SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2010. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Highlights and New Analysis

- Net revenues increased for all zones from 2009 to 2010 as a result of higher energy revenues, and, in most zones, higher capacity revenues.

- Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the Pepco and BGE zones for a new entrant CT and less than full annual fixed cost recovery in the other zones. Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the AECO, BGE, DPL, and Pepco zones for a new entrant CC and less than full annual fixed cost recovery in the other zones. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010.

- Analysis of actual 2010 net revenues shows that capacity market revenues were required to provide supplemental revenue to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Such units included CTs, CCs and coal units.

- Analysis of actual 2010 net revenues shows that revenues from energy, ancillary and capacity markets were sufficient to cover avoidable costs for all CC technologies and nearly all CT technologies.

- Analysis of actual 2010 net revenues shows that a number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues were considered. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. These units are considered at risk of retirement. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs.

- Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies in response to regulatory mandates. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue.

- Analysis of actual, unit specific net revenues and avoidable costs for coal plants lacking environmental controls in 2010 found that between 14,345 MW and 19,068 MW of installed capacity, depending on the nature of the requirements, would require an increase in energy or capacity revenue in order to recover avoidable costs including the project investment costs and remain in operation if faced with mandatory investment in environmental controls.

- There were no scarcity pricing events in 2010 under PJM's current Emergency Action based Scarcity Pricing Rules.

- Analysis of net resource levels found there were no reserve shortages in 2010. There were a number of relatively high load days in July, August and September of 2010.

- Operating reserve charges increased 74.6 percent in 2010 compared to 2009. Higher loads, locationally volatile natural gas prices, and increases in outages were the primary causes. Eastern reliability credits increased 9,584.1 percent in 2010 compared to 2009, mainly as a result of units required to operate for a specific transmission outage, and an increase in weather-related alerts.

- Balancing transaction operating reserve credits paid in December 2010 represent 82.9 percent of all balancing transaction operating reserve credits since 2000.

- The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits.

- In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation. Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent.

- At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues.

- Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards.

Recommendations

- The MMU recommends that the limits on operational parameters apply to both price and cost-based schedules in order to prevent the exercise of market power.

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- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market.

- The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total 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 and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, 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.

  In 2010, while total net revenues were not adequate to cover annual fixed costs for a new entrant coal plant (CP) in any zone, total net revenues were adequate to cover annual fixed costs for a new entrant CT in Pepco zone and in BGE zone, and total net revenues were adequate for a new entrant CC in the AECO, BGE, DPL and Pepco zones. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs than for other technologies, reflecting a relatively favorable spread between LMP and the cost of natural gas compared to the spread between LMP and the cost of delivered coal.

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In 2010, total net revenues were higher than in 2009. The increases in total net revenues by technology type were the result of increases in energy revenues, from an increase in energy prices which exceeded increases in fuel costs, and in most cases, increases in capacity revenues, from capacity prices determined in prior RPM auctions. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

For the new entrant CT, all zones had higher total net revenue in 2010 compared to 2009 (Table 3-9). For the new entrant CT, all zones had higher energy net revenue, and all zones but two, BGE and Pepco, had higher available capacity revenues.[1] The 2010/2011 Base Residual Auction (BRA) cleared with much less price separation by location than prior BRAs and at a higher price for the RTO Locational Deliverability Area (LDA) than previous BRAs. As a result, zones that previously cleared in constrained LDAs saw only slight increases or, in the case of SWMAAC, decreases, in capacity revenue available for calendar year 2010, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The BGE and Pepco zones, which previously cleared in the SWMAAC LDA for the 2009/2010 delivery year, had a lower clearing price associated with the unconstrained RTO LDA for the 2010/2011 BRA. The decreases in available capacity revenue in BGE and Pepco were more than offset by increases in energy net revenue. The six zones which had previously cleared in the EMAAC LDA (AECO, DPL, JCPL, PECO, PSEG and RECO) that were part of the MAAC+APS LDA for the 2009/2010 BRA had slightly higher capacity revenues available. Of these six zones, DPL showed the highest increase in capacity prices as DPL South separated and cleared at a slightly higher price than the RTO LDA in the 2010/2011 BRA. The five zones that had cleared in the unconstrained RTO LDA (AEP, ComEd, DAY, DLCO and Dominion) for the 2009/2010 BRA had significantly higher capacity revenues available as a result of higher capacity prices for the 2010/2011 BRA. The four zones that cleared in the MAAC+APS LDA and that had cleared with the unconstrained RTO LDA in the 2008/2009 BRA (AP, Met-Ed, PENELEC, and PPL) had significantly higher capacity revenues available associated with the constrained MAAC+APS LDA in the 2009/2010 BRA, but slightly lower capacity revenues associated with the 2010/2011BRA.

For the new entrant CC, all zones had higher total net revenue in 2010 compared to 2009 (Table 3-11). For the new entrant CC, all zones showed an increase in energy net revenue. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

For the new entrant coal plant (CP), all zones had higher total net revenue in 2010 compared to 2009 (Table 3-13). For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

- **Actual Net Revenue and Avoidable Costs.** 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 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

1 This section discusses available capacity revenues to new and existing units based on the clearing prices in Base Residual Auctions (BRA). It is not intended to reflect actual revenues associated with RPM.

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cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a measure of the extent to which units in PJM may be at risk of retirement.

It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

- For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

- The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2010 was 6,769 MW. Generally, coal units that did not recover avoidable costs in 2010 tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs. These units may be considered for deactivation.

- Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units under recovering avoidable costs excluding capital recovery as they may stay in service for the duration of the project life.

- Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. There are pending regulations that would require significant capital expenditures in environmental controls for existing coal units in PJM and a significant portion of these units would require additional revenues if faced with project investment for environmental controls. The MMU analyzed two scenarios based on actual energy and capacity revenues and avoidable costs in 2010 for units that may require project investments in environmental controls. In the first scenario, units accounting for 14,345 MW of installed capacity would require additional revenue for recovery of project investments. In the second scenario, which assumes more stringent unit specific NO_x control requirements, units accounting for 19,068 MW of installed capacity would require additional revenue for recovery of project investments. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,512.1 MW on December 31, a decrease of 1,341.7 MW or 0.8 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2010, 40.8 percent was coal; 29.1 percent was natural gas; 18.3 percent was nuclear; 6.1 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.4 percent was wind.

- **Generation Fuel Mix.** In 2010, coal provided 49.3 percent, nuclear 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 1.2 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in 2010.** PJM did not declare a scarcity event in 2010.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

- **Scarcity and High Load Analyses.** The MMU analysis of net resource levels in the June through September period showed no evidence of reserve shortage events in the period. There were, however, a number of relatively high load days in July, August and September of 2010.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole payments, operating reserve credits are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those

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participants paying the operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2010.** The level of operating reserve credits and corresponding charges increased in 2010 by 74.6 percent compared to 2009, to $569 million in 2010 from $325 million in 2009. Reliability credits increased 268.0 percent, or $82 million, in 2010 compared to 2009.

  The overall increase in operating reserve charges in 2010 is comprised of a 4.5 percent decrease in day-ahead operating reserve charges, a 71.1 percent decrease in synchronous condensing charges and a 109.1 percent increase in balancing operating reserve charges. The increase in balancing charges can be attributed primarily to higher levels of demand in 2010 along with sustained periods of higher natural gas prices during winter months. December 2010, which includes 8.5 percent of the days in the year, accounted for 16.9 percent, or $96,032,958 of the annual operating reserve charges.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  One purpose of the rule changes was to allocate a larger portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in 2010. The new operating reserve rules resulted in an increase of $112,691,690 in charges assigned to real-time load and exports for 2010.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $26 million less in operating reserve charges in 2010 than they would have paid under the old rules.

  As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $18 million, or 6.0 percent, higher for 2010 than they would have been under the old rules.

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.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

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 non market 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.

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In 2010, energy market revenues were generally higher for new entrant combustion turbines and combined cycles, both using natural gas, as energy market prices increased more than the average delivered price of natural gas in most zones. Energy market net revenues for new entrant coal plants were substantially higher in all zones as energy market prices increased more than the average delivered price of low sulfur coal.

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. All zones had more high demand days in 2010 than in 2009 and all zones showed a higher frequency of hours of real-time LMP greater than $200. The average on peak LMP for PJM increased 21 percent for 2010 compared to 2009. The PJM average real-time LMP was greater than $200 for twenty-six hours in 2010, compared to two hours in 2009. As a result, the average increase in energy net revenue for a new entrant CT was 274 percent, and the increases in energy net revenue for BGE and Pepco zones were 355 and 368 percent.

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 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 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.

Coal plants (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. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. In 2010, particularly in the third quarter, CCs and CTs ran more often, which resulted in an increase in the net revenue received by coal plants.

Net Revenue

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 quantifies the contribution to capital and avoidable costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[2] Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[3]

2 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over defined hours of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that, in contrast to the perfect dispatch model, 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.

Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Net revenue equals total gross revenue 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. Fixed costs, in this sense, include all but short run variable costs.

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.

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, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2010 for the Real-Time Energy Market and from all hours during 2000 to 2010 for the Day-Ahead Energy Market, when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2010, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2010, adjusted for forced outages, it would have received $129,146 per installed MW-year in net revenue from the Real-Time Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $123,943 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2010.

4 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 marginal cost could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

5 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for the same hour of operation.

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Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2010

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738	$220,494	$283,747
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750	$141,212	$203,458
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122	$73,039	$129,146
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568	$38,171	$82,421
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669	$21,792	$56,843
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282	$13,197	$40,790
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343	$8,353	$30,125
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666	$5,366	$22,648
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360	$3,479	$17,114
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397	$2,349	$13,049
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713	$1,588	$9,928
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971	$1,067	$7,497
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281	$731	$5,679
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222	$484	$4,358
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288	$323	$3,355
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351	$205	$2,591
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196	$119	$1,978
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630	$69	$1,468
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464	$41	$1,077
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643	$15	$806

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2010.[6]

6 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used in the Day-Ahead Energy Market analysis for the period from January 1, 2000 to May 31, 2000.

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Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2010

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557	$218,865	$281,075
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221	$138,961	$199,891
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084	$70,736	$123,934
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678	$29,918	$69,720
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374	$13,695	$40,641
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287	$6,695	$24,802
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996	$3,134	$15,286
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349	$1,433	$9,230
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159	$599	$5,466
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761	$189	$3,153
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157	$38	$1,761
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650	$4	$1,015
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633	$0	$596
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706	$0	$352
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594	$0	$202
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034	$0	$115
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929	$0	$64
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173	$0	$32
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611	$0	$13
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209	$0	$0

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve for 2010 is higher than for 2009 for all levels of marginal costs. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve for 2010 is higher than for 2009 for all levels of marginal cost below $200.

The increase in 2010 Real-Time Energy Market net revenue compared to 2009 was the result of changes in the frequency distribution of energy prices. In 2010, prices were greater than or equal to $30 per MWh more frequently than in 2009. The 2010 simple average LMP was $44.83 per MWh, a substantial increase compared to $37.08 per MWh in 2009. The Real-Time Energy Market LMP was greater than, or equal to, $30 per MWh during 62 percent of all hours in 2009, and during 77 percent of all hours in 2010.

The increase in 2010 compared to 2009 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2010, prices were greater than, or equal to, $30 more frequently than in 2009 as the simple average LMP was $44.57 per MWh in 2010 compared to $37.00 per MWh in 2009. The Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 69 percent of all hours in 2009, and during 82 percent of all hours in 2010.

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Average price levels in 2010 were significantly higher than in 2009 and, as a result, net revenue levels were higher for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2010 were higher compared to those in 2009, and price levels increased more than fuel costs. An efficient CT could have produced energy at an average cost of $60 in 2010. An efficient CC could have produced energy at an average cost of $40 in 2010. An efficient CP could have produced energy at an average cost of $30 in 2010. Energy Market net revenues for a new entrant CT, CC and CP were higher in nearly all zones in 2010 due to PJM price levels increasing more rapidly than the average prices of natural gas and delivered coal. The result is that, while natural gas-fired units and coal-fired units experienced slightly higher marginal costs compared to 2009, the increase in average PJM prices in 2010 was greater, meaning higher energy net revenue in all control zones for 2010.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2010

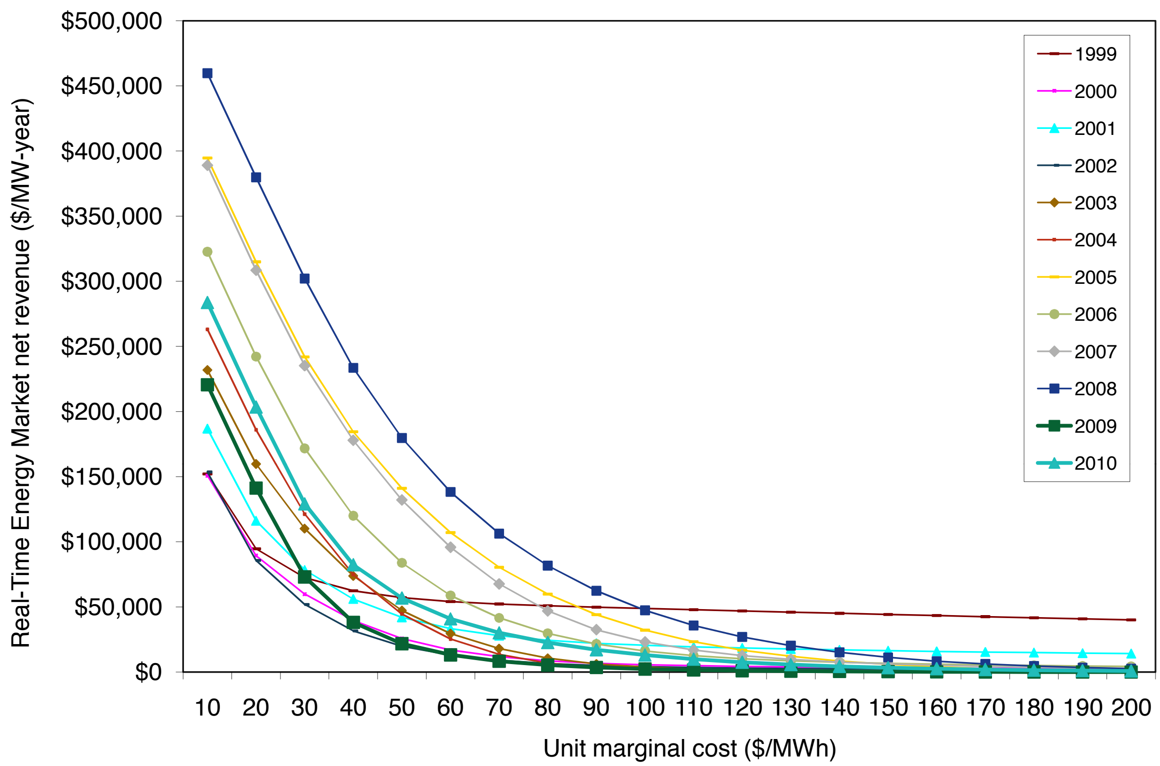
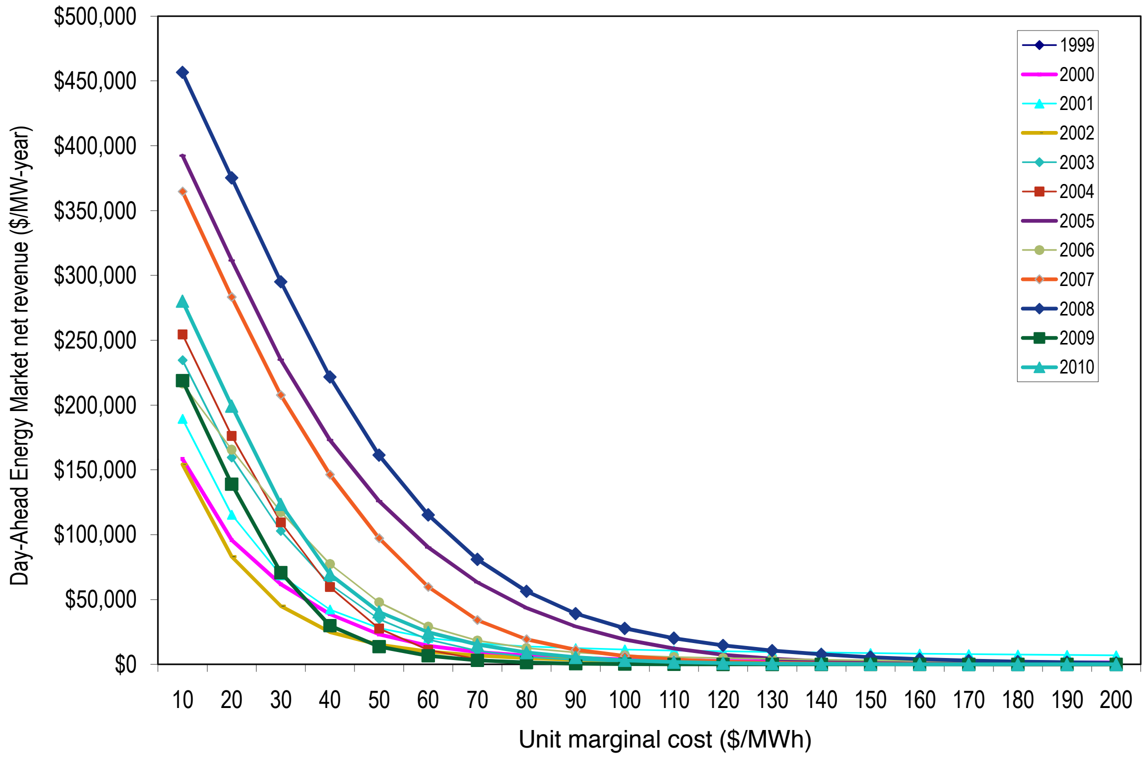


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2010



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[7] The Real-Time and Day-Ahead Energy Market curves are very similar for lower marginal cost levels, particularly below $30 per MWh. The Real-Time Energy Market curve shows significantly higher net revenues as marginal costs increase beyond $80 per MWh because, while average Real-Time LMP is very close to Day-Ahead LMP, the Real-Time LMP is more volatile and shows a higher frequency of high priced hours compared to Day-Ahead LMP.

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and therefore represent an upper bound of the direct contribution to generator fixed costs from the Energy Market. All other things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC plant, a two-hour hot status notification plus

7 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

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startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours. The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP plant with an eight-hour cold status notification plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue. Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue Conversely, 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. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1 through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity. This was the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive capacity payments determined in the first RPM Auction for their corresponding Locational Deliverability Area (LDA). The RPM Base Residual Auction clearing prices are shown by zone and LDA in Table 3-3.[8]

8 The value in Table 3-3 associated with DPL represents a load-weighted average clearing price for the DPL control zone, because the DPL South LDA is sub-zonal. Table 3-3 shows capacity revenues per unforced MW-year from RPM BRAs. Table 3-4 shows capacity revenues per installed MW-year from RPM BRAs, adjusted using the system forced outage rate.

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Table 3-3 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2010

	Base Residual Auction 2009/2010			Base Residual Auction 2010/2011			RPM Revenue
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	2010 $/MW
AECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408	RTO	$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL South/RTO	$178.57	$38,214	$67,103
JCPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837	RTO	$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889	RTO	$174.29	$37,298	$66,187
PJM	NA	$154.47	$23,325	NA	$174.42	$37,327	$60,652

Table 3-4 shows zonal capacity revenue for the twelve-year period 1999 to 2010.[9] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[10] Capacity revenue for 2010 includes five months of the 2009/2010 auction clearing price and seven months of the 2010/2011 auction clearing price.[11] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[12]

9 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

10 In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA clearing price for the remaining seven months

11 The 2007 capacity revenue value for PJM in Table 3-4 similarly combines load-weighted CCM and RPM BRA revenues. The 2008-2010 RPM revenue values for PJM are load-weighted averages based on the BRA LDA clearing prices in Table 3-3 and the cleared MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year for the whole PJM footprint.

12 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-9, Table 3-11 and Table 3-13 as capacity revenues by technology type are adjusted for technology-specific outage rates.

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Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$21,198
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$67,871	$29,188
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$35,836	$48,912	$21,132
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$48,912	$20,879
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$35,836	$48,912	$24,637
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$62,273	$26,495
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$67,871	$29,188
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$61,423	$20,951
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$26,424
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$61,423	$29,197
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$44,814	$56,287	$22,346

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, 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 both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA 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 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. The coal plant is a western Virginia 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.

All net revenue calculations include the effect of actual hourly local ambient air temperature[13] on plant heat rates[14] and generator output for each of the three plant configurations.[15] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.[16] The effect of ambient air conditions on plant generation capability was calculated hourly.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[17] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[18] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $7.46 per MWh for the CT plant, $3.23 per MWh for the CC plant and $3.07 per MWh for the CP plant.[19] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[20] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[21] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[22]

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2010 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time 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.[23] This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

13 Hourly ambient conditions supplied by Telvent DTN for multiple points in PJM RTO. PJM net revenue calculations include the average of all points in PJM RTO. Zonal net revenue calculations include zone specific ambient air temperatures.

14 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for the MMU.

15 Pasteris Energy, Inc.

16 All heat rate calculations are expressed in Btu per net kWh. 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, but is off for every uneconomic hour. Therefore, there is a single offer point and no offer curve.

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

18 Outage figures obtained from the PJM eGADS database.

19 These estimates were provided by a consultant to the MMU, Pasteris Energy, Inc.

20 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

21 Gas daily cash prices obtained from Platts.

22 Coal prompt prices obtained from Platts.

23 The adder reflects the modifications to the regulation market rules that were effective on December 1, 2008.

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Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2010, for CTs, the calculated rate is $2,384 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[24]

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2010 is shown in Table 3-5, Table 3-6 and Table 3-7 for new entrant CT, CC and CP facilities. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[25] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year):[26] Net revenue for calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$10,735	$49,154	$29,089
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,206	$10,929	$4,972
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$12,546	$32,870	$12,333
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$14,995	$61,400	$28,892
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$2,393	$8,642	$5,678
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$2,981	$10,340	$4,817
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$4,704	$17,087	$7,569
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$14,319	$48,940	$35,441
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$13,410	$47,388	$26,080
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$11,622	$44,372	$24,706
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$10,057	$44,747	$22,198
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$9,513	$41,761	$22,174
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$6,019	$22,092	$12,527
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$23,362	$70,361	$31,771
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$8,970	$38,365	$18,844
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$9,155	$42,106	$23,318
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$7,846	$37,166	$16,977
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$5,113	$36,925	$16,841

24 The CT plant reactive revenues are based on 44 filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 filings with the FERC for CP reactive costs. These figures have not changed from those reported in the *2009 State of the Market Report for PJM* as there were no reactive filings with the FERC in calendar year 2010 for PJM resources.

25 Zonal net revenues for 2009 and 2010 reflect locational zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.

26 The energy net revenues presented for PJM for 2010 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for PJM represent the simple average energy net revenue.

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Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$48,544	$108,930	$56,729
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$25,145	$44,299	$27,562
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$52,645	$85,547	$35,134
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$55,496	$125,692	$59,223
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$18,839	$33,705	$28,529
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$25,301	$43,620	$27,408
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$26,316	$47,493	$39,371
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$53,240	$108,343	$50,636
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$52,338	$107,753	$53,790
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$50,649	$103,923	$52,346
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$44,671	$100,209	$44,601
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$44,636	$97,940	$49,814
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,615	$67,791	$34,930
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$71,539	$141,024	$62,102
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$42,046	$90,886	$41,247
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$47,113	$101,655	$50,958
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$43,137	$91,866	$47,394
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$31,581	$88,275	$40,943

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2010

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$92,287	$160,597	$181,761
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$29,034	$65,893	$111,803
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$62,730	$109,575	$165,805
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$47,837	$98,635	$167,882
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$53,680	$116,282	$129,956
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$40,214	$86,984	$110,391
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$36,538	$84,666	$104,604
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$52,969	$152,362	$207,871
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$44,299	$159,204	$174,131
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$81,687	$155,249	$172,555
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$64,568	$150,184	$162,420
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$82,938	$148,818	$166,684
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$84,807	$124,253	$141,650
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$76,426	$170,080	$179,929
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$78,012	$125,429	$156,247
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$105,739	$135,636	$175,550
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$78,553	$148,988	$204,253
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$49,022	$128,990	$140,067

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New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[27] for at least two hours during each four-hour block.[28] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[29]

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-8 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CT's total net revenue.

Table 3-8 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532
2009	$5,113	$48,441	$0	$0	$2,384	$55,939
2010	$36,925	$55,309	$0	$0	$2,384	$94,619

Table 3-9 shows the total net revenue (the Total column in Table 3-8) for the new entrant CT in each zone.[30]

27 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 15 (October 27, 2010), startup and shutdown 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. No-load costs are included in the heat rate.

28 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

29 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.

30 New entrant CT zonal net revenue for 2010 reflects the estimated zonal, daily delivered price of natural gas.

Table 3-9 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$70,287	$111,894	$56,729
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$40,513	$61,376	$27,562
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$67,078	$95,611	$35,134
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$91,770	$130,476	$59,223
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$39,700	$59,089	$28,529
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$40,288	$60,787	$27,408
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$30,782	$53,923	$37,015	$42,012	$67,534	$39,371
Dominion	NA	NA	NA	NA	NA	NA	NA	$9,360	$20,075	$72,734	$51,626	$99,387	$50,636
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$72,963	$110,964	$53,790
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$71,175	$107,113	$52,346
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$64,589	$107,488	$44,601
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$69,066	$104,501	$49,814
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$60,552	$84,833	$34,930
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$100,138	$139,437	$62,102
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$63,502	$101,106	$41,247
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$68,708	$104,847	$50,958
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$67,399	$99,907	$47,394
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$55,939	$94,619	$40,943

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[31] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct burner firing, including fuel and, if applicable, emissions allowance credits.[32] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-6 results.

31 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 15 (October 27, 2010), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

32 Duct burner firing dispatch rate is developed using same methodology described for unfired dispatch rate, with temperature adjustments to duct burner fired heat rate and output provided by Pasteris Energy, Inc.

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Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CC's total net revenue.

Table 3-10 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928
2009	$31,581	$46,596	$0	$0	$3,198	$81,376
2010	$88,275	$38,588	$0	$0	$3,198	$130,061

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CC in each zone.

Table 3-11 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$112,738	$171,758	$103,161
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$65,604	$76,549	$48,318
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$111,482	$117,797	$69,225
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$138,066	$199,824	$103,777
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$59,298	$65,955	$51,145
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$65,760	$75,870	$47,888
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$83,104	$155,267	$61,141	$66,775	$79,742	$77,003
Dominion	NA	NA	NA	NA	NA	NA	NA	$23,734	$44,520	$155,658	$93,699	$140,593	$91,641
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$110,969	$180,121	$116,532	$170,582	$94,656
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$114,843	$166,751	$96,557
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$103,508	$132,459	$80,913
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$108,830	$160,768	$89,923
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$97,452	$100,041	$61,645
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$154,109	$215,157	$108,516
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$100,883	$123,136	$75,139
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$111,307	$164,483	$98,205
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$107,331	$154,695	$101,466
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$81,376	$130,061	$72,094

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New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-12 for the years 1999 through 2010. This table shows the contribution of each market individually to the new entrant CP's total net revenue. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 3-12 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2010

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144
2009	$49,022	$43,931	$0	$231	$1,783	$94,968
2010	$128,990	$36,117	$0	$174	$1,783	$167,064

Table 3-13 shows the total net revenue (the Total column 7 in Table 3-12) for the new entrant CP in each zone.[33]

33 New Entrant CP zonal net revenue for 2010 incorporates the zone specific, delivered price of coal.

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Table 3-13 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2010

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$151,958	$218,375	$210,868
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$66,176	$94,972	$131,941
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$117,241	$138,658	$185,768
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$124,582	$166,838	$200,051
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$91,497	$145,678	$150,662
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$77,760	$116,152	$130,510
DLCO	NA	NA	NA	NA	NA	NA	$125,720	$240,844	$157,544	$168,655	$73,721	$113,765	$146,708
Dominion	NA	NA	NA	NA	NA	NA	NA	$108,418	$328,069	$312,361	$90,049	$181,505	$204,080
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,209	$339,158	$379,198	$103,715	$217,051	$203,285
JCPL	$117,951	$129,972	$133,840	$110,499	$165,751	$186,365	$290,815	$203,813	$352,520	$374,748	$141,256	$213,033	$201,714
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$119,008	$179,319	$183,860
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$142,528	$206,581	$195,864
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$140,148	$153,536	$163,307
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$153,255	$238,386	$212,150
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$132,526	$154,502	$177,700
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$165,919	$193,358	$204,725
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$138,107	$206,773	$235,438
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$94,968	$167,064	$163,748

New Entrant Day-Ahead Net Revenues

Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis. The results for the Day-Ahead Energy Market for each class are presented in Table 3-14, Table 3-15 and Table 3-16 [34]

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Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$6,373	$29,417	$15,622
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,180	$6,516	$2,262
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$5,397	$21,371	$6,576
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$7,792	$38,774	$14,214
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$480	$5,361	$2,383
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$733	$6,428	$2,062
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$7,613	$31,080	$17,469
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,098	$8,128	$2,272
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$6,840	$28,205	$14,297
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$5,007	$26,623	$11,844
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$4,619	$27,017	$11,469
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$4,920	$25,963	$11,934
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$3,303	$15,763	$6,587
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$15,816	$50,566	$17,341
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$4,345	$22,048	$9,428
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$4,051	$24,878	$11,873
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$3,156	$22,543	$7,910
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$1,966	$22,981	$8,142

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$51,240	$96,081	$63,452
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$23,139	$39,674	$20,887
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$47,963	$79,090	$39,003
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$58,133	$110,793	$58,784
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$14,225	$27,543	$20,650
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$21,226	$38,678	$19,364
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$21,270	$93,788	$70,871
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$21,270	$42,658	$18,909
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$52,846	$93,757	$58,680
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$50,315	$93,788	$57,293
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$44,189	$87,136	$49,654
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$46,590	$88,938	$52,433
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$38,970	$68,844	$33,955
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$73,603	$132,021	$65,509
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,987	$77,977	$44,670
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$47,111	$89,472	$59,080
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$41,780	$82,357	$58,299
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$28,360	$78,976	$37,239

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Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$95,836	$156,696	$182,765
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$23,732	$62,642	$106,436
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$55,868	$105,988	$158,498
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$48,315	$85,346	$165,844
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$48,765	$114,310	$127,483
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$33,606	$84,563	$102,626
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$51,927	$151,933	$197,438
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$28,243	$83,593	$100,595
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$42,395	$154,904	$178,909
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$81,671	$155,257	$176,249
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$63,430	$146,606	$165,495
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$86,272	$150,181	$173,893
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$86,110	$130,041	$146,810
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$76,927	$168,309	$180,972
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$78,730	$121,740	$160,647
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$108,656	$131,909	$178,304
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$78,117	$151,109	$204,934
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$45,844	$126,772	$140,204

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-17, Table 3-18 and Table 3-19 for the CT, CC and CP plants.

On average, the Real-Time Energy Market net revenue was 39 percent higher than the Day-Ahead Market net revenue for the CT plant, 18 percent higher for the CC plant and 3 percent higher for the CP.[35]

35 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-17, Table 3-18 and Table 3-19, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
2010	$36,925	$22,981	$13,944	38%
Avg.	$13,316	$8,142	$5,175	39%

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
2010	$88,275	$78,976	$9,299	11%
Avg.	$45,544	$37,239	$8,305	18%

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Table 3-19 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
2010	$128,990	$126,772	$2,218	2%
Avg.	$144,352	$140,204	$4,148	3%

Net Revenue Adequacy

To put the 2010 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2010.[36] The estimated, 20-year levelized fixed costs[37] are $131,044 per installed MW-year for the new entrant CT plant,[38] $175,250 per installed MW-year for the new entrant CC plant and $465,455 per installed MW-year for the new entrant CP plant. Levelized fixed costs increased for all three technologies. Table 3-20 shows the 20-year levelized costs for each technology for the period 2005 through 2010.[39] The increased costs of constructing generation facilities from 2005 through 2008 are the result of a combination of factors, including increased worldwide demand in recent years. The estimated levelized fixed costs for both 2009 and 2010 show smaller increases than in prior years.

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

36 The MMU began evaluating fixed costs for all three technologies in 2005. In the following tables and figures, the 20-year levelized fixed costs from 2005 are used as a proxy for the preceding years.

37 Annual fixed costs may vary by location. The fixed costs presented here are associated with a location in the EMAAC LDA and are meant to serve as a baseline for comparison.

38 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 internal rate of return (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.

39 The figures in Table 3-20 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Eastern Mid-Atlantic Region.

Table 3-20 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost	2010 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705	$131,044
CC	$93,549	$99,230	$143,600	$171,361	$173,174	$175,250
CP	$208,247	$267,792	$359,750	$492,780	$446,550	$465,455

New Entrant Combustion Turbine

In 2010, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $94,619 per installed MW-year. The associated operating costs were between $60 and $65 per MWh, based on a design heat rate of 10,500 Btu per kWh and a VOM rate of $7.46 per MWh.[40] The average PJM net revenue in 2010 would not have covered the fixed costs of a new CT. As shown in Table 3-21, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999.

Table 3-21 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
2009	$128,705	$55,939	43%
2010	$131,044	$94,619	72%
Average	$88,317	$40,943	46%

Table 3-22 includes the 20-year levelized fixed cost in 2010 for a new entrant CT, the economic dispatch net revenue for each zone in 2010 and average net revenue and average fixed costs for the period 1999 to 2010. There were two control zones with net revenues sufficient to cover 100 percent of the levelized fixed costs in 2010: BGE and Pepco control zones of the SWMAAC LDA, showing 100 and 106 percent recovery. Figure 3-3 summarizes the information in Table 3-22, showing the 2010 average net revenue for a new entrant CT, the zonal net revenue for the

40 The analysis used the daily gas costs and associated production costs for CTs and CCs. Heat rates for the CT, CC and CP are cited for an ambient temperature of 50 degrees and rounded to the nearest hundredth.

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period 1999 to 2010 and the levelized 2010 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is significantly dependent on location, which affects both energy and capacity revenue. Figure 3-4 shows total net revenues for the new entrant CT by market for 2010. Total net revenues in 2010 are higher than the twelve year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CT technology. Figure 3-5 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2010. In 2008, 2009 and 2010 there were multiple zones with sufficient revenues to cover the fixed costs of investment in a new CT.

Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$111,894	$131,044	85%	$56,729	$88,317	64%
AEP	$61,376	$131,044	47%	$27,562	$88,317	31%
AP	$95,611	$131,044	73%	$35,134	$88,317	40%
BGE	$130,476	$131,044	100%	$59,223	$88,317	67%
ComEd	$59,089	$131,044	45%	$28,529	$88,317	32%
DAY	$60,787	$131,044	46%	$27,408	$88,317	31%
DLCO	$67,534	$131,044	52%	$39,371	$88,317	45%
Dominion	$99,387	$131,044	76%	$50,636	$88,317	57%
DPL	$110,964	$131,044	85%	$53,790	$88,317	61%
JCPL	$107,113	$131,044	82%	$52,346	$88,317	59%
Met-Ed	$107,488	$131,044	82%	$44,601	$88,317	51%
PECO	$104,501	$131,044	80%	$49,814	$88,317	56%
PENELEC	$84,833	$131,044	65%	$34,930	$88,317	40%
Pepco	$139,437	$131,044	106%	$62,102	$88,317	70%
PPL	$101,106	$131,044	77%	$41,247	$88,317	47%
PSEG	$104,847	$131,044	80%	$50,958	$88,317	58%
RECO	$99,907	$131,044	76%	$47,394	$88,317	54%
PJM	$94,619	$131,044	72%	$40,943	$88,317	46%

Figure 3-3 New entrant CT real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

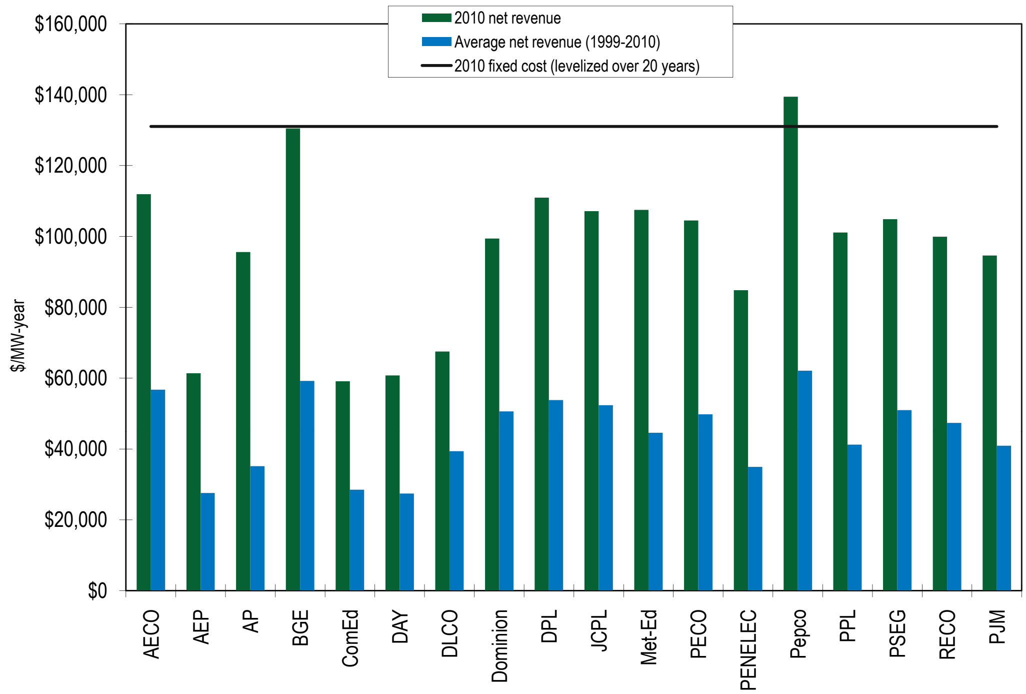

Figure 3-4 New entrant CT zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

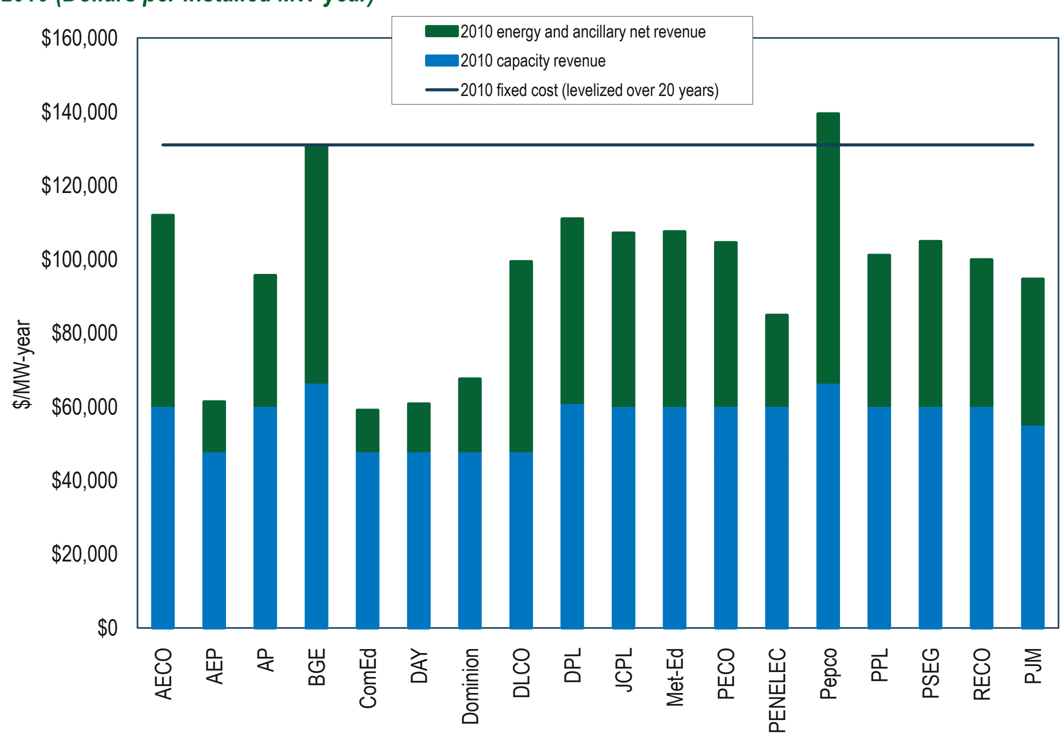

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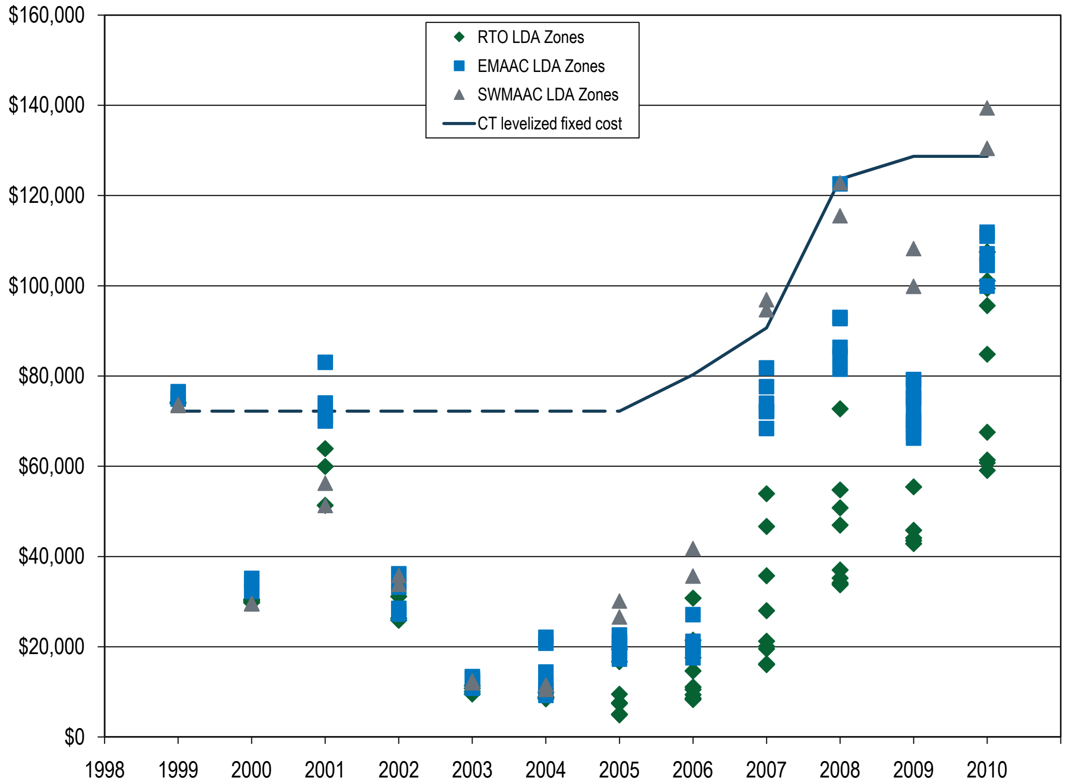
Figure 3-5 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



New Entrant Combined Cycle

In 2010, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $149,912 per installed MW-year. The associated operating costs were between $35 and $40 per MWh, based on a design heat rate of 6,900 Btu per kWh, average daily delivered natural gas prices of $5.02 per MBtu and a VOM rate of $3.23 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-23 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2010. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but some zonal net revenues were sufficient to cover the fixed costs for a new CC in several other years.

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Table 3-23 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
2009	$173,174	$81,376	47%
2010	$175,250	$130,061	74%
Avg.	$118,122	$72,094	61%

Table 3-24 compares the 20-year levelized fixed cost in 2010 for a new entrant CC to the economic dispatch net revenue for each zone in 2010, along with average net revenue for the period 1999 to 2010 and average fixed costs. The average PJM net revenue is not enough to cover the levelized fixed costs. There are four zones that show more than adequate net revenue to cover 100 percent of the levelized fixed costs of a CC in 2010: AECO, BGE, DPL and Pepco. Figure 3-6 summarizes the information in Table 3-24, showing the 2010 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2010 by zone and the levelized 2010 capital cost for a new entrant CC.[41] The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is significantly dependent on location, which affects both energy and capacity revenue. Figure 3-7 shows total net revenues for the new entrant CC by market for 2010. Total net revenues in 2010 are higher than the twelve year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CC technology. Figure 3-8 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2010. In 2007, 2008 and 2010 there were multiple zones with sufficient revenues to cover the fixed costs of investment in a new CC, and the two SWMAAC zones show sufficient revenues in each of the three years.

41 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

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Table 3-24 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$175,900	$175,250	100%	$103,506	$118,122	88%
AEP	$98,280	$175,250	56%	$51,940	$118,122	44%
AP	$152,516	$175,250	87%	$73,565	$118,122	62%
BGE	$199,355	$175,250	114%	$103,738	$118,122	88%
ComEd	$87,686	$175,250	50%	$54,767	$118,122	46%
DAY	$97,600	$175,250	56%	$51,510	$118,122	44%
DLCO	$101,473	$175,250	58%	$80,625	$118,122	68%
Dominion	$162,324	$175,250	93%	$95,987	$118,122	81%
DPL	$175,605	$175,250	100%	$95,074	$118,122	80%
JCPL	$170,893	$175,250	98%	$96,902	$118,122	82%
Met-Ed	$167,178	$175,250	95%	$83,806	$118,122	71%
PECO	$164,909	$175,250	94%	$90,268	$118,122	76%
PENELEC	$134,761	$175,250	77%	$64,538	$118,122	55%
Pepco	$214,688	$175,250	123%	$108,477	$118,122	92%
PPL	$157,856	$175,250	90%	$78,033	$118,122	66%
PSEG	$168,625	$175,250	96%	$98,551	$118,122	83%
RECO	$158,836	$175,250	91%	$101,984	$118,122	86%
PJM	$149,912	$175,250	86%	$73,748	$118,122	62%

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Figure 3-6 New entrant CC real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

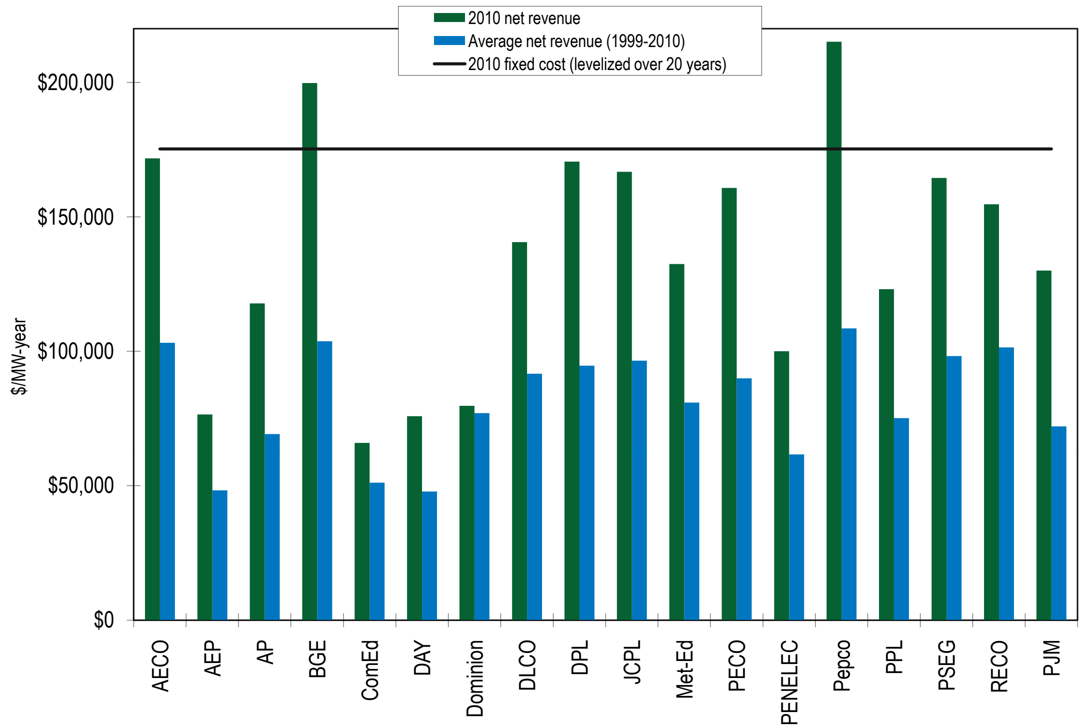

Figure 3-7 New entrant CC zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

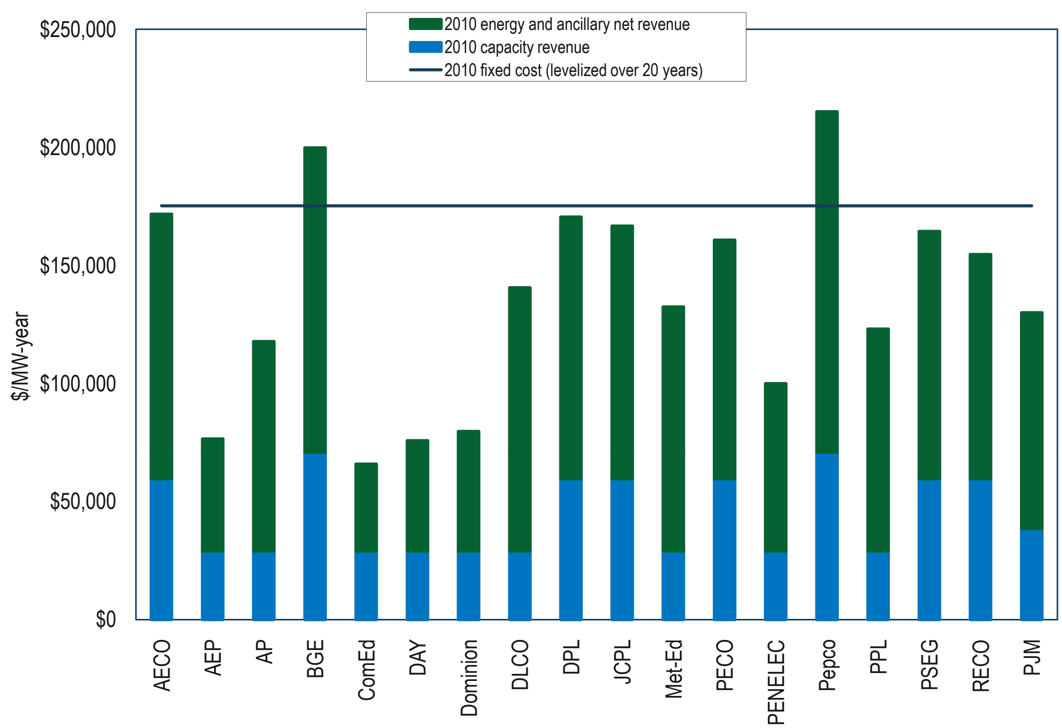

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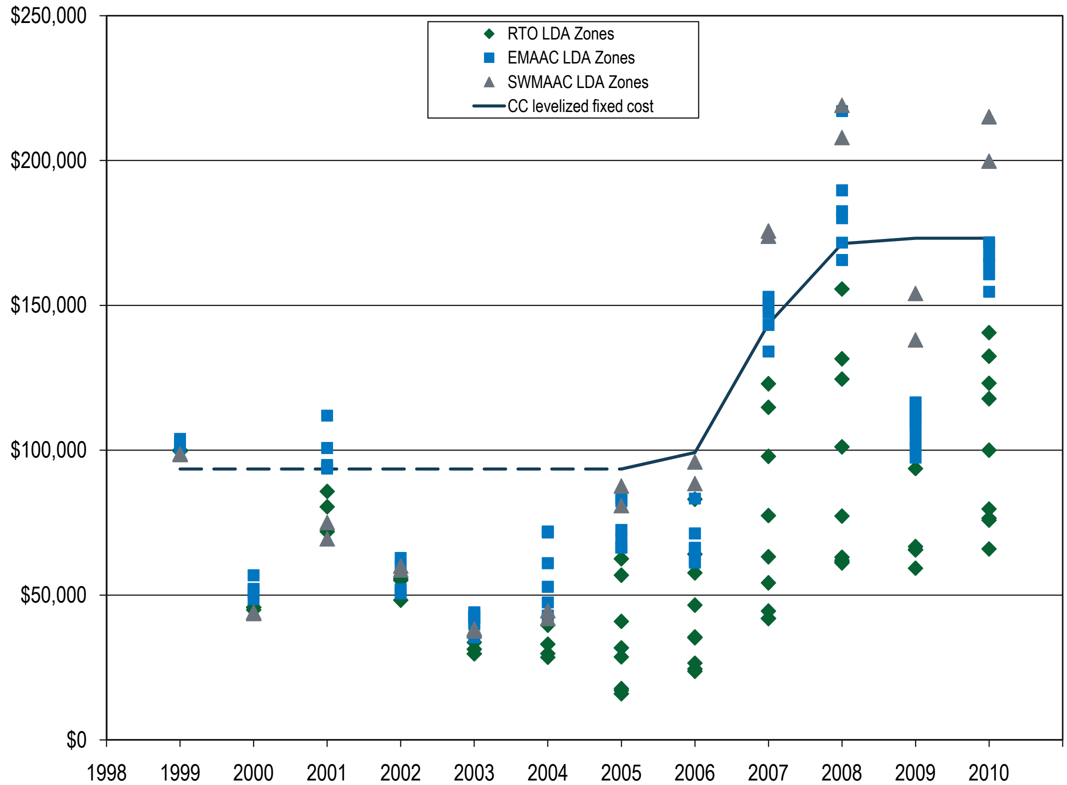
Figure 3-8 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



New Entrant Coal Plant

In 2010, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $185,644 per installed MW-year. The associated operating costs were between $30 and $35 per MWh, based on a design heat rate of 9,100 Btu per kWh and a VOM rate of $3.07 per MWh.[42]

Table 3-25 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2010. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005. However, several zonal net revenues were sufficient to cover the fixed costs for a new CP in 2005 and two zonal net revenues were sufficient to cover fixed costs in 2007. Average 2010 net revenue for a CP shows a significant increase from 2009 reflecting the higher average energy price levels in PJM and the more substantial impact of energy market net revenues for the CP technology.

42 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-25 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
2009	$446,550	$94,968	21%
2010	$465,455	$185,644	40%
Avg.	$290,838	$165,296	57%

Table 3-26 compares the 20-year levelized fixed cost in 2010 for a new entrant CP to the economic dispatch net revenue for each zone in 2010, along with average net revenue for the period 1999 to 2010 and average fixed costs. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010. Figure 3-9 summarizes the information in Table 3-26, showing the 2010 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2010 by zone and the levelized 2010 capital cost for a new entrant CP.[43] For every zone, 2010 energy net revenues for a CP are higher than 2009, and, for most zones, capacity revenues are higher.[44] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is significantly dependent on location, which affects both energy and capacity revenue as well as fuel costs. Figure 3-10 shows total net revenue for the new entrant coal plant by market for 2010. Total net revenues in 2010 are lower than the twelve year average for all control zones, and this is driven by lower energy price levels and lower energy net revenues, which comprise a significant portion of total revenue for the CP technology. Figure 3-12 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999 to 2010.

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Table 3-26 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

	2010			12-Year Average (1999-2010)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$222,251	$465,455	48%	$211,191	$290,838	73%
AEP	$115,311	$465,455	25%	$135,331	$290,838	47%
AP	$171,154	$465,455	37%	$189,830	$290,838	65%
BGE	$166,399	$465,455	36%	$200,014	$290,838	69%
ComEd	$166,017	$465,455	36%	$154,052	$290,838	53%
DAY	$136,491	$465,455	29%	$133,900	$290,838	46%
DLCO	$134,104	$465,455	29%	$150,098	$290,838	52%
Dominion	$201,844	$465,455	43%	$208,148	$290,838	72%
DPL	$221,754	$465,455	48%	$203,677	$290,838	70%
JCPL	$216,909	$465,455	47%	$202,037	$290,838	69%
Met-Ed	$211,816	$465,455	46%	$186,569	$290,838	64%
PECO	$210,457	$465,455	45%	$196,187	$290,838	67%
PENELEC	$186,033	$465,455	40%	$166,015	$290,838	57%
Pepco	$237,947	$465,455	51%	$212,113	$290,838	73%
PPL	$186,998	$465,455	40%	$180,408	$290,838	62%
PSEG	$197,234	$465,455	42%	$205,048	$290,838	71%
RECO	$210,649	$465,455	45%	$235,922	$290,838	81%
PJM	$185,644	$465,455	40%	$165,296	$290,838	57%

Figure 3-9 New entrant CP real-time 2010 net revenue, twelve-year average net revenue and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): Calendar years 1999 to 2010

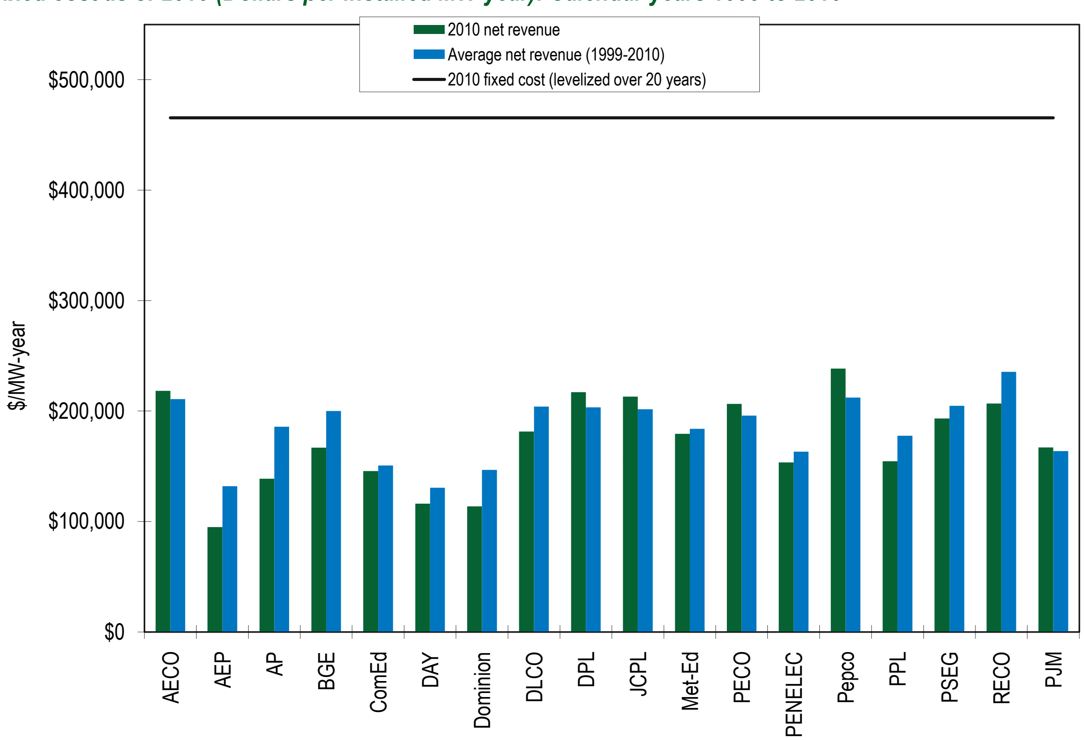


Figure 3-10 New entrant CP zonal real-time 2010 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year)

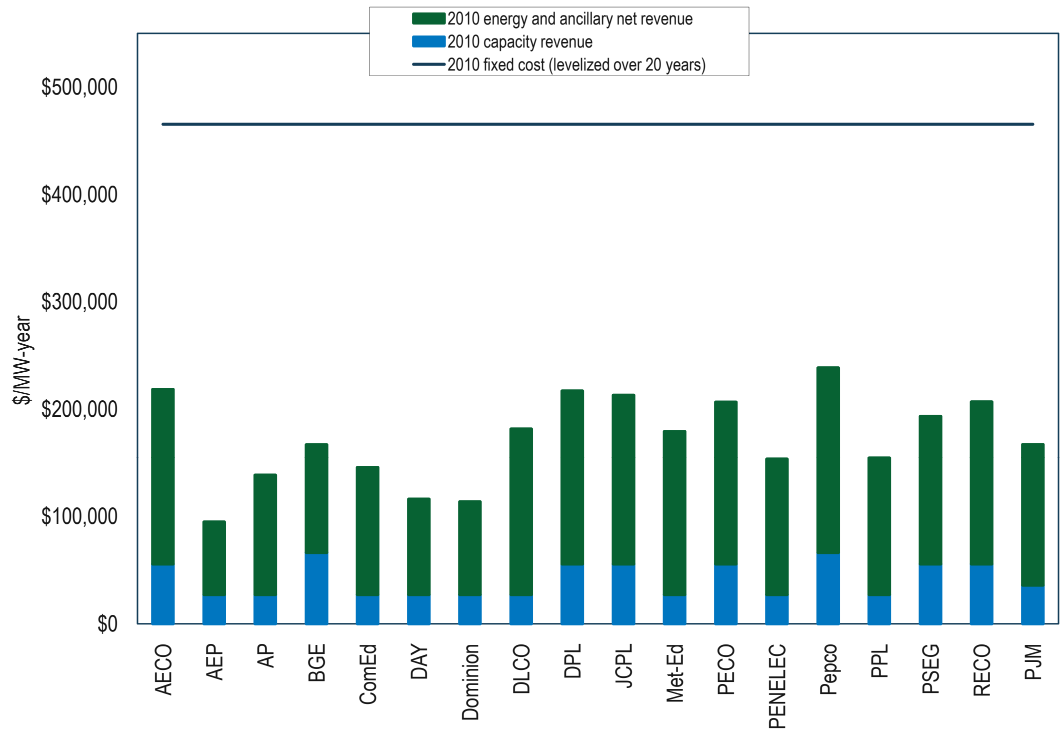
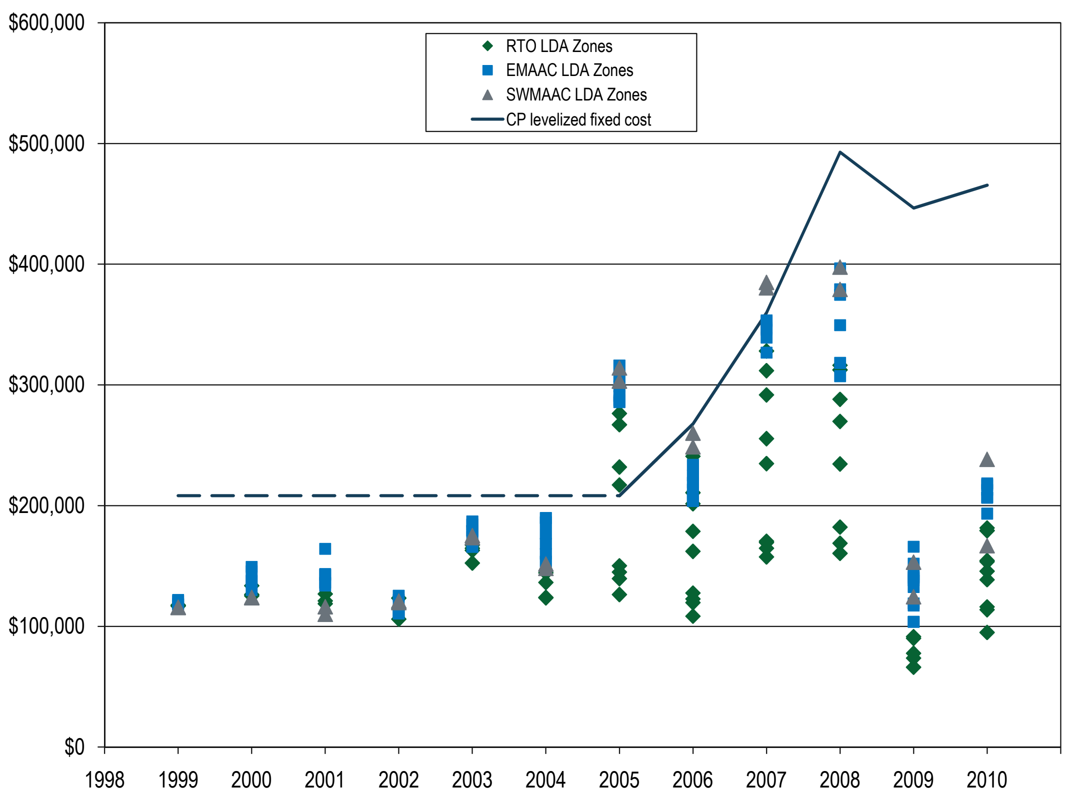


Figure 3-11 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



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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. Analysis of 2010 net revenue indicates that the contribution of capacity revenue from RPM has a more significant effect on the incentive to invest in a new entrant CT or CC than other technologies. The profitability of new entrant peaking units, specifically, is substantially impacted by the local capacity market clearing price. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. The delivered price of coal increased more than the delivered price of natural gas in most zones, as the price of low sulfur coal increased by 13 percent while the price of natural gas increased by 11.4 percent. [45] As a result, the natural gas fired power plants, particularly the more efficient combined cycle, show higher percentage increases in energy net revenues from 2010 than the coal-fired power plant. The net revenues in BGE zone of the SWMAAC LDA were approximately adequate to cover the annualized fixed costs for both the new entrant CT and CC, and the net revenues in Pepco zone were more than adequate to cover the annualized fixed costs for both the new entrant CT and CC.

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 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. There were relatively few high demand days in 2009 but in 2010, high demand days were more frequent. 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 can be an inaccurate estimate of actual net revenues in the current operating year. In 2010, Capacity Market prices and revenues were relatively high, which had a substantial impact on the profitability of investing in CTs and CCs. Energy net revenues increased significantly in all PJM control zones, and capacity market prices increased for most PJM control zones. As a result, there were some zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CT or CC in 2010.

The net revenue performance of combined cycle units (CCs) was comparable to that of CTs. CCs, like CTs, burn gas, but are more efficient than CTs and have higher fixed costs than CTs. Thus, as clearing prices set by CTs decline, net revenues from the Energy Market decline for CCs. However, in 2010, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing in some months, for some zones, there are a number of hours in which the CC has lower generating costs than the CP.[46] Across zones, the average number of hours during which a

45 The spread between changes in coal prices and natural gas prices is particularly pronounced in the first and fourth quarters. In the third quarter, natural gas prices increased more in comparison to third quarter 2009 than coal prices, however, annual averages still show coal price increases exceeded price increases for natural gas.

46 The number of hours for which the incremental costs for a new entrant CC are lower than for the new entrant CP vary by zone as a result of zone specific estimates of delivered natural gas and coal costs, and, is generally higher for eastern zones where there are significant delivery costs associated with coal.

CC had lower generating costs than a CP was 2,059; for zones in MAAC LDA, the average number of hours was 2,411; and for zones in the rest of the RTO, the average number of hours was 1,413.

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. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs. But, with natural gas prices increasing at a slower rate in some months than coal prices, these inframarginal energy revenues were lower than in prior years.

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 3-20. Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-27.[47]

Table 3-27 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	$136,205	13.5%	$183,174	13.5%	$495,455	13.7%
Base Case	$128,705	12.0%	$173,174	12.0%	$465,455	12.0%
Sensitivity 2	$121,205	10.4%	$163,174	10.4%	$435,455	10.3%
Sensitivity 3	$113,705	8.7%	$153,174	8.8%	$405,455	8.4%
Sensitivity 4	$106,205	6.9%	$143,174	7.1%	$375,455	6.5%
Sensitivity 5	$98,705	4.9%	$133,174	5.3%	$345,455	4.4%
Sensitivity 6	$91,205	2.7%	$123,174	3.4%	$315,455	2.1%

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 3-28 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 3-29 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.

47 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.

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Table 3-28 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	CT		CC	
	Equity as a percentage of total financing (%)	Levelized annual revenue requirement	Equity as a percentage of total financing (%)	Levelized annual revenue requirement
Sensitivity 1	60%	$139,446	60%	$186,000
Sensitivity 2	55%	$135,245	55%	$180,627
Base Case	50%	$131,044	50%	$175,250
Sensitivity 3	45%	$126,843	45%	$169,880
Sensitivity 4	40%	$122,642	40%	$164,505
Sensitivity 5	35%	$118,439	35%	$159,132
Sensitivity 6	30%	$114,238	30%	$153,758

Table 3-29 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	CT		CC	
	Term of debt in years	Levelized annual revenue requirement	Term of debt in years	Levelized annual revenue requirement
Sensitivity 1	30	$117,871	30	$158,432
Sensitivity 2	25	$122,861	25	$164,790
Base Case	20	$131,044	20	$175,250
Sensitivity 3	15	$137,917	15	$184,045
Sensitivity 4	10	$147,032	10	$195,703

Table 3-30 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.

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Table 3-30 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%	$127,825	$0	0.0%	$172,422
Sensitivity 2	$3,759	1.2%	$129,436	$5,475	0.8%	$173,838
Base Case	$7,518	2.5%	$131,044	$10,951	1.6%	$175,250
Sensitivity 3	$11,278	3.7%	$132,652	$16,426	2.4%	$176,670
Sensitivity 4	$15,037	5.0%	$134,260	$21,902	3.2%	$178,084
Sensitivity 5	$18,796	6.2%	$135,868	$27,377	3.9%	$179,500
Sensitivity 6	$22,555	7.4%	$137,476	$32,852	4.7%	$180,916
Sensitivity 7	$50,000	16.5%	$149,216	$50,000	7.2%	$185,350
Sensitivity 8	$75,000	24.7%	$159,911	$75,000	10.8%	$191,814
Sensitivity 9	$100,000	33.0%	$170,606	$100,000	14.4%	$198,278

Actual Net Revenue

The analysis of net revenues in this section 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, the actual avoidable costs include APIR when unit owners have included APIR in unit offers. This affects the interpretation of the conclusions. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. Potential APIR is not a sunk cost and a rational decision about retirement would consider the expected probability of recovering the costs of such new investments over the remaining life of the unit.

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.

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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 for each quartile based on actual submitted Avoidable Cost Rate (ACR) data for units within a quartile associated with the most recent 2009/2010 and 2010/2011 RPM Auctions.[48] For units that did not submit ACR data, the default ACR was used. Avoidable costs were calculated for calendar year 2010 using the 2009/2010 avoidable cost data for 151 days and the 2010/2011 delivery year avoidable for 214 days.

An estimated annual avoidable cost rate for nuclear units was developed by Pasteris Energy, Inc from publicly available information and used to determine an avoidable cost proxy for all nuclear units.[49] While avoidable costs for other technologies are quartile specific averages based on unit specific avoidable costs, the nuclear avoidable cost rate represents a class average, consistent for all nuclear units both within and across quartiles.

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 2009/2010 and 2010/2011 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. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[50] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied, which may understate actual revenues, since units may bid an export price into the auction as an opportunity cost and provide capacity to the market with the higher price.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM, including three classes of combined cycle plants, six classes of combustion turbine plants and two classes of coal plants.[51] In addition, net revenues were analyzed for diesel units, run of river hydro plants, nuclear plants, and oil-fired and gas-fired steam units.

The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 3-31 provides a summary of results, with average net revenues and associated recovery of average avoidable costs from energy markets and average total revenues and associated recovery of average avoidable costs from all markets, by technology class, as well as the total installed capacity associated with each technology analyzed. The class average energy and ancillary net revenues for the Frame F CC and Frame F CT and for the nuclear and run of river hydro technologies were more than sufficient to recover class average avoidable costs. The class average energy and ancillary net revenues for the first and second generation

48 If a unit submitted updated ACR data for an incremental auction for either the 2009/2010 or the 2010/2011 delivery year, that data was used instead of the ACR data submitted for the Base Residual Auction.

49 Data from the Nuclear Energy Institute (NEI) website (http://www.nei.org/) was used to develop an avoidable cost rate based on 2009 information, which was escalated through 2010. The NEI shows in a table titled U.S. Electric Production Costs and Components that the average non-fuel O&M cost for a nuclear power plant in 2009 was $14.60/MWh. This includes costs related to labor, material & supplies, contractor services, licensing fees, and miscellaneous costs such as employee expenses and regulatory fees and insurance. Property tax costs which were not included in the NEI value were obtained from public information and were $0.72/MWh and was added to the NEI value. The NEI value included VOM which is estimated at $2.00/MWh and this value was subtracted from the NEI value. Accordingly, the final adjusted avoidable cost is $13.32 in 2009. To determine 2010 costs, general 2009 costs were escalated at 2.5 percent to 2010. Plant O&M was escalated using the Handy-Whitman July 1 Index for "Total Nuclear Production Plant." The 2010 avoidable cost is $13.72/MWh.

50 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.

51 Pumped storage units, wind and solar units, landfill gas burning units and municipal waste burning units were excluded from the analysis. Combined cycle units of two on one or three on one Frame F technology were combined to create a single technology class with a greater sample size. Waste coal units were combined with the sub-critical coal units to create a single technology class with a greater sample size.

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aero frame CT and LM 6000 aero frame CT were approximately sufficient to recover class average avoidable costs. The class average energy and ancillary net revenues for the Frame B CT, the third generation Pratt & Whitney aero frame CT, the diesel, oil-fired or gas-fired steam technologies and both coal technologies were not sufficient to recover class average avoidable costs. However, class average total revenues, including capacity revenues, were more than sufficient to recover class average avoidable costs for all technologies.

Table 3-31 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

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average recovery of class average avoidable costs from energy revenue	Class average energy net revenue and capacity revenue ($/MW-year)	Class average recovery from all markets of class average avoidable costs
CC - NUG Cogeneration Frame B or E Technology	1,329	$25,941	67%	$85,531	220%
CC - Three on One Frame E Technology	4,225	$57,354	415%	$110,253	797%
CC - Two or Three on One Frame F Technology	12,677	$44,790	273%	$102,745	627%
CT - First & Second Generation Aero (P&W FT 4)	3,620	$11,927	104%	$70,370	616%
CT - First & Second Generation Frame B	4,466	$5,709	49%	$65,718	560%
CT - Second Generation Frame E	5,913	$15,115	193%	$67,286	859%
CT - Third Generation Aero (GE LM 6000)	1,774	$19,048	100%	$75,808	397%
CT - Third Generation Aero (P&W FT- 8 TwinPak)	1,550	$8,884	87%	$62,437	615%
CT - Third Generation Frame F	9,298	$23,307	279%	$74,870	895%
Diesel	241	$5,946	62%	$67,212	699%
Hydro	1,933	$198,114	1159%	$256,524	1501%
Nuclear	29,208	$267,121	238%	$325,204	289%
Oil or Gas Steam	9,656	$6,859	22%	$67,205	217%
Sub-Critical Coal	25,524	$72,322	99%	$126,690	173%
Super Critical Coal	19,053	$70,199	76%	$126,366	137%

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 3-31 incorporate 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.[52] 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. Table 3-32 shows average energy and ancillary service net revenues by quartile for select technology classes.

52 Several technologies, including the CC NUG Cogeneration Frame B or E, the three on one Frame E, the Pratt & Whitney third generation aero frame, are included in Table 3-32 but excluded from the analysis by quartile due to confidentiality concerns based on the number of units. Similarly, in tables analyzing by technology by quartiles, for some technologies and some quartiles, if minimal data requirements were not met, the tables show "NA". However, these technologies are represented and quartiles included in the proportion of units at risk shown in Table 3-37.

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Table 3-32 Average energy and ancillary service net revenue by quartile for select technologies for calendar year 2010

Technology	First quartile average energy and ancillary net revenue ($/MW-year)	Second quartile average energy and ancillary net revenue ($/MW-year)	Third quartile average energy and ancillary net revenue ($/MW-year)	Fourth quartile average energy and ancillary net revenue ($/MW-year)
CC - Two or Three on One Frame F Technology	$18,793	NA	$45,274	$77,446
CT - First & Second Generation Aero (P&W FT 4)	$1,434	$4,435	$8,182	$32,821
CT - First & Second Generation Frame B	$372	$2,267	$4,405	$15,635
CT - Second Generation Frame E	$1,632	$4,294	$8,693	$44,032
CT - Third Generation Aero (GE LM 6000)	$2,999	$8,488	$16,045	$46,000
CT - Third Generation Frame F	$3,017	$8,200	$19,847	$58,469
Diesel	($1,085)	$1,630	$3,675	$16,613
Hydro	$87,840	$147,889	$194,925	$346,919
Nuclear	NA	$228,569	$319,729	$349,903
Oil or Gas Steam	($1,629)	$935	$4,430	$22,259
Sub-Critical Coal	$13,325	$55,848	$77,138	$140,688
Super Critical Coal	NA	$55,691	$80,902	$119,414

The first quartiles for the diesel and oil or gas-fired steam technologies show negative net energy revenues. This means that some of these units operated in PJM energy markets at a net loss and that the resulting average energy and ancillary service net revenue for the lowest 25 percent of units is negative. This results, for example, when a unit runs during unprofitable hours independent of PJM dispatch. For some older units, this may occur because of an inability to follow PJM dispatch. In other cases, a unit may have an incentive to run during hours when LMP is lower than operating costs because it is receiving revenues from outside PJM markets, via a bilateral agreement.[53]

Unit specific avoidable costs were averaged for each quartile and compared to the quartile average net energy revenues in Table 3-32. Table 3-33 shows the percentage recovery of quartile avoidable cost using the quartile average energy and ancillary service net revenue. The average energy net revenues for the first three quartiles are not adequate to recover avoidable costs for several of the older CT technologies and for the diesel technology and the average energy net revenues are not adequate to recover avoidable costs in any quartile for oil-fired or gas-fired steam units. However, the newer Frame F CT and CC technologies show average energy net revenues greater than average avoidable costs for the second, third and fourth quartiles. For sub-critical and super critical coal plants, the second quartile average avoidable cost recoveries are 70.5 percent and 64.7 percent. For super critical coal plants, the fourth quartile, which is the highest 25 percent of coal plants in energy and ancillary net revenue, shows a lower recovery of average avoidable costs than the third quartile. This is because the fourth quartile has higher average avoidable costs than does the third quartile. The average energy net revenues for the nuclear and hydro technologies are greater than the quartile average avoidable cost rate for each quartile.

53 For units that operated with a net loss in energy markets for calendar year 2010 and that operated more than 100 hours, for any hour that the unit was operating at a loss and not following dispatch, that hourly loss was set to zero to prevent units with bilateral contracts or out of market incentives to run at a loss from biasing average net revenues. This assumption affected less than 60 units and did not result in any changes in conclusions about risk of retirement.

Table 3-33 Avoidable cost recovery by quartile from energy and ancillary service net revenue for select technologies for calendar year 2010

Technology	First quartile recovery of avoidable costs	Second quartile recovery of avoidable costs	Third quartile recovery of avoidable costs	Fourth quartile recovery of avoidable costs
CC - Two or Three on One Frame F Technology	146.7%	NA	216.1%	409.6%
CT - First & Second Generation Aero (P&W FT 4)	11.7%	50.5%	88.1%	215.3%
CT - First & Second Generation Frame B	3.8%	20.9%	28.3%	146.2%
CT - Second Generation Frame E	20.9%	54.8%	112.5%	555.7%
CT - Third Generation Aero (GE LM 6000)	16.7%	44.1%	83.0%	231.4%
CT - Third Generation Frame F	34.6%	94.9%	248.9%	717.2%
Diesel	(12.0%)	18.0%	32.5%	183.4%
Hydro	680.1%	775.8%	1,076.3%	1,908.7%
Nuclear	NA	203.4%	284.5%	311.4%
Oil or Gas Steam	(5.9%)	2.8%	14.8%	67.7%
Sub-Critical Coal	20.9%	70.5%	115.7%	168.8%
Super Critical Coal	NA	64.7%	150.3%	73.1%

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 quartile 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. For example, the quartile average energy and ancillary service revenues for the first and second generation Frame B CT technology, which range from $372 per MW-year and 3.8 percent recovery of avoidable costs to $15,635 per MW-year and 146.2 percent recovery, reflect average net revenues from units with heat rates ranging from 12,000 Btu/kWh to greater than 17,000 Btu/kWh, from units that burn natural gas or oil distillates and units that are spread among 15 different PJM Control Zones.

Table 3-34 shows average revenue from all PJM Markets by the same quartiles established for energy and ancillary service net revenues in Table 3-32.

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Table 3-34 Average total net revenue by quartile for select technologies for calendar year 2010

Technology	First quartile average total revenue ($/MW-year)	Second quartile average total net revenue ($/MW-year)	Third quartile average total net revenue ($/MW-year)	Fourth quartile average total net revenue ($/MW-year)
CC - Two or Three on One Frame F Technology	$73,586	NA	$108,508	$137,834
CT - First & Second Generation Aero (P&W FT 4)	$60,928	$64,604	$66,752	$88,474
CT - First & Second Generation Frame B	$57,611	$61,490	$60,573	$82,961
CT - Second Generation Frame E	$57,641	$56,341	$60,861	$92,711
CT - Third Generation Aero (GE LM 6000)	$60,627	$60,065	$69,797	$109,652
CT - Third Generation Frame F	$53,729	$57,081	$74,333	$110,548
Diesel	$57,822	$57,680	$66,126	$83,022
Hydro	$152,496	$206,753	$245,947	$405,957
Nuclear	NA	$283,662	$382,987	$412,232
Oil or Gas Steam	$58,876	$57,846	$65,870	$84,458
Sub-Critical Coal	$67,412	$108,316	$132,680	$196,000
Super Critical Coal	NA	$109,875	$128,693	$182,360

Table 3-35 shows the average avoidable cost recovery from all PJM markets by the same quartiles. Capacity payments in calendar year 2010 range from approximately $52,700 in the unconstrained RTO Control zones to $73,100 in the SWMAAC LDA. The result is that for the CC technology and both CT technologies, after capacity payments are considered, each quartile average total revenue far exceeded quartile average avoidable costs, and nearly all units experienced full recovery of average avoidable costs.

In some years, for some technologies, capacity payments significantly exceeded the avoidable costs. As a result of energy market conditions, many CC and CT units received sufficient revenue from the energy market to cover avoidable costs, and, once capacity revenues were considered, total revenues were well in excess of avoidable costs. For example, the third and fourth quartile average net revenue for the combined cycle and combustion turbine Frame F technologies were sufficient to cover avoidable costs before capacity revenues are considered. Average total net revenues, including capacity, for the third and fourth quartiles for the CC technology, and, for all quartiles for the CT technology, are several times greater than the quartile average avoidable costs.

While the average total revenues for the all quartiles of sub-critical and supercritical coal units are sufficient to cover avoidable costs, the two coal technologies generally show lower average recovery of avoidable costs than CTs and CCs. Avoidable costs for coal plants are considerably higher than for CTs and CCs, and revenues received from the capacity market make up a smaller portion of avoidable costs. As a result, the profitability of coal units is more dependent upon net revenues received in the energy market.

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Table 3-35 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2010

Technology	First quartile recovery of avoidable costs	Second quartile recovery of avoidable costs	Third quartile recovery of avoidable costs	Fourth quartile recovery of avoidable costs
CC - Two or Three on One Frame F Technology	574.5%	NA	517.9%	729.1%
CT - First & Second Generation Aero (P&W FT 4)	498.7%	736.3%	718.9%	580.5%
CT - First & Second Generation Frame B	592.7%	565.9%	388.6%	775.7%
CT - Second Generation Frame E	736.6%	718.8%	787.5%	1,170.0%
CT - Third Generation Aero (GE LM 6000)	338.5%	312.2%	361.2%	551.7%
CT - Third Generation Frame F	615.5%	660.3%	932.2%	1,356.1%
Diesel	638.2%	636.7%	585.4%	916.4%
Hydro	1,180.7%	1,084.6%	1,358.1%	2,233.5%
Nuclear	NA	252.4%	340.8%	366.9%
Oil or Gas Steam	214.0%	175.0%	219.4%	256.7%
Sub-Critical Coal	105.8%	136.7%	199.0%	235.1%
Super Critical Coal	NA	127.7%	239.0%	111.6%

Quartile averages can be affected by outliers, and do not indicate the proportion of actual units in PJM not covering avoidable costs. Table 3-36 shows the proportion of units with full recovery of avoidable costs from energy markets and from all markets for calendar years 2009 and 2010.[54] In both years, some units for all technologies, other than hydro and nuclear, do not achieve full recovery of avoidable costs through energy markets alone. A substantial portion of Cogeneration units, all CT technologies, oil or gas-fired steam units, and coal plants do not achieve full recovery of avoidable costs through energy markets alone.

54 Units that provided notice of deactivation in 2010 and units that are designated reliability must run (RMR) were excluded from this analysis. Additionally, any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.

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Table 3-36 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 and 2010

	2009		2010	
Technology	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	0%	100%	30%	100%
CC - Three on One Frame E Technology	54%	100%	85%	100%
CC - Two or Three on One Frame F Technology	83%	100%	93%	100%
CT - First & Second Generation Aero (P&W FT 4)	6%	100%	32%	100%
CT - First & Second Generation Frame B	2%	100%	22%	99%
CT - Second Generation Frame E	0%	100%	42%	100%
CT - Third Generation Aero (GE LM 6000)	16%	100%	32%	100%
CT - Third Generation Aero (P&W FT- 8 TwinPak)	0%	100%	33%	100%
CT - Third Generation Frame F	25%	100%	62%	100%
Diesel	12%	96%	13%	100%
Hydro	100%	100%	100%	100%
Nuclear	93%	100%	100%	100%
Oil or Gas Steam	3%	92%	3%	92%
Sub-Critical Coal	30%	75%	52%	82%
Super Critical Coal	35%	82%	50%	82%

For the first and second generation CT technologies and the third generation aero technologies, less than 50 percent of the units in PJM received sufficient revenue from the energy market to recover avoidable costs in both years analyzed, but RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs. For the combined cycle technology, the proportion of units recovering avoidable costs through energy market revenue was below 50 percent in both years for the cogeneration technology, and above 50 percent in both years for the more efficient frame E and F technologies. Capacity revenues were sufficient in both years to provide full recovery for all combined cycle units showing less than full recovery from energy market revenue. For the oil or gas-fired steam technology, approximately three percent of units received sufficient revenue from the energy market to recover avoidable costs in both years analyzed, and, in both years, when capacity revenues were considered, total revenues were sufficient for 92 percent to recover avoidable costs. In 2010, the small proportion of oil or gas fired steam units and Frame B CTs not recovering avoidable costs after capacity revenues represent approximately 720 MW. These units are characterized by higher than class average forced outage rates, which affect both energy and capacity revenues, as well as higher than class average avoidable costs, in some cases associated with capital expenditures to improve reliability.

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for most units that do not recover 100 percent of fixed costs through energy market revenue.

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A significant number of sub-critical and supercritical coal units did not recover avoidable costs from energy market revenues alone in 2009 and 2010. In addition seven percent of nuclear units did not recover the class average nuclear avoidable cost rate from energy market revenues alone in 2009. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal and nuclear units relies more heavily on energy market revenues.

A number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues are considered. These units are considered at risk of retirement.

Energy market net revenues are a function of energy prices and operating costs, which are a function of the cost of inputs and plant efficiencies. 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 3-37 shows characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues in 2010, compared to coal plants with greater than or equal to 100 percent recovery. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. The average size of coal plants that did not cover avoidable costs was 225.6 MW, compared to 282.1 for coal plants that did cover avoidable costs. These units were, on average, less efficient. These units had a class average heat rate of approximately 11,430 Btu/kWh and average operating costs of $43.08/MWh compared to 10,870 btu/kWh and $29.92/MWh for coal plants with full recovery. A subset of these units run less often and operate as mid-merit or even peaking units in the supply stack. They are called on during periods of high LMP and may continue to operate in unprofitable hours due to more severe operating constraints compared to the CT and CC technologies. This subset of coal plants did not recover avoidable costs from energy and capacity revenues.

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. In addition, units that did not cover avoidable costs tended to have higher avoidable costs, and some showed significant levels of capital expenditures represented in Avoidable Project Investment Rate (APIR). It is possible that these units cleared at a level below 2010 avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated with each delivery year which led to an offer cap that understated the annual recovery needed in 2010 from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap, including APIR. Such offers are rational, for example, if project costs are considered sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate. In either case, these units may be at a lower risk of retirement than units under recovering avoidable costs exclusive of the recovery of capital investments.

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Table 3-37 Profile of coal units not recovering avoidable costs from all PJM Market net revenues for 2010

Technology	Coal plants with full recovery of avoidable costs	Coal plants with less than full recovery of avoidable costs
Total Installed Capacity	37,808	6,769
Installed Capacity within MAAC	12,978	6,021
Avg. Installed Capacity (ICAP)	282.1	225.6
Avg. Age of Plant (Years)	40	50
Avg. Heat Rate (Btu/kWh)	10,872	11,429
Avg. Run Hours (Hours)	6,505	3,847
Avg. Avoidable Costs	$61,748	$145,904
Avg. Incremental Cost per MWh	$29.92	$43.08

There were 93 coal units analyzed in 2010 with capacity less than or equal to 200 MW. Of those units, 20 did not cover their avoidable costs and three were close to not covering 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 3-38 shows the installed capacity (MW) associated with various levels of recovery for coal plants with less than or just over 100 percent recovery. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs.

Table 3-38 Installed capacity associated with various levels of avoidable cost recovery: Calendar year 2010

Groups of coal plants by percent recovery of avoidable cost	Installed Capacity (MW)	Percent of Total
0% - 65%	2,763	30.9%
65% - 75%	2,099	23.5%
75% - 90%	818	9.1%
90% - 100%	1,089	12.2%
100% - 115%	2,178	24.3%
Total	8,947	100.0%

Analysis of 2010 actual net revenues indicates that, for several technologies, there is a significant proportion of units not receiving sufficient net revenue in the PJM Energy Market to cover avoidable costs. For the CT, CC, diesel and oil-fired or gas-fired steam technologies, capacity revenue from RPM provides a sufficient supplement for units to fully recover avoidable costs. In 2010, a year of higher energy revenues compared to 2009, nuclear units and run of river hydro units did not require supplemental revenues from the capacity market in order to recover avoidable costs. In 2010, despite higher load levels and, generally higher price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues.

Impact of Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. There are pending regulations that would require significant capital expenditures on environmental controls for existing units. These capital expenditures, if required, would significantly impact the profitability of existing coal-fired units. Existing units facing these capital expenditures may be retired if it is not expected that the units 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.

The MMU analyzed the impact that pending environmental regulations regarding SO_2 and NO_x emissions may have on existing coal plants in the PJM footprint, given calendar year 2010 energy and capacity net revenues.[55] Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies. Table 3-39 shows the number of units and associated installed capacity lacking controls for either NO_x emissions, SO_2 emissions, or both. Approximately 75 units accounting for 14,388 MW of installed capacity may be at risk of facing significant capital expenditures associated with environmental controls.

Table 3-39 Units lacking controls for either NO_x emission rates, SO_2 emission rates, or both as of January 2010

Characteristics	Coal plants without NOx controls in place	Coal plants without SO2 controls in place	Coal plants without NOx and without SO2 controls in place	Total
Number of units	4	63	8	75
Total installed capacity (ICAP)	212	13,543	633	14,388

Table 3-40 shows attributes of coal plants with controls in place for both NO_x and SO_2 emissions compared to units that lack controls for either NO_x emissions, SO_2 emissions, or both. Of those 14,388 MW associated with plants that lack at least one control technology, 4,835 MW, or 34 percent, are located within MAAC, while 9,552 MW, or 66 percent are located in the rest of the RTO. About 12,105 MW, or 84 percent, are associated with plants online for more than 40 years and 5,359 MW, or 37 percent, are associated with coal plants less than 200 MW in size. Additionally, of the 14,388 MW of installed capacity lacking at least one control technology, 1,451 MW are associated with plants that did not fully recover avoidable costs in 2010.

55 FRR committed units are excluded from this analysis since they receive compensation out of PJM Markets.

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Table 3-40 Attributes of units lacking controls for either NO_x emission rates, SO_2 emission rates, or both as of January, 2010

Characteristics	Coal plants with both NOx and SO2 controls in place	Coal plants lacking controls for either NOx or SO2
Units	89	75
Total installed capacity (ICAP)	30,189	14,388
ICAP within MAAC	14,163	4,835
ICAP in rest of RTO	16,026	9,552
ICAP associated with plants older than 40 years	13,811	12,105
ICAP associated with small coal plants (200 MW or less)	4,322	5,359
ICAP associated with medium-sized coal plants (between 200 and 500 MW)	5,457	3,603
ICAP associated with large coal plants (500 MW or greater)	19,910	5,426
ICAP associated with 100 percent recovery of avoidable costs	24,872	12,936
ICAP associated with less than 100 percent recovery of avoidable costs	5,318	1,451

The MMU estimated the increase in avoidable costs, including APIR, associated with project investments for units in Table 3-40 lacking controls for NO_x emissions, SO_2 emissions, or both, as a base case. A second case was developed to represent stricter NO_x emission controls, in which some units with some earlier or less effective forms of environmental controls are required to invest in Selective Catalytic Reduction (SCR) technologies for NO_x control. In both cases, the MMU estimated an associated avoidable project investment recovery (APIR) rate using a 0.450 annual capital recovery rate factor (CRF), since it is assumed to be mandatory environmental capital expenditure, and estimated for each unit, the increase in energy or capacity revenues required for project investment recovery in 2010.[56] Figure 3-12 shows the amount of installed capacity associated with various levels of required increases in total revenues. Table 3-41 summarizes the information in Figure 3-12. Approximately 14,300 MW in the base case and 19,100 MW in the second case require an increase in energy or capacity revenue in order to cover projected avoidable costs. Approximately 13,000 MW in the base case and 14,300 MW in the second case require at least $400/MW-day or $152,880/MW-year; approximately 5,500 MW in the base case and 9,900 MW in the sensitivity require at least $500/MW-day or $184,310/MW-year.

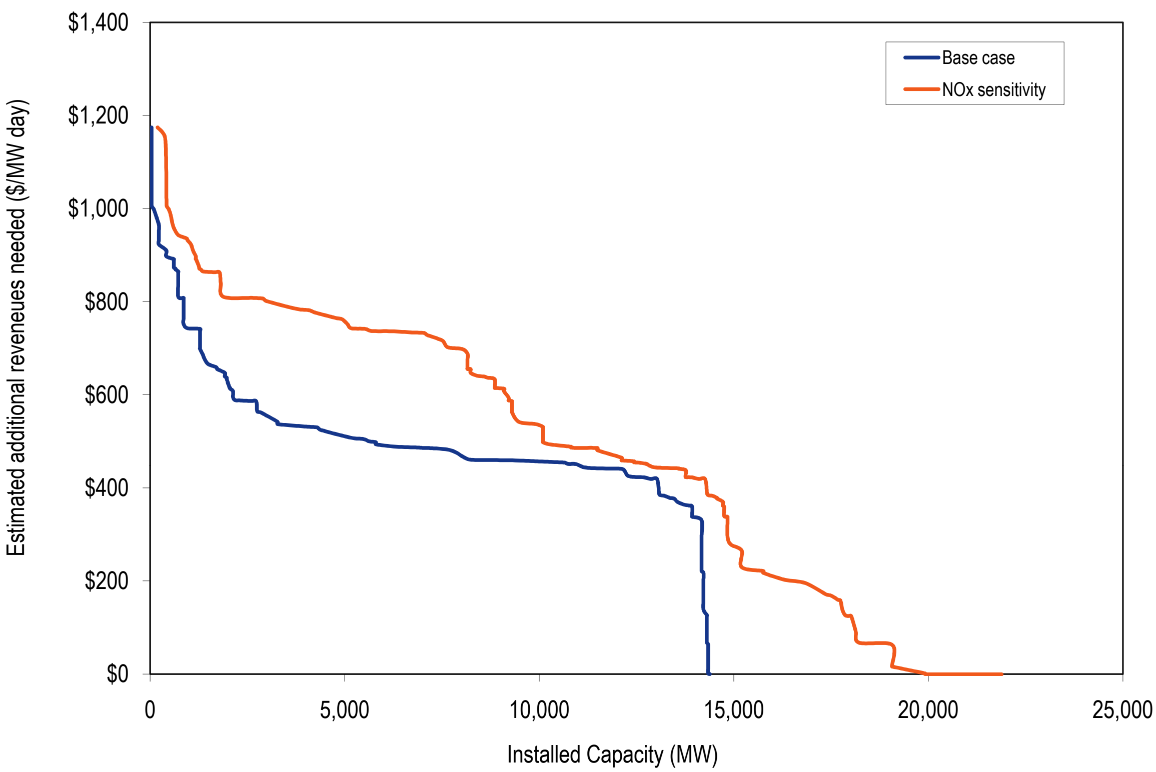
This analysis is not intended to forecast future energy or capacity prices or avoidable costs. It represents the various levels of shortfall, based on actual energy and capacity revenues in 2010, which would have been incurred if project investments associated with environmental controls were to have been recovered in 2010, assuming unit specific emission requirements and the recovery by the mandatory CRF defined in the PJM Tariff for avoidable project investment recovery. Actual owners in PJM may choose to account for project recovery internally over a longer project life than the applicable CRF allows and may therefore offer in to RPM below the calculated avoidable cost based offer cap. In this case, units may be achieving target returns yet show under recovery of calculated avoidable cost rates. If under recovery of avoidable costs including project investment rates is expected after energy and capacity revenues are considered, the decision to deactivate the unit rather than to make significant investments in environmental controls would be an economically rational decision.

56 Attachment DD, section 6.8 (a) of the PJM Tariff defines the applicable CRF used in avoidable cost calculations.

Table 3-41 Total installed capacity associated with estimated levels of additional revenue needed for recovery of project investment associated with environmental controls

Ranges of additional revenue needed ($/MW-day)	Installed capacity (ICAP) associated base case	Cumulative installed capacity (ICAP) associated with base case	Installed capacity (ICAP) associated with NOx sensitivity	Cumulative installed capacity (ICAP) associated with NOx sensitivity
$0	43	43	2,816	2,816
$1 - $99	121	164	1,050	3,867
$100 - $199	50	214	1,706	5,573
$200 - $299	0	214	1,560	7,133
$300 - $399	1,143	1,357	489	7,621
$400 - $499	7,554	8,911	4,352	11,973
$500 - $599	3,420	12,331	815	12,788
$600 - $799	1,336	13,666	6,107	18,894
$800 or greater	721	14,388	2,990	21,884

Figure 3-12 Total installed capacity associated with estimated levels of additional revenue needed for full project investment recovery in 2010



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Existing and Planned Generation

Installed Capacity and Fuel Mix

In calendar year 2010, PJM installed capacity declined from 167,853.8 MW on January 1 to 166,512.1 MW on December 31, a decrease of 1,341.7 MW or 0.8 percent, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2010, PJM installed capacity was 167,853.8 MW (Table 3-42).[57] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in a decrease in installed capacity to 167,400.7 MW on May 31, 2010.[58]

Table 3-42 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2010

	1-Jan-10		31-May-10		1-Jun-10		31-Dec-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	68,007.0	40.8%
Gas	49,238.8	29.3%	48,991.4	29.3%	48,424.5	29.0%	48,513.8	29.1%
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,954.5	4.8%
Nuclear	30,611.9	18.2%	30,599.3	18.3%	30,619.0	18.4%	30,552.2	18.3%
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,193.6	6.1%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	680.1	0.4%
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	610.9	0.4%
Total	167,853.8	100.0%	167,400.7	100.0%	166,756.8	100.0%	166,512.1	100.0%

At the beginning of the new planning year on June 1, 2010, installed capacity decreased by 643.9 MW to 166,756.8, a 0.4 percent decrease in total PJM capacity over the May 31 level.

On December 31, 2010, PJM installed capacity was 166,512.1 MW.[59]

Energy Production by Fuel Source

In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation (Table 3-43). Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent.

57 Percents shown in Table 3-42 and Table 3-43 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables

58 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

59 Wind-based resources accounted for 610.9 MW of installed capacity in PJM on December 31, 2010. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market. The wind capacity in this section is the full nameplate capacity, unless otherwise noted.

Table 3-43 PJM generation (By fuel source (GWh)): Calendar year 2010[60]

	2009 GWh	Percent	2010 GWh	Percent	Change in Output
Coal	349,818.2	50.5%	362,075.4	49.3%	3.5%
Nuclear	249,392.3	36.0%	254,534.1	34.6%	2.1%
Gas	67,218.9	9.7%	86,265.5	11.7%	28.3%
Natural Gas	65,848.2	9.5%	84,570.1	11.5%	28.4%
Landfill Gas	1,368.5	0.2%	1,695.0	0.2%	23.9%
Biomass Gas	2.2	0.0%	0.5	0.0%	(78.9%)
Hydroelectric	14,123.0	2.0%	14,384.4	2.0%	1.9%
Wind	5,489.7	0.8%	8,812.8	1.2%	60.5%
Waste	5,664.7	0.8%	5,356.6	0.7%	(5.4%)
Solid Waste	4,147.0	0.6%	4,157.5	0.6%	0.3%
Miscellaneous	1,517.7	0.2%	1,199.1	0.2%	(21.0%)
Oil	1,568.1	0.2%	3,243.2	0.4%	106.8%
Heavy Oil	1,383.7	0.2%	2,748.3	0.4%	98.6%
Light Oil	162.9	0.0%	446.9	0.1%	174.3%
Diesel	14.4	0.0%	32.3	0.0%	123.9%
Kerosene	7.1	0.0%	15.7	0.0%	120.8%
Jet Oil	0.0	0.0%	0.1	0.0%	51.9%
Solar	3.5	0.0%	5.7	0.0%	64.7%
Battery	0.3	0.0%	0.3	0.0%	18.9%
Total	693,278.7	100.0%	734,678.2	100.0%	6.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 3-44).[61]

60 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

61 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or deratings.

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Table 3-44 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 to 2010[62]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue W was active through January 31, 2011.

Capacity in generation request queues for the nine year period beginning in 2010 and ending in 2018 decreased by 310 MW from 76,725 MW in 2009 to 76,415 MW in 2010, or zero percent (Table 3-45).[63] Queued capacity scheduled for service in 2010 decreased from 22,734 MW to 11,585 MW, or 49 percent. Queued capacity scheduled for service in 2011 decreased from 15,873 MW to 13,793 MW, or 13 percent. The 76,415 MW includes generation with scheduled in-service dates in 2010 and units still active in the queue with in-service dates scheduled before 2010, listed at nameplate capacity, although these units are not yet in service.

62 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

63 See the *2009 State of the Market Report for PJM* (March 11, 2010), pp. 179-180, for the queues in 2009.

Table 3-45 Queue comparison (MW): Calendar years 2010 vs. 2009

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	11,585	(11,149)	(49%)
2011	15,873	13,793	(2,080)	(13%)
2012	11,053	13,261	2,207	20%
2013	6,350	11,244	4,894	77%
2014	13,439	13,888	449	3%
2015	3,091	5,960	2,869	93%
2016	950	1,350	400	42%
2017	1,640	2,140	500	30%
2018	1,594	3,194	1,600	100%
Total	76,725	76,415	(310)	(0%)

Table 3-46 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[64]

64 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

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Table 3-46 Capacity in PJM queues (MW): At December 31, 2010[65, 66]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	15,833	20,478
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	17,637	18,432
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,679	22,795
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	4,904	5,007
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	160	2,336	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	4,128	4,632
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,678	1,346	411	4,137	7,572
P Expired 31-Jan-06	853	1,798	1,132	4,918	8,701
Q Expired 31-Jul-06	1,759	963	3,329	8,563	14,614
R Expired 31-Jan-07	5,312	649	820	16,234	23,015
S Expired 31-Jul-07	3,137	1,549	1,233	14,975	20,893
T Expired 31-Jan-08	11,411	607	754	14,845	27,617
U Expired 31-Jan-09	9,329	196	592	24,696	34,812
V Expired 31-Jan-10	13,076	64	134	3,704	16,979
W Expires 31-Jan-11	19,062	0	32	3,685	22,780
Total	67,014	26,533	9,401	214,459	317,408

Data presented in Table 3-46 show that through 2010, 48.0 percent of total in-service capacity from all the queues was from Queues A and B and an additional 8.2 percent was from Queues C, D and E.[67] As of December 31, 2010, 31.8 percent of the capacity in Queues A and B has been placed in service, and 8.4 percent of all queued capacity has been placed in service.

The data presented in Table 3-47 show that for successful projects there is an average time of 756 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 443 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

65 The *2010 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.
66 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
67 The data for Queue W include projects through December 31, 2010.

Table 3-47 Average project queue times (days): At December 31, 2010

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	756	613	0	4,420
In-Service	773	641	0	3,287
Suspended	2,301	736	890	3,849
Under Construction	1,155	900	0	4,370
Withdrawn	443	528	0	3,186

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.

Table 3-48 shows the RTEP projects under construction or active as of December 31, 2010, by unit type and control zone. Most of the steam projects (84.4 percent of the MW) and most of the wind projects (94.5 percent of the MW) are outside the Eastern MAAC (EMAAC)[68] and Southwestern MAAC (SWMAAC)[69] locational deliverability areas (LDAs).[70] Of the total capacity additions, only 16,084 MW or 21.0 percent are projected to be in EMAAC, while 2,572 MW or 3.4 percent are projected to be constructed in SWMAAC. Of total capacity additions, only 23,330 MW, or 30.5 percent of capacity, is being added inside MAAC zones. Overall, 75.6 percent of capacity is being added outside EMAAC and SWMAAC, and 69.5 percent of capacity is being added outside EMAAC, SWMAAC and WMAAC.

Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues.[71] Wind projects account for 3,423 MW of capacity in MAAC LDAs, or 14.7 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 2,079 MW of capacity, or 12.9 percent.

68 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

69 SWMAAC consists of the BGE and Pepco Control Zones.

70 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

71 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 38,301 MW of wind resources, the 76,415 MW currently active in the queues would be reduced to 43,093 MW.

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Table 3-48 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2010

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
AECO	0	1,255	766	17	0	0	1,117	665	1,414	5,233
AEP	0	1,845	593	7	170	84	142	2,219	12,715	17,776
AP	32	958	0	6	78	0	463	772	1,340	3,649
BGE	0	29	0	30	0	1,640	0	132	0	1,831
ComEd	20	1,680	1,038	65	23	750	39	1,366	17,172	22,152
DAY	0	0	0	2	112	0	40	12	1,740	1,906
DLCO	0	0	0	0	0	91	0	0	0	91
DPL	0	929	109	0	0	0	244	43	645	1,969
Dominion	0	2,685	595	13	30	1,839	137	302	1,910	7,511
JCPL	0	2,605	27	33	0	0	938	0	0	3,603
Met-Ed	23	650	9	31	0	24	152	10	0	899
PECO	0	663	37	5	0	510	41	0	0	1,257
PENELEC	0	0	65	23	0	0	142	90	883	1,204
Pepco	0	725	0	6	0	0	10	0	0	741
PPL	20	0	139	10	143	1,600	165	33	461	2,571
PSEG	0	2,518	1,077	0	0	79	284	45	20	4,022
Total	95	16,541	4,454	250	555	6,617	3,913	5,689	38,301	76,415

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-49 shows that in the EMAAC LDA, gas burning unit types account for 62.1 percent of the capacity additions. Steam additions (coal) account for about 4.6 percent of the MW and solar projects account for 16.3 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 93.1 percent of the MW capacity additions in the SWMAAC LDA. The wind capacity in this section is reported at nameplate capacity and not reduced to 13 percent of nameplate.

Table 3-49 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2010[72]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
EMAAC	0	7,969	2,016	56	0	589	2,623	753	2,079	16,084
SWMAAC	0	754	0	36	0	1,640	10	132	0	2,572
WMAAC	43	650	213	65	143	1,624	459	133	1,344	4,673
Non-MAAC	52	7,168	2,226	94	413	2,764	820	4,671	34,878	53,085
Total	95	16,541	4,454	250	555	6,617	3,913	5,689	38,301	76,415

72 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-50 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 3-48) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Table 3-50 Existing PJM capacity 2010[73] (By zone and unit type (MW))

	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Wind	Total
AECO	0	0	608	23	0	0	0	1,264	8	1,902
AEP	0	4,355	3,668	57	1,005	2,106	0	21,568	1,053	33,811
AP	0	1,129	1,180	36	108	0	0	7,773	516	10,742
BGE	0	0	841	7	0	1,705	0	3,026	0	5,578
ComEd	0	1,814	7,129	111	0	10,376	0	6,791	1,945	28,165
DAY	0	0	1,358	52	0	0	3	3,572	0	4,985
DLCO	0	101	188	0	6	1,777	0	1,239	0	3,311
DPL	0	376	2,496	96	0	0	0	1,919	0	4,887
Dominion	0	3,173	3,853	161	3,558	3,494	0	8,484	0	22,723
External	0	974	1,574	0	70	439	0	9,470	185	12,712
JCPL	0	1,192	1,423	25	400	615	0	318	0	3,972
Met-Ed	0	2,000	406	23	20	805	0	890	0	4,143
PECO	1	2,552	836	7	1,642	4,509	3	2,129	0	11,679
PENELEC	0	0	287	39	505	0	0	6,834	517	8,181
Pepco	0	230	1,325	12	0	0	0	4,706	0	6,273
PPL	0	956	1,362	63	571	2,375	0	5,532	217	11,075
PSEG	0	2,921	2,860	0	5	3,553	58	2,535	0	11,932
Total	1	21,772	31,392	711	7,890	31,753	64	88,048	4,440	186,071

Table 3-51 shows the age of PJM generators by unit type. As most steam units in PJM are from 30 to 50 years old, it appears likely that significant and disproportionate retirements of steam units will occur within the next 10 to 20 years, particularly if stricter environmental regulations make steam units more costly to operate. While steam units comprise 47.3 percent of all current MW, steam units 40 years of age and older comprise 84.6 percent of all MW 40 years of age and older and 92.5 percent of such MW if hydroelectric is excluded from the total. Approximately 7,458 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC, or 19.1 percent of all steam units 40 years and older.

73 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

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Table 3-51 PJM capacity (MW) by age

Age (years)	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,307	18,684	377	10	0	1,372	64	4,440	42,254
10 to 20	0	4,206	4,448	126	49	0	6,081	0	0	14,910
20 to 30	0	158	490	38	3,509	16,186	9,807	0	0	30,187
30 to 40	0	101	5,269	39	435	14,953	31,657	0	0	52,454
40 to 50	0	0	2,501	128	2,480	615	24,289	0	0	30,012
50 to 60	0	0	0	4	348	0	13,338	0	0	13,690
60 to 70	0	0	0	0	32	0	1,356	0	0	1,388
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	27	0	0	0	0	27
Total	1	21,772	31,392	711	7,890	31,753	88,048	64	4,440	186,071

Table 3-52 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. In 2018, CC and CT generators would account for 54.4 percent of EMAAC generation, an increase of 10.0 percentage points from 2010 levels. Accounting for the fact that about 940 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 47 percent to about 54 percent. The proportion of gas-fired capacity in EMAAC would increase to 56.7 percent if the derating to 13 percent of nameplate for wind capacity is reflected, meaning that the effective capacity additions are 14,276 MW.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 65.1 percent of all new capability in EMAAC and 73.8 percent when the derating of wind capacity is reflected.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 80.8 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 29.1 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[74] In these zones, 92.2 percent of all generation 40 years or older is steam (primarily coal).With the retirement of these units in 2018, wind farms would comprise 27.2 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

74 Non-MAAC zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

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Table 3-52 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[75]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	0	1	0.0%
	Combined Cycle	0	0.0%	7,041	20.5%	7,969	15,011	33.6%
	Combustion Turbine	955	12.2%	8,224	23.9%	2,016	9,284	20.8%
	Diesel	49	0.6%	150	0.4%	56	156	0.4%
	Hydroelectric	2,042	26.0%	2,047	6.0%	0	2,047	4.6%
	Nuclear	615	7.8%	8,676	25.2%	589	8,651	19.4%
	Solar	0	0.0%	61	0.2%	2,623	2,685	6.0%
	Steam	4,192	53.4%	8,164	23.8%	753	4,725	10.6%
	Wind	0	0.0%	8	0.0%	2,079	2,087	4.7%
	EMAAC Total	7,853	100.0%	34,372	100.0%	16,084	44,646	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	754	984	9.3%
	Combustion Turbine	540	14.2%	2,165	18.3%	0	1,625	15.3%
	Diesel	0	0.0%	19	0.2%	36	55	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	31.5%
	Solar	0	0.0%	0	0.0%	10	10	0.1%
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	43.3%
	SWMAAC Total	3,807	100.0%	11,851	100.0%	2,572	10,617	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	43	43	0.2%
	Combined Cycle	0	0.0%	2,956	12.6%	650	3,606	16.6%
	Combustion Turbine	296	4.3%	2,054	8.8%	213	1,971	9.1%
	Diesel	35	0.5%	125	0.5%	65	154	0.7%
	Hydroelectric	444	6.5%	1,096	4.7%	143	1,238	5.7%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	22.2%
	Solar	0	0.0%	0	0.0%	459	459	2.1%
	Steam	6,042	88.6%	13,256	56.6%	133	7,346	33.9%
	Wind	0	0.0%	734	3.1%	1,344	2,078	9.6%
	WMAAC Total	6,817	100.0%	23,399	100.0%	4,673	21,657	100.0%
Non-MAAC	Battery	0	0.0%	0	0.0%	52	52	0.0%
	Combined Cycle	0	0.0%	11,545	9.9%	7,168	18,713	13.2%
	Combustion Turbine	709	2.6%	18,949	16.3%	2,226	20,466	14.4%
	Diesel	48	0.2%	418	0.4%	94	463	0.3%
	Hydroelectric	1,401	5.0%	4,747	4.1%	413	3,758	2.7%
	Nuclear	0	0.0%	18,192	15.6%	2,764	20,956	14.8%
	Solar	0	0.0%	3	0.0%	820	823	0.6%
	Steam	25,632	92.2%	58,896	50.6%	4,671	37,935	26.8%
	Wind	0	0.0%	3,699	3.2%	34,878	38,576	27.2%
	Non-MAAC Total	27,790	100.0%	116,449	100.0%	53,085	141,744	100.0%
All Areas	Total	46,267		186,071		76,415	218,663	

75 Percents shown in Table 3-52 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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Characteristics of Wind Units

Table 3-53 shows the capacity factor of wind units in PJM. In 2010, the capacity factor of wind units in PJM was 27.4 percent. Wind units that were capacity resources had a capacity factor of 27.9 percent and an installed capacity of 3,371 MW. Wind units that were classified as energy only had a capacity factor of 25.0 percent and an installed capacity of 1,069 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 3-53 Capacity factor of wind units in PJM, Calendar year 2010

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	25.0%	102,819	1,069
Capacity Resource	27.9%	292,651	3,371
All Units	27.4%	395,470	4,440

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 3-54 presents data on negative offers by wind units. Wind units were the only unit types to make negative offers. On average, 664.6 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 1,287 separate five minute intervals, or 1.22 percent of all intervals. On average, 1,541.0 MW of wind were offered daily. Overall, wind units were marginal in 1,682 separate five minute intervals, or 1.60 percent of all intervals.

Table 3-54 Wind resources in real time offering at a negative price in PJM, Calendar year 2010

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	664.6	1,287	1.22%
All Wind	1,541.0	1,682	1.60%

Wind output differs from month to month, based on weather conditions. Figure 3-13 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in October, November, and December, and lowest in June, July, and August. The highest average hour, 1,735.2 MW, occurred in December, and the lowest average hour, 257.2 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 3-13 Average hourly real-time generation of wind units in PJM, Calendar year 2010

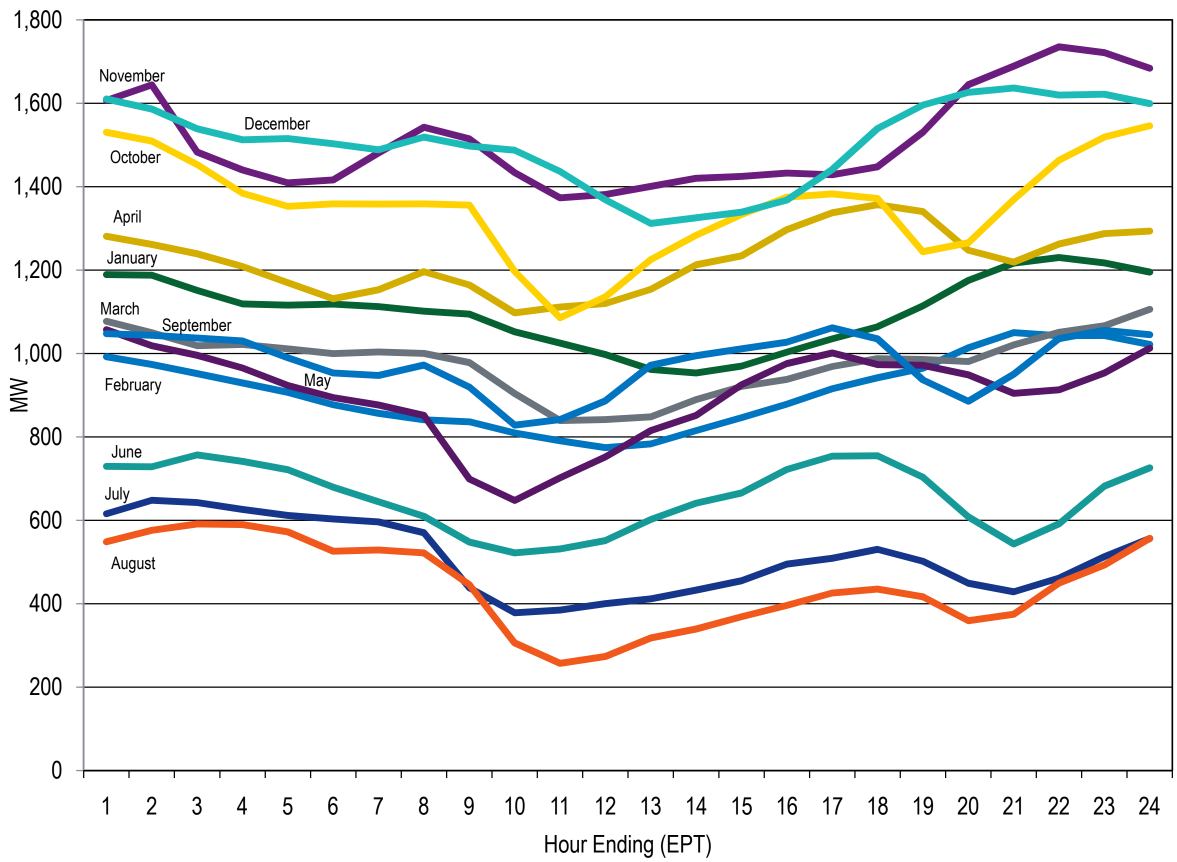

Table 3-55 shows the generation and capacity factor of wind units in each month of 2010. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 35.7 percent in January, and the lowest capacity factor was 12.1 percent in August, a difference of 23.6 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2010, and are included in this analysis as they were added.

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Table 3-55 Capacity factor of wind units in PJM by month, Calendar year 2010[76]

Month	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%
February	612,044.4	28.6%
March	727,819.1	29.5%
April	881,317.4	35.5%
May	670,571.5	26.2%
June	472,775.6	18.6%
July	380,114.8	14.4%
August	330,818.7	12.1%
September	705,289.0	24.0%
October	1,006,233.1	32.5%
November	1,088,610.5	35.5%
December	1,118,789.3	35.3%
Annual	8,812,807.2	27.4%

Table 3-56 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load for on peak and off peak periods. The on peak winter capacity factor was 31.4 percent while the on peak summer capacity factor was 17.8 percent. The off peak winter capacity factor was 2.2 percentage points higher than during the on peak period, while the off peak summer capacity factor was 2.4 percentage points higher than during the on peak period.

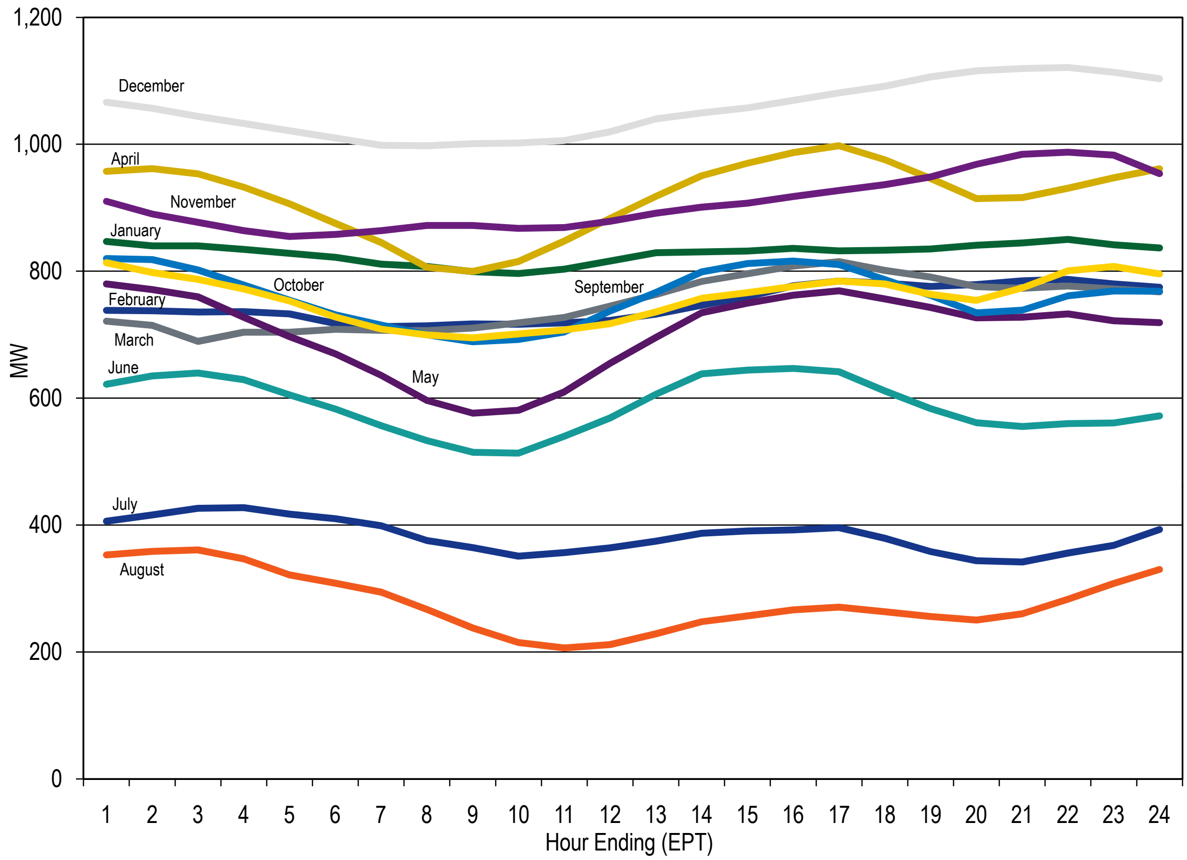
Table 3-56 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): Calendar year 2010

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	31.4%	34.5%	17.8%	32.3%	26.2%
	Average Wind Generation	1,093.1	1,188.6	650.8	1,357.7	961.6
	Average Load	88,262.4	73,871.4	95,159.1	76,305.2	87,919.6
Off-Peak	Capacity Factor	33.6%	36.5%	20.2%	35.5%	28.5%
	Average Wind Generation	1,161.1	1,257.9	736.7	1,493.0	1,045.3
	Average Load	77,105.8	59,326.6	74,018.2	63,372.1	72,056.0

Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 3-14 shows the average hourly day-ahead time generation of wind units in PJM, by month.

76 Capacity factor shown in Table 3-55 is based on all hours in 2010.

Figure 3-14 Average hourly day-ahead generation of wind units in PJM, Calendar year 2010



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 3-15 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2010. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2010. Wind output varies daily, and on average is about 248 MW lower from peak average output (2300 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the displaced fuel at times when wind resources were on the margin. In effect this means that there was no displacement for those hours.

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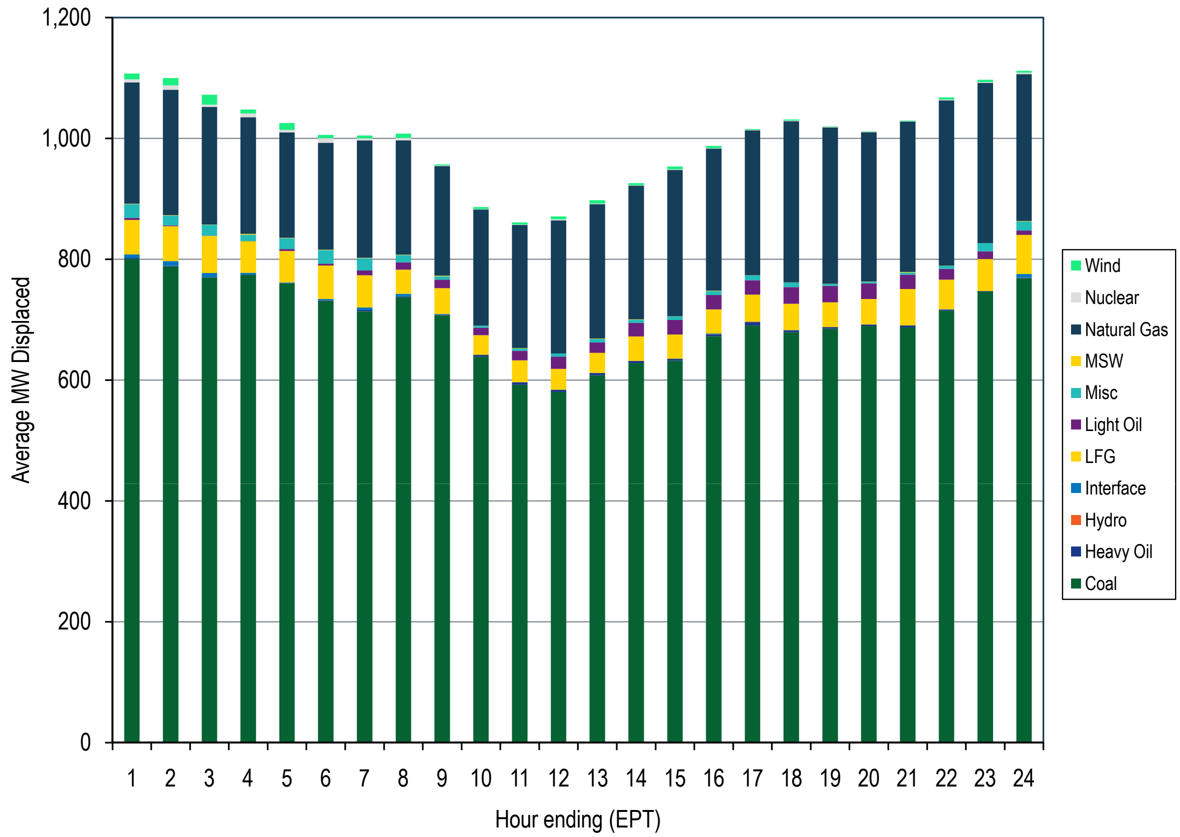
Figure 3-15 Marginal fuel at time of wind generation in PJM, Calendar year 2010



Environmental Regulatory Impacts

Emission Allowances Trading

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

Since September 25, 2008, a total of ten auctions have been held for 2009-2011 compliance period allowances, and eight auctions have been held for 2012-2014 compliance period allowances. Table 3-57 shows the RGGI CO_2 auction clearing prices and quantities for the ten 2009-2011 compliance period auctions held as of the end of calendar year 2010. The weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2010 calendar year was $2.40. Auction prices within the 2010 calendar year for the 2009-2011 compliance period peaked at $2.07 in March 10, 2010. Subsequent 2010 calendar year auctions for the 2009-2011 compliance period saw the clearing price fall, with the last auctions of the year, both the September 10, 2010 auction and the December 1, 2010 auction, providing the lowest auction price of the year at $1.86 an allowance. This price, $1.86 per allowance, is the current price floor for RGGI auctions, as determined in the first RGGI auction. The average 2010 spot price for a 2009-2011 compliance period allowance was $2.00 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in January at $2.17 per ton and declining to $1.88 per ton by December, slightly above the auction's price floor of $1.86 on December 1, 2010.

Figure 3-16 shows average, daily settled prices for NOx and SO_2 emission within PJM. In 2010, seasonal NOx prices were 61.6 percent lower than in 2009. SO_2 prices were 70.1 percent lower in 2010 than in 2009. Figure 3-16 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

Figure 3-16 Spot average emission price comparison: Calendar years 2009 to 2010

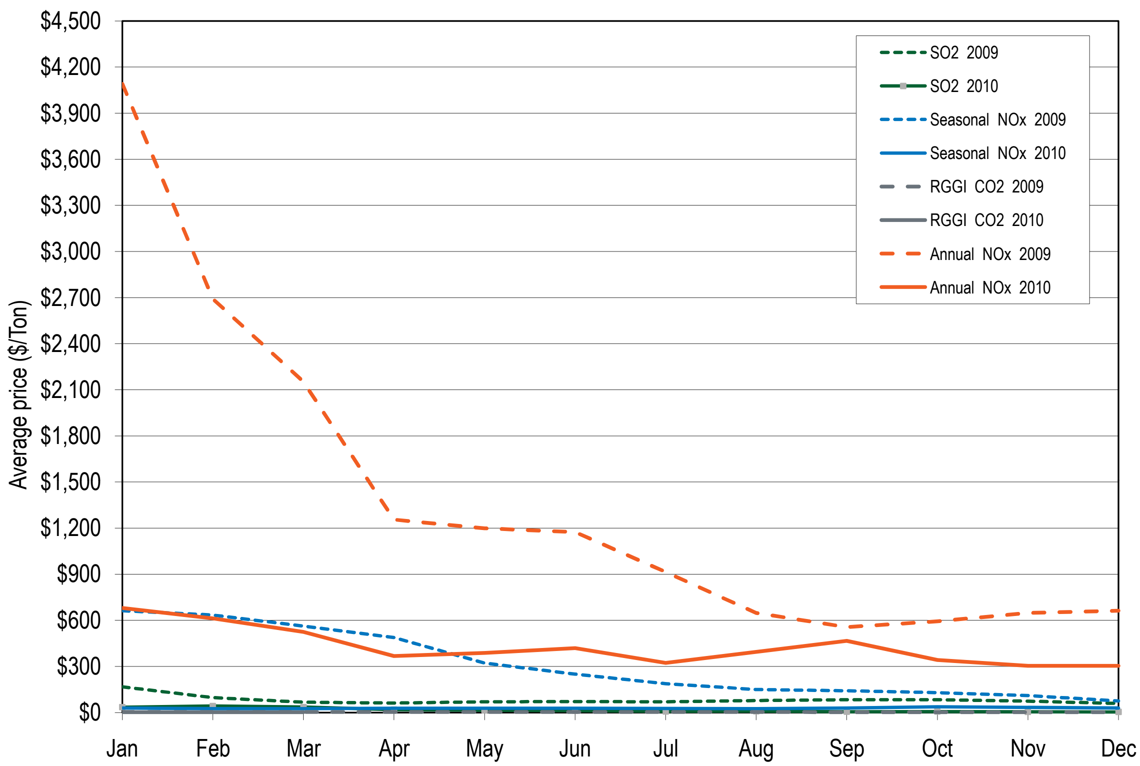


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Table 3-57 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000

Federal Regulation of Air Pollution

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA),[77] which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. EPA issues technology based standards for major sources and certain area sources of emissions.[78] In recent years, the EPA has been actively defining and tightening its standards and considering potential mechanisms, such as cap and trade, to facilitate meeting those standards. EPA actions have and are expected to continue to affect the costs to build and operate generating units in PJM which in turn affect wholesale energy prices and capacity prices.

Control of NO_x and SO_2 Emissions Allowances

The CAA requires States to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[79] The EPA has sought to promulgate default Federal rules to achieve this objective.

The EPA's initial effort is the Clean Air Interstate Rule (CAIR). CAIR requires upwind states to implement control measures to reduce emissions of NO_x and SO_2 and created an optional interstate cap and trade program for these pollutants. CAIR went into effect across the 28 eastern states and the District of Columbia on January 1, 2009, mandating emissions cuts of NO_x. Mandates for SO_2 emissions commenced on January 1, 2010.

The U.S. Court of Appeals for the District of Columbia Circuit found CAIR unlawful under the CAA, but allowed CAIR to remain in effect while the EPA developed its replacement.[80] On July 6, 2010, the EPA proposed replacement regulations to reduce interstate transport of emissions.[81] One of

77 42 U.S.C. § 7401 et seq. (2000),

78 EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

79 CAA § 110(a)(2)(D)(i)(I).

80 *See North Carolina v. Environmental Protection Agency, et al.*, 531 F.3d 896 (D.C. Cir. 2008), *reh'g granted in part*, 550 F.3d 1176 (DC Cir. 2008).

81 *See* Proposed Rule, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA Docket No. RIN 2060-AP50, 75 Fed. Reg. 45210 ("Proposed Rule").

the Court's concerns about CAIR was its creation of a multi-state market to meet reduction targets regionally contrary to the state by state reductions mandated under CAA Title I.[82]

The EPA's new rule, known as the Clean Air Transport Rule (CATR), currently is subject to an administrative notice and comment proceeding, and a final rule is expected in July, 2011. The EPA has proposed to sunset CAIR after 2011, which means that allowances allocated for periods post 2011 "should not be usable for any purpose."[83]

CATR would reduce power plant emissions of SO_2 and NO_x to meet state by state emission reductions targets. The EPA anticipates that power plants will take steps such as (i) operating already installed pollution control equipment more frequently, (ii) installing new control equipment, and (iii) using lower sulfur coal in order to achieve compliance. The emission reductions are scheduled to begin in 2012, within one year after the rule is finalized. All PJM states are included in the 28 states that would be required to reduce both annual SO_2 and NO_x emissions.

The CAA requires EPA to review and, if appropriate, revise the air quality criteria for the primary (health-based) and secondary (welfare-based) NAAQs every five years. The NAAQS are the targets to which compliance mechanisms such the CATR are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010 (Docket No. EPA-HQ-OAR-2007-0352). The EPA has initiated proceedings to review secondary NAAQS for NO_x and SO_2 (Docket No. EPA-HQ-OAR-2007-1145) and primary and secondary NAAQS for Ozone (O_3) (Docket No. EPA-HQ-OAR-2008-0699). Proposed rules are expected to issue, respectively, in July, 2011 and May, 2013.

Emissions Control of Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.

On July 9, 2004, the EPA proposed a rule in Docket No. EPA-HQ-OAR-2002-0058, that would finalize emission standards for boilers and process heaters located at major sources, including "fossil fuel-fired units less than 25 megawatts and all utility boilers firing a non-fossil fuel that is not a solid waste."[84] A major source of hazardous air pollutants is defined as any stationary source or group of stationary sources within a contiguous area and under common control that emits or has the potential to emit, considering physical and operational design, in the aggregate, 10 tons per year or more of any single hazardous air pollutant or 25 tons per year or more of multiple pollutants. Sources that emit levels less than these amounts are known as area sources. Under the Urban Air Toxic Strategy, some types of area sources will have also have air toxic standards.

The CAA requires the standards to reflect the maximum degree of reduction in hazardous air pollutant emissions that is achievable taking into consideration the cost of achieving the emissions reductions, any non air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the Maximum Achievable Control Technology (MACT).

82 531 F.3d at 906–908.
83 Proposed Rule at 45337.
84 Proposed Rule, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, 75 Fed. Reg. 32006, 32016 (June 4, 2010).

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The MACT floor is the minimum control level allowed for NESHAP and ensures that all major hazardous air pollutant emission sources achieve the level of control already achieved by the better-controlled and lower-emitting sources in each category.

On July 9, 2004, the EPA proposed a rule in Docket No. EPA-HQ-OAR-2006-0790, that would establish national emission standards for control of hazardous air pollutants from two area source categories, one of which is industrial boilers, including those in electric generating units.[85] A final rule is under review from the OMB, and is expected in January 2011. The rule covers area source boilers that burn coal, oil, biomass, or secondary "non-waste" materials, but not natural gas. The rule aims to reduce emissions of a number of toxic air pollutants including mercury, other metals,[86] and organic air toxics. The standards for area sources must be technology-based. Standards for area sources can be based on either generally available control technology (GACT), or MACT.

EPA is also required under a consent decree to issue a notice of proposed rulemaking no later than March 16, 2011, in a proceeding to promulgate MACT specifically applicable to coal- and oil-fired electric utility steam generating units. A final rule is due by November 16, 2011 in Docket Nos. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2005-0031. Implementation would occur three years later, which would occur in the 2014/2015 Delivery Year.

Permitting/Prevention of Significant Deterioration

In 2007, the U.S. Supreme Court overruled EPA's determination that it was not authorized to regulate green house gas emissions under the CAA and remanded the matter to EPA to determine whether green house gases endanger public health and welfare.[87] On December 7, 2009, the EPA determined that green house gases, in including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[88]

On May 13, 2010, the EPA issued a rule addressing green house gases (GHG) from the largest stationary sources, including power plants.[89] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011. Affected facilities will be required to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tons per year (tpy) CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[90] In July 2011, the rule expands to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[91] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[92]

Standards of Performance for New Stationary Resources

On December 23, 2010, the EPA entered a settlement agreement to resolve the States and other litigants request for performance standards and emission guidelines for GHG emissions under

85 Proposed Rule, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Proposed Rule*, 75 Fed. Reg. 31896 (June 4, 2010).
86 Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium.
87 *Massachusetts v. EPA*, 549 U.S. 497 (2007)
88 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).
89 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, Docket ID No. EPA–HQ–OAR–2009–0517, 75 Fed. Reg. 31514.
90 *Id.* at 31516.
91 *Id.*.
92 *Id.* at 31520.

Sections 111(b) and (d) of the CAA. The EPA agreed to issue a notice of proposed rulemaking by July 26, 2011, and a final rule by May 26, 2012. The new rule will amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.[93]

Clean Water Regulations

The EPA has initiated a rulemaking proceeding (EPA-HQ-OW-2008-0667) to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the Clean Water Act (CWA). EPA expects to issue a proposed rule in March, 2011.

Emission Controlled Capacity in the PJM Region

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 76,220.7 MW of coal steam capacity in PJM, 48,946.7 MW of capacity, 64.2 percent, has some form of FGD technology. Table 3-58 shows emission controls by unit type, of fossil fuel units in PJM.

Table 3-58 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2010

	SO2 Controlled	No SO2 Controls	Total	Percent Controlled
Coal Steam	48,946.7	27,274.0	76,220.7	64.2%
Combined Cycle	0.0	21,542.4	21,542.4	0.0%
Combustion Turbine	0.0	31,519.2	31,519.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	0.0	10,837.0	10,837.0	0.0%
Total	48,946.7	91,515.0	140,461.7	34.8%

NO_x emission controlling technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 127,420.9 MW, or 90.7 percent, of 140,461.7 MW of capacity in PJM, have emission controls for NO_x. Table 3-59 shows NO_x emission controls by unit type of fossil fuel units in PJM.

93 See 40 CFR Part 60.

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Table 3-59 NO_x emission controls by unit type (MW), as of December 31, 2010

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	74,122.9	2,097.8	76,220.7	97.2%
Combined Cycle	21,392.4	150.0	21,542.4	99.3%
Combustion Turbine	26,097.5	5,421.7	31,519.2	82.8%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	127,420.9	13,040.8	140,461.7	90.7%

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 74,621.7 MW, 97.9 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 3-60 shows particulate emission controls by unit type of fossil fuel units in PJM.

Table 3-60 Particulate emission controls by unit type (MW), as of December 31, 2010

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	74,621.7	1,599.0	76,220.7	97.9%
Combined Cycle	0.0	21,542.4	21,542.4	0.0%
Combustion Turbine	0.0	31,519.2	31,519.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	3,047.0	7,790.0	10,837.0	28.1%
Total	77,668.7	62,793.0	140,461.7	55.3%

Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2020. As Table 3-61 shows, New Jersey will require 20.37 percent of load to be served by renewable resources, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction, for example, Illinois requires only utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

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Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not recognized as part of PJM markets. Revenues from RECs markets are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources", which includes resources such as wind, solar, and run-of-river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the Generation Attribute Tracking System (GATS), which is used by many jurisdictions to track these renewable energy credits. The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices.

Table 3-61 Renewable standards of PJM jurisdictions to 2020[94,95]

Jurisdiction	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Delaware	5.50%	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	18.00%	20.00%	20.00%
Indiana	No Standard										
Illinois	5.00%	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%
Kentucky	No Standard										
Maryland	5.53%	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%
Michigan			<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	7.41%	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%
North Carolina	0.02%	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%
Ohio	5.00%	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%
Pennsylvania	6.70%	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.50%
West Virginia						10.00%	10.00%	10.00%	10.00%	10.00%	15.00%

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 3-61, but must be met by solar RECs only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2020.[96] Michigan, Virginia, and West Virginia have no specific solar standard. In 2010, the most stringent standard in PJM was New Jersey's, requiring 0.22 percent of load to be served by solar resources. As Table 3-62 shows, by 2020, the most stringent standard will be Delaware's which requires at least 2.01 percent of load to be served by solar.

94 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

95 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

96 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

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Table 3-62 Solar renewable standards of PJM jurisdictions to 2020

Jurisdiction	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Delaware	0.02%	0.05%	0.10%	0.20%	0.35%	0.56%	0.80%	1.11%	1.55%	2.01%	2.01%
Indiana	No Standard										
Illinois			0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%
Kentucky	No Standard										
Maryland	0.03%	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%
Michigan	No Solar Standard										
New Jersey	0.22%	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%
North Carolina	0.02%	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%
Ohio	0.01%	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%
Pennsylvania	0.01%	0.02%	0.03%	0.05%	0.08%	0.14%	0.14%	0.25%	0.29%	0.34%	0.39%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.03%	0.38%	0.07%	0.08%	0.10%	0.13%	0.16%	0.19%	0.23%	0.28%	0.33%
West Virginia	No Solar Standard										

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 3-63 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 3.75 percent in 2010 and escalating to 13.13 percent in 2020. Maryland, New Jersey, Pennsylvania[97], and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits. North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards, while New Jersey requires 2,164 GWh of solar generation by 2020 (Table 3-63).

Table 3-63 Additional renewable standards of PJM jurisdictions to 2020

Jurisdiction		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Illinois	Wind Requirement	3.75%	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)		306	442	596	772	965	1,150	1,357	1,591	1,858	2,164
North Carolina	Swine Waste			0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)			170	700	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	4.20%	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%

97 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $639 per MWh. Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the renewable portfolio standard be met through alternative compliance payments. Table 3-64 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

Table 3-64 Renewable alternative compliance payments in PJM jurisdictions: 2010

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$15.28		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$639.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 3-65 shows generation by jurisdiction and renewable resource type in 2010. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 8,812.8 GWh of 17,087.9 Tier I GWh, or 51.6 percent, in the PJM footprint. As shown in Table 3-65, 42,442.1 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 40.3 percent.

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Table 3-65 Renewable generation by jurisdiction and renewable resource type (GWh): Calendar year 2010

Jurisdiction	Battery	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	0.0	44.7	0.0	0.0	0.0	0.0	0.0	0.0	44.7	89.3
Indiana	0.0	0.0	0.0	44.8	0.0	0.0	0.0	2,153.7	2,198.5	2,198.5
Illinois	0.0	148.2	0.0	0.0	0.0	17.1	0.0	3,822.9	3,971.1	3,988.1
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	68.2	0.0	1,667.8	0.0	615.3	0.0	15.0	1,751.1	2,366.3
Michigan	0.0	32.1	0.0	66.1	0.0	0.0	0.0	0.0	98.2	98.2
New Jersey	0.0	298.6	515.4	18.1	1.5	1,435.3	0.0	11.5	329.7	2,280.3
North Carolina	0.0	0.0	0.0	674.7	0.0	0.0	0.0	0.0	674.7	674.7
Ohio	0.0	38.8	0.0	137.3	3.2	0.0	0.0	0.0	179.3	179.3
Pennsylvania	0.3	876.9	2,391.2	2,090.7	1.0	2,443.1	10,685.5	1,875.5	4,844.0	20,364.2
Tennessee	0.0	0.0	0.0	0.0	0.0	308.8	0.0	0.0	0.0	308.8
Virginia	0.0	187.9	4,904.0	915.5	0.0	1,149.7	0.0	0.0	1,103.4	7,157.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	0.0	959.0	0.0	0.0	888.6	934.2	1,893.2	2,781.8
Total	0.3	1,695.5	7,810.5	6,573.9	5.7	5,969.3	11,574.1	8,812.8	17,087.9	42,442.1

Table 3-66 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[98] This analysis includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. Pennsylvania has the largest amount of renewable capacity in PJM, 8,131.3 MW, or 32.1 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 58.4 MW, or 91.4 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 2,998.1 MW, or 67.5 percent of the total wind capacity.

98 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 3-66 PJM renewable capacity by jurisdiction (MW), on December 31, 2010

Jurisdiction	Battery	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	8.1	1,827.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,848.1
Illinois	0.0	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	60.0	24.9	129.0	69.0	0.0	1,162.0	0.0	109.0	0.0	70.0	1,623.9
Michigan	0.0	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	0.0	74.9	0.0	0.0	400.0	5.0	58.4	191.1	0.0	7.5	736.9
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	0.0	3,537.7	4.5	0.0	18.0	0.0	46.0	2.5	0.0	0.0	0.0	3,608.7
Pennsylvania	1.0	0.0	199.4	2,240.3	0.0	2,575.0	664.9	3.0	280.0	1,418.9	748.8	8,131.3
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	0.0	109.1	80.0	17.0	3,588.0	426.1	0.0	231.0	0.0	0.0	4,451.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	318.0	0.0	0.0	0.0	0.0	257.6	0.0	0.0	130.0	430.5	1,136.1
PJM Total	1.0	3,915.7	493.8	4,276.3	117.0	6,563.0	2,898.7	63.9	976.1	1,548.9	4,439.9	25,294.3

Table 3-67 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not PJM units. This includes solar capacity of 302.4 MW of which 204.2 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 3-67 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

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Table 3-67 Renewable capacity by jurisdiction, non-PJM units registered in GATS[99,100] (MW), on December 31, 2010

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	8.5	0.0	0.1	8.6
Illinois	0.0	8.7	97.8	0.0	0.0	0.0	10.4	0.0	302.5	419.5
Indiana	0.0	0.0	19.2	0.0	679.1	0.0	0.1	0.0	0.0	698.5
Kentucky	0.0	2.0	16.0	0.0	0.0	0.0	0.2	88.0	0.0	106.2
Maryland	0.0	0.0	5.0	0.0	0.0	0.0	13.5	10.0	0.0	28.5
Michigan	0.0	0.0	37.0	0.0	0.0	0.0	0.0	20.0	0.0	57.0
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	36.5	0.0	0.0	23.8	204.2	0.0	0.2	264.7
New York	0.0	179.9	0.0	0.0	0.0	0.0	0.2	0.0	0.0	180.2
North Carolina	0.0	225.0	5.3	0.0	0.0	0.0	1.9	0.0	0.0	232.2
Ohio	607.0	1.0	42.4	52.6	45.0	0.0	18.5	109.3	9.7	885.5
Pennsylvania	0.0	0.2	5.4	4.8	85.5	0.3	41.3	0.0	0.0	137.5
Tennessee	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	2.4	318.1	0.0	347.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	1.0
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.1	44.6	0.0	53.7
Total	607.0	438.4	282.7	57.4	809.6	24.1	302.4	590.0	458.6	3,570.2

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[101] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. That is the reason for the development of administrative scarcity pricing mechanisms such as the Reliability Pricing Model (RPM) capacity market and the scarcity pricing mechanism in the energy market.

99 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
100 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 25, 2011).
101 See *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2009 and 2010."

Designation of Maximum Emergency MW

During extreme system conditions when PJM declares Maximum Emergency Alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability because of environmental limitations, fuel limitations, emergency conditions at the unit or it represents temporary capacity additions obtained by operating the unit past its normal limits.[102,103] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined issue limiting its economic availability is defined as maximum emergency MW which can be made available, at PJM direction, to maintain the system during emergency conditions.

Declarations of a Hot/Cold Weather Alerts also affect declarations of Maximum Emergency Capacity under the rules.[104,105] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability be removed from economic availability and made available as emergency only capacity.[106] The Hot/Cold Weather Alert rule regarding Maximum Emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent. While the Maximum Emergency Alert rule limits maximum emergency designations to capacity with limited availability during extreme system conditions, the Hot/Cold Weather Alert rule defines specific availability limitations which require that capacity be defined as maximum emergency during extreme system conditions.

The indicated references are the only place in the tariff that there is a clear definition of maximum emergency status. The analysis suggests that some MW are inappropriately designated as maximum emergency at times of declared Maximum Emergency Alerts. The analysis also suggests that some MW are designated as maximum emergency at times other than declared Maximum Emergency Alerts, which do not meet this definition. Such designations could be considered a form of withholding. There should be a clear definition of maximum emergency status that applies throughout the tariff.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

102 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations pp. 1839-1840 . Effective Date: 9/17/2010 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), pp. 69.

103 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), p. 69: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets." See also PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations pp. 1839-1840.

104 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, p 41.

105 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, p 39.

106 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010, pp 37-38. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Hot Weather Alert.

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Given these incentives to keep capacity incorrectly designated as maximum emergency under normal system conditions, the rules regarding maximum emergency designations are expected to result in a decrease in the level of capacity designated as maximum emergency during Maximum Emergency Alerts because MW designated as maximum emergency, which do not have to meet a clear standard at other times, must comply with the tariff definition of maximum emergency during Maximum Emergency Alerts. The pattern of daily average maximum emergency levels before and during Maximum Emergency Alerts is generally consistent with this expectation. Figure 3-17 shows that declared maximum emergency MW fell, from the previous day's levels, on July 7 and July 23 after Maximum Emergency Alert declarations. Capacity which was designated as maximum emergency prior to a declaration of Maximum Emergency Alerts but which did not meet this tariff definition was reported as on forced outage or as available economic capacity after such a declaration.

During Maximum Emergency Alert Days, capacity designated as maximum emergency was used to produce energy in every hour of each day, despite the fact that prices were below $500 and there were no PJM instructions to load the maximum emergency generation. This behavior suggests that a portion of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

There are incentives to increase declared outages and potential incentives to decrease declared outages during high demand periods. In fact, for each summer month in 2010, declared outage MW during Hot Weather Alerts were lower than the average declared outage MW in each summer month, although reductions in outage MW were offset to a minor extent (1.6 percent of MW) by increases in maximum emergency generation declarations.

Definitions

PJM's current administrative scarcity pricing mechanism is designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Administrative scarcity pricing results when PJM takes identified emergency actions. The scarcity price is based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when a region of the PJM system is low on economic sources of energy and reserves. Such actions include voltage reductions,[107] emergency power purchases, manual load dump, and loading of maximum emergency generation.[108] These do not represent all of the emergency actions that are available to PJM operators, but the listed steps are defined in the PJM Tariff as the triggers for scarcity pricing events.[109]

This section defines scarcity to exist when the demand for power exceeds the capacity available to provide both energy and 10 minute synchronized reserves. There were no such scarcity events in 2010. This section defines a high-load day to exist when hourly real time demand, including a 30 minute reserve target, equals 95 percent or more of total, within-30 minute supply in the absence

107 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision 42 (Effective January 24, 2010), p. 24. Note that curtailment of nonessential building load is implemented prior to, or at this same time as, a voltage reduction action.

108 See PJM. "Manual 13: Emergency Operations," Revision: 42 (Effective January 24, 2010), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

109 See OATT, Sheet No. 402A.01.

of non market administrative intervention, on an hourly integrated basis over a two hour period.[110] There were eighteen high load days in June, July, August and September of 2010.

2010 Results: High-Load Days

While PJM did not declare scarcity conditions in 2010, there were a number of days when, on a local or regional basis, the PJM system experienced relatively high resource requirements. Table 3-68 provides a description of the maximum emergency alerts and actions that can be posted by PJM.

Table 3-68 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action Transmission Contingency Support	Real time notice that maximum emergency generation may be required to provide local contingency support
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support

Table 3-69 shows high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions for June through September. There was one high load day on which PJM took emergency generation actions (August 11, 2010), but the emergency generation action was to control for local, rather than regional or system-wide reliability issues, and did not trigger a scarcity event. There were two high load days for which Maximum Emergency Generation Alerts were declared. There were three Maximum Emergency Alert days in 2010, May 26, June 24 and August 24, which did not meet the definition of a high load day. From June through September, PJM declared thirty one Hot Weather Alert days. Nine of these days met the definition of a high load day.

110 See PJM. "Manual 13: Emergency Operations", Revision 42. Effective Date January 24, 2011. p 11. The thirty minute reserve target is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

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Table 3-69 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: June through September 2010

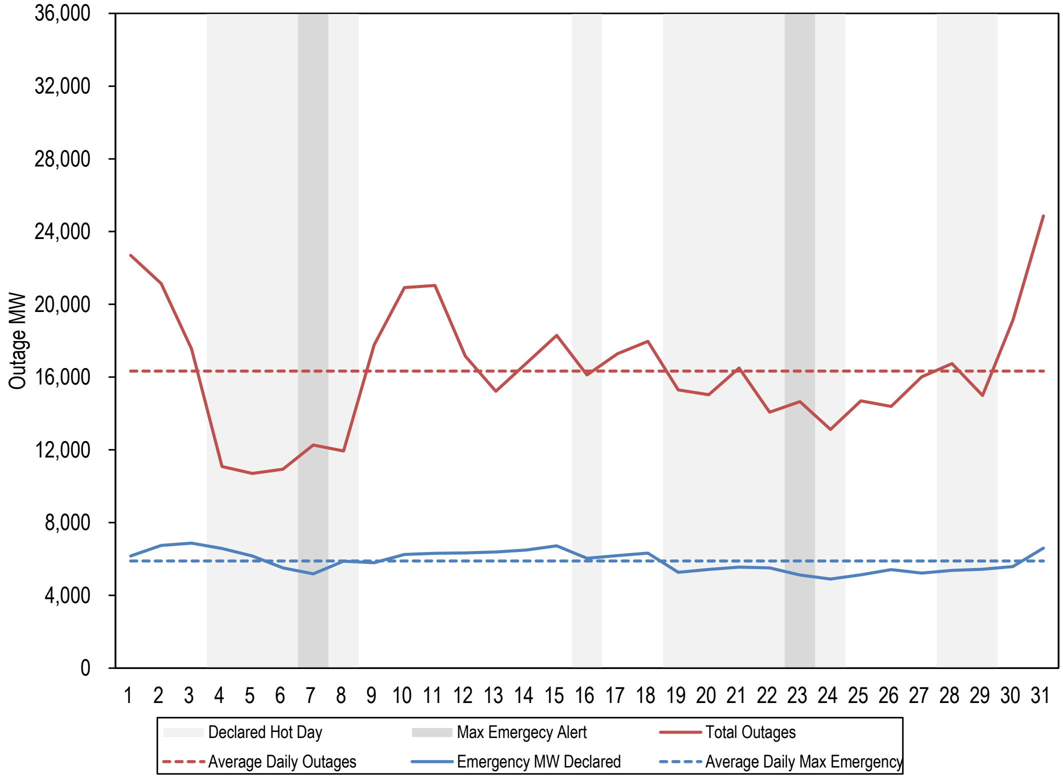
Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Action Transmission Contigency Support	Maximum Emergency Generation Action
6/5/2010	2				
6/11/2010				PEPCO	
6/18/2010		Mid Atlantic and Southern			
6/20/2010		Mid Atlantic and Southern			
6/22/2010		PJMCA plus Southern			
6/23/2010	2	PJM			
6/24/2010		Mid Atlantic and Southern		AE (Atl City Elec) Sub Transmission Zone	
6/25/2010		Mid Atlantic and Southern			
6/26/2010		Mid Atlantic and Southern			
6/27/2010		Mid Atlantic and Southern			
6/28/2010		Mid Atlantic and Southern			
6/29/2010	2	Mid Atlantic and Southern			
7/4/2010		Mid Atlantic and Southern			
7/5/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/6/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/7/2010	2	AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern	Mid Atlantic Southern Region		
7/8/2010		AEP, AP, DAY, DLCO, OVEC, Mid Atlantic, Southern			
7/16/2010		Mid Atlantic and Southern			
7/19/2010		Mid Atlantic and Southern			
7/20/2010		Mid Atlantic and Southern			
7/21/2010	7	Mid Atlantic and Southern			
7/22/2010		Mid Atlantic and Southern			
7/23/2010	5	PJM	Mid Atlantic		
7/24/2010	3	PJM			
7/25/2010		Mid Atlantic, DOM			
7/27/2010	4				
7/28/2010	4	Mid Atlantic and Southern			
7/29/2010	4	Southern			
8/3/2010	2				
8/4/2010	4				
8/5/2010		Mid Atlantic, Southern			
8/9/2010	5				
8/10/2010	5	AEP, AP, DAY, DLCO, Mid Atlantic, Southern, DOM			
8/11/2010	5	Mid Atlantic, Southern			PEPCO
8/12/2010		Western			
8/27/2010	2				
8/30/2010		AP, DLCO, Mid Atlantic, Southern			
9/1/2010	4	AP, DLCO, Mid Atlantic, DOM			
9/2/2010	4	Mid Atlantic, Domininion			
9/23/2010		RTO	PJM: AP, BC, PEPCO		AP, BGE and PEPCO
9/24/2010		RTO	PJM RTO		AP, BGE and PEPCO

There were eighteen high load days, which must include two contiguous high load hours, from June through September, 2010, which included 66 high load hours. There were four additional days with one high load hour each, for a total of 70 high-load hours in 2010.

Seven of the eighteen high load days of 2010 and 29 of the 70 high load hours in 2010 occurred in July. Figure 3-17 shows, for July, the daily and monthly average outage MW and the daily and monthly average maximum emergency MW. Emergency MW are measured as declared maximum emergency capacity offers plus any actual generation in excess of declared maximum emergency capacity in any hour. For example, a 100 MW generator has 10 MW of its offered capacity listed as emergency MW in its offer curve. If the generator produced 102 MWh of output in one hour, it would be counted as 12 MW of emergency MW in that hour. The same unit would be counted as offering 10 MW of emergency when it was not operating. Figure 3-17 also shows the days for which PJM declared Hot Weather Alerts and days for which PJM declared Maximum Emergency Generation Alerts in July. Hot Weather Alerts and Maximum Emergency Generation Alerts are declared in advance of the operating day.

Despite a nuclear outage (Salem 1) in July, outage levels in the Hot Weather Alert period, July 4 through July 8, were lower than the July average.

Figure 3-17 July daily average outage and maximum emergency MW vs. July average outage and maximum emergency MW by day



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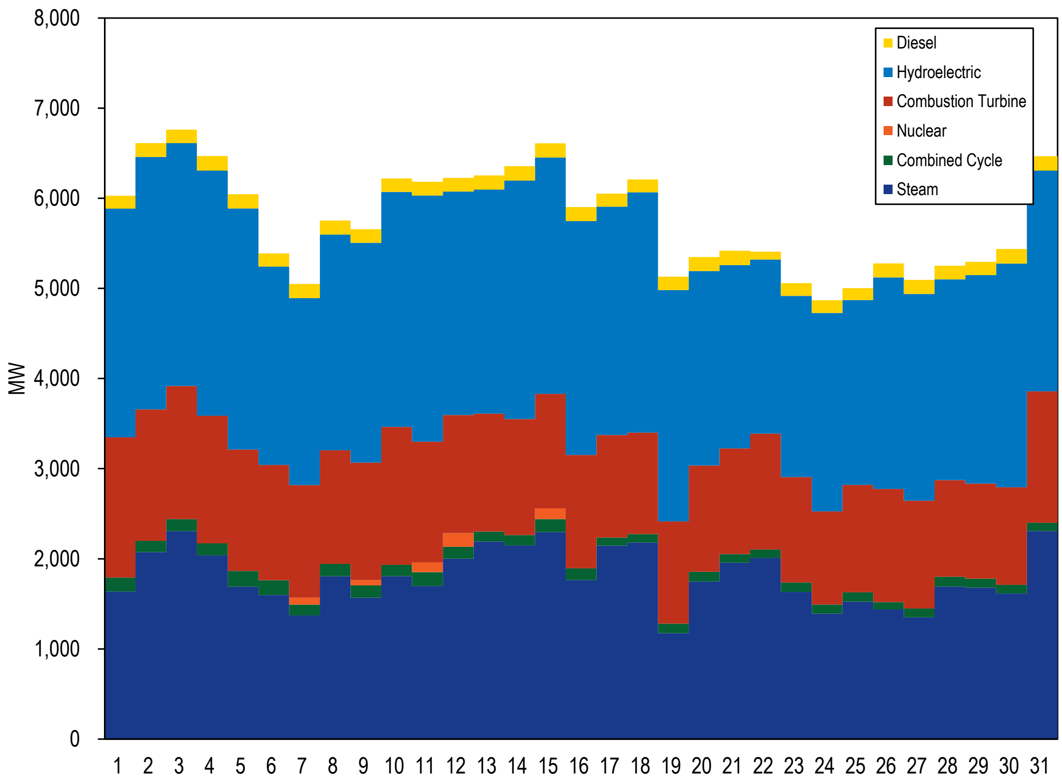
July 7 and July 23 were both Maximum Emergency Alert Days. Figure 3-18 shows average hourly declared emergency MW by day and by technology type for July. Hourly average emergency MW did fall slightly on July 7 and July 23 relative to the prior day's emergency MW. Figure 3-18 shows that steam units had the greatest variance in the total maximum emergency MW in July. Steam resources showed the largest decline in maximum emergency MW in the five day Hot Day period from July 4 through July 8. Figure 3-17 and Figure 3-18 show that behavior on both July 7 and July 23 was consistent with PJM market rules regarding maximum emergency MW declarations during a Maximum Emergency Alert. Maximum emergency MW declarations on both days were lower than the previous day's declarations levels on an aggregate basis. The same aggregate behavior was observed on September 23 and September 24, two other days with Maximum Emergency Alerts.

Figure 3-18 Average hourly declared emergency MW by day and by source: July 2010



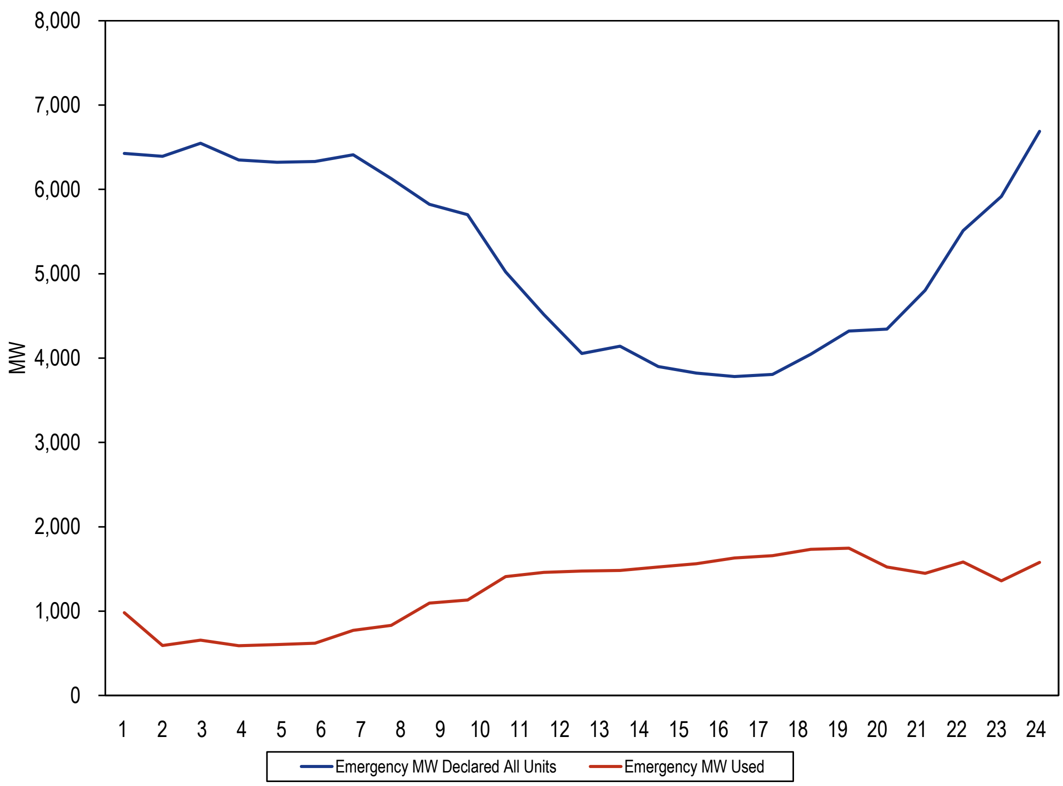
On July 7, a Maximum Emergency Alert Day, units produced energy from maximum emergency MW in every hour of the day, ranging from 46 MWh in hour 0500 to 740 MWh of energy in hour 1900, despite the fact that hourly integrated prices were below $500 and there were no PJM instructions to load the maximum emergency generation. Including energy from MW in excess of economic or emergency MW offers, from 591 (hour 0400) to 1,746 (hour 2000) MWh of energy was produced from maximum emergency capacity on July 7. This behavior suggests that a portion of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days when the tariff definition of maximum emergency applies.

Figure 3-19 shows, by hour, the total emergency MW declared and total emergency MW used to produce energy on July 7. Steam units produced, on an hourly average basis, 57 percent of the energy from emergency MW on July 7.

The intent of the rule regarding maximum emergency designation is to permit capacity with extremely limited short run availability for specific reasons to not offer or run even during a Maximum Emergency Alert so that it can be made available, at PJM direction, to maintain system reliability during designated emergency conditions.

The actual energy output from emergency MW on July 7 suggests that a substantial amount of capacity designated as maximum emergency MW did not behave in a manner consistent with the rule. Despite the fact that no Maximum Emergency Generation Action was declared on July 7, Figure 3-19, shows that on July 7 these maximum emergency MW were being used to provide energy in every hour and at hourly integrated prices below $500. This behavior suggests that a portion (11.9 percent on average) of MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

Figure 3-19 July 7 hourly declared emergency MW, hourly emergency MW



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Operating Reserve

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of total operating reserve credits and corresponding charges increased in 2010 by 74.6 percent compared to 2009, to a total of $569,062,688. This was primarily the result of a large increase in the amount of balancing operating reserve credits. The increase in operating reserve credits was the result of a number of factors including the increase in summer and winter load, the increase in fuel costs and the related increases in generator offer prices, LMP and congestion in 2010.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

New rules governing the payment of operating reserve credits and the allocation of operating reserve charges became effective on December 1, 2008. The new Operating Reserve Construct will be referred to as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.[111]

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories**.** Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-70 shows the categories of credits and charges and their relationship. The bottom half of this table shows how credits are allocated under the new operating reserve construct. Table 3-71 shows the different types of deviations.

111 See the *2009 State of the Market Report for PJM*, Volume II, Section 3, "Energy Market Part 2".

Table 3-70 Operating reserve credits and charges

Credits Received	Charges Paid
Day ahead:	Day-ahead demand
Day-Ahead Energy Market	Decrement bids
Day-ahead import transactions	Day-ahead export transactions
Synchronous condensing	Real-time load
	Real-time export transactions
Balancing:	
Balancing energy market	Real-time deviations
Lost opportunity cost	from day-ahead schedules
Real-time import transactions	
Balancing Energy Market Credits Received	**Balancing Energy Market Charges Paid**
(RTO, Eastern Region, Western Region)	Real-time load
Reliability Credits	Real-time export transactions
Deviation Credits	Real-time deviations
	from day-ahead schedules

Table 3-71 Operating reserve deviations

	Deviations	
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

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Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market and day-ahead import transaction credits. The rules governing these credits and associated charges were not modified in the new rules.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-74 shows monthly day-ahead operating reserve charges for calendar years 2009 and 2010.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[112] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-74 shows monthly synchronous condensing charges for calendar years 2009 and 2010.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

112 "Manual 28: Operating Agreement Accounting," Revision 46 (October 1, 2010).

Table 3-72 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 3-72 shows the allocation process for balancing operating reserves. Credits are assigned to units during two periods, the reliability analysis and the Real-Time Market. During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations and to meet real-time load. Conservative operations means that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are committed to operate in real time to augment the physical units committed in the Day-Ahead Market in order to meet the forecasted real-time load plus the operating reserve requirement. The resultant credits are defined as deviation credits and are allocated to supply, demand, and generator deviations.

In the Real-Time Market, credits are also allocated for reliability or to meet load. Credits are paid to units that are called on by PJM and in which the LMP is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as Reliability Credits and are allocated to real-time load plus exports. Balancing operating reserve credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations from day-ahead schedules.

Credits are allocated regionally based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

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Credit and Charge Results

Overall Results

Table 3-73 shows total operating reserve credits from 1999 through 2010.[113,114] Total operating reserve credits increased by 74.6 percent in 2010 from 2009. Table 3-73 shows the ratio of total operating reserve credits to the total value of PJM billings.[115] This ratio increased from 1.2 percent in 2009 to 1.6 percent in 2010. This is the highest this ratio has been since 2005, and is the first annual increase since 2004.

Table 3-73 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2010

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	NA	0.535	NA
2001	$290,867,269	34.0%	8.7%	0.275	(19.5%)	1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.164	(40.4%)	0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.226	38.2%	1.197	52.0%
2004	$414,891,790	43.3%	4.8%	0.230	1.7%	1.236	3.3%
2005	$682,781,889	64.6%	3.0%	0.076	(66.9%)	2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.078	2.6%	1.331	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.057	(27.0%)	2.331	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.084	48.0%	2.113	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.120	42.3%	1.1100*	(47.5%)
2010	$569,062,688	74.6%	1.6%	0.113	(5.7%)	2.3103*	108.1%

Table 3-73 shows the average day-ahead operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.0068 per MWh or 5.7 percent from $0.1201 per MWh in 2009 to $0.1133 per MWh in 2010. The balancing operating reserve rate increased $1.2003 per MWh, or 108.1 percent, from $1.1100 per MWh in 2009 to $2.3103 per MWh in 2010. The balancing rates of $2.3103 per MWh for 2010 and $1.1100 for 2009 (as indicated with asterisk) represent what the rate would have been if calculated under the old operating construct rules, taking each day's total balancing operating reserve credits, and dividing by total demand, supply, and generator deviations. This was derived by taking all regional reliability and deviation credits for the day and dividing by total PJM supply, demand, and generator deviations, netted across the RTO rather than zone, hub, or interface. The rates shown in the table are the averages of the daily rates across the year.

113 Table 3-73 includes all categories of credits as defined in Table 3-68 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 14, 2011.

114 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

115 See the *2010 State of the Market Report for PJM*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010," for the value of PJM billings during the period indicated.

Total operating reserve charges in 2010 were $569,062,688, up from the total of $325,842,346 in 2009. Table 3-74 compares monthly operating reserve charges by category for calendar years 2009 and 2010. The overall increase of 74.6 percent in 2010 is comprised of a 4.5 percent decrease in day-ahead operating reserve charges, a 71.1 percent decrease in synchronous condensing charges and a 109.1 percent increase in balancing operating reserve charges. The day-ahead operating reserve charges proportion of total operating reserve charges decreased by 13.2 percentage points to 15.9 percent, the synchronous condensing charges proportion decreased 0.7 percentage points to 0.1 percent, and the balancing charges proportion increased 13.8 percentage points to 83.9 percent.

Table 3-74 Monthly operating reserve charges: Calendar years 2009 and 2010

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,472,496	$50,803,869
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,346,529	$33,786,738
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,823,288	$25,782,991
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$7,633,141	$93,253	$22,870,495	$30,596,889
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$5,127,307	$131,600	$39,144,404	$44,403,311
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$3,511,264	$33,923	$56,989,229	$60,534,415
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255	$4,601,788	$88,136	$63,190,853	$67,880,778
Aug	$7,697,174	$1	$21,164,586	$28,861,761	$3,622,670	$66,535	$41,690,612	$45,379,817
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577	$8,433,892	$27,971	$40,637,086	$49,098,949
Oct	$7,046,301	$0	$17,026,425	$24,072,727	$7,719,744	$1,543	$30,433,986	$38,155,273
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519	$6,556,715	$29,674	$20,020,310	$26,606,698
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245	$12,951,879	$59,954	$83,021,125	$96,032,958
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$90,702,132	$720,142	$477,640,414	$569,062,688
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	15.9%	0.1%	83.9%	100.0%

Table 3-75 shows the amount and percentages of regional balancing charge allocations across PJM for 2010. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not include charges attributed for lost opportunity cost credits, cancelled pool-scheduled resources, resources providing quick start reserve and resources performing annual, scheduled black start tests.

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Table 3-75 Regional balancing charges allocation: Calendar year 2010[116]

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$42,122,972 12.6%	$1,689,055 0.5%	$43,812,027 13.1%	$102,864,673 30.7%	$48,547,311 14.5%	$32,906,726 9.8%	$184,318,710 54.9%	$228,130,737 68.0%
East	$46,474,131 13.9%	$1,712,870 0.5%	$48,187,002 14.4%	$15,404,606 4.6%	$6,727,200 2.0%	$3,852,121 1.1%	$25,983,926 7.7%	$74,170,928 22.1%
West	$19,829,984 5.9%	$862,677 0.3%	$20,692,661 6.2%	$6,916,779 2.1%	$3,022,844 0.9%	$2,577,253 0.8%	$12,516,876 3.7%	$33,209,536 9.9%
Total	$108,427,088 32.3%	$4,264,602 1.3%	$112,691,690 33.6%	$125,186,058 37.3%	$58,297,355 17.4%	$39,336,099 11.7%	$222,819,512 66.4%	$335,511,201 100%

Deviations

Categories

Under the old rules, all operating reserve charges that resulted from paying balancing operating reserve credits were allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market, netted across the RTO. Table 3-74 shows monthly balancing operating reserve charges for calendar years 2009 and 2010. Under the new rules, only credits allocated to generators defined to be operating to control for deviations on the system are charged to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[117] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[118] plus real-time exports scheduled through the EES.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or

116 The total charges shown in Table 3-75 do not equal the total balancing charges shown in Table 3-74 because the totals in Table 3-74 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-75 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

117 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

118 PJM's eSchedules is an application used by participants for internal bilateral transactions.

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the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted.

- **Netting.** Demand and supply deviations are netted by zone, hub, or interface in which they occur. For example, a negative deviation in a zone can be offset by a positive deviation that occurs in that zone. The sum of each organization's netted deviations by zone, hub, or interface is categorized into either the eastern or western region, depending on where the zone, hub, or interface is located. The RTO region is the sum of an organization's eastern and western region deviations, plus deviations that occurred at hubs that include buses in both regions. Generators that deviate from real-time dispatch may offset deviations by another generator at the same bus. The set of generators that are allowed to be netted must be electrically equivalent at the bus, and owned by the same participant.

- An organization's total daily balancing operating reserve charges are equal to the sum of the three deviation categories, by region, for the day, multiplied by the regional daily balancing operating reserve rates.

Allocation

Under the new rules, a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-76 shows monthly real-time deviations for demand, supply and generator categories for 2009 and 2010. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were higher in 2010 than 2009 by 9,825,957 MWh. Demand deviations increased by 12.8 percent, supply deviations decreased by 11.1 percent, and generator deviations increased by 13.6. From 2009 to 2010, the share of total deviations in the demand category increased by 3.6 percentage points, the share of supply deviations decreased by 4.9 percentage points, and the share of generator deviations increased by 1.2 percentage points.

Effective December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.[119] The goal of this rule change was to further incent generators to follow PJM dispatch instruction in order to increase market efficiency, and improve reliability. Additionally, a deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

119 Manual 28: *Operating Agreement Accounting* Section 5: Operating Reserve Accounting 5.2.1

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Table 3-76 Monthly balancing operating reserve deviations (MWh): Calendar years 2009 and 2010

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,128,112	5,575,170	2,630,917	17,334,199	9,439,465	5,707,965	2,698,568	17,845,998
Feb	7,044,702	4,153,575	2,107,229	13,305,505	7,675,656	5,332,236	2,456,048	15,463,940
Mar	7,214,090	4,352,550	2,409,507	13,976,146	8,101,950	5,138,264	2,264,951	15,505,165
Apr	6,873,427	3,836,896	2,275,153	12,985,477	7,006,983	4,668,407	2,132,045	13,807,435
May	6,958,699	5,184,983	2,382,351	14,526,033	9,004,034	4,228,004	2,416,103	15,648,141
Jun	8,569,879	4,603,052	2,635,991	15,808,922	10,936,989	3,964,478	3,174,230	18,075,697
Jul	9,233,511	5,129,409	2,243,337	16,606,257	10,928,408	3,847,011	3,412,498	18,187,917
Aug	9,961,944	5,425,344	2,427,539	17,814,827	9,747,045	3,417,328	3,188,437	16,352,810
Sep	7,972,378	4,171,876	2,109,506	14,253,759	9,480,237	3,587,356	2,524,213	15,591,806
Oct	7,028,775	4,543,635	2,203,723	13,776,133	7,170,712	2,913,554	2,368,303	12,452,569
Nov	6,742,675	4,248,221	2,193,013	13,183,910	7,606,971	2,860,054	2,485,153	12,952,178
Dec	8,301,680	4,682,157	3,113,047	16,096,884	10,069,627	4,027,236	3,513,489	17,610,352
Total	95,029,874	55,906,867	28,731,313	179,668,054	107,168,079	49,691,893	32,634,039	189,494,011
Share of Annual Deviations	52.9%	31.1%	16.0%	100.0%	56.6%	26.2%	17.2%	100.0%

Real-time load, real-time exports, and deviations in each region are shown in Table 3-77. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.[15]

Table 3-77 Regional charges determinants (MWh): Calendar year 2010

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	697,390,682	28,285,676	725,676,358	107,168,079	49,691,893	32,634,039	189,494,011	915,170,369
East	381,897,104	14,877,468	396,774,572	66,283,874	31,674,848	17,028,384	114,987,106	511,761,678
West	315,493,578	13,408,208	328,901,786	40,576,952	17,936,701	15,605,655	74,119,308	403,021,094

The MMU has analyzed the impact of the new rules which net supply and demand deviations by zone, hub, or interface, and net generator deviations at the same electrically equivalent bus. Under the new netting rules, total deviations in 2010 were 12,817,998 MWh, 7.3 percent higher than if they had been calculated under the old rules. In order to isolate the impact of the netting changes, the analysis did not take into account the changes made for ramp limited desired MW. Under the new netting rules, demand deviations were 9,380,066 MWh higher, supply deviations

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were 3,599,194 MWh higher, and generator deviations were 161,261 MWh lower, in 2010, than if they had been calculated under the old rules. Table 3-78 shows the monthly impacts of netting deviations for each category.

Table 3-78 Monthly impacts on netting deviations: Calendar year 2010

Month	Demand Deviations (MWh) Old Rules	Demand Deviations (MWh) New Rules	Difference	Supply Deviations (MWh) Old Rules	Supply Deviations (MWh) New Rules	Difference	Generator Deviations (MWh) Old Rules	Generator Deviations (MWh) New Rules	Difference
Jan	8,243,822	9,439,465	1,195,643	5,143,977	5,707,965	563,988	2,709,298	2,698,568	(10,730)
Feb	6,833,397	7,675,656	842,259	4,988,991	5,332,236	343,245	2,462,260	2,456,048	(6,212)
Mar	7,347,674	8,101,950	754,276	4,765,342	5,138,264	372,922	2,269,634	2,264,951	(4,683)
Apr	6,252,224	7,006,983	754,758	4,018,539	4,668,407	649,868	2,146,341	2,132,045	(14,296)
May	8,196,632	9,004,034	807,403	3,703,829	4,228,004	524,175	2,429,552	2,416,103	(13,448)
Jun	10,076,412	10,936,989	860,577	3,591,018	3,964,478	373,460	3,188,180	3,174,230	(13,949)
Jul	10,094,282	10,928,408	834,126	3,644,685	3,847,011	202,326	3,434,716	3,412,498	(22,219)
Aug	9,072,262	9,747,045	674,784	3,287,880	3,417,328	129,448	3,199,527	3,188,437	(11,089)
Sep	8,727,517	9,480,237	752,721	3,403,670	3,587,356	183,686	2,528,532	2,524,213	(4,319)
Oct	6,587,772	7,170,712	582,940	2,843,181	2,913,554	70,373	2,394,899	2,368,303	(26,595)
Nov	7,120,018	7,606,971	486,954	2,852,925	2,860,054	7,129	2,491,869	2,485,153	(6,716)
Dec	9,236,002	10,069,627	833,625	3,848,661	4,027,236	178,575	3,540,494	3,513,489	(27,005)
Total	97,788,014	107,168,079	9,380,066	46,092,699	49,691,893	3,599,194	32,795,300	32,634,039	(161,261)

Table 3-79 shows the summary for each category of deviations under the old rules and the new rules.

Table 3-79 Summary of impact on netting deviations: Calendar year 2010

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	97,788,014	46,092,699	32,795,300	176,676,013
New Rules (Netting)	107,168,079	49,691,893	32,634,039	189,494,011
Difference	9,380,066	3,599,194	(161,261)	12,817,998

Balancing Operating Reserve Charge Rate

Under the new balancing operating reserve cost allocation rules, PJM calculates six separate balancing rates, a reliability rate for each region, and a deviation rate for each region. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. See Table 3-72 for how these credits are allocated.

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Figure 3-20 shows the daily RTO reliability and deviation balancing operating reserve rates for 2010. The average daily RTO deviation rate for 2010 was $0.9116 per MWh, while the average daily RTO reliability rate was $0.0579 per MWh. The largest daily rate occurred on December 15, 2010, when the RTO deviation rate was $13.1590 per MWh.

Figure 3-20 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): Calendar year 2010

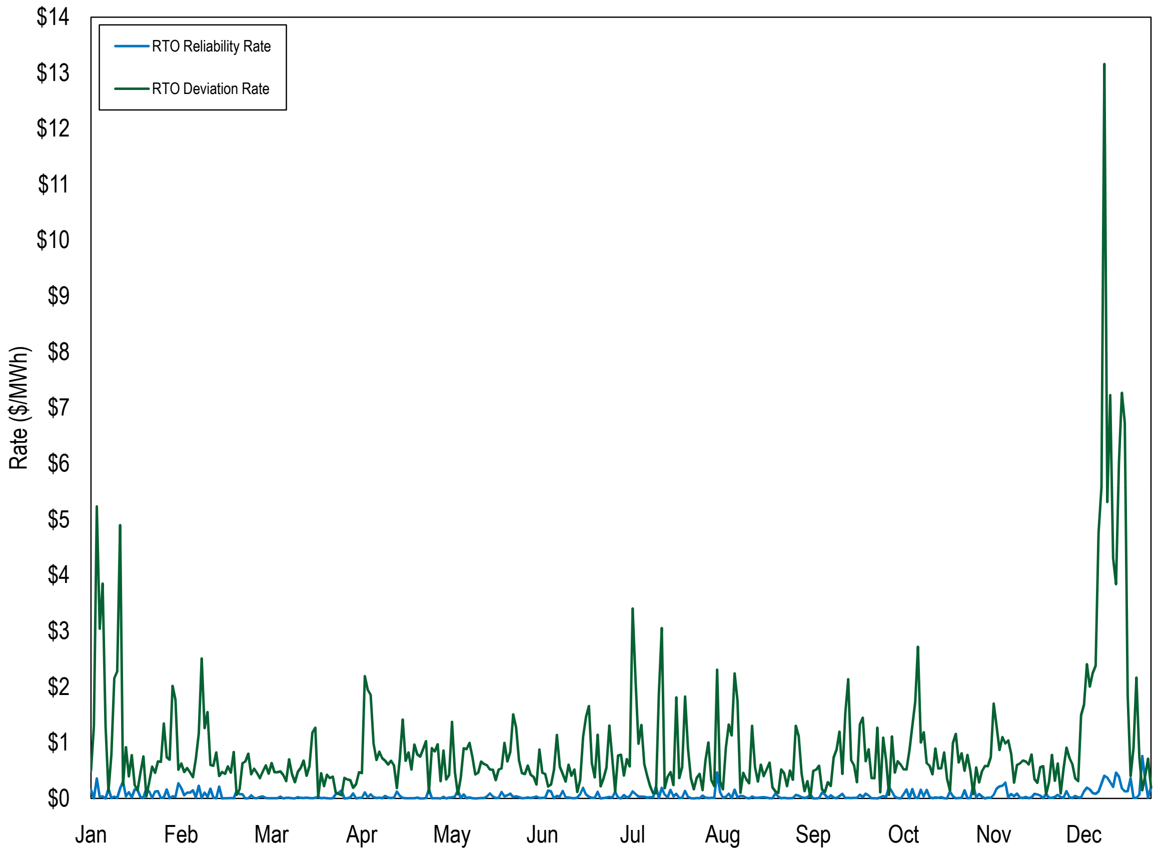

Figure 3-21 shows the daily regional reliability and deviation rates for 2010.

Figure 3-21 Daily regional reliability and deviation rates ($/MWh): Calendar year 2010

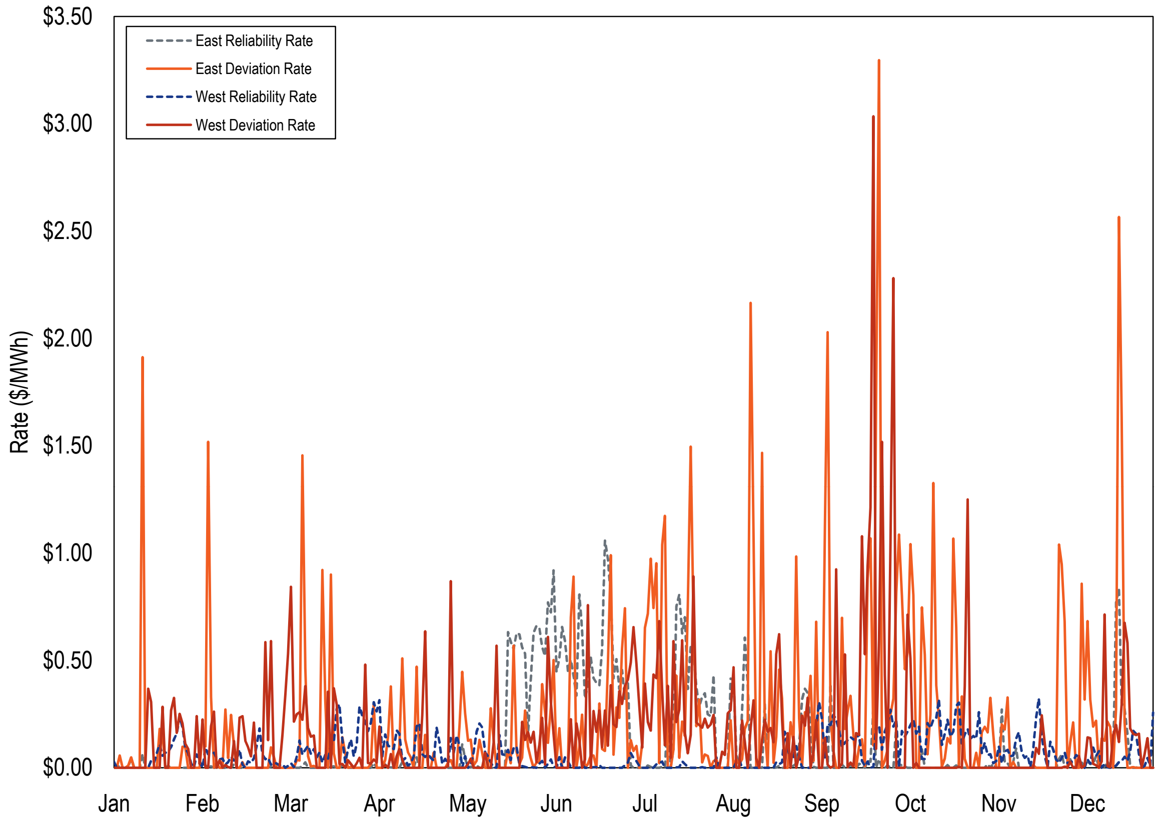

Table 3-80 shows the rates for each region in each category. Regional reliability rates are higher than the RTO reliability rate. The RTO deviation rate is substantially higher than the regional deviation rates.

Table 3-80 Regional balancing operating reserve rates ($/MWh): Calendar year 2010

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.058	0.912
East	0.108	0.225
West	0.070	0.161

Operating Reserve Credits by Category

Figure 3-22 shows that 79.4 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits.

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Figure 3-22 Operating reserve credits: Calendar year 2010

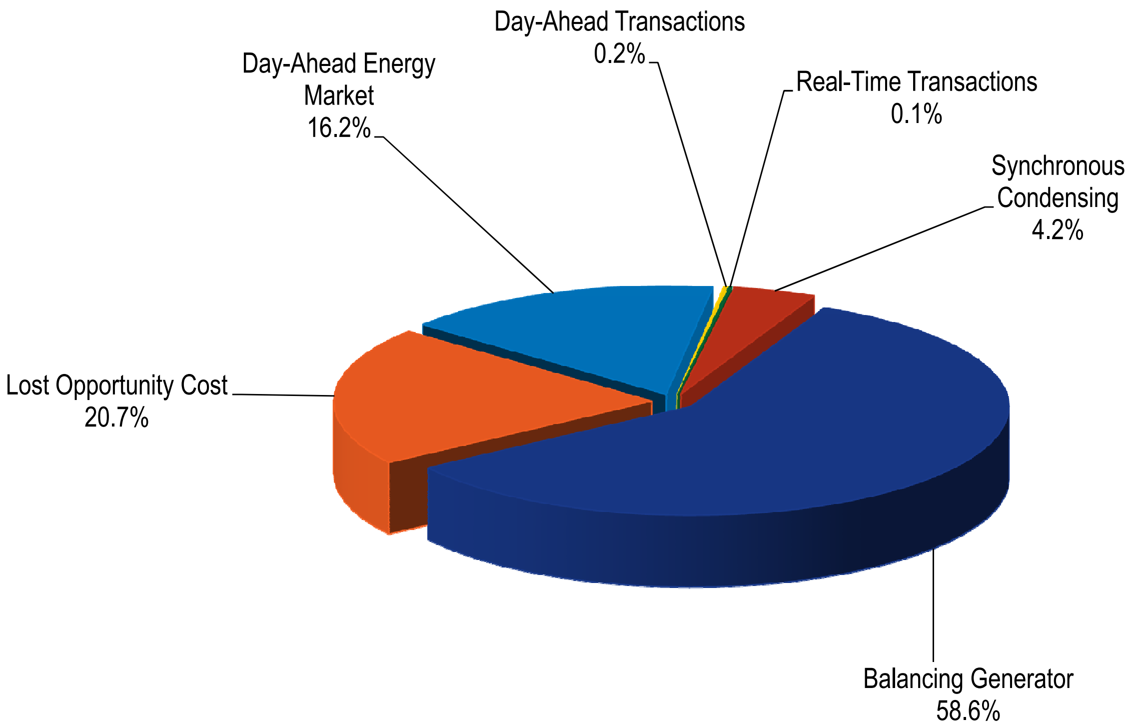

Table 3-81 shows the monthly totals for each type of credit for 2010. The winter months of 2010, which include January, February, November, and December, accounted for 36.2 percent of operating reserve credits for the year, while the summer months, which include May, June, July and August, accounted for 38.2 percent, and the shoulder months 25.6 percent. These credits do not equal the total amount of charges paid of $569,062,688. The difference of $18,407,371 was operating reserve billing adjustments made by PJM directly to participants' bills.[120]

120 PJM Settlements makes offline adjustments for credits to participants on a continuous basis, and these adjustments are not classified in one of the reported categories.

Table 3-81 Credits by month (By operating reserve market): Calendar year 2010[121]

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$34,146,809	$0	$3,333,858	$47,812,040
Feb	$11,382,585	$42,910	$14,715	$17,778,182	$77,139	$1,712,235	$31,007,765
Mar	$8,831,771	$5,115	$122,817	$13,931,307	$15,603	$1,971,841	$24,878,454
Apr	$7,633,141	$0	$93,253	$17,089,233	$0	$4,531,810	$29,347,437
May	$5,117,845	$9,462	$131,600	$23,339,866	$1,236	$15,665,943	$44,265,953
Jun	$3,469,143	$42,121	$33,923	$38,816,038	$196,537	$15,681,736	$58,239,499
Jul	$3,974,505	$627,284	$88,136	$36,965,861	$0	$23,571,309	$65,227,095
Aug	$3,391,194	$231,476	$66,535	$24,130,734	$0	$15,010,705	$42,830,644
Sep	$8,248,826	$185,065	$27,971	$26,086,355	$0	$13,876,042	$48,424,259
Oct	$7,719,743	$0	$1,543	$22,431,618	$4,053	$7,998,315	$38,155,272
Nov	$6,491,210	$65,505	$29,674	$16,412,647	$251,730	$3,355,934	$26,606,700
Dec	$12,951,611	$268	$59,954	$51,284,168	$22,546,342	$7,017,855	$93,860,198
Total	$89,411,108	$1,291,023	$720,142	$322,412,819	$23,092,640	$113,727,584	$550,655,317
Share of Credits	16.2%	0.2%	0.1%	58.6%	4.2%	20.7%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-82 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.)

Table 3-82 Credits by unit types (By operating reserve market): Calendar year 2010

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	33.5%	0.0%	61.1%	5.4%	$128,185,049
Combustion Turbine	2.0%	0.4%	58.5%	39.1%	$173,770,791
Diesel	2.5%	0.0%	83.1%	14.4%	$761,532
Hydro	0.0%	0.0%	100.0%	0.0%	$1,322,714
Landfill	0.0%	0.0%	0.0%	100.0%	$18,038,251
Nuclear	0.0%	0.0%	0.0%	100.0%	$3,155,919
Steam	21.4%	0.0%	69.9%	8.7%	$200,804,340
Wind Farm	0.0%	0.0%	100.0%	0.0%	$233,059

121 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills.

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Table 3-83 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units received 96.2 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits.

Table 3-83 Credits by operating reserve market (By unit type): Calendar year 2010

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	48.1%	0.0%	24.3%	6.1%
Combustion Turbine	3.8%	100.0%	31.5%	59.8%
Diesel	0.0%	0.0%	0.2%	0.1%
Hydro	0.0%	0.0%	0.4%	0.0%
Landfill	0.0%	0.0%	0.0%	15.9%
Nuclear	0.0%	0.0%	0.0%	2.8%
Steam	48.1%	0.0%	43.5%	15.4%
Wind Farm	0.0%	0.0%	0.1%	0.0%
Total	$89,411,108	$720,142	$322,412,819	$113,727,584

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are allocated on a segmented basis for each unique period that a unit operates, rather than an hour to hour basis. Therefore it is possible for a unit to have a segment during which some hours are economic and some hours are noneconomic. For example, if a unit is turned on to control a constraint, it would be considered economic at that time if the unit set the price in the constrained area or was inframarginal. However, if that unit needs to satisfy a minimum runtime because of physical operating characteristics, the unit may become noneconomic for the remainder of its runtime. Noneconomic and economic status may also change when units are run through the overnight hours in order to be available for morning load pickups.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each hour was first determined to be economic or noneconomic based solely on the unit's hourly energy offer. The hourly energy offer does not include the hourly no-load cost or any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-84 shows the number of economic and noneconomic hours for each unit type. For example, of the 32,507 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit was higher than its real-time energy offer in 19,562 hours, or 60.2 percent of the time.

Table 3-84 Economic vs. noneconomic hours: Calendar year 2010

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	19,562	60.2%	12,945	39.8%	32,507
Combustion Turbine	16,888	33.4%	33,641	66.6%	50,529
Diesel	1,011	31.7%	2,182	68.3%	3,193
Steam	57,536	78.7%	15,590	21.3%	73,126

Geography of Balancing Credits and Charges

Table 3-85 and Table 3-86 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generation charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.[122] On average, 49.7 percent of balancing generator charges and 49.7 percent of lost opportunity cost charges were paid by generators deviating in the Eastern Region while these generators received 78.4 percent of all balancing generator credits and 83.2 percent of all lost opportunity cost credits. Table 3-85 and Table 3-86 also show generator credits and charges as shares of total operating reserve credits and charges.

Table 3-85 Monthly balancing operating reserve charges and credits to generators (Eastern Region): Calendar year 2010

	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$1,913,490	$249,304	$2,162,794	$29,069,084	$2,730,988	$31,800,072
Feb	$1,069,496	$138,378	$1,207,873	$14,194,451	$1,375,982	$15,570,433
Mar	$591,204	$125,590	$716,795	$8,223,758	$1,399,277	$9,623,035
Apr	$904,242	$342,520	$1,246,763	$12,334,741	$3,370,088	$15,704,830
May	$919,969	$1,219,952	$2,139,922	$17,804,209	$13,869,787	$31,673,995
Jun	$1,335,181	$1,454,729	$2,789,910	$33,707,188	$14,552,023	$48,259,211
Jul	$2,254,298	$2,323,868	$4,578,166	$30,003,084	$19,048,045	$49,051,129
Aug	$1,575,868	$1,449,154	$3,025,022	$18,782,501	$10,495,220	$29,277,721
Sep	$1,199,555	$971,724	$2,171,280	$17,115,023	$12,709,146	$29,824,169
Oct	$1,399,801	$763,452	$2,163,252	$15,514,301	$7,391,601	$22,905,901
Nov	$934,410	$314,847	$1,249,257	$12,632,087	$2,966,149	$15,598,237
Dec	$5,370,588	$648,599	$6,019,187	$43,530,775	$4,659,867	$48,190,642
Avg.	49.7%	49.7%	49.7%	78.4%	83.2%	79.7%

122 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ComEd, DLCO, and DAY Control Zones.

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Table 3-86 Monthly balancing operating reserve charges and credits to generators (Western Region): Calendar year 2010

	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$1,971,007	$263,791	$2,234,797	$5,077,725	$602,870	$5,680,596
Feb	$998,751	$132,679	$1,131,430	$3,583,730	$336,253	$3,919,983
Mar	$756,085	$166,509	$922,594	$5,707,549	$572,564	$6,280,114
Apr	$1,099,662	$393,474	$1,493,136	$4,754,491	$1,161,722	$5,916,213
May	$935,038	$1,196,289	$2,131,327	$5,535,658	$1,796,157	$7,331,815
Jun	$1,233,687	$1,360,809	$2,594,496	$5,108,850	$1,129,713	$6,238,563
Jul	$1,883,906	$1,998,293	$3,882,198	$6,962,777	$4,523,264	$11,486,041
Aug	$1,478,290	$1,641,533	$3,119,823	$5,348,233	$4,515,485	$9,863,718
Sep	$1,573,967	$1,208,792	$2,782,759	$8,971,332	$1,166,896	$10,138,228
Oct	$1,060,568	$698,071	$1,758,639	$6,917,317	$606,714	$7,524,031
Nov	$880,641	$326,613	$1,207,254	$3,780,560	$389,785	$4,170,344
Dec	$5,822,566	$736,978	$6,559,544	$7,753,394	$2,357,989	$10,111,382
Avg.	50.3%	50.3%	50.3%	21.6%	16.8%	20.3%

Table 3-87 shows that on average, generator charges were 9.6 percent of all operating reserve charges and generator credits were 78.6 percent of all operating reserve credits. In 2009, generator charges were 8.4 percent of all charges, and generator credits were 68.7 percent of all credits.

Table 3-87 Percentage of unit credits and charges of total credit and charges: Calendar year 2010

	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	8.6%	78.4%
Feb	6.9%	62.9%
Mar	6.4%	63.9%
Apr	9.0%	73.7%
May	9.6%	88.1%
Jun	8.9%	93.6%
Jul	12.3%	92.8%
Aug	13.5%	91.4%
Sep	10.1%	82.5%
Oct	10.3%	79.8%
Nov	9.1%	74.3%
Dec	10.6%	62.1%
Avg.	9.6%	78.6%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

The MMU has analyzed the net impact of allocating a proportion of balancing operating reserve credits to real-time load and exports. Credits that are received by generators that operate for reliability purposes are now paid as charges by organizations with real-time load and exports. Credits that are received by generators that operate for deviation purposes are still paid as charges by organizations that have deviations. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, real-time load and exports, and away from those creating deviations. The MMU calculated what balancing operating reserve charges would have been under the old rules and compared it to what actually happened in 2010.

Total reliability and deviation balancing operating reserve credits were $335,511,201 in 2010.[123] This is a 93.5 percent increase from 2009, which totaled $173,349,483. Table 3-88 shows each category of credits by region.

Table 3-88 Regional balancing operating reserve credits: Calendar year 2010

	Reliability Credits	Deviation Credits	Total Credits
RTO	$43,812,027	$184,318,710	$228,130,737
East	$48,187,002	$25,983,926	$74,170,928
West	$20,692,661	$12,516,876	$33,209,536
Total	$112,691,690	$222,819,512	$335,511,201

Table 3-89 shows the total amount of deviations in the demand, supply, and generator categories for 2010.

Table 3-89 Total deviations: Calendar year 2010

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	107,168,079	49,691,893	32,634,039	189,494,011

Under the old operating reserve rules, total charges for a day would have been applied to each organization's demand, supply, and generator deviations to calculate total charges.

For comparative purposes only, the old balancing rate in Table 3-90 was calculated as the total credits in Table 3-88 divided by total deviations in Table 3-89, or $335,511,201/189,494,011 MWh, a rate of $1.7706 per MWh. The MMU derived the rates on a daily basis and recalculated organizational charges.

123 Only balancing generator charges were in this analysis. The charges shown in this section do not include lost opportunity cost, cancellation, or local charges.

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Table 3-90 Charge allocation under old operating reserve construct: Calendar year 2010

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	107,168,079	49,691,893	32,634,039	189,494,011
Balancing Rate ($/MWh)	1.771	1.771	1.771	1.771
Charges ($)	$189,747,902	$87,982,658	$57,780,641	$335,511,201

Under the new operating reserve rules, rates are calculated separately for reliability and deviation categories in the Eastern, Western, and RTO Regions, resulting in six balancing rates. The Eastern and Western reliability rates are calculated by taking each region's daily reliability credits and dividing by each region's real-time load and exports. These regional rates are then charged to each organization's regional real-time load and exports. The RTO reliability rate is calculated by taking the total RTO reliability rates for the day and dividing it by the sum of eastern and western real-time load and exports. This rate is then charged to the sum of an organization's eastern and western real-time load and exports. Regional deviation credits are charged to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at hubs that span both regions apply to RTO deviations).[124] Total RTO deviations are the sum of the eastern deviations, western deviations, and the deviations at hubs that span both regions.

For 2010, charges were actually allocated as shown in Table 3-91. For comparative purposes only, the reliability and deviation rates in the table are the annual credits divided by either real-time load and exports or total deviations ($43,812,027 / 725,676,358 = 0.0604, the RTO reliability rate). The charges are calculated based on the actual daily rates.

Table 3-91 Actual regional credits, charges, rates and charge allocation (MWh): Calendar year 2010

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$43,812,027	725,676,358	0.060	$43,812,027	$184,318,710	189,494,011	0.973	$184,318,710	$228,130,737
East	$48,187,002	396,774,572	0.121	$48,187,002	$25,983,926	115,064,099	0.226	$25,983,926	$74,170,928
West	$20,692,661	328,901,786	0.063	$20,692,661	$12,516,876	74,189,868	0.169	$12,516,876	$33,209,536
Total	$112,691,690	725,676,358	NA	$112,691,690	$222,819,512	189,494,011	NA	$222,819,512	$335,511,201

The difference between the charges based on the old operating reserve rules (Table 3-90) and the actual charges allocated under the current rules is shown in Table 3-90, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

124 Only two hubs span across both the eastern and western regions: the Dominion Hub and the Western Int. Hub.

Table 3-92 Difference in total operating reserve charges between old rules and new rules: Calendar year 2010

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$189,747,902	$87,982,658	$57,780,641	$335,511,201
Charges (Current)	$108,427,088	$4,264,602	$112,691,690	$125,186,058	$58,297,355	$39,336,099	$222,819,512
Difference	$108,427,088	$4,264,602	$112,691,690	($64,561,844)	($29,685,303)	($18,444,542)	($112,691,690)

An increase of $112,691,690 of charges was assigned to real-time load and exports for 2010. Real-time load paid an additional $108,427,088, while real-time exports paid an additional $4,264,602. These increases were matched by a decrease of $64,343,546 in charges to demand deviations, a decrease of $29,548,082 in charges to supply deviations, and a decrease of $18,764,061 in charges to generator deviations. Reliability charges accounted for 33.6 percent of total balancing operating reserve charges.

Impact on decrement bids and incremental offers

The MMU has estimated the impact of the new balancing operating reserve rules on the allocation of charges to virtual activity. The level of virtual activity that was not otherwise netted out was calculated by organization for increment offers and decrement bids. All organizational deviations were grouped into regions. “Total Increment Offers” and “Total Decrement Bids”, shown in Table 3-93, is the sum of cleared virtual activity for 2010. “Adjusted Increment Offer Deviations” and “Adjusted Decrement Bid Deviations” are the net deviations for each type of virtual trade that were not offset by other positions, such as load, sales, purchases, exports, or imports. For example if a participant has the following position: in the Day-Ahead Market, a 100 MWh decrement bid, 50 MWh load, 10 MWh sale, and a 5 MWh export transaction, and in the Real-Time Market, a 55 MWh load, a 5 MWh sale, and a 5 MWh export transaction. The additional 5 MWh of real-time load, and deficiency of 5 MWh of real-time sales offset each other, leaving a 100 MWh net deviation from the decrement bid.

Table 3-93 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar year 2010

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047
Feb	8,323,844	11,828,781	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
Apr	7,568,471	9,989,951	2,214,314	2,066,270
May	8,306,597	11,573,314	2,250,271	3,437,786
Jun	8,304,139	12,735,819	2,223,204	4,058,044
Jul	8,389,094	12,813,573	1,840,017	3,503,722
Aug	7,862,123	11,648,289	1,465,333	2,676,901
Sep	8,188,967	11,532,284	2,103,152	3,105,498
Oct	7,777,616	10,423,935	1,564,871	2,163,717
Nov	8,027,852	11,041,950	1,408,786	2,467,942
Dec	9,416,187	12,320,592	1,920,956	3,451,929
Total	98,488,750	140,097,307	23,609,817	35,212,727

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In order to determine what these deviation charges would have been under the old balancing operating reserve rules, balancing operating reserve rates were determined for each day. Balancing operating reserve credits paid to generators were recalculated using the old rules that evaluated units over the entire 24 hours for each day. The new rules evaluate units by operating segments within a day. Supply, demand, and generator deviations were recalculated by netting participants' deviations across the RTO. The new rules net supply and demand deviations by zone, hub, or interface, and net generator deviations by bus, provided they are electrically equivalent and owned by the same participant. Generator deviations were not adjusted for changes in regard to the use of ramp-limited desired MW under the current rules. The resulting daily balancing operating reserve rate was determined by dividing balancing operating reserve credits by supply, demand, and generator deviations, then adding the daily lost opportunity cost rate.

Total charges were calculated for each company using this balancing rate and the sum of their adjusted increment offer and decrement bids. The resulting total amount of charges that would have been paid by virtual activity in 2010 was $132,741,464. Under the current rules, this charge is $106,719,600. The monthly differences can be seen in Table 3-94.

Table 3-94 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2010

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)
Feb	$5,319,874	$3,936,420	($1,383,454)
Mar	$4,797,076	$3,468,829	($1,328,248)
Apr	$6,480,725	$5,301,308	($1,179,417)
May	$13,658,944	$10,158,307	($3,500,637)
Jun	$18,021,960	$10,673,612	($7,348,348)
Jul	$17,068,724	$14,327,987	($2,740,737)
Aug	$9,394,993	$7,575,980	($1,819,013)
Sep	$13,065,704	$10,820,010	($2,245,694)
Oct	$9,019,721	$6,456,368	($2,563,353)
Nov	$5,817,780	$3,925,450	($1,892,330)
Dec	$17,570,579	$19,884,462	$2,313,884
Total	$132,741,464	$106,719,600	($26,021,864)

The net result is that virtual offers and bids paid $26,021,864 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports. A summary showing this breakdown for each region is shown in Table 3-95.

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Table 3-95 Summary of impact on virtual bids under balancing operating reserve allocation: Calendar year 2010

Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Old Rules ($/MWh)	Balancing Rate Current Rules ($/MWh)	Charges Under Old Rules	Charges Under Current Rules	Differerence
RTO	23,609,817	35,212,727	58,822,544	2.17	1.53	$132,741,464	$94,844,415	($37,897,048)
East	14,596,342	20,413,754	35,010,096	0.00	0.16	$0	$8,056,742	$8,056,742
West	8,933,131	14,491,720	23,424,851	0.00	0.00	$0	$3,818,443	$3,818,443

Segmented Make Whole Payments

Under the old operating reserve rules, balancing operating reserves for units were evaluated over the entire 24-hour period of the day. Under the new rules: [125]

> "Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable, will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources)."

The primary intent of this rule was to provide incentives for generating units to follow PJM dispatch after the end of their day-ahead schedule or minimum run time and to provide incentives to offer flexible schedules and to follow dispatch when economic.

The MMU analyzed the impact of segmented make whole payments on balancing operating reserves. The MMU compared what balancing credits would have been for each unit for each day under the old rules to what the credits were under the new rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $26,262,054 higher, or 5.2 percent, from December 1, 2008 through December 31, 2010. The total increase for the calendar year 2010 was $18,087,648, or 6.0 percent. Table 3-96 provides a breakdown of monthly differences between the two methods of calculation since December 2008.

125 Manual 28: *Operating Agreement Accounting* Section 5: Operating Reserve Accounting 5.2.1

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Table 3-96 Impact of segmented make whole payments: December 2008 through December 2010

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,120	$13,672,172	$214,052
2010	Apr	$16,441,644	$17,036,058	$594,414
2010	May	$21,854,306	$23,455,721	$1,601,415
2010	Jun	$36,297,521	$38,885,349	$2,587,828
2010	Jul	$32,251,623	$37,053,630	$4,802,007
2010	Aug	$21,867,024	$24,335,171	$2,468,147
2010	Sep	$24,293,196	$25,686,790	$1,393,593
2010	Oct	$21,839,101	$22,478,455	$639,354
2010	Nov	$15,795,391	$16,238,383	$442,991
2010	Dec	$49,180,164	$51,293,810	$2,113,646
Total		$502,883,559	$529,145,613	$26,262,054

Table 3-97 shows the effect of segmented make whole payments on each type of unit that received balancing operating reserve credits for the period from December 1, 2008 through December 31, 2010. “Number of Unit-Days” in the table is the count of units that received balancing credits each day, summed across the entire year. For example, an average of 26 combined-cycle units received credits for each day of the year (9,482 / 365 = 26). The average daily amount received in credits for a unit for each method of calculation was analyzed to show the impact of an average day for each type of unit. The last three columns in the table show the total difference in credits for the time period across each unit type.

Table 3-97 Impact of segmented make whole payments (By unit type): Calendar year 2010

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	9,482	$7,608	$8,254	$646	$72,138,362	$78,262,392	$6,124,030
Large Frame Combustion Turbine (135 - 180 MW)	3,885	$9,129	$10,143	$1,015	$35,465,394	$39,406,789	$3,941,395
Medium Frame Combustion Turbine (30 - 65 MW)	9,827	$3,491	$3,834	$342	$34,309,724	$37,673,652	$3,363,928
Medium-Large Frame Combustion Turbine (65 - 125 MW)	2,947	$5,884	$6,365	$481	$17,340,058	$18,757,970	$1,417,912
Petroleum/Gas Steam (Pre-1985)	1,171	$59,386	$60,537	$1,151	$69,541,058	$70,888,358	$1,347,300
Sub-Critical Coal	29,988	$1,737	$1,763	$26	$52,100,107	$52,880,369	$780,262
Petroleum/Gas Steam (Post-1985)	2,328	$2,472	$2,778	$306	$5,754,062	$6,466,904	$712,842
Small Frame Combustion Turbine (0 - 29 MW)	3,690	$1,691	$1,779	$88	$6,240,408	$6,564,842	$324,434
Diesel	4,561	$123	$139	$16	$559,413	$634,601	$75,188
Super-Critical Coal	9,044	$1,104	$1,104	$0	$9,982,209	$9,982,565	$357
Hydro	768	$196	$196	$0	$150,717	$150,717	$0

From December 1, 2008, through December 31, 2009, combined-cycles received nearly 50 percent of the increase in segmented make-whole payments, and combustion turbines 37.9 percent. In 2010, combustion turbines received 50.0 percent of this increase, and combined-cycles 33.9 percent (Table 3-98). This is a result of the increased dispatch in 2010 related to higher loads which led to the overall increase of balancing operating reserve credits paid to combustion turbines in 2010 (Table 3-82 and Table 3-83). Under the old rules, combustion turbines would have been paid $93,355,584, and with segmented make whole payments, the units received $102,403,253, a total difference of $9,047,669, or a 9.7 percent increase.

Table 3-98 Share of balancing operating reserve increases for segmented make whole payments (By unit type): December 2008 through December 2010

Unit Type	Share of Increase
Combustion Turbines	50.0%
Combined-Cycle	33.9%
Steam	15.7%
Diesel	0.4%
Hydro	0.0%

Unit Operating Parameters

The use of restrictive operating parameters to exercise market power and inflate operating reserve credits was addressed, based on the MMU's analysis and positions, in the revised operating reserve rules. The MMU's prior analyses indicated that operating reserve credits may result from the submission of artificially restrictive, unit-specific operating parameters.[126] The MMU also pointed out that restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

126 See the *2009 State of the Market Report for PJM*, Volume II, "Section 3, Energy Market, Part 2" at "Operating Reserve."

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The new operating reserves rules addressed the parameter issue by establishing a parameter limited schedule (PLS) that helps prevent the use of restrictive operating parameters when units have local market power. Table 3-99 shows the parameter limited matrix for periods that are currently effective.[127]

Table 3-99 Unit Parameter Limited Schedule Matrix

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 65 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Units may request exceptions to the values in the matrix. The MMU analyzed the frequency with which these exceptions affected market outcomes. The only units included in the analysis were units put on their cost schedule after failing the TPS test. There were 568 events, affecting 58 unique units, when a unit with a PLS exception was capped and received balancing operating reserve credits (Table 3-100). The number of events occurring in 2010 more than doubled from the period December 1, 2008 through December 31, 2009, during which 216 events, and 44 unique units, were capped while receiving credits.

Table 3-100 Units receiving credits from a parameter limited schedule: December 2008 through December 2010

Unit Type	Number of Units	Observations
Combined-Cycle	4	11
Large Frame Combustion Turbine (135 - 180 MW)	10	105
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	152
Petroleum/Gas Steam (Pre-1985)	5	15
Sub-Critical Coal	28	284
Super-Critical Coal	1	1

127 See PJM "Parameter Limited Schedule Matrix," for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx> (104 KB).

Issues in Operating Reserves

Market Power Issues

The exercise of market power by units that are paid operating reserve credits has contributed to the level of operating reserve charges paid by PJM members. The inflexible operating parameter issue was addressed by the introduction of new PJM rules implementing parameter limited schedules.

Markup

The MMU analyzed the top 10 units receiving operating reserve credits to determine the contribution that markup makes to operating reserve payments.[128] The markup for the top 10 units averaged 33.8 percent in 2010. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of operating reserve credits had a weighted average markup of 0.0 percent in 2010. The generation owners with the second and third largest share (22.8 and 22.8 percent each) had a weighted-average markup of 16.3 percent and 76.5 percent.

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. As Table 3-101 shows, the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. The top 20 units received 42.2 percent of total operating reserve credits in 2010 and 46.0 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits.

128 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 11 (December 2, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

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Table 3-101 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2010

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%

Table 3-102 shows the distribution of operating reserve credits to units by zone. The top three zones accounted for 63.5 percent of the total. The PSEG Control Zone had the largest share of credits with 25.2 percent, the Dominion Control Zone was the second highest with 19.2 percent, and the Pepco Control Zone was third with a 19.1 percent share.

Table 3-102 Unit operating reserve credits for units (By zone): Calendar year 2010

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$671,820	$5,514	$2,197,947	$3,905,127	$6,780,409	1.3%
AEP	$2,870,042	$13,296	$40,332,870	$3,704,606	$46,920,814	8.9%
AP	$2,027,358	$0	$6,426,335	$8,054,017	$16,507,710	3.1%
BGE	$8,956,887	$0	$12,312,645	$522,499	$21,792,031	4.1%
ComEd	$1,580,732	$4,080	$9,486,213	$6,808,692	$17,879,718	3.4%
DAY	$211,857	$0	$2,225,821	$328,481	$2,766,159	0.5%
DLCO	$2,634,354	$0	$11,030,377	$263,615	$13,928,345	2.6%
Dominion	$5,725,788	$0	$40,320,399	$54,819,450	$100,865,636	19.2%
DPL	$3,768,620	$10,337	$12,471,215	$2,119,131	$18,369,303	3.5%
JCPL	$2,887,195	$0	$7,851,450	$879,855	$11,618,499	2.2%
Met-Ed	$433,474	$0	$2,524,121	$805,995	$3,763,590	0.7%
PECO	$2,253,955	$2,095	$8,290,005	$2,552,626	$13,098,681	2.5%
PENELEC	$621,324	$27,409	$1,512,030	$5,416,639	$7,577,402	1.4%
Pepco	$8,614,205	$0	$77,353,307	$14,720,240	$100,687,751	19.1%
PPL	$429,429	$0	$8,230,711	$2,686,247	$11,346,387	2.2%
PSEG	$45,724,070	$657,410	$79,847,372	$6,140,365	$132,369,216	25.2%
RECO	$0	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	$0	0.0%
Total	$89,411,108	$720,142	$322,412,819	$113,727,584	$526,271,654	100.0%

Table 3-103 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $43,439,277 for 2010, or 8.3 percent of the total operating reserve credits paid to all units, compared to 12.7 percent for the top unit of 2009. The cumulative distribution column shows that the top 10 units had a 33.2 percent share of the total operating reserve credits in 2010. The top organization had a 24.9 percent share of the total credits, or $131,269,636, compared to 32.8 percent in 2009. The top 10 organizations receiving credits had a cumulative share of 83.1 percent.

Table 3-103 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2010

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$43,439,277	8.3%	8.3%	$131,269,636	24.9%	24.9%
2	$31,556,899	6.0%	14.3%	$97,277,079	18.5%	43.4%
3	$21,543,721	4.1%	18.3%	$62,600,022	11.9%	55.3%
4	$18,256,867	3.5%	21.8%	$37,756,657	7.2%	62.5%
5	$14,332,143	2.7%	24.5%	$25,523,773	4.8%	67.3%
6	$13,921,639	2.6%	27.2%	$21,725,470	4.1%	71.5%
7	$13,399,983	2.5%	29.7%	$20,941,025	4.0%	75.5%
8	$6,284,703	1.2%	30.9%	$18,484,418	3.5%	79.0%
9	$6,186,466	1.2%	32.1%	$13,949,799	2.7%	81.6%
10	$5,556,922	1.1%	33.2%	$7,749,082	1.5%	83.1%

Table 3-104 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $19,218,254, or 21.5 percent of the total day-ahead generator credits, which is nearly identical with 2009. The second unit had a 12.3 percent share, which when combined with the top unit was 33.8 percent of the total credits. The top organization in 2010 received 51.0 percent of the day-ahead credits, compared to 48.9 percent in 2009. The top 10 organizations received 90.3 percent of the day-ahead credits.

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Table 3-104 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2010

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$19,218,254	21.5%	21.5%	$45,588,536	51.0%	51.0%
2	$10,979,961	12.3%	33.8%	$9,200,533	10.3%	61.3%
3	$8,237,693	9.2%	43.0%	$7,569,378	8.5%	69.7%
4	$3,596,128	4.0%	47.0%	$4,721,875	5.3%	75.0%
5	$3,418,695	3.8%	50.8%	$3,233,156	3.6%	78.6%
6	$3,165,849	3.5%	54.4%	$3,157,821	3.5%	82.2%
7	$2,573,784	2.9%	57.3%	$2,315,364	2.6%	84.8%
8	$2,315,364	2.6%	59.8%	$2,182,215	2.4%	87.2%
9	$2,119,032	2.4%	62.2%	$1,470,017	1.6%	88.8%
10	$1,555,872	1.7%	64.0%	$1,271,978	1.4%	90.3%

Table 3-105 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 91.3 percent of synchronous condensing credits, up from 89.4 percent in 2009.

Table 3-105 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2010

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$55,449	7.7%	7.7%	$657,410	91.3%	91.3%
2	$54,979	7.6%	15.3%	$27,409	3.8%	95.1%
3	$52,148	7.2%	22.6%	$14,309	2.0%	97.1%
4	$51,860	7.2%	29.8%	$13,296	1.8%	98.9%
5	$47,298	6.6%	36.3%	$4,080	0.6%	99.5%
6	$43,700	6.1%	42.4%	$2,095	0.3%	99.8%
7	$37,144	5.2%	47.6%			
8	$34,526	4.8%	52.4%			
9	$32,934	4.6%	56.9%			
10	$31,449	4.4%	61.3%			

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Table 3-106 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.5 percent of total credits, down from 29.3 percent in 2009. The top ten organizations received a total of 87.4 percent of all the balancing generator credits.

Table 3-106 Top 10 units and organizations receiving balancing generator credits: Calendar year 2010

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$32,448,468	10.1%	10.1%	$78,884,956	24.5%	24.5%
2	$21,542,992	6.7%	16.7%	$56,452,837	17.5%	42.0%
3	$17,918,553	5.6%	22.3%	$49,475,085	15.3%	57.3%
4	$12,365,767	3.8%	26.1%	$33,453,646	10.4%	67.7%
5	$12,302,180	3.8%	30.0%	$16,516,178	5.1%	72.8%
6	$9,977,020	3.1%	33.0%	$16,311,940	5.1%	77.9%
7	$6,094,250	1.9%	34.9%	$15,007,623	4.7%	82.5%
8	$4,616,286	1.4%	36.4%	$6,063,758	1.9%	84.4%
9	$4,119,971	1.3%	37.6%	$5,254,273	1.6%	86.0%
10	$3,805,134	1.2%	38.8%	$4,459,378	1.4%	87.4%

Table 3-107 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 35.4 percent of the total lost opportunity cost credits and 80.9 percent were received by the top 10 organizations.

Table 3-107 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2010

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$4,577,153	4.0%	4.0%	$40,232,616	35.4%	35.4%
2	$4,567,656	4.0%	8.0%	$18,458,356	16.2%	51.6%
3	$3,598,190	3.2%	11.2%	$7,751,095	6.8%	58.4%
4	$3,288,209	2.9%	14.1%	$6,138,734	5.4%	63.8%
5	$3,097,224	2.7%	16.8%	$3,913,969	3.4%	67.3%
6	$2,702,194	2.4%	19.2%	$3,657,338	3.2%	70.5%
7	$2,691,504	2.4%	21.6%	$3,444,927	3.0%	73.5%
8	$2,597,591	2.3%	23.8%	$3,415,707	3.0%	76.5%
9	$2,557,217	2.2%	26.1%	$2,899,720	2.5%	79.1%
10	$2,494,927	2.2%	28.3%	$2,120,795	1.9%	80.9%

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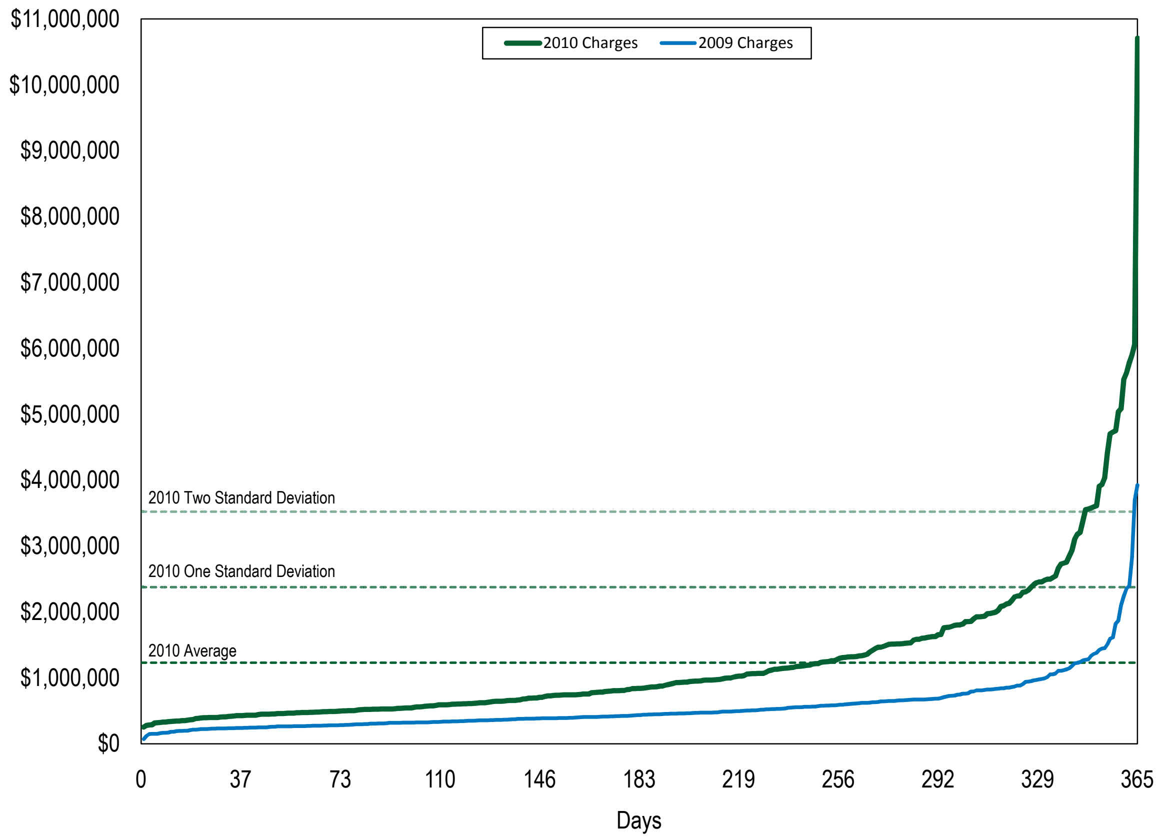
Increased Operating Reserve Charges

Summary

Operating reserve charges in 2010 increased 74.6 percent overall when compared to 2009, including a 120.0 percent increase in balancing generator credits. Total balancing generator credits for 2010 totaled $449,325,457, compared to $204,229,481 in 2009. Figure 3-23 shows the distribution of daily balancing generator credits for 2010 and 2009. The distribution curve for 2010 is higher for each day of the year, and starts to diverge towards the upper end of the distribution. The highest level of balancing generator credits paid for one day in 2010 was $10,707,778, compared to $3,927,226 in 2009. Figure 3-23 shows that the average daily balancing credits paid to generators was $1,231,103, with a standard deviation of $1,145,882. Only 22 days in 2009, or 6.0 percent of the days in the year, had daily balancing operating reserve credits paid to generators higher than the average daily payment in 2010.

Figure 3-23 Balancing Generator Credits Daily Distribution: Calendar year 2010 and 2009



Causes

Weather is one of the primary drivers of load in PJM. The summer of 2010 had higher than average temperatures across the PJM region. PJM hourly average real-time load increased in 2010 by 4.7 percent from 2009. Increases in demand require more generators to operate for longer periods of time. PJM declared Hot Weather Alerts on 36 days. This may result in extra generators being scheduled in order to meet the expected loads. A period of consecutive days with high temperatures requires more generating units to remain online for long periods of time. Increased forced outages result.

Table 3-108 shows the MWh loss from outages in 2010 and 2009. This includes planned, maintenance, and forced outages. MWh loss is the MW reduction of the outage multiplied by length in hours of the outage. The MWh lost due to outages increased by 13,464,130 MWh, or 5.5 percent, in 2010. Lengthy outages from large baseload coal units to make long-term improvements occurred in 2010, resulting in the increase of MWh lost.

Table 3-108 Loss of MWh from outages: Calendar year 2009 and 2010

Unit Type	2009 MWh Loss	2010 MWh Loss	MWh Loss Difference
Steam	157,405,677	173,295,820	15,890,143
Combined Cycle	26,419,761	29,524,036	3,104,275
Combustion Turbine	18,100,396	19,063,448	963,052
Other	10,451,976	8,712,275	(1,739,701)
Nuclear	31,498,585	26,744,946	(4,753,639)
Total	243,876,395	257,340,525	13,464,130

Fuel prices play a major role in the overall level of operating reserve credits to generators. Fuel prices are the largest and most volatile component of a units' daily offers. Eastern and western natural gas prices were 12.3 and 11.0 percent higher in 2010 than in 2009. Light fuel No. 2 oil and heavy fuel No. 6 oil prices were 29.3 and 32.3 percent higher in 2010 than in 2009.[129] Natural gas prices are relatively volatile prices. There are 13 major pipelines serving the PJM region. Transco pipeline pricing points Zone 5, Zone 6 Non New York, and Zone 6 New York, and the Texas Eastern M3 pricing point, have the most volatile natural gas prices of the pipelines and associated delivery zones. There are a large group of generators served by these pipelines that are located in high load areas of PJM. During periods of extreme cold, typically when temperatures reach 10 degrees Fahrenheit or less, these pipelines charge a premium for gas, which can be as high as three times the non premium price. When offers increase, the cost to operate units increases and credits paid to generators increase. Table 3-109 compares the minimum, maximum, average, and standard deviation of daily delivery prices ($/MMBtu) for Transco Zone 5, Zone 6 Non New York, and Zone 6 New York, Texas Eastern M3 zone, and all other pricing points used for PJM generator offers.

Table 3-109 Natural Gas Pipeline and Zone Delivery Price Summary: Calendar Year 2010[21]

Year	Pricing Points	Min	Max	Mean	Std. Dev
2010	Transco and Texas Eastern M3	$5.19	$20.34	$3.28	$1.89
2010	Other Pricing Points	$4.45	$7.94	$2.85	$0.74

129 Fuel data reported in this analysis are the average of daily fuel price indices in the PJM footprint. All data from Platts.

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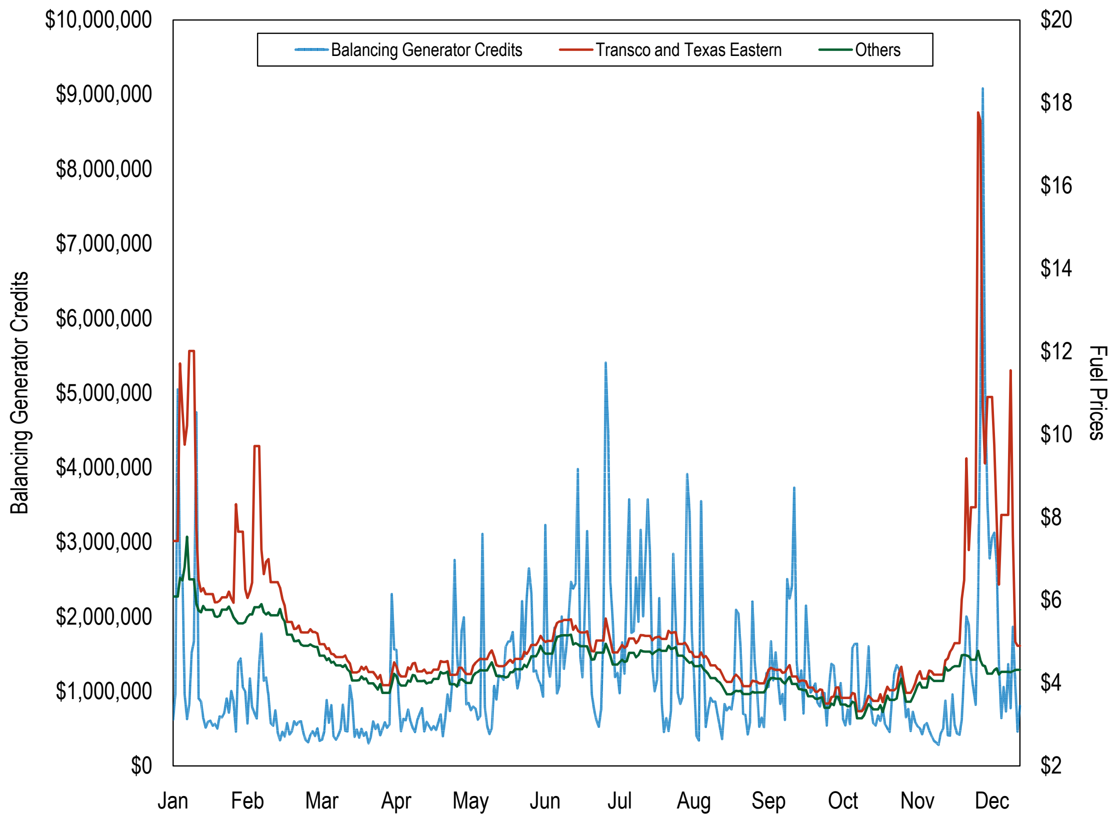
On December 13th, 2010, PJM issued a Cold Weather Alert, during which PJM notified generation owners to be prepared to call in additional staff to prepare all generating units to run for the morning pickup. As a result of the increased number of out of merit units, and high natural gas prices, balancing operating reserve credits received during the period from December 13 through December 22, 2010, which accounts for 2.7 percent of the days of the year, were $56,595,618.00, or 12.6 percent of all operating reserve credits for the year.

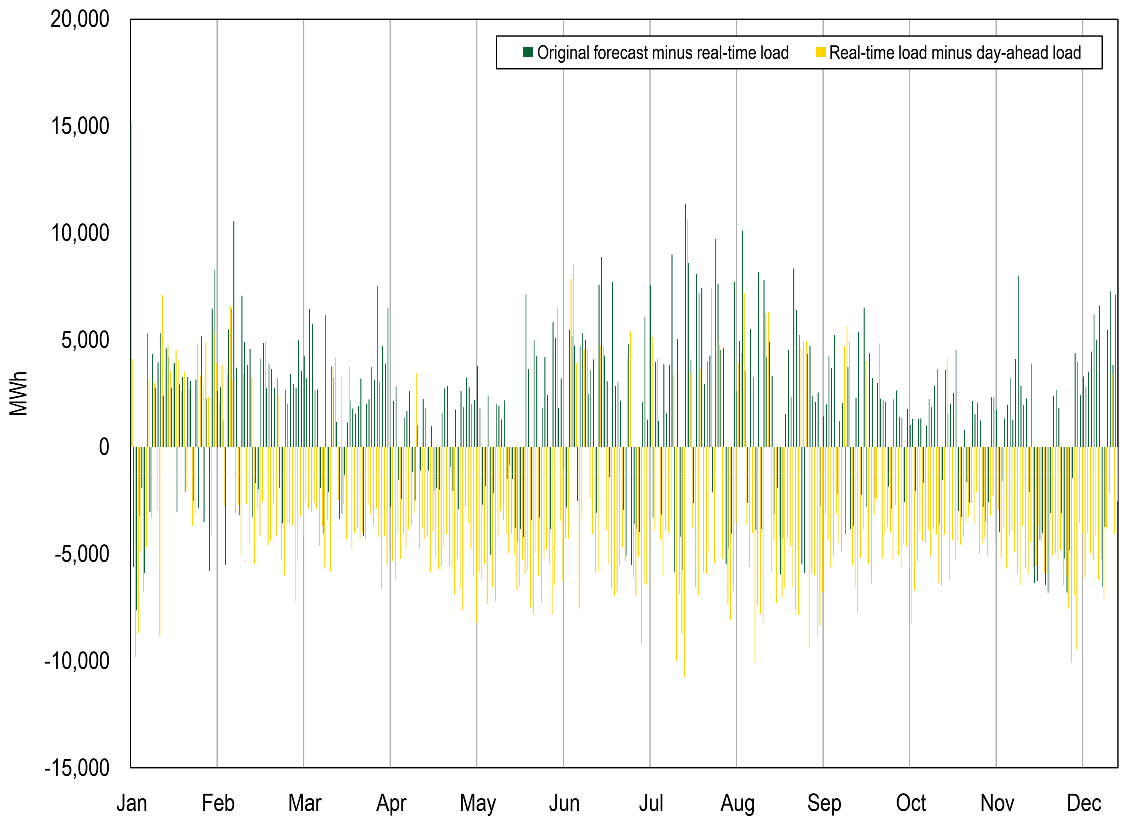
Figure 3-24 shows the average daily spot price ($/MMBtu) for various natural gas pricing points serving the PJM territory. The "Transco and Texas Eastern" group are the Transco Zone 5, Zone 6 Non New York, Zone 6 New York, and the Texas Eastern M3 prices, and the "Others" group are all other pricing points used for PJM generator offers.

Figure 3-24 Daily Natural Gas Pipeline and Zone Delivery Prices: Calendar year 2010



Forecasting load also plays a role in the level of operating reserves paid to generators. Over-forecasting or under-forecasting could result in running units uneconomically. For example, if Day-Ahead load is over-forecasted, additional generators may be scheduled in the Day-Ahead Market. If they are not needed during the operational day, generators can receive cancellation costs. If a unit has a day-ahead schedule and is started at a specific hour in order to meet real-time load, but is not needed during the operational day, they must remain online to satisfy minimum runtimes, and be made whole for the entire period. Short-term forecasts are also updated throughout the operating day. If short-term forecasts are high, and PJM instructed additional units to start that are no longer needed, they will remain on to satisfy minimum runtimes. These units are frequently combustion turbines running on natural gas or oil. When load is under-forecasted, PJM must dispatch units during the operating day that can start quickly to adjust for the unexpected load. Again, these are frequently combustion turbines running on natural gas or oil. Figure 3-25 shows the daily maximum hourly difference between the original PJM forecasted load and the actual real-time load, and the daily maximum hourly difference of the actual real-time load and day-ahead load. Original PJM forecasted load refers to the last forecast made on a day for real-time load the next operating day.

Figure 3-25 Actual Daily Loads and Forecasts: Calendar year 2010



The level of imports and exports is partially responsible for fluctuations in balancing operating reserve credits. Changes in tie flows can cause the redispatch of the system, and require generators to run out of economic merit order. Loop flow may also cause redispatch of the system, and require units to run out of economic merit order. Figure 3-26 shows hourly loop flows for some interfaces that had higher levels of loop flow activity in 2010.

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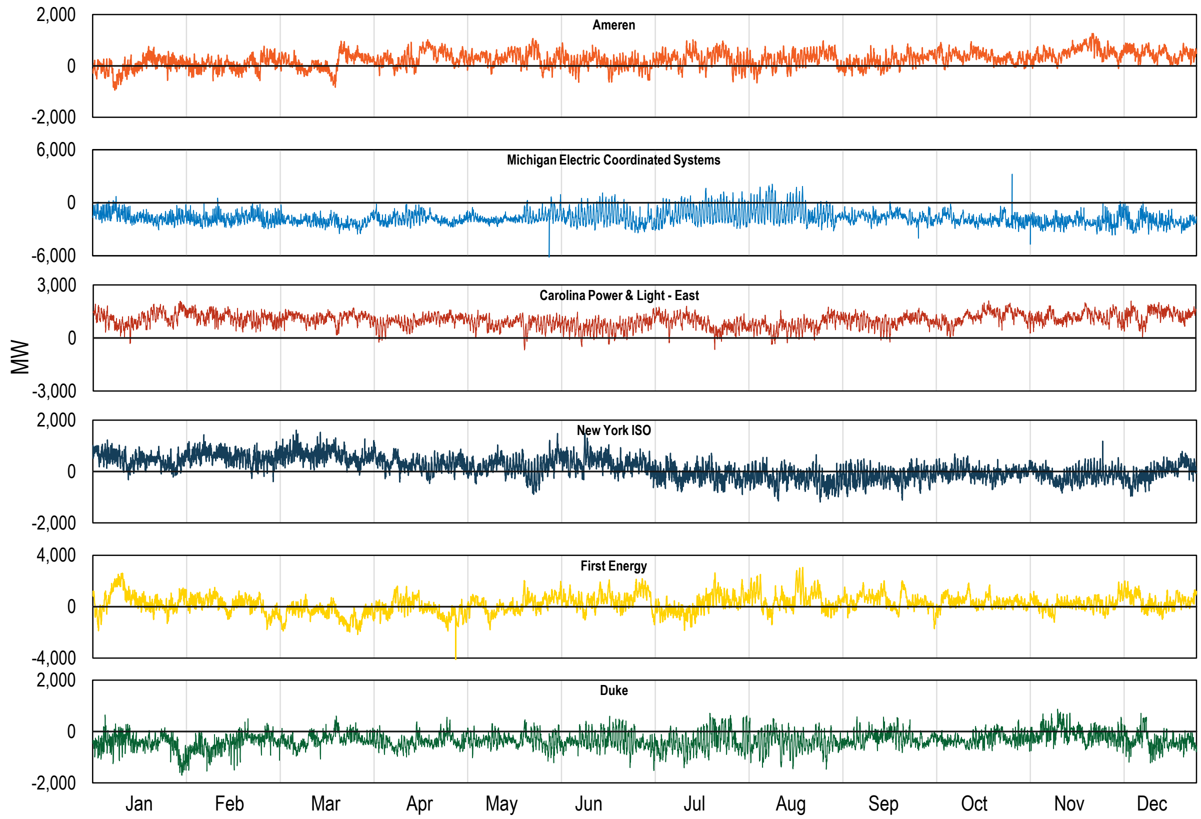
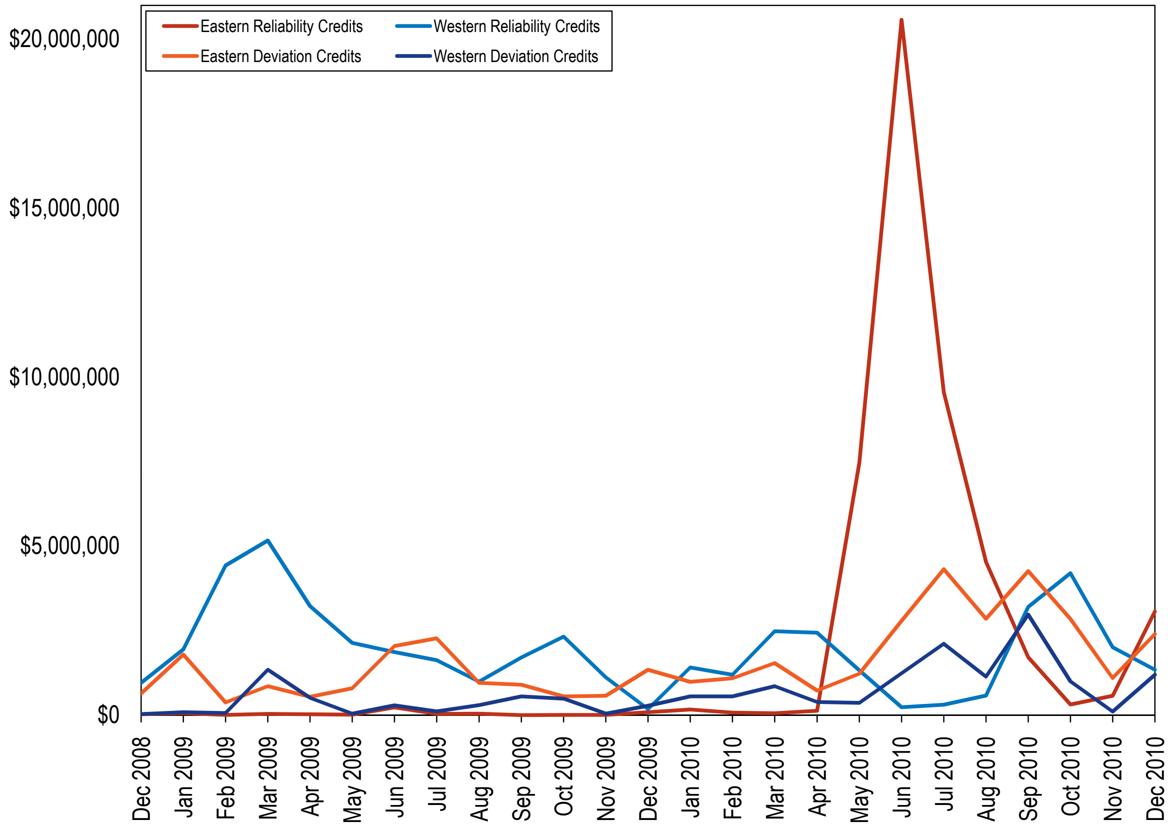
Figure 3-26 Hourly interface loop flows: Calendar year 2010



Eastern Reliability Credits

Figure 3-27 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules.

Figure 3-27 Monthly regional reliability and deviations credits: December 2008 through December 2010



One of the purposes of the new operating reserve rules was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In 2010, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In 2010, $112,691,690 of reliability charges, which included $48,187,002 of Eastern reliability credits, were allocated to participants serving real-time load and exports, which would have been charged to supply, demand, and generator deviations under the prior rules. May, June, and July accounted for $37,587,708, or 78.0 percent of the Eastern reliability credits in 2010. Figure 3-28 shows the six categories of total balancing generator credits for each month in 2010.[130]

130 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost.

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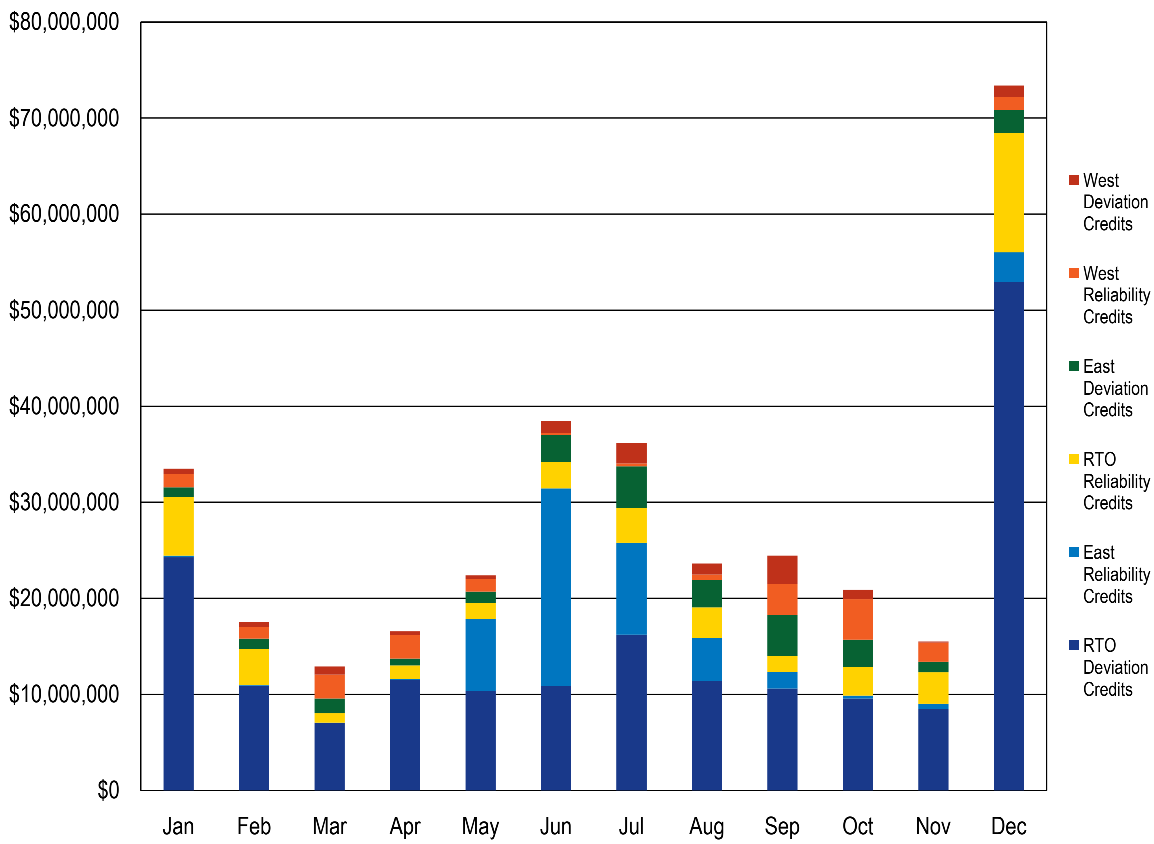
Figure 3-28 Monthly balancing operating reserve categories: Calendar year 2010



In mid May, maintenance work began on a 230kV line in the eastern region of PJM. This transmission outage, coupled with higher loads due to high temperatures in the region and the physical characteristics and operating parameters of the relevant units, required certain units to operate continuously in order to maintain system reliability. This continuous operation required significant balancing operating reserve credits to cover the offers of the units. The balancing operating reserve credits paid to these units were allocated to real-time load and exports. Table 3-110 shows the breakdown of these credits by month.

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Table 3-110 Monthly balancing operating reserve categories: Calendar year 2010

Date	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$6,119,792	$164,034	$1,408,756	$24,275,260	$980,832	$551,706
Feb	$3,730,998	$71,112	$1,192,894	$10,910,706	$1,085,923	$552,538
Mar	$981,402	$55,004	$2,480,550	$6,994,205	$1,537,198	$850,687
Apr	$1,375,806	$127,499	$2,436,919	$11,506,105	$721,388	$387,016
May	$1,650,356	$7,462,340	$1,320,404	$10,366,522	$1,225,542	$358,820
Jun	$2,765,366	$20,571,439	$229,942	$10,870,297	$2,786,236	$1,235,853
Jul	$3,649,811	$9,553,929	$305,048	$16,223,617	$4,312,914	$2,106,625
Aug	$3,157,164	$4,527,239	$576,921	$11,361,170	$2,850,328	$1,138,954
Sep	$1,706,764	$1,710,724	$3,200,795	$10,598,552	$4,260,925	$2,969,837
Oct	$2,971,034	$308,136	$4,199,921	$9,572,029	$2,842,250	$996,386
Nov	$3,259,804	$572,585	$2,002,226	$8,463,705	$1,096,254	$99,424
Dec	$12,445,498	$3,062,960	$1,338,284	$52,948,237	$2,392,579	$1,191,752
Total	$43,813,795	$48,187,002	$20,692,661	$184,090,404	$26,092,368	$12,439,598

Eastern reliability credits were a primary reason for the large increase in operating reserves in 2010. As seen in Figure 3-27, there was inconsistency in the regular pattern of operating reserves for the year. Total balancing generator credits increased 93.5 percent in 2010 to $335,511,201, up from $173,349,483 in 2009. Deviation credits increased 56.1 percent, or $80,095,925, while reliability credits increased 268.0 percent, or $82,065,794. The increase in reliability credits included a 10.3 percent decrease in western credits, a 520.4 percent increase in RTO credits, and a 9,584.1 percent increase in eastern credits. In 2009, eastern balancing generator credits were $497,589, while they were $48,187,002 in 2010. Table 3-109 shows the impact of the new rules on the allocation of these credits.

Table 3-111 Charges re-allocated to real-time load and exports: Calendar year 2009 and 2010

Credit Type	Region	2009	2010	Difference	Percentage Difference
Deviations	RTO	$125,850,691	$184,318,710	$58,468,019	46.5%
	East	$12,904,076	$25,983,926	$13,079,851	101.4%
	West	$3,968,820	$12,516,876	$8,548,056	215.4%
	Total	$142,723,586	$222,819,512	$80,095,925	56.1%
Reliability	RTO	$7,061,503	$43,812,027	$36,750,525	520.4%
	East	$497,589	$48,187,002	$47,689,413	9,584.1%
	West	$23,066,804	$20,692,661	($2,374,144)	(10.3%)
	Total	$30,625,896	$112,691,690	$82,065,794	268.0%
Total		$173,349,483	$335,511,201	$162,161,719	93.5%

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Dispatchable Transaction Credits

Dispatchable transactions, also known as “real-time with price” transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. If the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

The $22,546,342 level of dispatchable transaction credits in December 2010 was unprecedented. From January of 2000 thru November 2010, the amount of balancing transaction credits in PJM totaled $3,854,605. This amount, received over the past 131 months, represents just 17.1 percent of the balancing transaction credits received in December 2010. Figure 3-29 shows the amount of balancing transaction credits received by all participants since the year 2000.

Figure 3-29 Monthly balancing transactions credits: 2000 through 2010

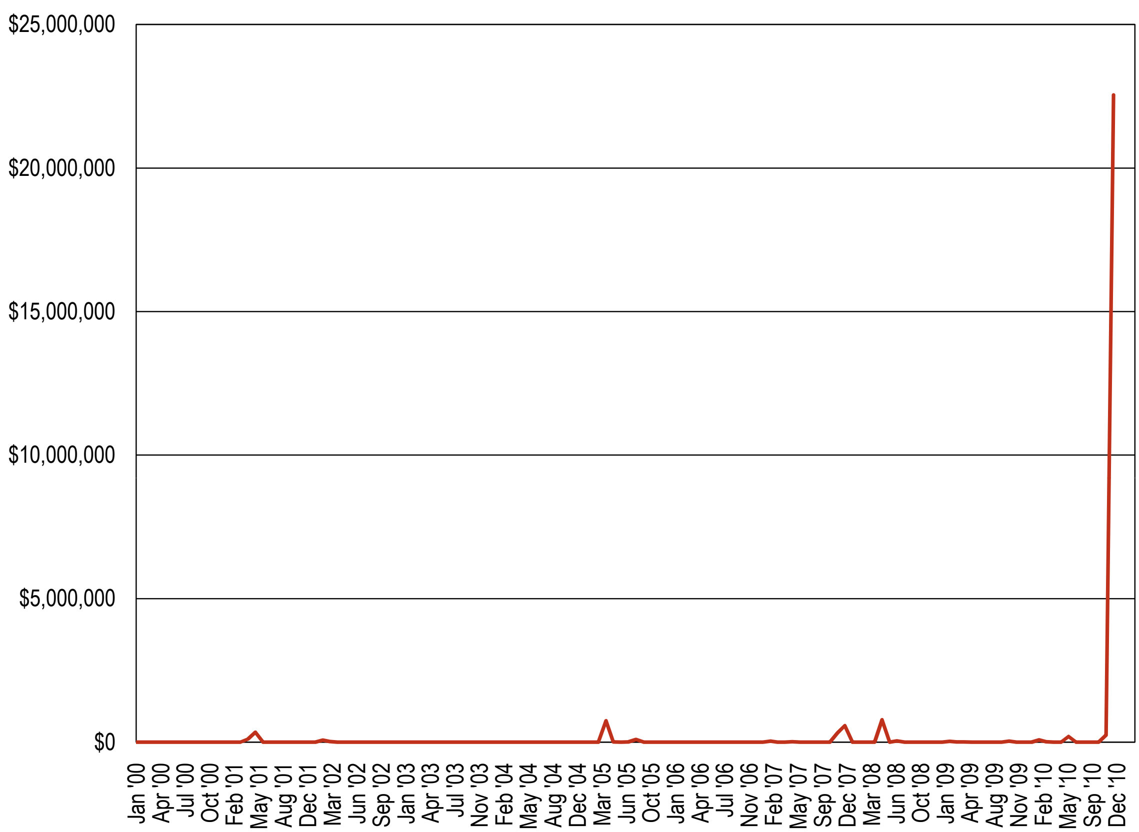

Table 3-112 shows the annual amount of balancing transaction credits since 2000. The amount of balancing transaction credits received in December of 2010 represents about 25 percent of all balancing operating reserve credits for the month, a percentage which is usually under 0.2 percent. Of this amount, 95.1 percent, or $21,438,881, was received by one market participant.

Table 3-112 Annual balancing transaction credits: 2000 through 2010

Year	Balancing Transaction Credit
2000	$0
2001	$0
2002	$98,065
2003	$0
2004	$1,146
2005	$857,550
2006	$8,826
2007	$966,213
2008	$827,633
2009	$91,293
2010	$23,092,640

The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled similar to a unit being bid with a one hour minimum run time. This will eliminate the potential for a dispatchable transaction to be loaded, and inadvertently continue to flow in subsequent hours where the transaction would not be economic, thus accruing a large amount of balancing operating reserve credits. Including dispatchable transactions in the GCA software would provide the most economic dispatch of PJM system resources.

Parameter-Limited Schedules

According to current rules, units are required to submit schedules with parameter limits consistent with the parameter limited schedule matrix for cost-based schedules and price-based parameter-limited schedules.[131] Units are placed on cost-based schedules when they are called on for transmission constraints and fail the TPS test, in which case they are then required to follow their parameter limits, as submitted with their cost-based schedules. In the case of a Maximum Generation Emergency alert, units are placed on a parameter-limited price-based schedule, in which the energy offers of their schedule may still be market based, but the operating parameters must adhere to their pre-defined parameter limits.

Price-based schedules are not required to follow any pre-defined parameter limits. This could allow participants to use price-based schedule parameters to exercise market power in order to receive

131 See PJM. "Manual 11: Energy & Ancillary Services Market Operations", Revision 45 (June 23, 2010), Section 2: Overview of the PJM Energy Markets 2.3.4.

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additional operating reserve credits. A generation owner could extend the minimum runtime of a unit prior to every weekend in order to ensure that the unit was running for PJM and receiving operating reserve credits rather than shutting down or self scheduling.

Units also offer more flexible parameters on the price-based schedule than the cost-based schedule at times. When this occurs it demonstrates that, contrary to the intent of parameter limited schedules, the unit is more flexible than reflected in its parameter limits.

The MMU also recommends that startup and notification time parameters for both cost based and price based offers be added to the list of parameters with required levels. This will prevent the submission of artificially long start and notification parameters which are designed to address economic issues with units rather than the physical issues that parameters are intended to address. Limits on these parameters will help ensure that capacity resources, paid for in RPM, meet their obligation to make legitimate and competitive offers in the Day-Ahead Market every day.

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