)
PSEG	$57,910	$101,819	$114,948	$96,614	$88,596	(8%)
RECO	$51,808	$93,724	$96,232	$90,921	$92,865	2%
PJM	$52,260	$89,027	$106,616	$97,259	$81,012	(17%)

Table 7-8 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$122,290	$168,811	$173,768	$145,892	$155,464	7%
AEP	$67,189	$97,252	$129,223	$108,243	$75,051	(31%)
AP	$114,134	$153,200	$160,460	$120,834	$88,873	(26%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$148,448	$193,279	$177,704	$166,850	$168,604	1%
ComEd	$58,043	$83,567	$93,193	$82,089	$50,446	(39%)
DAY	$65,333	$96,308	$128,966	$113,852	$78,163	(31%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$65,078	$100,841	$128,541	$109,515	$72,747	(34%)
Dominion	$106,362	$166,534	$161,429	$123,945	$92,089	(26%)
DPL	$124,547	$169,258	$171,090	$164,812	$165,043	0%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$121,704	$167,642	$171,777	$145,129	$163,835	13%
Met-Ed	$110,482	$159,833	$158,551	$139,501	$146,902	5%
PECO	$118,069	$162,119	$168,703	$142,894	$149,146	4%
PENELEC	$103,957	$142,941	$155,947	$149,678	$167,866	12%
Pepco	$149,836	$190,565	$168,042	$159,174	$168,333	6%
PPL	$107,366	$149,481	$158,010	$135,211	$144,586	7%
PSEG	$118,137	$163,986	$161,850	$144,446	$158,645	10%
RECO	NA	NA	NA	NA	NA	NA
PJM	$102,286	$146,014	$153,536	$129,221	$114,939	(11%)

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.

Table 7-9 PJM-wide net revenue for a CP by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$62,062	$48,385	$0	$2,213	$286	$112,945
2010	$119,478	$56,226	$0	$898	$601	$177,203
2011	$73,178	$45,956	$0	$1,025	$272	$120,431
2012	$34,410	$30,354	$0	$1,154	$117	$66,034
2013	$61,339	$33,657	$0	$2,187	$2,876	$100,059

Table 7-10 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$87,901	$149,022	$75,325	$23,302	$41,305	77%
AEP	$19,251	$56,227	$72,858	$41,246	$77,765	89%
AP	$49,303	$98,671	$99,020	$54,555	$89,641	64%
ATSI	NA	NA	NA	$47,276	$90,238	91%
BGE	$46,299	$80,689	$56,940	$23,391	$50,867	117%
ComEd	$42,738	$106,599	$94,493	$53,815	$57,925	8%
DAY	$27,905	$77,082	$65,842	$43,029	$91,857	113%
DEOK	NA	NA	NA	$36,521	$81,303	123%
DLCO	$22,971	$76,395	$47,075	$43,906	$20,885	(52%)
Dominion	$46,756	$144,290	$77,310	$17,548	$106,130	505%
DPL	$38,833	$147,279	$94,908	$29,103	$42,291	45%
EKPC	NA	NA	NA	NA	$32,142	NA
JCPL	$74,389	$147,559	$71,437	$30,519	$47,574	56%
Met-Ed	$57,888	$139,228	$61,703	$38,563	$38,916	1%
PECO	$78,602	$142,542	$74,834	$24,475	$37,354	53%
PENELEC	$77,650	$122,426	$95,440	$52,899	$103,732	96%
Pepco	$70,058	$160,627	$73,476	$23,707	$47,769	101%
PPL	$71,601	$114,549	$76,697	$18,080	$37,379	107%
PSEG	$171,879	$124,533	$47,550	$22,590	$63,026	179%
RECO	$71,025	$143,410	$59,111	$29,259	$68,678	135%
PJM	$62,062	$119,478	$73,178	$34,410	$61,339	78%

Table 7-11 Zonal combined net revenue from all markets for a CP (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$148,766	$211,834	$122,803	$68,057	$114,314	68%
AEP	$57,769	$106,816	$120,002	$60,960	$90,366	48%
AP	$105,209	$161,578	$146,086	$74,196	$102,069	38%
ATSI	NA	NA	NA	NA	NA	NA
BGE	$125,422	$150,436	$104,233	$66,784	$119,146	78%
ComEd	$81,344	$157,093	$141,510	$73,666	$70,859	(4%)
DAY	$66,301	$127,524	$112,974	$62,727	$104,310	66%
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$61,485	$126,935	$94,132	$63,737	$34,689	(46%)
Dominion	$85,174	$194,621	$124,773	$37,890	$118,355	212%
DPL	$100,379	$210,936	$142,910	$78,990	$119,042	51%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$135,346	$210,360	$118,692	$74,961	$120,469	61%
Met-Ed	$113,865	$202,056	$108,848	$81,612	$107,399	32%
PECO	$139,510	$205,362	$121,945	$69,115	$110,468	60%
PENELEC	$133,259	$185,220	$142,324	$95,700	$171,249	79%
Pepco	$148,753	$229,888	$120,561	$67,029	$120,239	79%
PPL	$127,425	$177,453	$123,816	$61,532	$105,906	72%
PSEG	$232,222	$187,396	$95,621	$70,346	$137,820	96%
RECO	NA	NA	NA	NA	NA	NA
PJM	$112,945	$177,203	$120,431	$66,034	$100,059	52%

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.

Table 7-12 PJM-wide net revenue for a DS by market (Dollars per installed MW-year): 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$2,914	$48,385	$0	$0	$0	$51,298
2010	$6,491	$56,226	$0	$0	$0	$62,716
2011	$4,391	$45,956	$0	$0	$0	$50,348
2012	$1,579	$30,354	$0	$0	$0	$31,932
2013	$2,368	$33,657	$0	$0	$0	$36,026

Table 7-13 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$3,778	$10,802	$6,783	$1,586	$1,122	(29%)
AEP	$392	$490	$1,725	$844	$503	(40%)
AP	$2,081	$1,743	$2,019	$1,087	$771	(29%)
ATSI	NA	NA	NA	$1,109	$23,776	2,044%
BGE	$5,594	$13,673	$7,961	$2,619	$2,758	5%
ComEd	$107	$473	$817	$928	$399	(57%)
DAY	$375	$545	$1,906	$971	$535	(45%)
DEOK	NA	NA	NA	$708	$477	(33%)
DLCO	$758	$2,882	$2,180	$941	$1,269	35%
Dominion	$5,265	$10,589	$4,172	$1,700	$1,600	(6%)
DPL	$4,926	$9,548	$5,842	$2,431	$1,125	(54%)
EKPC	NA	NA	NA	NA	$297	NA
JCPL	$3,829	$8,364	$6,681	$1,741	$2,083	20%
Met-Ed	$3,343	$8,422	$5,093	$1,866	$1,292	(31%)
PECO	$3,300	$8,266	$5,446	$1,967	$1,024	(48%)
PENELEC	$829	$1,102	$2,671	$2,167	$1,141	(47%)
Pepco	$5,955	$12,838	$6,149	$2,046	$2,332	14%
PPL	$3,079	$7,428	$5,380	$1,782	$1,088	(39%)
PSEG	$3,187	$7,142	$5,519	$1,730	$1,302	(25%)
RECO	$2,733	$6,038	$4,310	$1,771	$2,469	39%
PJM	$2,914	$6,491	$4,391	$1,579	$2,368	50%

Table 7-14 Zonal combined net revenue from all markets for a DS (Dollars per installed MW-year): 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$62,363	$72,207	$52,721	$44,724	$69,860	56%
AEP	$36,180	$49,388	$47,662	$19,573	$8,749	(55%)
AP	$55,521	$63,149	$47,957	$19,816	$9,284	(53%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$81,830	$81,524	$53,899	$44,498	$65,781	48%
ComEd	$35,895	$49,371	$46,755	$19,658	$8,141	(59%)
DAY	$36,163	$49,443	$47,844	$19,700	$8,277	(58%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$36,546	$51,781	$48,118	$19,671	$9,011	(54%)
Dominion	$41,054	$59,488	$50,110	$20,429	$9,342	(54%)
DPL	$63,511	$71,799	$52,372	$50,830	$72,431	42%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$62,415	$69,770	$52,618	$44,878	$69,699	55%
Met-Ed	$56,784	$69,828	$51,031	$43,744	$64,315	47%
PECO	$61,885	$69,672	$51,384	$45,105	$68,639	52%
PENELEC	$54,269	$62,508	$48,609	$44,003	$64,135	46%
Pepco	$82,191	$80,689	$52,087	$43,924	$69,486	58%
PPL	$56,519	$68,834	$51,317	$43,660	$64,111	47%
PSEG	$61,772	$68,547	$51,456	$47,953	$71,081	48%
RECO	NA	NA	NA	NA	NA	NA
PJM	$51,298	$62,716	$50,348	$31,932	$36,026	13%

New Entrant Nuclear Plant

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

Table 7-15 PJM-wide net revenue for a nuclear plant by market (Dollars per installed MW-year): 2012 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$218,504	$35,789	$0	$0	$0	$254,293
2010	$261,098	$48,898	$0	$0	$0	$309,996
2011	$270,022	$45,938	$0	$0	$0	$315,960
2012	$201,658	$18,730	$0	$0	$0	$220,387
2013	$233,502	$7,743	$0	$0	$0	$241,244

Table 7-16 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2012 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AEP	$218,504	$261,098	$270,022	$201,658	$233,502	16%

Table 7-17 Zonal combined net revenue from all markets for a nuclear plant (Dollars per installed MW-year): 2012 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AEP	$254,293	$309,996	$315,960	$220,387	$241,244	9%

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. Capacity revenue was calculated using a 13 percent capacity factor. Wind net revenues include both production tax credits and RECs.

Table 7-18 ComEd net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

ComEd	Energy	Credits	Capacity	Total	Change (%)
2012	$67,294	$57,709	$2,435	$127,438	NA
2013	$82,934	$62,837	$1,007	$146,777	15.2%

Table 7-19 PENELEC net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

PENELEC	Energy	Credits	Capacity	Total	Change (%)
2012	$68,913	$58,450	$5,439	$132,802	NA
2013	$87,404	$66,885	$8,189	$162,479	22.3%

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. Capacity revenue was calculated using a 38 percent capacity factor. Solar net revenues include SRECs.

Table 7-20 PSEG net revenue for a solar installation by market (Dollars per installed MW-year): 2012 through 2013

PSEG	Energy	Credits	Capacity	Total	Change (%)
2012	$50,363	$314,530	$17,565	$382,458	NA
2013	$81,813	$428,449	$26,516	$536,778	40.3%

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 7-21 includes new entrant levelized total costs for selected technologies. The levelized total costs of both the combined cycle and combustion turbine decreased in 2013 from 2012 as a result of competitive pressures in the equipment market.

Net revenue includes net revenue 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 Fixed Costs

Table 7-21 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year)): 2009 through 2013[15, 16]

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

New Entrant Combustion Turbine

In 2013, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone. But the results bifurcate the zones into two groups with very different results. This separation is also illustrated in Figure 7-4. There are ten zones in which net revenues cover more than 75 percent of levelized fixed costs. These ten zones are in the eastern part of PJM. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six zones net revenues cover less than 30 percent of levelized fixed costs with the lowest zone at 18 percent. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets. Covering 75 percent of levelized fixed costs would result in a rate of return slightly less than half the rate of return included in the calculation of levelized fixed costs. (See Table 7-29.)

15 Levelized fixed costs provided by Pasteris Energy, Inc.

16 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.

Table 7-22 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013
AECO	56%	81%	87%	61%	82%
AEP	31%	49%	64%	32%	20%
AP	51%	75%	75%	36%	24%
ATSI	NA	NA	NA	NA	NA
BGE	72%	95%	89%	70%	86%
ComEd	30%	48%	58%	30%	18%
DAY	31%	50%	64%	34%	20%
DEOK	NA	NA	NA	NA	NA
DLCO	32%	54%	67%	34%	21%
Dominion	40%	73%	80%	40%	27%
DPL	57%	82%	85%	72%	89%
EKPC	NA	NA	NA	NA	NA
JCPL	56%	80%	85%	60%	86%
Met-Ed	51%	80%	82%	60%	77%
PECO	54%	79%	86%	62%	81%
PENELEC	48%	69%	74%	58%	78%
Pepco	74%	94%	85%	66%	88%
PPL	50%	76%	84%	58%	77%
PSEG	54%	79%	79%	63%	84%
RECO	NA	NA	NA	NA	NA
PJM	49%	73%	78%	52%	60%

Figure 7-3 compares zonal net revenue for a new entrant CT to the 2013 levelized fixed cost. Figure 7-4 shows zonal net revenue for the new entrant CT by LDA with the applicable annual levelized fixed cost.

Figure 7-3 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

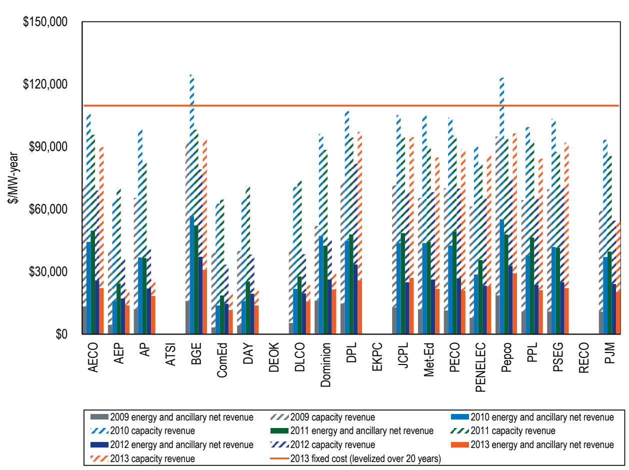


Figure 7-4 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013

New Entrant Combined Cycle

In 2013, a new CC would have received net revenue sufficient to cover levelized fixed costs in seven zones. The results bifurcate the zones into two groups with very different results. This separation is also illustrated in Figure 7-6. There are ten zones in which net revenues cover more than 95 percent of levelized fixed costs. These are the same ten zones with higher net revenues for CTs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. These ten zones are in the eastern part of PJM. In the remaining six zones net revenues cover less than 65 but more than 33 percent of levelized fixed costs. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets.

Table 7-23 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue: 2009 through 2013

Zone	2009	2010	2011	2012	2013
AECO	71%	96%	113%	94%	103%
AEP	39%	55%	84%	70%	50%
AP	66%	87%	104%	78%	59%
ATSI	NA	NA	NA	NA	NA
BGE	86%	110%	116%	107%	112%
ComEd	34%	48%	61%	53%	33%
DAY	38%	55%	84%	73%	52%
DEOK	NA	NA	NA	NA	NA
DLCO	38%	58%	84%	71%	48%
Dominion	61%	95%	105%	80%	61%
DPL	72%	97%	111%	106%	110%
EKPC	NA	NA	NA	NA	NA
JCPL	70%	96%	112%	93%	109%
Met-Ed	64%	91%	103%	90%	98%
PECO	68%	93%	110%	92%	99%
PENELEC	60%	82%	101%	96%	111%
Pepco	87%	109%	109%	102%	112%
PPL	62%	85%	103%	87%	96%
PSEG	68%	94%	105%	93%	105%
RECO	NA	NA	NA	NA	NA
PJM	61%	84%	100%	87%	85%

Figure 7-5 compares zonal net revenue for a new entrant CC to the 2013 levelized fixed cost. Figure 7-6 shows zonal net revenue for the new entrant CC for by LDA with the applicable yearly levelized fixed cost.

Figure 7-5 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

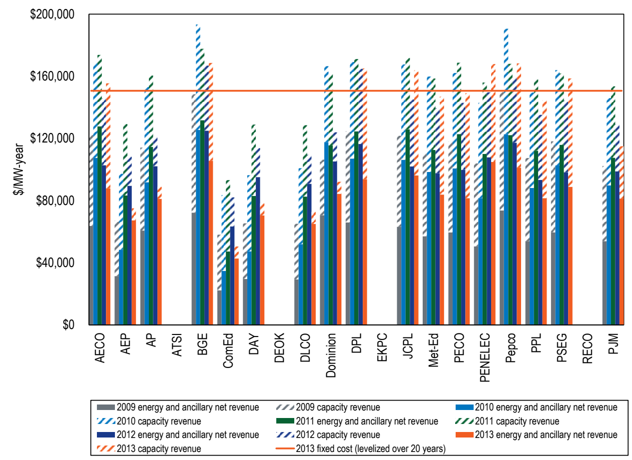
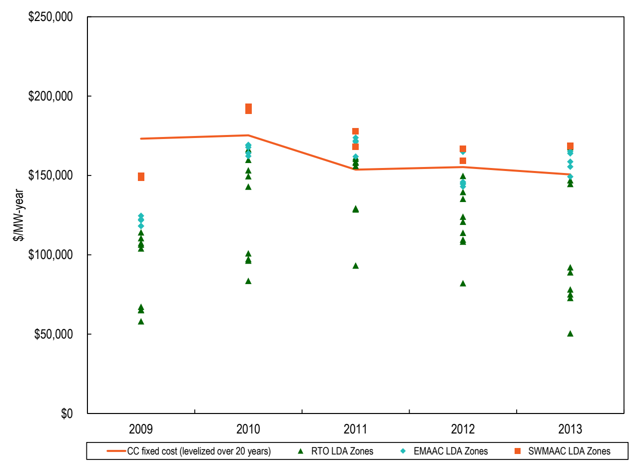


Figure 7-6 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013



New Entrant Coal Plant

In 2013, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for CPs in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013. This improvement is also illustrated in Figure 7-8.

Table 7-24 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue: 2009 through 2013

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

Figure 7-7 compares zonal net revenue for a new entrant CP to the 2012 levelized fixed cost. Figure 7-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed cost.

Figure 7-7 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

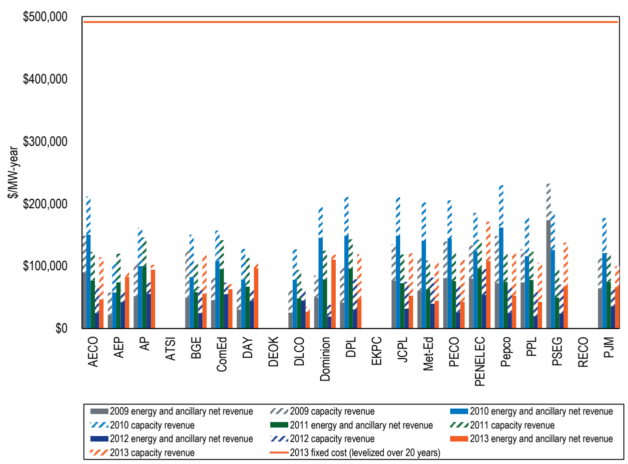
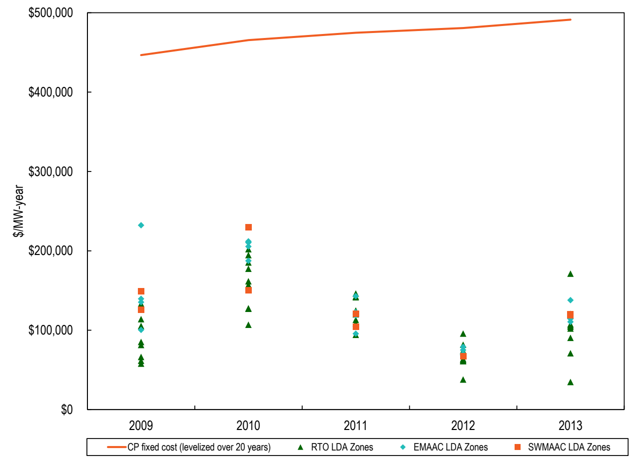


Figure 7-8 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013



New Entrant Nuclear Plant

In 2013, a new nuclear plant in the western AEP zone would not have received sufficient net revenue to cover levelized fixed costs. The combination of lower energy market revenues and lower capacity market revenues in the AEP zone, similar to the other western zones, than in the eastern zones resulted in a low level of coverage of fixed costs for a nuclear power plant.

Table 7-25 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2009	2010	2011	2012	2013
AEP	32%	39%	39%	28%	30%

Figure 7-9 compares net revenue for a new entrant nuclear plant to the 2013 levelized fixed cost.

Figure 7-9 New entrant nuclear plant net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

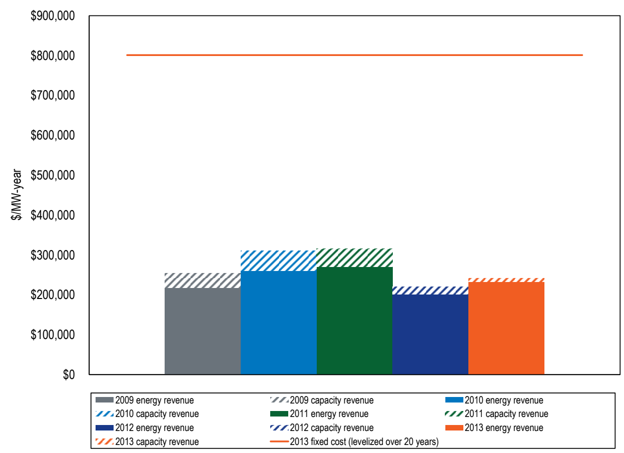
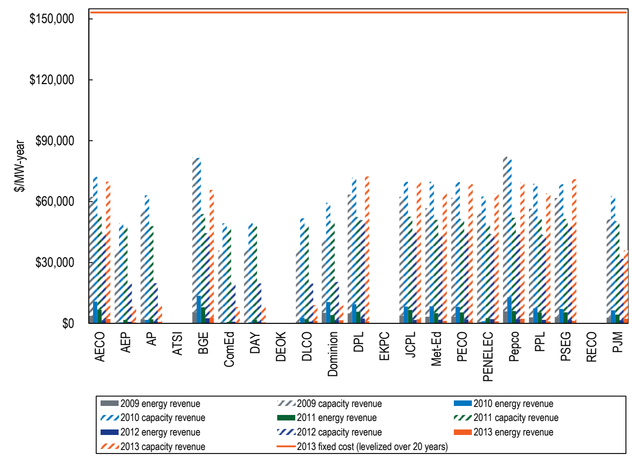


Figure 7-10 compares zonal net revenue for a new entrant DS plant to the 2013 levelized fixed cost.

Figure 7-10 New entrant DS plant net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013



New Entrant Diesel Plant

In 2013, a new diesel plant would not have received sufficient net revenue to cover levelized fixed costs in any zone. The highest net revenues were in the 10 eastern zones with higher capacity prices than in the six western zones. Energy market revenues were very low for the diesel plant across all zones as diesels were economically dispatched in very few hours.

Table 7-26 Percent of 20-year levelized fixed costs recovered by DS energy and capacity net revenue

Zone	2009	2010	2011	2012	2013
AECO	41%	47%	34%	29%	46%
AEP	24%	32%	31%	13%	6%
AP	36%	41%	31%	13%	6%
ATSI	NA	NA	NA	NA	NA
BGE	53%	53%	35%	29%	43%
ComEd	23%	32%	31%	13%	5%
DAY	24%	32%	31%	13%	5%
DEOK	NA	NA	NA	NA	NA
DLCO	24%	34%	31%	13%	6%
Dominion	27%	39%	33%	13%	6%
DPL	41%	47%	34%	33%	47%
EKPC	NA	NA	NA	NA	NA
JCPL	41%	46%	34%	29%	46%
Met-Ed	37%	46%	33%	29%	42%
PECO	40%	45%	34%	29%	45%
PENELEC	35%	41%	32%	29%	42%
Pepco	54%	53%	34%	29%	45%
PPL	37%	45%	34%	29%	42%
PSEG	40%	45%	34%	31%	46%
RECO	NA	NA	NA	NA	NA
PJM	33%	41%	33%	21%	24%

New Entrant Wind Installation

In 2013, a new wind installation would not have received sufficient net revenue to cover levelized fixed costs.

Table 7-27 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012	2013
ComEd	65%	75%
PENELEC	68%	83%

New Entrant Solar Installation

In 2013, a new solar installation would have received sufficient net revenue to cover 203 percent of levelized fixed costs. Net revenues from the energy market, SRECs and the capacity market all increased substantially. Net revenues from SRECs are the reason for the high solar net revenues. Net revenues from SRECs were 79.8 percent of total net revenues in 2013 and 82.2 percent of total net revenues in 2012.

Table 7-28 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012	2013
PSEG	97%	203%

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 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 2013, the yearly average operating cost of the CC was lower than the average operating costs of the CP for seven out of twelve months, driven by the relative cost of gas versus coal although that relationship reversed toward the end of the year. (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 2013, zonal energy net revenues decreased for most CCs and CTs, while capacity market prices increased in ten zones and decreased in six zones. As a result, there are ten zones in which net revenues covered more than 95 percent of levelized fixed costs for CCs. These are the same ten zones with higher net revenues for CTs. These ten zones are in the eastern part of PJM. The lower net revenues in these zones resulted from reductions 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 fixed costs from Table 7-21 The results are shown in Table 7-29.[17]

17 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 7-29 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	$117,231	13.8%	$160,654	13.7%	$521,240	13.6%
Base Case	$109,731	12.0%	$150,654	12.0%	$491,240	12.0%
Sensitivity 2	$102,231	10.1%	$140,654	10.2%	$461,240	10.3%
Sensitivity 3	$94,731	8.1%	$130,654	8.3%	$431,240	8.6%
Sensitivity 4	$87,231	5.9%	$120,654	6.3%	$401,240	6.8%
Sensitivity 5	$79,731	3.5%	$110,654	4.1%	$371,240	4.9%
Sensitivity 6	$72,231	0.5%	$100,654	1.7%	$341,240	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 7-30 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 7-30 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$116,792	$159,857
Sensitivity 2	55%	$113,262	$155,255
Base Case	50%	$109,731	$150,654
Sensitivity 3	45%	$106,201	$146,052
Sensitivity 4	40%	$102,671	$141,450
Sensitivity 5	35%	$99,140	$136,849
Sensitivity 6	30%	$95,610	$132,247

Table 7-31 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 7-31 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	$98,680	$136,249
Sensitivity 2	25	$102,856	$141,693
Base Case	20	$109,731	$150,654
Sensitivity 3	15	$115,508	$158,183
Sensitivity 4	10	$123,167	$168,166

Table 7-32 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 7-32 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$106,246	$0	0.0%	$146,885
Sensitivity 2	$4,998	1.6%	$107,988	$7,990	1.2%	$148,769
Base Case	$9,996	3.2%	$109,731	$15,981	2.5%	$150,654
Sensitivity 3	$14,994	4.8%	$111,474	$23,971	3.7%	$152,538
Sensitivity 4	$19,992	6.4%	$113,217	$31,962	4.9%	$154,422
Sensitivity 5	$24,990	8.0%	$114,959	$39,952	6.2%	$156,306
Sensitivity 6	$29,988	9.6%	$116,702	$47,943	7.4%	$158,190
Sensitivity 7	$50,953	16.4%	$123,679	$50,953	7.9%	$158,675
Sensitivity 8	$76,430	24.6%	$132,396	$76,430	11.8%	$164,571
Sensitivity 9	$101,906	32.8%	$141,113	$101,906	15.7%	$170,466

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 2012/2013 and 2013/2014 RPM Auctions.[18] 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 2012/2013 and 2013/2014 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 2013. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[19] 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 7-33 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed.

18 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.

19 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.

Table 7-33 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[20]: 2013

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	1,787	$49,306	$114,076	$42,719
CC - Two on Three on One Frame F Technology	13,731	$25,764	$58,454	$17,592
CT - First & Second Generation Aero (P&W FT 4)	3,073	$4,312	$62,711	$9,513
CT - First & Second Generation Frame B	3,324	$1,046	$58,231	$10,883
CT - Second Generation Frame E	9,334	$12,281	$46,215	$9,237
CT - Third Generation Aero	3,543	$11,990	$58,351	$17,074
CT - Third Generation Frame F	8,051	$22,098	$44,014	$8,889
Diesel	490	($3,904)	$36,716	$8,521
Hydro and Pumped Storage	5,409	$136,938	$183,775	$24,887
Nuclear	29,884	$218,245	$253,956	$801,100
Oil or Gas Steam	8,556	$15,589	$68,266	$32,542
Sub-Critical Coal	29,649	$29,835	$59,184	$59,827
Super Critical Coal	19,186	$55,265	$89,076	$56,987

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-33 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 7-34 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 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 7-34 Energy and ancillary service net revenue by quartile for select technologies for 2013

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$2,970	$16,579	$33,988
CC - Two on Three on One Frame F Technology	$5,682	$14,400	$50,241
CT - First & Second Generation Aero (P&W FT 4)	($935)	$542	$3,496
CT - First & Second Generation Frame B	($2,111)	($60)	$2,353
CT - Second Generation Frame E	$769	$6,143	$13,046
CT - Third Generation Aero	$2,008	$13,700	$25,528
CT - Third Generation Frame F	$6,387	$21,064	$32,756
Diesel	($1,771)	$0	$3,255
Hydro and Pumped Storage	$51,469	$106,000	$194,111
Nuclear	$179,256	$237,779	$253,598
Oil or Gas Steam	($5,260)	$442	$4,586
Sub-Critical Coal	$3,589	$18,677	$42,227
Super Critical Coal	$40,395	$54,870	$61,442

Table 7-35 shows capacity market net revenues by quartile for select technology classes.

Table 7-35 Capacity revenue by quartile for select technologies for 2013

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$64,169	$67,515	$72,084
CC - Two on Three on One Frame F Technology	$8,018	$8,346	$66,414
CT - First & Second Generation Aero (P&W FT 4)	$58,500	$64,490	$70,175
CT - First & Second Generation Frame B	$38,435	$63,168	$67,793
CT - Second Generation Frame E	$8,105	$8,438	$68,206
CT - Third Generation Aero	$8,157	$64,571	$73,158
CT - Third Generation Frame F	$8,010	$8,255	$8,936
Diesel	$8,046	$24,461	$75,993
Hydro and Pumped Storage	$8,338	$63,941	$68,535
Nuclear	$8,319	$8,603	$68,358
Oil or Gas Steam	$7,832	$68,136	$72,245
Sub-Critical Coal	$7,478	$8,227	$64,194
Super Critical Coal	$4,222	$24,502	$64,590

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

Table 7-36 shows total net revenues by quartile for select technology classes.

Table 7-36 Combined revenue from all markets by quartile for select technologies for 2013

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$67,140	$84,094	$106,072
CC - Two on Three on One Frame F Technology	$13,700	$22,746	$116,655
CT - First & Second Generation Aero (P&W FT 4)	$57,565	$65,032	$73,671
CT - First & Second Generation Frame B	$36,325	$63,107	$70,146
CT - Second Generation Frame E	$8,875	$14,580	$81,252
CT - Third Generation Aero	$10,165	$78,272	$98,686
CT - Third Generation Frame F	$14,396	$29,319	$41,692
Diesel	$6,275	$24,461	$79,248
Hydro and Pumped Storage	$59,807	$169,940	$262,646
Nuclear	$187,574	$246,382	$321,957
Oil or Gas Steam	$2,572	$68,578	$76,831
Sub-Critical Coal	$11,067	$26,904	$106,421
Super Critical Coal	$44,617	$79,372	$126,032

Table 7-37 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2013, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. Although there is not good public data on nuclear unit avoidable costs, the table includes the total annualized costs for a new nuclear unit as a rough proxy for the avoidable costs of an existing nuclear unit. This is only an approximation to provide a rough benchmark for avoidable cost results.

Table 7-37 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for 2012

	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	28%	50%	205%
CC - Two on Three on One Frame F Technology	50%	79%	208%
CT - First & Second Generation Aero (P&W FT 4)	NA	8%	35%
CT - First & Second Generation Frame B	NA	0%	37%
CT - Second Generation Frame E	22%	57%	85%
CT - Third Generation Aero	4%	68%	114%
CT - Third Generation Frame F	64%	213%	312%
Diesel	NA	NA	0%
Hydro and Pumped Storage	308%	462%	740%
Nuclear	22%	27%	31%
Oil or Gas Steam	NA	1%	11%
Sub-Critical Coal	11%	37%	68%
Super Critical Coal	56%	76%	137%

Table 7-38 shows the avoidable cost recovery from all PJM markets by quartiles. While the net revenues from all markets cover avoidable costs for most technology types, sub-critical coal units are the exception. The total annualized costs for a new nuclear unit is used as a rough proxy for the avoidable costs of an existing nuclear unit. This is only an approximation to provide a rough benchmark for avoidable cost results.

Table 7-38 Avoidable cost recovery by quartile from all PJM Markets for select technologies for 2013

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	181%	215%	461%
CC - Two on Three on One Frame F Technology	133%	246%	624%
CT - First & Second Generation Aero (P&W FT 4)	576%	664%	734%
CT - First & Second Generation Frame B	478%	630%	698%
CT - Second Generation Frame E	154%	196%	814%
CT - Third Generation Aero	143%	200%	815%
CT - Third Generation Frame F	291%	393%	822%
Diesel	NA	87%	532%
Hydro and Pumped Storage	567%	793%	1,134%
Nuclear	23%	32%	39%
Oil or Gas Steam	71%	220%	267%
Sub-Critical Coal	54%	92%	131%
Super Critical Coal	117%	150%	180%

Table 7-39 and Table 7-40 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of coal and oil or gas steam units.

Table 7-39 Proportion of units recovering avoidable costs from energy and ancillary markets : 2009 to 2013

	Units with full recovery from energy and ancillary services markets				
Technology	2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	64%	77%	60%	65%	61%
CC - Two on Three on One Frame F Technology	71%	73%	70%	64%	54%
CT - First & Second Generation Aero (P&W FT 4)	44%	35%	25%	15%	20%
CT - First & Second Generation Frame B	32%	32%	31%	23%	15%
CT - Second Generation Frame E	63%	54%	72%	67%	48%
CT - Third Generation Aero	50%	53%	77%	78%	52%
CT - Third Generation Frame F	45%	64%	72%	81%	75%
Diesel	77%	77%	72%	57%	53%
Hydro and Pumped Storage	98%	98%	95%	98%	97%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	44%	52%	48%	41%	44%
Sub-Critical Coal	80%	81%	59%	40%	51%
Super Critical Coal	87%	87%	74%	48%	53%

Table 7-40 Proportion of units recovering avoidable costs from all markets: 2009 to 2013

	Units with full recovery from all markets				
Technology	2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	95%	95%	96%	90%	100%
CC - Two on Three on One Frame F Technology	100%	95%	98%	92%	85%
CT - First & Second Generation Aero (P&W FT 4)	95%	90%	90%	90%	86%
CT - First & Second Generation Frame B	99%	99%	95%	94%	91%
CT - Second Generation Frame E	100%	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	97%	89%
CT - Third Generation Frame F	100%	100%	100%	94%	96%
Diesel	97%	98%	91%	85%	73%
Hydro and Pumped Storage	100%	100%	100%	100%	100%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	97%	95%	85%	75%	81%
Sub-Critical Coal	93%	95%	88%	55%	69%
Super Critical Coal	100%	100%	91%	68%	89%

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.[21]

Units' 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 7-41. These units are considered at risk of retirement.

These results mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW 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 7-41 Profile of units that did not recover avoidable costs from total market revenues or did not clear the 15/16 BRA or 16/17 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2013 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	30	1,195	393	13,454	31
Coal	22	8,650	6,808	10,577	45
Diesel	16	161	1,641	11,288	24
Oil or Gas Steam	11	2,542	2,076	11,502	33
Other	8	2,049	5,600	5,954	35
Total	87	14,597	3,197	11,391	34

21 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 outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.