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), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- In the first six months of 2013, energy market net revenues for a new entrant coal plant exceeded 2012 annual energy market net revenues in nine zones. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.
- In the first six months of 2013, average energy market net revenues for a new entrant CT were 43 percent of 2012 annual energy market net revenues. In the first six months of 2013, average energy market net revenues for a new entrant CC were 40 percent of 2012 annual energy market net revenues.
- In the first six months of 2013, average energy market net revenues for a new entrant wind plant were over 69 percent and for a new entrant solar plant were over 77 percent of 2012 annual net revenues.

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.

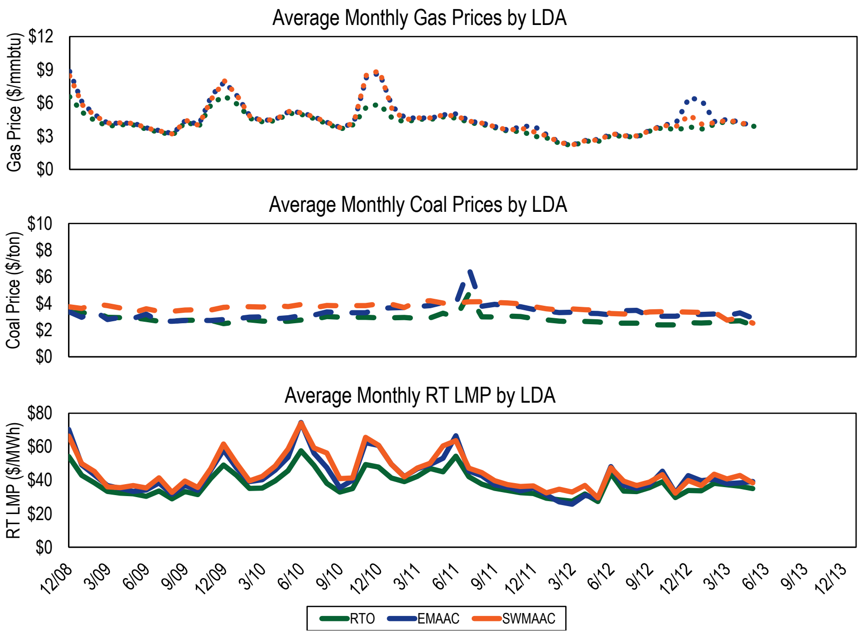
Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 21.6 percent higher in the first six months of 2013 than in the first six months of 2012, $37.96 per MWh versus $31.21 per MWh. Comparing fuel prices in the first six months of 2013 to fuel prices in the first six months of 2012, the price of Northern Appalachian coal was 0.5 percent lower; the price of Central Appalachian coal was 4.1 percent higher; the price of Powder River Basin

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.

coal was 18.0 percent higher; the price of eastern natural gas was 52.7 percent higher; and the price of western natural gas was 35.4 percent higher.

Figure 6-1 Energy Market net revenue factor trends: December 2008 through June 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 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 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 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 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 DS plant consists of one oil fired CAT 2 MW unit using ultra low sulfur fuel.
- 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.

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.

Net revenue calculations for the CT, CC, CP and IGCC 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 were calculated to 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 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.[6] 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 any of the unit 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.

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 estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[8] 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.[9]

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.

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.
5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
6 Outage figures obtained from the PJM eGADS database. The CC outage rate was used for the IGCC plant.
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.

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 6-1 Energy Market net revenue[10] for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan-Jun)
AECO	$12,421	$40,037	$46,157	$24,993	$10,208
AEP	$3,696	$11,575	$20,839	$16,263	$6,682
AP	$11,136	$32,494	$32,958	$21,029	$8,850
ATSI	NA	NA	NA	$18,296	$7,266
BGE	$15,126	$52,411	$48,642	$36,307	$15,983
ComEd	$2,445	$9,446	$15,081	$13,780	$5,474
DAY	$3,313	$11,701	$21,705	$18,573	$6,602
DEOK	NA	NA	NA	$16,004	$6,095
DLCO	$4,471	$17,525	$24,179	$18,773	$6,813
Dominion	$15,253	$42,922	$38,945	$25,375	$10,935
DPL	$13,886	$40,530	$44,339	$32,587	$11,566
JCPL	$11,994	$39,409	$44,968	$24,117	$13,124
Met-Ed	$11,083	$39,409	$40,802	$25,396	$10,523
PECO	$10,611	$38,311	$45,853	$25,884	$10,119
PENELEC	$6,986	$24,309	$32,090	$22,463	$10,013
Pepco	$17,798	$50,906	$44,233	$32,011	$14,892
PPL	$10,045	$33,649	$42,872	$22,817	$10,284
PSEG	$10,079	$37,626	$37,929	$24,081	$10,313
RECO	$8,717	$35,022	$32,178	$22,808	$12,999
PJM	$9,945	$32,781	$36,104	$23,240	$9,934

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.[11] 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 6-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan-Jun)
AECO	$62,063	$106,643	$126,869	$101,124	$38,503
AEP	$29,759	$47,591	$82,324	$87,908	$35,217
AP	$59,052	$91,032	$113,561	$100,499	$40,373
ATSI	NA	NA	NA	$94,387	$38,277
BGE	$70,571	$124,665	$130,806	$123,367	$50,227
ComEd	$20,613	$33,906	$46,293	$61,754	$21,377
DAY	$27,904	$46,647	$82,067	$93,517	$36,665
DEOK	NA	NA	NA	$82,044	$32,335
DLCO	$27,649	$51,180	$81,642	$89,180	$30,905
Dominion	$68,932	$116,873	$114,530	$103,610	$41,871
DPL	$64,321	$106,245	$123,599	$114,808	$42,306
JCPL	$61,477	$105,474	$124,878	$100,386	$43,173
Met-Ed	$55,400	$97,665	$111,653	$96,018	$37,344
PECO	$57,843	$99,951	$121,804	$98,151	$35,912
PENELEC	$48,876	$80,773	$109,048	$106,236	$47,926
Pepco	$71,959	$121,952	$121,143	$115,691	$48,146
PPL	$52,285	$87,314	$111,111	$91,727	$36,335
PSEG	$57,910	$101,819	$114,951	$96,617	$39,180
RECO	$51,808	$93,724	$96,235	$90,924	$44,060
PJM	$52,260	$89,027	$106,618	$97,260	$38,954

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

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

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 6-3 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan-Jun)
AECO	$87,901	$149,022	$75,325	$23,301	$23,595
AEP	$19,251	$56,227	$72,858	$41,244	$28,182
AP	$49,303	$98,671	$99,020	$54,552	$47,966
ATSI	NA	NA	NA	$47,274	$42,740
BGE	$46,299	$80,689	$56,940	$23,390	$29,167
ComEd	$42,738	$106,599	$94,493	$53,813	$39,249
DAY	$27,905	$77,082	$65,842	$43,027	$50,368
DEOK	NA	NA	NA	$36,519	$44,665
DLCO	$22,971	$76,395	$47,075	$43,904	$25,078
Dominion	$46,756	$144,290	$77,310	$17,547	$23,681
DPL	$38,833	$147,279	$94,908	$29,102	$27,020
JCPL	$74,389	$147,559	$71,437	$30,517	$22,961
Met-Ed	$57,888	$139,228	$61,703	$38,561	$16,821
PECO	$78,602	$142,542	$74,834	$24,474	$21,617
PENELEC	$77,650	$122,426	$95,440	$52,897	$52,597
Pepco	$70,058	$160,627	$73,476	$23,706	$45,091
PPL	$71,601	$114,549	$76,697	$18,079	$20,572
PSEG	$171,879	$124,533	$47,550	$22,590	$44,767
RECO	$71,025	$143,410	$59,111	$29,258	$41,783
PJM	$62,062	$119,478	$73,178	$34,408	$34,101

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 6-4 PJM Energy Market net revenue for a new entrant IGCC (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan-Jun)
Dominion	$13,130	$5,583

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 6-5 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through June 2013

Zone	2013 (Jan-Jun)
AECO	$6,840
AEP	$4,542
AP	$4,970
ATSI	$4,706
BGE	$7,250
ComEd	$4,347
DAY	$4,651
DEOK	$4,288
DLCO	$4,241
Dominion	$5,953
DPL	$7,101
JCPL	$6,991
Met-Ed	$6,527
PECO	$6,612
PENELEC	$5,066
Pepco	$6,531
PPL	$6,192
PSEG	$6,831
RECO	$6,690
PJM	$5,807

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 6-6 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan-Jun)
AEP	$201,658	$116,873

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 6-7 PJM Energy Market net revenue for a new entrant wind installation (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan-Jun)
ComEd	$125,004	$82,626
PENELEC	$127,364	$90,644

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 6-8 PJM Energy Market net revenue for a new entrant solar installation (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan-Jun)
PSEG	$364,893	$282,086