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), integrated gasification combined cycle (IGCC), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- Net revenues are significantly affected by energy prices, fuel prices and capacity prices. Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG. The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.

- The total net revenues did not cover the annual levelized fixed costs of a new entrant CT in any zone. The total net revenues covered the annual levelized fixed costs of a new entrant CC in three zones and covered more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones. The total net revenues did not cover the annual levelized fixed costs of a new entrant CP in any zone and did not exceed 20 percent of the annual levelized fixed costs of a new entrant CP in any zone.

- The total net revenues covered only five percent of the annual levelized fixed costs of a new entrant IGCC. The total net revenues covered only 28 percent of the annual levelized fixed costs of a new entrant nuclear plant. The total net revenues covered more than 65 percent of the annual levelized fixed costs of a new entrant wind installation. The total net revenues covered 97 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 80 percent of the net revenue of a solar installation.

- Of existing sub-critical coal units, 39 percent did not recover even avoidable costs from total net revenues and of existing supercritical coal units, 15 percent did not recover even avoidable costs from total net revenues. Coal units that have not declared their intent to retire and did not cover avoidable costs from total market revenues comprise 3,725 MW of capacity. These units can be considered to be at risk of retirement.

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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

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.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

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.

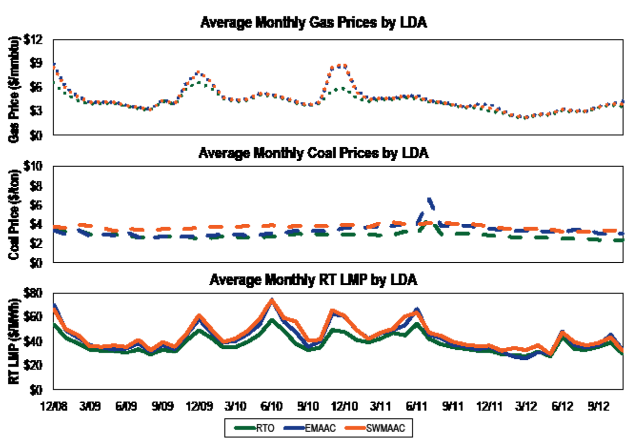
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute 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 payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The system average LMP was 22.7 percent lower in 2012 than in 2011. Both coal and natural gas decreased in price in 2012. Comparing prices in 2012 to prices in 2011, the price of Northern Appalachian coal was 16.5 percent lower; the price of Central Appalachian coal was 18.4 percent lower; the price of Powder River Basin coal was 31.5 percent lower; the price of eastern natural gas was 36.2 percent lower; and the price of western natural gas was 31.9 percent lower.[2] Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG.

The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.

Figure 6-1 Energy Market net revenue factor trends: December 2008 through December 2012



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 the economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes seven power plant configurations:

- The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NOx reduction.
- The CC plant 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 NOx reduction with a single steam turbine generator.[3]
- The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NOx control, a Flue Gas Desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.
- The IGCC plant consists of a coal gasification plant producing a low BTU gas product which is fired in two modified GE Frame 7FA CTs in CC configuration.
- The nuclear plant 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, CP and IGCC include the hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4,5] Plant heat rates were calculated for each hour to account for the

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 All fuel prices are from Platts.

3 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.

4 Hourly ambient conditions supplied by Schneider Electric.

5 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.

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 in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[6]

A forced outage rate for each class of plant was calculated from PJM data.[7] This class-specific outage rate was then incorporated into all revenue calculations. Each CT, CC, CP and IGCC 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 three plant types are set to zero. Ancillary service revenues for the provision of regulation service for the CT, CC and IGCC plant are also set to zero since these plant types typically do not provide regulation service in PJM. No black start service capability is assumed for the reference CT plant configuration in either costs or revenues or for any of the other plant types.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. 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.

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. IGCC generators are assumed to receive reactive revenues equal to the CP plant.

6 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

7 Outage figures obtained from the PJM eGADS database. The CC outage rate was used for the IGCC plant.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[8] The delivered fuel cost for natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[9] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[10]

Operating costs are the marginal cost of operations and include fuel costs, emissions costs, and VOM costs. Average zonal operating costs in 2012 for a CT were $38.85 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $8.34 per MWh. Average zonal operating costs for a CP were $30.65 per MWh, based on a design heat rate of 9,250 Btu per kWh and a VOM rate of $3.29 per MWh. Average zonal operating costs for a CC were $22.45 per MWh, based on a design heat rate of 7,127 Btu per kWh and a VOM rate of $1.50 per MWh. Average zonal operating costs for an IGCC were $36.51 per MWh, based on a design heat rate of 9,407 Btu per kWh and a VOM rate of $6.89 per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.[11]

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.

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 fixed costs. Capacity revenue for 2012 includes five months of the 2011/2012 RPM auction clearing price and seven months of the 2012/2013 RPM

8 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.

9 Gas daily cash prices obtained from Platts.

10 Coal prompt prices obtained from Platts.

11 VOM rates provided by Pasteris Energy, Inc.

auction clearing price.[12] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[13]

Table 6-1 Capacity revenue by PJM zones[14] (Dollars per MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Average
AECO	$58,586	$61,406	$45,938	$43,138	$52,267
AEP	$35,789	$48,898	$45,938	$18,730	$37,339
AP	$53,440	$61,406	$45,938	$18,730	$44,878
ATSI	NA	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$41,878	$57,976
ComEd	$35,789	$48,898	$45,938	$18,730	$37,339
DAY	$35,789	$48,898	$45,938	$18,730	$37,339
DEOK	NA	NA	NA	NA	NA
DLCO	$35,789	$48,898	$45,938	$18,730	$37,339
Dominion	$35,789	$48,898	$45,938	$18,730	$37,339
DPL	$58,586	$62,251	$46,530	$48,399	$53,941
JCPL	$58,586	$61,406	$45,938	$43,138	$52,267
Met-Ed	$53,440	$61,406	$45,938	$41,878	$50,666
PECO	$58,586	$61,406	$45,938	$43,138	$52,267
PENELEC	$53,440	$61,406	$45,938	$41,837	$50,655
Pepco	$76,236	$67,851	$45,938	$41,878	$57,976
PPL	$53,440	$61,406	$45,938	$41,878	$50,666
PSEG	$58,586	$61,406	$45,938	$46,223	$53,038
RECO	NA	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$30,354	$45,230

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 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$9,945	$47,188	$0	$0	$887	$58,020
2010	$32,781	$55,186	$0	$0	$4,320	$92,287
2011	$36,104	$45,972	$0	$0	$3,587	$85,664
2012	$23,240	$30,116	$0	$0	$891	$54,246

Table 6-3 Energy Market net revenue[15] for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$12,421	$40,037	$46,157	$24,993	(46%)
AEP	$3,696	$11,575	$20,839	$16,263	(22%)
AP	$11,136	$32,494	$32,958	$21,029	(36%)
ATSI	NA	NA	NA	$18,296	NA
BGE	$15,126	$52,411	$48,642	$36,307	(25%)
ComEd	$2,445	$9,446	$15,081	$13,780	(9%)
DAY	$3,313	$11,701	$21,705	$18,573	(14%)
DEOK	NA	NA	NA	$16,004	NA
DLCO	$4,471	$17,525	$24,179	$18,773	(22%)
Dominion	$15,253	$42,922	$38,945	$25,375	(35%)
DPL	$13,886	$40,530	$44,339	$32,587	(27%)
JCPL	$11,994	$39,409	$44,968	$24,117	(46%)
Met-Ed	$11,083	$39,409	$40,802	$25,396	(38%)
PECO	$10,611	$38,311	$45,853	$25,884	(44%)
PENELEC	$6,986	$24,309	$32,090	$22,463	(30%)
Pepco	$17,798	$50,906	$44,233	$32,011	(28%)
PPL	$10,045	$33,649	$42,872	$22,817	(47%)
PSEG	$10,079	$37,626	$37,929	$24,081	(37%)
RECO	$8,717	$35,022	$32,178	$22,808	(29%)
PJM	$9,945	$32,781	$36,104	$23,240	(36%)

Table 6-4 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$70,445	$104,628	$95,698	$68,683	(28%)
AEP	$39,487	$63,889	$70,380	$35,737	(49%)
AP	$64,142	$97,085	$82,498	$40,503	(51%)
ATSI	NA	NA	NA	NA	NA
BGE	$90,364	$123,328	$98,182	$78,747	(20%)
ComEd	$38,235	$61,760	$64,622	$33,254	(49%)
DAY	$39,104	$64,015	$71,246	$38,047	(47%)
DEOK	NA	NA	NA	NA	NA
DLCO	$40,261	$69,839	$73,719	$38,247	(48%)
Dominion	$51,043	$95,237	$88,486	$44,849	(49%)
DPL	$71,910	$105,950	$94,472	$81,497	(14%)
JCPL	$70,018	$103,999	$94,509	$67,807	(28%)
Met-Ed	$64,089	$103,999	$90,342	$67,837	(25%)
PECO	$68,635	$102,902	$95,394	$69,574	(27%)
PENELEC	$59,992	$88,900	$81,631	$64,862	(21%)
Pepco	$93,036	$121,823	$93,774	$74,451	(21%)
PPL	$63,051	$98,240	$92,412	$65,258	(29%)
PSEG	$68,103	$102,217	$87,469	$70,832	(19%)
RECO	NA	NA	NA	NA	NA
PJM	$58,020	$92,287	$85,664	$54,246	(37%)

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

13 The PJM capacity revenues differ slightly from those presented in Table 6-2, Table 6-5 and Table 6-8 as these capacity revenues by technology type are adjusted for technology-specific outage rates.

14 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the RECO zone.

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

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.[16] 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.

Table 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$52,260	$50,184	$0	$0	$1,641	$104,085
2010	$89,027	$58,324	$0	$0	$762	$148,113
2011	$106,618	$48,306	$0	$0	$964	$155,889
2012	$97,260	$31,422	$0	$0	$1,608	$130,290

Table 6-6 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$62,063	$106,643	$126,869	$101,124	(20%)
AEP	$29,759	$47,591	$82,324	$87,908	7%
AP	$59,052	$91,032	$113,561	$100,499	(12%)
ATSI	NA	NA	NA	$94,387	NA
BGE	$70,571	$124,665	$130,806	$123,367	(6%)
ComEd	$20,613	$33,906	$46,293	$61,754	33%
DAY	$27,904	$46,647	$82,067	$93,517	14%
DEOK	NA	NA	NA	$82,044	NA
DLCO	$27,649	$51,180	$81,642	$89,180	9%
Dominion	$68,932	$116,873	$114,530	$103,610	(10%)
DPL	$64,321	$106,245	$123,599	$114,808	(7%)
JCPL	$61,477	$105,474	$124,878	$100,386	(20%)
Met-Ed	$55,400	$97,665	$111,653	$96,018	(14%)
PECO	$57,843	$99,951	$121,804	$98,151	(19%)
PENELEC	$48,876	$80,773	$109,048	$106,236	(3%)
Pepco	$71,959	$121,952	$121,143	$115,691	(5%)
PPL	$52,285	$87,314	$111,111	$91,727	(17%)
PSEG	$57,910	$101,819	$114,951	$96,617	(16%)
RECO	$51,808	$93,724	$96,235	$90,924	(6%)
PJM	$52,260	$89,027	$106,618	$97,260	(9%)

Table 6-7 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$124,469	$171,103	$176,119	$147,387	(16%)
AEP	$68,520	$99,077	$131,574	$108,905	(17%)
AP	$116,122	$155,492	$162,812	$121,495	(25%)
ATSI	NA	NA	NA	NA	NA
BGE	$151,283	$195,811	$180,056	$168,326	(7%)
ComEd	$59,374	$85,392	$95,544	$82,751	(13%)
DAY	$66,664	$98,133	$131,317	$114,513	(13%)
DEOK	NA	NA	NA	NA	NA
DLCO	$66,409	$102,666	$130,892	$110,177	(16%)
Dominion	$107,693	$168,359	$163,780	$124,606	(24%)
DPL	$126,726	$171,582	$173,472	$166,517	(4%)
JCPL	$123,883	$169,934	$174,128	$146,649	(16%)
Met-Ed	$112,470	$162,125	$160,903	$140,977	(12%)
PECO	$120,248	$164,411	$171,054	$144,414	(16%)
PENELEC	$105,945	$145,233	$158,298	$151,152	(5%)
Pepco	$152,672	$193,098	$170,394	$160,650	(6%)
PPL	$109,354	$151,773	$160,361	$136,687	(15%)
PSEG	$120,316	$166,279	$164,201	$146,074	(11%)
RECO	NA	NA	NA	NA	NA
PJM	$104,085	$148,113	$155,889	$130,290	(16%)

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 6-8 PJM-wide net revenue for a CP by market (Dollars per installed MW-year): 2009 through 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$62,062	$47,469	$0	$2,213	$286	$112,029
2010	$119,478	$54,670	$0	$898	$601	$175,648
2011	$73,178	$44,282	$0	$1,029	$272	$118,760
2012	$34,408	$29,326	$0	$1,154	$117	$65,006

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

Table 6-9 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$87,901	$149,022	$75,325	$23,301	(69%)
AEP	$19,251	$56,227	$72,858	$41,244	(43%)
AP	$49,303	$98,671	$99,020	$54,552	(45%)
ATSI	NA	NA	NA	$47,274	NA
BGE	$46,299	$80,689	$56,940	$23,390	(59%)
ComEd	$42,738	$106,599	$94,493	$53,813	(43%)
DAY	$27,905	$77,082	$65,842	$43,027	(35%)
DEOK	NA	NA	NA	$36,519	NA
DLCO	$22,971	$76,395	$47,075	$43,904	(7%)
Dominion	$46,756	$144,290	$77,310	$17,547	(77%)
DPL	$38,833	$147,279	$94,908	$29,102	(69%)
JCPL	$74,389	$147,559	$71,437	$30,517	(57%)
Met-Ed	$57,888	$139,228	$61,703	$38,561	(38%)
PECO	$78,602	$142,542	$74,834	$24,474	(67%)
PENELEC	$77,650	$122,426	$95,440	$52,897	(45%)
Pepco	$70,058	$160,627	$73,476	$23,706	(68%)
PPL	$71,601	$114,549	$76,697	$18,079	(76%)
PSEG	$171,879	$124,533	$47,550	$22,590	(52%)
RECO	$71,025	$143,410	$59,111	$29,258	(51%)
PJM	$62,062	$119,478	$73,178	$34,408	(53%)

Table 6-10 Zonal combined net revenue from all markets for a CP (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012	Change in 2012 from 2011
AECO	$147,643	$209,652	$120,857	$66,479	(45%)
AEP	$57,078	$104,980	$118,055	$60,207	(49%)
AP	$104,183	$159,395	$144,140	$73,443	(49%)
ATSI	NA	NA	NA	NA	NA
BGE	$123,964	$148,075	$102,287	$65,248	(36%)
ComEd	$80,652	$155,257	$139,564	$72,912	(48%)
DAY	$65,610	$125,687	$111,028	$61,975	(44%)
DEOK	NA	NA	NA	NA	NA
DLCO	$60,794	$125,098	$92,186	$62,985	(32%)
Dominion	$84,483	$192,785	$122,827	$37,138	(70%)
DPL	$99,256	$208,730	$140,942	$77,234	(45%)
JCPL	$134,223	$208,178	$116,745	$73,383	(37%)
Met-Ed	$112,840	$199,873	$106,902	$80,076	(25%)
PECO	$138,387	$203,180	$119,999	$67,537	(44%)
PENELEC	$132,233	$183,038	$140,378	$94,165	(33%)
Pepco	$147,296	$227,527	$118,615	$65,493	(45%)
PPL	$126,399	$175,270	$121,869	$59,997	(51%)
PSEG	$231,098	$185,214	$93,675	$68,664	(27%)
RECO	NA	NA	NA	NA	NA
PJM	$112,015	$175,164	$118,488	$64,889	(45%)

New Entrant Integrated Gasification Combined Cycle

Energy market net revenue was calculated for an IGCC plant located in the Dominion zone assuming that the IGCC 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 operations.

Table 6-11 Net revenue for an IGCC by market (Dollars per installed MW-year): 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2012	$13,130	$19,388	$0	$0	$1,608	$34,126

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 6-12 Net revenue for a nuclear plant by market (Dollars per installed MW-year): 2012

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2012	$201,658	$19,917	$0	$0	$0	$221,575

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 6-13 Net revenue for a wind installation by market[17] (Dollars per installed MW-year): 2012

	Energy	Credits	Capacity	Total
2012 (ComEd)	$67,294	$57,709	$2,435	$127,438
2012 (PENELEC)	$68,913	$58,450	$5,439	$132,802

17 Credits include a wind production tax credit and Renewable Energy Credits (RECs). See "Pricing" <http://paaeps.com/credit/pricing.do> (Accessed March 6, 2013) and "Public Notice of Winning Bidders and Average Prices" <http://www2.illinois.gov/ipa/Documents/Public-Notice-Ameren-ComEd-spring-2012-REC-Procurement-Results-2012-05-16.pdf> (Accessed March 6, 2013).

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 6-14 Net revenue for a solar installation by market[18] (Dollars per installed MW-year): 2012

	Energy	Credits	Capacity	Total
2012	$50,363	$314,530	$17,565	$382,458

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized fixed 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 over 20 years, at a constant nominal annual rate.

The extent to which net revenues cover the levelized fixed costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue.

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.

18 Credits include Solar Renewable Energy Credits (SRECs). See "SREC Pricing Archive" <http://www.njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing/archive> (Accessed March 6, 2013).

Table 6-15 New entrant 20-year levelized fixed costs[19, 20] (By plant type (Dollars per installed MW-year)): 2009 through 2012

	20-Year Levelized Fixed Cost			
	2009	2010	2011	2012
Combustion Turbine	$128,705	$131,044	$110,589	$113,027
Combined Cycle	$173,174	$175,250	$153,682	$155,294
Coal Plant	$446,550	$465,455	$474,692	$480,662
Integrated Gasification Combined Cycle				$714,550
Nuclear Plant				$801,100
Wind Installation (with 1603 grant)				$196,186
Solar Installation (with 1603 grant)				$394,855

New Entrant Combustion Turbine

In 2012, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone.

Table 6-16 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year): 2009 through 2012

Zone	2009	2010	2011	2012
AECO	55%	80%	87%	61%
AEP	31%	49%	64%	32%
AP	50%	74%	75%	36%
ATSI	NA	NA	NA	NA
BGE	70%	94%	89%	70%
ComEd	30%	47%	58%	29%
DAY	30%	49%	64%	34%
DEOK	NA	NA	NA	NA
DLCO	31%	53%	67%	34%
Dominion	40%	73%	80%	40%
DPL	56%	81%	85%	72%
JCPL	54%	79%	85%	60%
Met-Ed	50%	79%	82%	60%
PECO	53%	79%	86%	62%
PENELEC	47%	68%	74%	57%
Pepco	72%	93%	85%	66%
PPL	49%	75%	84%	58%
PSEG	53%	78%	79%	63%
RECO	NA	NA	NA	NA
PJM	45%	70%	77%	48%

Figure 6-2 compares zonal net revenue for a new entrant CT for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-3 shows zonal net revenue for the new entrant CT for 2009 through 2012 by LDA with the applicable annual levelized fixed cost.

19 Levelized fixed costs provided by Pasteris Energy, Inc.

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

Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

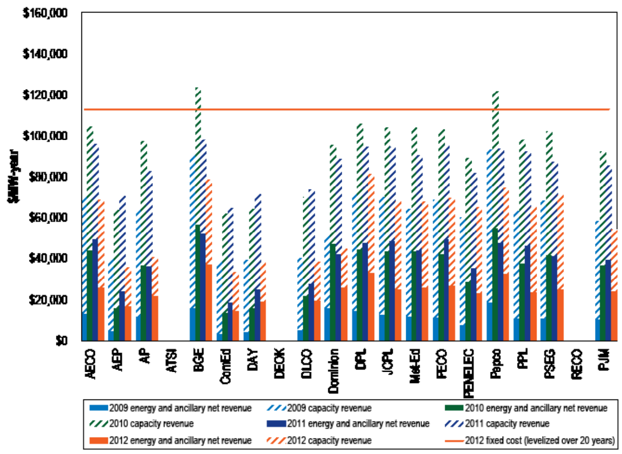


Figure 6-3 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012

New Entrant Combined Cycle

In 2012, a new CC would have received net revenue sufficient to cover levelized fixed costs in three zones and sufficient to cover more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones.

Table 6-17 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue: 2009 through 2012

Zone	2009	2010	2011	2012
AECO	72%	98%	115%	95%
AEP	40%	57%	86%	70%
AP	67%	89%	106%	78%
ATSI	NA	NA	NA	NA
BGE	87%	112%	117%	108%
ComEd	34%	49%	62%	53%
DAY	38%	56%	85%	74%
DEOK	NA	NA	NA	NA
DLCO	38%	59%	85%	71%
Dominion	62%	96%	107%	80%
DPL	73%	98%	113%	107%
JCPL	72%	97%	113%	94%
Met-Ed	65%	93%	105%	91%
PECO	69%	94%	111%	93%
PENELEC	61%	83%	103%	97%
Pepco	88%	110%	111%	103%
PPL	63%	87%	104%	88%
PSEG	69%	95%	107%	94%
RECO	NA	NA	NA	NA
PJM	60%	85%	101%	84%

Figure 6-4 compares zonal net revenue for a new entrant CC for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-5 shows zonal net revenue for the new entrant CC for 2009 through 2012 by LDA with the applicable yearly levelized fixed cost.

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

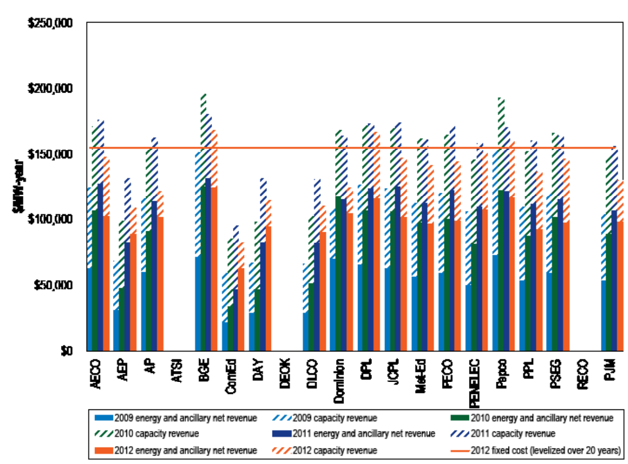
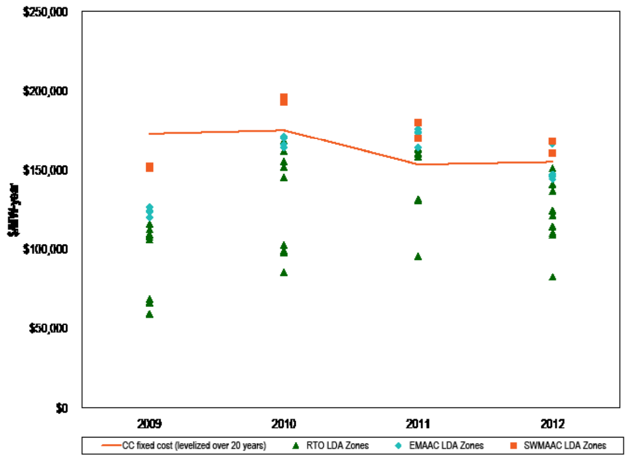


Figure 6-5 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012



New Entrant Coal Plant

In 2012, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone and would not have received sufficient net revenue to cover more than 20 percent of levelized fixed costs in any zone.

Table 6-18 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue: 2009 through 2012

Zone	2009	2010	2011	2012
AECO	33%	45%	25%	14%
AEP	13%	23%	25%	13%
AP	23%	34%	30%	15%
ATSI	NA	NA	NA	NA
BGE	28%	32%	22%	14%
ComEd	18%	33%	29%	15%
DAY	15%	27%	23%	13%
DEOK	NA	NA	NA	NA
DLCO	14%	27%	19%	13%
Dominion	19%	41%	26%	8%
DPL	22%	45%	30%	16%
JCPL	30%	45%	25%	15%
Met-Ed	25%	43%	23%	17%
PECO	31%	44%	25%	14%
PENELEC	30%	39%	30%	20%
Pepco	33%	49%	25%	14%
PPL	28%	38%	26%	12%
PSEG	52%	40%	20%	14%
RECO	NA	NA	NA	NA
PJM	25%	38%	25%	13%

Figure 6-6 compares zonal net revenue for a new entrant CP for 2009 through 2012 to the 2012 levelized fixed cost. Figure 6-7 shows zonal net revenue for the new entrant CP for 2009 through 2012 by LDA with the applicable yearly levelized fixed cost.

Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

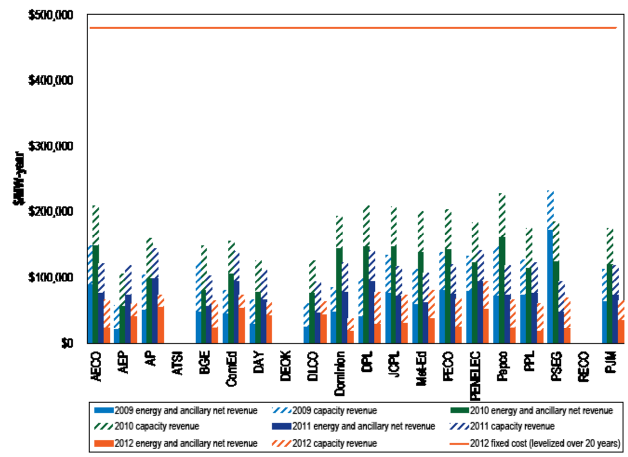
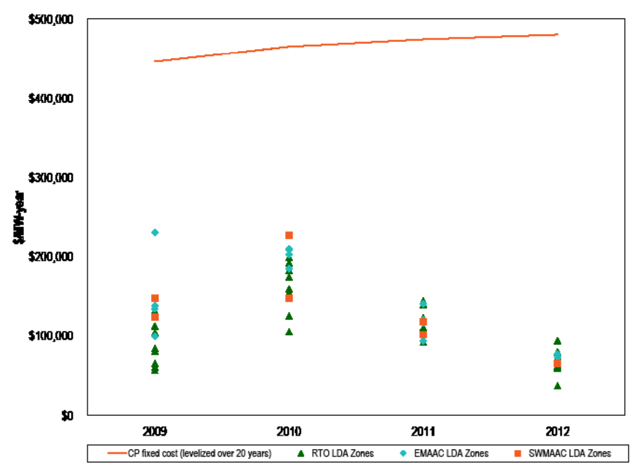


Figure 6-7 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012



New Entrant Integrated Gasification Combined Cycle

In 2012, a new IGCC would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-19 Percent of 20-year levelized fixed costs recovered by IGCC energy and capacity net revenue

Zone	2012
Dominion	5%

New Entrant Nuclear Plant

In 2012, a new nuclear plant would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-20 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2012
AEP	28%

New Entrant Wind Installation

In 2012, a new wind installation would not have received sufficient net revenue to cover levelized fixed costs.

Table 6-21 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012
ComEd	65%
PENELEC	68%

New Entrant Solar Installation

In 2012, a new solar installation would have received sufficient net revenue to cover 97 percent of levelized fixed costs.

Table 6-22 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012
PSEG	97%

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 2012, the yearly average operating cost of the CC was lower than the average operating costs of the CP, driven by the relative cost of gas versus coal although that relationship reversed toward the end of the year.

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 2012, zonal energy net revenues decreased for most CCs and all CTs, while capacity market prices decreased in all but DPL and PSEG. As a result, there were three zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CC in 2012.

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. However, when 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 6-15 The results are shown in Table 6-23.[21]

Table 6-23 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	$120,527	13.8%	$165,294	13.7%	$510,662	13.6%
Base Case	$113,027	12.0%	$155,294	12.0%	$480,662	12.0%
Sensitivity 2	$105,527	10.2%	$145,294	10.2%	$450,662	10.3%
Sensitivity 3	$98,027	8.2%	$135,294	8.4%	$420,662	8.5%
Sensitivity 4	$90,527	6.1%	$125,294	6.5%	$390,662	6.7%
Sensitivity 5	$83,027	3.8%	$115,294	4.4%	$360,662	4.7%
Sensitivity 6	$75,527	0.9%	$105,294	2.1%	$330,662	2.5%

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 6-24 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 6-25 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 6-24 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%	$120,273	$164,751
Sensitivity 2	55%	$116,650	$160,023
Base Case	50%	$113,027	$155,294
Sensitivity 3	45%	$109,405	$150,566
Sensitivity 4	40%	$105,783	$145,837
Sensitivity 5	35%	$102,160	$141,110
Sensitivity 6	30%	$98,536	$136,381

Table 6-25 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$101,686	$140,493
Sensitivity 2	25	$105,973	$146,087
Base Case	20	$113,027	$155,294
Sensitivity 3	15	$118,955	$163,030
Sensitivity 4	10	$126,814	$173,287

Table 6-26 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.

21 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. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 6-26 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%	$109,587	$0	0.0%	$151,576
Sensitivity 2	$4,904	1.5%	$111,307	$7,841	1.2%	$153,435
Base Case	$9,809	3.1%	$113,027	$15,682	2.4%	$155,294
Sensitivity 3	$14,714	4.6%	$114,747	$23,523	3.5%	$157,153
Sensitivity 4	$19,618	6.1%	$116,466	$31,364	4.7%	$159,012
Sensitivity 5	$24,522	7.7%	$118,186	$39,205	5.9%	$160,871
Sensitivity 6	$29,427	9.2%	$119,906	$47,046	7.1%	$162,730
Sensitivity 7	$50,000	15.7%	$127,120	$50,000	7.5%	$163,430
Sensitivity 8	$75,000	23.5%	$135,886	$75,000	11.3%	$169,357
Sensitivity 9	$100,000	31.3%	$144,652	$100,000	15.0%	$175,284

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. APIR may also reflect investments in environmental technology which were made in prior years to keep units in service and thus it would not be appropriate to include them in this analysis of the incentives to continue to operate units.

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 capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on actual submitted Avoidable Cost Rate (ACR) data for units associated with the most recent 2011/2012 and 2012/2013 RPM Auctions.[22] 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 2011/2012

22 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.

and 2012/2013 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 2012. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[23] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

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 6-28 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The 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 6-27 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: 2012

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	2,148	$18,722	$56,929	$44,714
CC - Two of Three on One Frame F Technology	13,353	$105,327	$133,370	$17,579
CT - First & Second Generation Aero (P&W FT 4)	3,219	$2,493	$43,763	$8,199
CT - First & Second Generation Frame B	3,759	($995)	$35,116	$9,595
CT - Second Generation Frame E	9,380	$23,083	$52,237	$8,519
CT - Third Generation Aero	3,325	$20,490	$53,194	$19,554
CT - Third Generation Frame F	7,646	$31,634	$55,734	$8,493
Diesel	496	$4,308	$39,606	$10,752
Hydro	1,995	$164,428	$196,127	$27,432
Nuclear	29,840	$172,750	$202,050	NA
Oil or Gas Steam	9,632	$14,743	$47,814	$27,009
Pumped Storage	4,952	$21,243	$61,676	$11,334
Sub-Critical Coal	31,433	$21,697	$45,368	$57,850
Super Critical Coal	23,454	$48,010	$69,035	$57,978

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 6-27 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed.

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 6-27 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.

23 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 6-28 Energy and ancillary service net revenue by quartile for select technologies for 2012

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$3,074	$35,327	$68,031
CC - Two of Three on One Frame F Technology	$20,329	$85,223	$126,132
CT - First & Second Generation Aero (P&W FT 4)	($1,259)	($336)	$5,135
CT - First & Second Generation Frame B	($4,467)	($1,195)	$451
CT - Second Generation Frame E	$1,385	$13,092	$28,711
CT - Third Generation Aero	$9,383	$26,680	$39,202
CT - Third Generation Frame F	$8,775	$29,801	$71,987
Diesel	($6,964)	($1)	$921
Hydro	$65,957	$128,200	$220,117
Nuclear	$142,688	$189,534	$207,802
Oil or Gas Steam	($1,559)	$85	$9,393
Pumped Storage	$10,510	$21,160	$29,131
Sub-Critical Coal	$1,100	$12,556	$40,312
Super Critical Coal	$32,515	$50,425	$65,786

Table 6-29 Capacity revenue by quartile for select technologies for 2012[24]

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$29,893	$42,994	$45,494
CC - Two of Three on One Frame F Technology	$19,407	$20,162	$43,059
CT - First & Second Generation Aero (P&W FT 4)	$39,749	$43,869	$46,169
CT - First & Second Generation Frame B	$19,464	$38,952	$44,122
CT - Second Generation Frame E	$19,264	$20,560	$45,061
CT - Third Generation Aero	$18,813	$20,081	$45,806
CT - Third Generation Frame F	$18,175	$19,428	$21,469
Diesel	$18,210	$20,187	$64,292
Hydro	$18,134	$38,698	$45,261
Nuclear	$20,013	$20,313	$44,808
Oil or Gas Steam	$17,332	$40,702	$45,497
Pumped Storage	$43,188	$45,216	$46,012
Sub-Critical Coal	$17,634	$19,468	$41,415
Super Critical Coal	$4	$18,622	$42,173

Table 6-30 Combined revenue from all markets by quartile for select technologies for 2012

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$32,966	$78,322	$113,525
CC - Two of Three on One Frame F Technology	$39,737	$105,385	$169,191
CT - First & Second Generation Aero (P&W FT 4)	$38,490	$43,533	$51,304
CT - First & Second Generation Frame B	$14,997	$37,757	$44,573
CT - Second Generation Frame E	$20,648	$33,652	$73,772
CT - Third Generation Aero	$28,197	$46,760	$85,007
CT - Third Generation Frame F	$26,949	$49,230	$93,456
Diesel	$11,246	$20,187	$65,213
Hydro	$84,090	$166,898	$265,378
Nuclear	$162,700	$209,847	$252,610
Oil or Gas Steam	$15,773	$40,787	$54,889
Pumped Storage	$53,698	$66,377	$75,143
Sub-Critical Coal	$18,733	$32,023	$81,727
Super Critical Coal	$32,518	$69,047	$107,959

24 A number of coal units did not clear the relevant RPM auctions and received no capacity revenue.

Table 6-31 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2012, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 6-32 shows the avoidable cost recovery from all PJM markets by quartiles.

Table 6-33 and Table 6-34 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets for 2009, 2010, 2011 and 2012. 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 6-31 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	54%	134%	262%
CC - Two of Three on One Frame F Technology	156%	381%	612%
CT - First & Second Generation Aero (P&W FT 4)	(17%)	(2%)	58%
CT - First & Second Generation Frame B	(48%)	(24%)	11%
CT - Second Generation Frame E	77%	133%	211%
CT - Third Generation Aero	94%	164%	187%
CT - Third Generation Frame F	138%	337%	540%
Diesel	(34%)	(10%)	51%
Hydro	472%	741%	1,061%
Nuclear	NA	NA	NA
Oil or Gas Steam	(17%)	0%	33%
Pumped Storage	0%	342%	577%
Sub-Critical Coal	0%	12%	65%
Super Critical Coal	41%	72%	100%

Table 6-32 Avoidable cost recovery by quartile from all PJM Markets for select technologies for 2012

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	151%	220%	339%
CC - Two of Three on One Frame F Technology	329%	551%	723%
CT - First & Second Generation Aero (P&W FT 4)	438%	497%	1,015%
CT - First & Second Generation Frame B	215%	373%	494%
CT - Second Generation Frame E	284%	415%	618%
CT - Third Generation Aero	205%	269%	368%
CT - Third Generation Frame F	418%	742%	1,010%
Diesel	102%	169%	471%
Hydro	634%	897%	1,199%
Nuclear	NA	NA	NA
Oil or Gas Steam	53%	143%	179%
Pumped Storage	162%	1,119%	1,154%
Sub-Critical Coal	28%	66%	111%
Super Critical Coal	89%	126%	154%

Table 6-33 Proportion of units recovering avoidable costs from energy and ancillary markets for 2009 to 2012

	Units with full recovery from energy and ancillary services markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	39%	71%	61%	67%
CC - Two of Three on One Frame F Technology	63%	76%	90%	86%
CT - First & Second Generation Aero (P&W FT 4)	8%	5%	7%	6%
CT - First & Second Generation Frame B	3%	11%	19%	18%
CT - Second Generation Frame E	21%	48%	63%	73%
CT - Third Generation Aero	17%	36%	72%	68%
CT - Third Generation Frame F	18%	39%	59%	77%
Diesel	64%	59%	56%	44%
Hydro	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	28%	42%	43%	36%
Pumped Storage	70%	90%	70%	90%
Sub-Critical Coal	76%	82%	70%	50%
Super Critical Coal	86%	94%	92%	61%

Table 6-34 Proportion of units recovering avoidable costs from all markets for 2009 to 2012

	Units with full recovery from all markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	87%	88%	89%	79%
CC - Two of Three on One Frame F Technology	92%	100%	100%	97%
CT - First & Second Generation Aero (P&W FT 4)	99%	99%	100%	100%
CT - First & Second Generation Frame B	99%	98%	92%	90%
CT - Second Generation Frame E	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	94%
CT - Third Generation Frame F	95%	96%	98%	96%
Diesel	95%	97%	91%	85%
Hydro	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	93%	88%	88%	73%
Pumped Storage	100%	100%	100%	100%
Sub-Critical Coal	88%	93%	87%	61%
Super Critical Coal	97%	100%	96%	85%

At-Risk Coal Plants

A number of sub-critical and supercritical coal units did not recover avoidable costs from total market revenues, including capacity market revenues. These units are considered at risk of retirement.

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[25]

Energy market net revenues are a function of energy prices and operating costs. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 6-35 compares characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues, to characteristics of coal plants with greater than or equal to 100 percent recovery. Units that did not cover their avoidable costs were, on average, less efficient, ran less often and had substantially higher avoidable costs.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. Units that did not cover avoidable costs tended to have higher avoidable costs. It is possible that these units cleared in the capacity market at a level below avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated

25 This 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.

with each delivery year which led to an offer cap that understated the annual recovery needed from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap.

Table 6-35 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	3,724	35,012
Avg. Installed Capacity (ICAP)	248	347
Avg. Age of Plant (Years)	46	36
Avg. Heat Rate (Btu/kWh)	10,999	10,564
Avg. Run Hours (Hours)	3,348	6,054
Avg. Avoidable Costs ($/MW-year)	167	149

In 2012, 15 coal units did not cover their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 6-36 shows the installed capacity (MW) associated with levels of recovery for coal plants.

Table 6-36 Installed capacity associated with levels of avoidable cost recovery: 2012

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	1,110	3%
65% - 75%	555	1%
75% - 90%	531	1%
90% - 100%	1,528	4%
> 100%	35,012	90%
Total	38,737	100%

Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. These capital expenditures, if required, would significantly impact the profitability of coal plants lacking sufficient environmental controls. Coal plants facing capital expenditures may be retired if it is not expected that the plants will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.Units lacking MATS compliant controls for NO_x emissions, SO_2 emissions, particulates, or all three, were identified as units potentially facing significant capital expenditures on environmental control technologies. Table 6-37 shows the number of units and associated installed capacity lacking MATS compliant environmental controls.

Table 6-37 Coal plants lacking MATS compliant environmental controls

	Coal plants without NO_x controls	Coal plants without SO_2 controls	Coal plants without particulate controls	Coal plants lacking NO_x, SO_2, and particulate controls
Number of units	49	22	33	11
Installed capacity (ICAP)	10,444	5,089	11,394	1,722