Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) and the Cross-State Air Pollution Rule (CSAPR) will require significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal and SO_2 and NO_X emissions. These investments may result in higher offers in the capacity market, and if units do not clear, in the retirement of some units. Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar-powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have had a significant impact on PJM wholesale markets.

Highlights

- In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross State Air Pollution Rule (CSAPR).[1] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed it to remain in effect until replaced.[2] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement to replace it.
- On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[3]
- The EPA proposed to exempt certain small reciprocating engines participating in DR programs as behind-the-meter generation from otherwise applicable run time restrictions. On May 22, 2012, the EPA proposed to increase the existing 15-hour exemption to 100 hours. EPA justified this exemption based on concerns about the impact on reliability and efficient operation of the wholesale energy markets.[4] The Market Monitor testified on this issue explaining that such concerns are unwarranted, and that, by providing a special exemption to units participating in demand response programs, the exemption would harm efficiency and reliability.[5]
- NO_x and SO_2 emission prices declined in January through September 2012, compared to 2011, while RGGI CO_2 prices increased. NOx prices declined 75.9 percent in 2012 compared to 2011, and SO_2 prices declined 55.2 percent in 2012 compared to 2011. Spot average RGGI CO_2 prices increased by 2.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances.
- The auction price of RGGI CO_2 allowances remained at the floor price of $1.93 during January through September 2012, and as of January 1, 2012, the state of New Jersey no longer participates in the RGGI program.
- Generation from wind units increased from 7,924.5 GWh in January through September 2011 to 8,944.7 GWh in January through September 2012, an increase of 12.9 percent. Generation from solar units increased from 37.9 GWh in January through September 2011 to 192.7 GWh in January through September 2012, an increase of 408.7 percent.

Conclusion

Initiatives at both the federal and state levels have an impact on the cost of energy and capacity in PJM markets. PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that could be used to incorporate renewable resource requirements to ensure that renewable resources have access to a broad market and are priced competitively so as to reflect their market value. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

1 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
2 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), *order on reh'g*, 550 F.3d 1176 (2008).
3 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
4 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Proposed Rule*, EPA Docket No. EPA-HQ-OAR-2008-0708, 77 Fed. Reg. 33812 (June 7, 2012).
5 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

Environmental Regulation

Federal Control of NO_x and SO_2 Emissions Allowances

The Clean Air Act (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.[6] The EPA has promulgated default federal rules intended to achieve this objective.

On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), which would have required specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states.[7] In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross-State Air Pollution Rule (CSAPR).[8] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed CAIR to remain in effect until replaced.[9] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement for the EPA to replace it.

Federal Environmental Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[10] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[11] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[12]

6 CAA § 110(a)(2)(D)(i)(I).
7 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (CSAPR).
8 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
9 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), ***order on reh'g***, 550 F.3d 1176 (2008).
10 Massachusetts v. EPA, 549 U.S. 497.
11 *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).
12 Coalition for Responsible Regulation, Inc., et al. v. EPA.

The EPA determined that in order to regulate greenhouse gas emissions, it would need to develop a different standard for determining major sources that require permits to emit greenhouse gases than the standards applied to other pollutants.[13] Application of the 100 or 250 tons per year (tpy) maximum annual emissions rate standards applied to other types of pollutants would have been so low compared to actual emissions as to impede the ability to construct or modify regulated facilities.[14]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[15] 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, referring to each phase as a step. In step 1, the EPA required affected facilities to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tpy CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[16] The U.S. Court of Appeals for the D.C. Circuit also upheld the Tailoring Rule in its June 26th decision.[17]

On December 23, 2010, the EPA entered a settlement agreement to resolve the requests by States and other litigants for performance standards and emission guidelines for GHG emissions for new and significantly modified sources, as provided under Sections 111(b) and (d) of the CAA. A proposed rule is expected to amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.

On July 1, 2011, the GHG Tailoring Rule was expanded under step 2 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.[18] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[19]

13 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, Docket No. EPA-HQ-OAR-2009-0517, 75 Fed. Reg. 31514 (June 3, 2010) ("GHG Tailoring Rule").
14 *Id.* at 31516.
15 *Id.*
16 *Id.* at 31516.
17 Coalition for Responsible Regulation, Inc., et al. v. EPA.
18 *Id.*
19 *Id.* at 31520.

Effective August 13, 2012, the EPA implemented step 3.[20] Step 3 leaves the step 2 thresholds unchanged. Step 3 allows permitting on a plant wide basis so that changes at a facility that do not violate the plant wide limits do not require additional permitting.[21]

On March 27, 2012, the EPA proposed an emissions standard for CO_2 from new fossil-fired electric utility generating units.[22] The proposed standard limits emissions from new units to 1,000 pounds of CO_2 per MWh. The rule excludes units currently in service or that have acquired full preconstruction permits prior to issuance of the proposal and that commence construction during the next 12 months. New units covered by the rule include only certain types of units that meet certain sales thresholds. Covered unit types include fossil fuel fired steam and combined cycle (CC) units, but exclude stationary simple cycle combustion turbine units. Covered units include only units that supply to the grid "more than one-third of [the unit's] potential annual electric output and more than 25 MW net-electrical output (MWe)."[23] EPA states that new natural gas CC units should be able to meet the proposed standard without add-on controls, based in part on data showing that nearly 95 percent of the natural gas CC units built between 2006 and 2010 would meet the standard. EPA states that new coal or petroleum coke units that incorporate technology to reduce carbon dioxide emissions, such as carbon capture and storage (CCS), could meet the standard.[24] New units that use CCS would have the option under the proposed rule to show twelve-month compliance with reference to a level calculated to consider an estimated 30-year average of CO_2 emissions, the year in which CCS would be installed, and the "best demonstrated performance of a coal-fired facility without CCS."[25]

Federal Environmental Regulation of Reciprocating Internal Combustion Engines (RICE)

The EPA has promulgated national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) under section 112 of the CAA.[26] The existing regulation allows a 15-hour run time exemption for emergency RICE participating in demand response programs, such as those administered by PJM.[27] In an amendment filed May 22, 2012, the EPA proposed to raise this exemption to 100 hours.[28] The EPA explained that it accepted arguments that an exemption is needed to allow RICE generators to contribute to reliability and efficient operations through DR programs, and specifically in order to accommodate RTO/ISO rules, such as PJM's 60-hour run time required for Limited DR.[29]

The Market Monitor filed comments in an earlier related proceeding taking the position that there is no legitimate market-based rationale to exempt RICE participating in DR programs.[30] From the perspective of PJM markets, there is no reason that the same environmental regulations should not apply to RICE without regard to whether it is participating in DR programs. RICE participating in PJM DR programs offers no special benefits to markets. The exemption would exacerbate existing problems associated with the role of Limited DR in the capacity market. Limited DR inappropriately suppresses prices in the capacity market, and PJM has identified a reliability risk in its increasing reliance on Limited DR.[31] The Market Monitor raised the same issues in testimony to the EPA on the rule at a hearing convened July 10, 2012.

20 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations*, Docket No. EPA-HQ-2009-0517, 77 Fed Reg 41051 (July 12, 2012).
21 *Id.* at 41055.
22 Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, EPA Docket No. EPA-HQ-OAR-2011-0660, 77 Fed. Reg. 22392 (April 13, 2012).
23 *Id.* at
24 *Id.* at 22405. EPA observes that PJM State Illinois currently requires CCS for new coal generation.
25 *Id.* at 22406.

26 *See, e.g.*, 40 CFR Part 63.
27 40 CFR § 63.6640(f)(1)(iii).
28 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 77 Fed. Reg. 33812 (June 7, 2012).
29 *Id.* at 33813 ("The 100 hours per year allowance would ensure that a sufficient number of hours are permitted for engines to meet independent system operator (ISO) and regional transmission organization (RTO) tariffs and other requirements for participating in various emergency demand response programs and would assist in stabilizing the grid, preventing electrical blackouts and supporting local electric system reliability.")
30 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).
31 *See* PJM Resource Adequacy Planning Department, Demand Resource Saturation Analysis at 15 (May 2010) ("Given the current interruption requirements applicable to DR, these study results indicate that the reliability value of DR saturates at an 8.5% penetration level for the RTO."), which can be accessed at: <*http://www.pjm.com/~/media/committees-groups/committees/pc/20100811/20100811-item-10-demand-response-saturation-report.ashx*>.; *see also, PJM Interconnection, L.L.C.*, 134 FERC ¶61,066 at PP 2–4 (2011) ("Under the Reliability Pricing Model (RPM) rules, PJM conducts forward auctions to secure capacity for a future delivery year, thereby allowing both existing and proposed generation, demand response and energy efficiency resources to compete to meet the region's installed capacity needs. PJM provides for demand resources to be offered into the auction in competition with generation and energy efficiency resources.[footnote omitted] These demand resources must reduce load subsequent to a request for load reduction from PJM following the declaration of a Maximum Emergency Generation action, unless the resource has already reduced load pursuant to PJM's economic load response program.[footnote omitted] The level of demand resources committed to PJM has grown with the implementation of RPM.[footnote omitted] Under the current RPM rules, demand resources can qualify for the RPM provided they: []can be interrupted during the hours of 12:00 p.m. to 8:00 p.m. (Eastern Prevailing Time) on non-Holiday weekdays during the months of June through September; []can be called upon for interruptions up to ten times during that period each year; and []can remain interrupted for up to six hours when called upon. PJM contends that as more megawatts of resources that are only available during narrowly defined peak periods are committed, fewer megawatts of more broadly available resources are committed. As a result, PJM raises a concern that commitment of fewer resources that are more broadly available increases the risk that PJM may have to call on a resource at a time, or in a manner, in which the resource is not required to respond.").

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort established 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.[32] As of January 1, 2012, the State of New Jersey no longer participates in the RGGI program.

Since September 25, 2008, a total of 14 auctions have been held for 2009–2011 compliance period allowances, and three auctions have been held for 2012–2014 compliance period allowances.

Table 7-1 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions held as of the end of calendar year 2011, and additional three auctions for the 2012-2014 compliance period held as of September 30, 2012. Prices for auctions held from January through September, 2012 for the 2012-2014 compliance period were $1.93 per allowance (equal to one ton), which is the current price floor for RGGI auctions. The average January through September 2012 spot price for a 2012-2014 compliance period allowance was $1.96 per ton. Monthly average spot prices for the 2012-2014 compliance period ranged from $2.00 per ton in February to $1.94 per ton in July.

Table 7-1 RGGI CO_2 allowance auction prices and quantities: 2009-2011 and 2012-2014 Compliance Periods[33] (See 2011 SOM, Table 7-3)

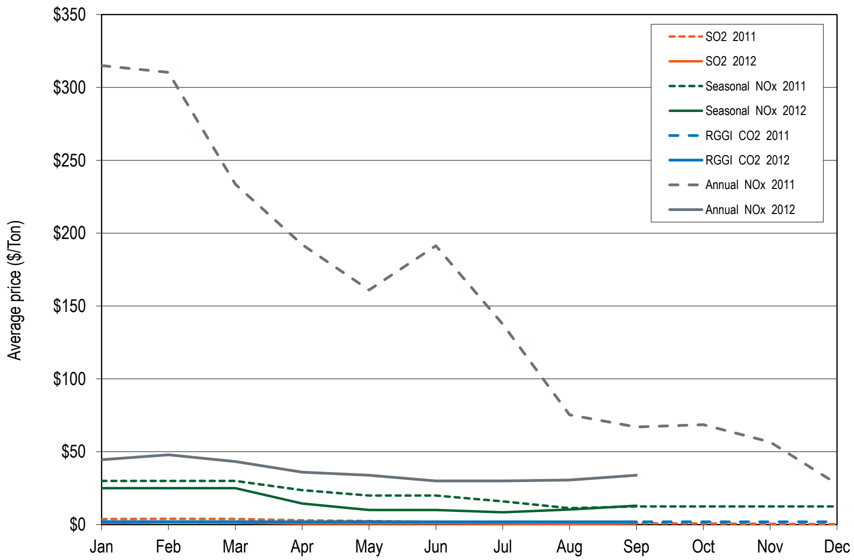
Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	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
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In January through September 2012, NOx prices were 75.9 percent lower than in 2011. SO_2 prices were 55.2 percent lower in January through September 2012 than in 2011. Figure 7-1 also shows the average, daily settled price for RGGI CO_2 allowances.

32 A similar regional initiative was organized under the Western Climate Initiative, Inc. (WCI). The California Air Resources Board (ARB) has organized a cap and trade program that it will implement in 2012. That program will be coordinated with other U.S. states and Canadian provinces participating in WCI. One such participant, Quebec, adopted cap and trade rules on December 15, 2011. British Columbia, Manitoba and Ontario are also expected to coordinate cap and trade policies through WCI.

33 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed October 16, 2012).

Figure 7-1 Spot monthly average emission price comparison: 2011 and January through September 2012 (See 2011 SOM, Figure 7-1)



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utility 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 2012, Delaware, Illinois, Michigan, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 1.50 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. Indiana and West Virginia have enacted renewable portfolio standards that have yet to take effect by 2012. Indiana's renewable portfolio standard will take effect in 2013, and West Virginia's will take effect in 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2022. As shown in Table 7-2, New Jersey will require 22.5 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).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or 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 per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits per MWh of electricity generated by "renewable energy resources", which include resources such as wind, solar, and run-of-river hydroelectric. Pennsylvania allows both Tier I resources and non-traditional Tier II resources, such as waste coal, municipal solid waste, integrated gasification combined cycle, and large-scale hydro.[34] 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 wholesale energy markets.

34 Pennsylvania Tier I resources include solar water heat, solar space heat, solar thermal, solar thermal process heat, solar photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal, fuel cells, CHP/cogeneration, and anaerobic digestion.

Table 7-2 Renewable standards of PJM jurisdictions to 2022[35,36] (See 2011 SOM, Table 7-4)

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%
Michigan	<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%
North Carolina	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%
Ohio	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%
Pennsylvania	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%
Washington, D.C.	7.50%	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%
West Virginia				10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	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 7-2 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 2022.[37] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2012, Washington D.C. had the most stringent standard in PJM, requiring 0.5 percent of load to be served by solar resources. As Table 7-3 shows, by 2022, New Jersey will have the most stringent standard, requiring 3.56 percent of load to be served by solar. In 2012, New Jersey passed Senate Bill 1925 which increased the percentage of load in 2014 that must be served by solar resources in New Jersey from 1.99 percent to 2.05 percent.

Table 7-3 Solar renewable standards of PJM jurisdictions to 2022 (See 2011 SOM Table 7-5)

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%	2.00%
Michigan	No Solar Standard										
New Jersey	0.39%	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%
North Carolina	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%
Pennsylvania	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%
West Virginia	No Solar Standard										

35 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
36 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.
37 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies.

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.

Table 7-4 shows generation by jurisdiction and renewable resource type in January through June 2012. 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 8,944.7 GWh of 15,486.7 Tier I GWh, or 57.8 percent, in the PJM footprint. As shown in Table 7-4, 31,734.7 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 48.8 percent.

Table 7-4 Renewable generation by jurisdiction and renewable resource type (GWh): January through September 2012 (See 2011 SOM, Table 7-8)

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	46.6	0.0	0.0	0.0	0.0	0.0	0.0	46.6	93.2
Illinois	104.3	0.0	0.0	0.0	0.0	0.0	3,848.5	3,952.8	3,952.8
Indiana	0.0	0.0	27.1	0.0	0.0	0.0	1,798.7	1,825.8	1,825.8
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	66.9	0.0	1,240.5	6.1	446.0	0.0	214.1	1,527.6	1,973.6
Michigan	22.0	0.0	42.0	0.0	0.0	0.0	0.0	64.0	64.0
New Jersey	285.2	328.2	8.4	173.8	1,039.7	0.0	6.1	473.6	1,841.4
North Carolina	0.0	0.0	298.3	0.0	0.0	0.0	0.0	298.3	298.3
Ohio	162.0	0.0	292.2	1.3	0.0	0.0	665.0	1,120.5	1,120.5
Pennsylvania	671.8	1,142.8	1,465.5	3.3	1,294.5	6,467.4	1,399.6	3,540.2	12,445.0
Tennessee	0.0	0.0	0.0	0.0	234.9	0.0	0.0	0.0	234.9
Virginia	311.1	3,626.0	541.4	8.1	879.0	0.0	0.0	860.6	5,365.6
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	8.1	0.0	755.9	0.0	0.0	789.5	1,012.7	1,776.7	2,566.2
Total	1,678.2	5,097.0	4,671.2	192.7	3,894.1	7,256.9	8,944.7	15,486.7	31,734.7

Table 7-5 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[38] The definition of renewables includes coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 27.3 percent of the total renewable capacity. New Jersey has the largest amount of solar capacity in PJM, 185.1 MW, or 87.6 percent of the total solar capacity. Wind resources are located primarily in the western PJM states of Illinois and Indiana, which include 3,307.6 MW, or 55.4 percent of the total wind capacity.

38 Defined fuel types result in designation as renewable as does the registration of a generator in the PJM GATS. The data include only units that are interconnected to the PJM system.

Table 7-5 PJM renewable capacity by jurisdiction (MW), on September 30, 2012 (See 2011 SOM, Table 7-9)

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,857.2
Illinois	0.0	72.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,254.4	2,347.3
Indiana	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	185.0	185.0
Maryland	60.0	28.7	129.0	31.9	0.0	581.0	16.1	109.0	0.0	120.0	1,075.8
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	162.1	191.1	0.0	7.5	851.2
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	5,688.5	45.9	125.5	225.0	0.0	178.0	1.1	0.0	0.0	500.0	6,764.0
Pennsylvania	35.0	210.6	2,366.7	0.0	1,505.0	682.3	3.0	247.0	1,422.2	1,185.0	7,656.7
Tennessee	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	121.6	80.0	16.9	3,588.0	457.1	2.7	215.0	0.0	0.0	4,481.3
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	14,322.5	580.0	4,986.5	287.6	5,493.0	2,481.5	185.1	926.1	1,552.2	5,968.6	36,783.1

Table 7-6 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not interconnected to PJM. This includes solar capacity of 1,036.4 MW, of which 695.0 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 7-6 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. The capacity that is not interconnected to PJM includes both behind the meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Table 7-6 Renewable capacity by jurisdiction, non-PJM units registered in GATS[39,40] (MW), on September 30, 2012 (See 2011 SOM, Table 7-10)

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	29.0	0.0	0.1	29.1
Illinois	0.0	6.6	100.4	0.0	0.0	0.0	31.3	0.0	302.5	440.8
Indiana	0.0	0.0	44.0	0.0	679.1	0.0	1.0	0.0	0.0	724.1
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.5	88.0	0.0	706.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	58.2	0.0	0.3	65.5
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
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	39.9	0.0	0.0	23.3	695.0	0.0	0.4	758.6
New York	0.0	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0
Ohio	0.0	1.0	38.1	52.6	67.0	1.0	49.5	109.3	15.9	334.5
Pennsylvania	0.0	5.5	10.0	5.6	86.2	0.3	156.7	0.0	3.2	267.5
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.5	318.1	0.0	351.0
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	1.2
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	5.3
Total	655.0	140.3	271.9	58.2	832.4	24.6	1,036.4	560.0	468.5	4,047.2

39 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.
40 See "Renewable Generators Registered in GATS" <*https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=501*> (Accessed October 02, 2012).

Emissions Controlled Capacity and Renewables in PJM Markets

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 78,962.7 MW of coal steam capacity in PJM, 53,542.2 MW of capacity, 67.8 percent, has some form of FGD technology. Table 7-7 shows emission controls by unit type, of fossil fuel units in PJM.

Table 7-7 SO_2 emission controls (FGD) by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-11)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	53,542.2	25,420.5	78,962.7	67.8%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,446.8	31,446.8	0.0%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	0.0	8,912.6	8,912.6	0.0%
Total	53,542.2	93,177.8	146,720.0	36.5%

NO_x emission control 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, 132,553.6 MW, or 90.3 percent, of 146,720.0 MW of capacity in PJM, have emission controls for NO_x (Table 7-8). While most units in PJM have NO_x emission controls, many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards such as MATS. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 7-8 NO_x emission controls by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-12)

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,061.3	2,901.4	78,962.7	96.3%
Combined Cycle	26,286.1	746.0	27,032.1	97.2%
Combustion Turbine	25,835.4	5,611.4	31,446.8	82.2%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	4,370.8	4,541.8	8,912.6	49.0%
Total	132,553.6	14,166.4	146,720.0	90.3%

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, 78,962.7 MW, 97.4 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-9 shows particulate emission controls by unit type of fossil fuel units in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which many coal steam units have not installed.

Table 7-9 Particulate emission controls by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-13)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	76,934.9	2,027.8	78,962.7	97.4%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,446.8	31,446.8	0.0%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	3,047.0	5,865.6	8,912.6	34.2%
Total	79,981.9	66,738.1	146,720.0	54.5%

Wind Units

Table 7-10 shows the capacity factor of wind units in PJM. In January through September 2012, the capacity factor of wind units in PJM was 25.2 percent. Wind units that were capacity resources had a capacity factor of 25.2 percent and an installed capacity of 4,738 MW. Wind units that were classified as energy only had a capacity factor of 21.6 percent and an installed capacity of 1,030 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. The capacity factors in Table 7-10 are calculated based on the full nameplate capacity and on the amount of derated capacity (cleared MW).

Table 7-10 Capacity[41] factor[42] of wind units in PJM, January through September 2012 (See 2011 SOM, Table 7-14)

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	21.6%	NA	1,030
Capacity Resource	25.7%	147.5%	4,738
All Units	25.2%	147.5%	5,769

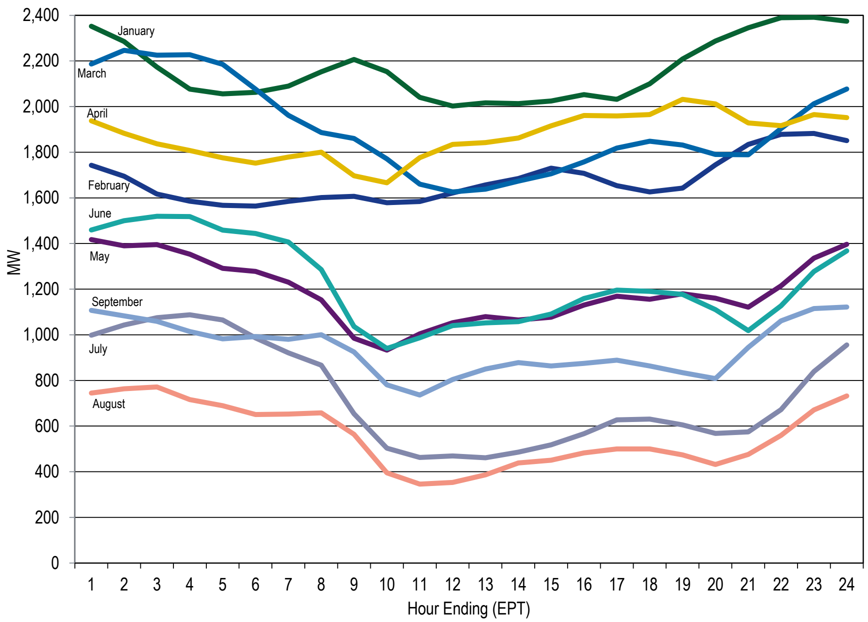
Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-11 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 819.3 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 4,425 separate five minute intervals, or 5.6 percent of all intervals. On average, 2,443.1 MW of wind were offered daily. Overall, wind units were marginal in 12,093 separate five minute intervals, or 15.4 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out of market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-11 Wind resources in real time offering at a negative price in PJM, January through September 2012 (See 2011 SOM, Table 7-15)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	819.3	4,425	5.6%
All Wind	2,443.1	12,093	15.4%

Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in January, and lowest in August. The highest average hour, 2,391.2 MW, occurred in January, and the lowest average hour, 344.5 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 7-2 Average hourly real-time generation of wind units in PJM: January through September 2012 (See 2011 SOM, Figure 7-2)



41 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource.
42 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

Table 7-12 shows the generation and capacity factor of wind units in each month of 2011 and January through September 2012. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 41.9 percent in January, and the lowest capacity factor was 10.1 percent in August. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2012, and are included in this analysis as they were added.

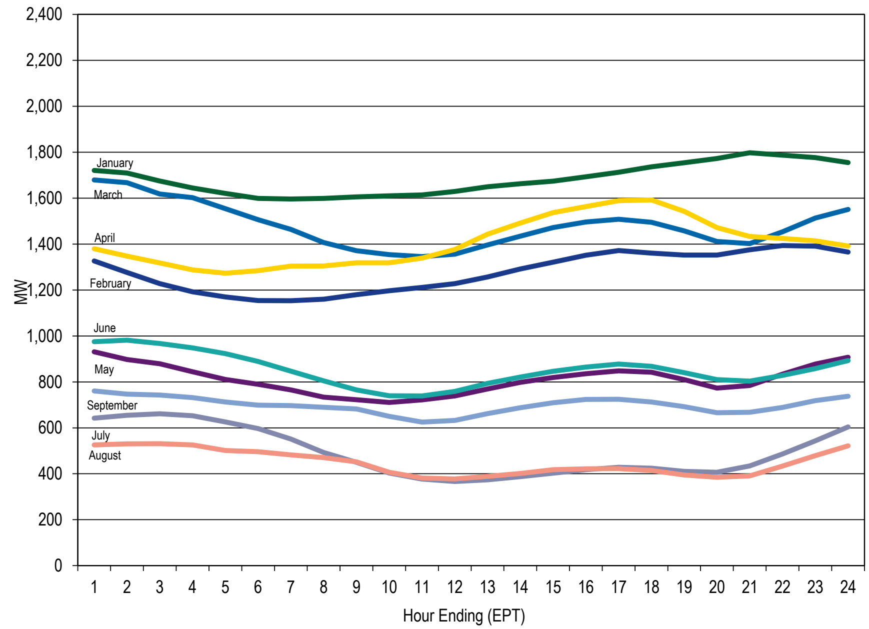
Table 7-12 Capacity factor of wind units in PJM by month, 2011 and 2012[43] (See 2011 SOM, Table 7-16)

	2011		2012	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	950,441.9	29.7%	1,608,349.8	41.9%
February	1,237,813.0	42.4%	1,167,011.9	32.4%
March	1,175,567.0	36.4%	1,416,278.0	35.6%
April	1,399,217.0	44.7%	1,345,643.3	34.7%
May	893,485.1	27.6%	885,583.1	21.6%
June	713,713.8	22.0%	882,597.0	22.2%
July	416,695.8	12.2%	546,676.9	13.3%
August	447,575.2	13.1%	415,544.3	10.1%
September	689,962.6	20.9%	677,001.8	17.0%
October	946,406.3	26.3%		
November	1,507,766.4	41.8%		
December	1,182,421.6	31.5%		
Annual	11,561,065.8	28.9%	8,944,685.9	25.2%

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 7-3 shows the average hourly day-ahead time generation of wind units in PJM for January through September, 2012.

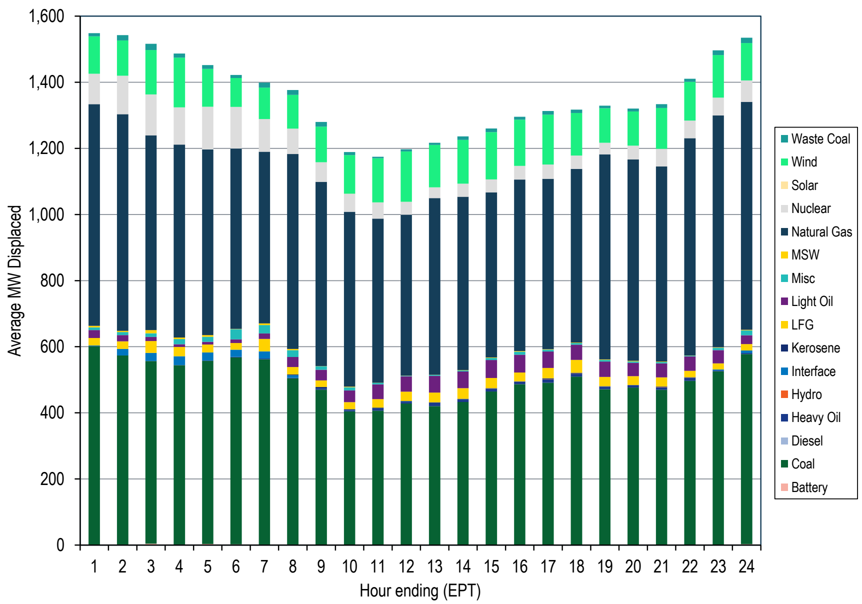
43 Capacity factor shown in Table 7-12 is based on all hours in January through September, 2012.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: January through September 2012 (See 2011 SOM, Figure 7-3)



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 7-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation during January through September 2012. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2012. Wind output varies daily, and on average is about 347 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. This means that wind was already on the margin and that there was no displacement of other fuel types for those hours.

Figure 7-4 Marginal fuel at time of wind generation in PJM: January through September 2012 (See 2011 SOM, Figure 7-4)



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 7-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in August. The highest average hour, 109.2 MW, occurred in August. In general, solar generation in PJM is highest during the hours of 1100 through 1300 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: January through September 2012 (See 2011 SOM, Figure 7-5)