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) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Cross-State Air Pollution Rule (CSAPR), would if implemented, potentially also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's High Electric Demand Day (HEDD) Rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when 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.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[2] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources).

  The MATS rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter.

- **Cross-State Air Pollution Rule.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[3] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[4] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

- **Greenhouse Gas Emissions Rule.** On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The

1 For quantification of the impact on new entrant wind and solar installations, see the *2012 State of the Market Report for PJM*, Section 6, "Net Revenue."

2 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

3 See EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

4 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708 (January 14, 2013).

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.[5]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule,[6] which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[7] New Jersey's HEDD rule is implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_X emission rates.

  The HEDD rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2012 for the 2012-2014 compliance period were $1.93 per ton throughout the year, the price floor for 2012.

5 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
6 N.J.A.C. § 7:27–19.
7 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Emissions Controls in PJM Markets

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. At the end of 2012, 68.2 percent of coal steam MW's had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control. NO_x emission controlling technology is used by nearly all fossil fuel unit types, and 90.9 percent of fossil fuel fired capacity in PJM has NO_x emission control technology in place.

State 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 2012, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from a requirement that renewables serve 1.5 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.

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 which is greater than the marginal cost of producing 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 marginal cost of producing minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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 formally recognized as part of 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 incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), 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.[8,9] In recent years, the EPA has been actively defining 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 cost to build and operate generating units in PJM which in turn affect wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the CAA affects generating plants that rely on draw water from jurisdictional water bodies.

Control of Mercury and Other 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.

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). 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. Section 112 of the CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing 5 sources for source categories with less than 30 sources).

On December 16, 2011, the EPA signed its Mercury and Air Toxics Standards rule (MATS) rule, promulgated pursuant to CAA § 112, and its Utility New Source Performance Standards (NSPS), promulgated pursuant to CAA § 111.[10]

The MATS rule applies the MACT to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. The rule establishes a compliance deadline of April 16, 2015, near the end of the 2014/2015 RPM Delivery Year.[11] A source may obtain an extension for up to one additional year where necessary for the installation of controls.

The MATS rule sets emissions limits separately for each pollutant. Only filterable particulate matter (PM), rather than both filterable and condensable PM, is considered for compliance with emissions limits. Work practice standards are included for startup and shutdown periods. The rule extends the period of averaging for Hg from 30 to 90 days, but tightens the applicable standards for sources using averaging. The rule requires either

8 42 U.S.C. § 7401 et seq. (2000),

9 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.

10 *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket Nos. EPA-HQ-OAR-2009-0234 (MATS) & EPA-HQ-OAR-2011-0044 (Utility NSPS), 77 Fed. Reg. 9304 (February 16, 2012).

11 *Id.* at 9465.

continuous monitoring or periodic quarterly testing to demonstrate continuous compliance. The revised rule establishes seven categories of covered units.

The Utility NSPS rule requires new coal- and oil-fired electric utility steam generating units constructed after May 3, 2012, to comply with amended emission standards for SO_2, NO_X and filterable PM.

On November 16, 2012, EPA proposed to change the startup and shutdown provisions related to the PM standard and definitional and monitoring provisions in the Utility NSPS under MATS.[12] MATS rules for existing units were unaffected.

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.[13] The EPA has sought to promulgate default Federal rules to achieve this objective.

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 as the rules regulating transport are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010.[14] A final rule for secondary NAAQS for NO_x and SO_x became effective June 4, 2012.[15] A proposed rule for primary and secondary NAAQS for Ozone (O_3) is expected in May 2013.[16] On February 17, 2013, EPA sent letters to state governments outlining the areas it is considering designating as nonattainment for the 2010 primary standard for sulfur dioxide. Some of these areas are in PJM states, including Pennsylvania, Ohio, Kentucky, Tennessee, Indiana and Illinois. Designation of a nonattainment area in the PJM region could impact the attainment status of generating units within PJM, and require investment in additional controls for SO_2.

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[17] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the EPA continues to process under CAIR a number of pending requests, including State Implementation Plans (SIPs), that were originally submitted under CSAPR.

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[18] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively “RICE Rules”).[19]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[20] The proposed rule allowed owners and operators of emergency stationary internal

12 *Reconsideration of Certain New Source and Startup/Shutdown Issues: National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket Nos. EPA-HQ-OAR-2009-0234 (MATS) & EPA-HQ-OAR-2011-0044 (Utility NSPS), 77 Fed. Reg. 71323, 71325 (November 30, 2012).

13 CAA § 110(a)(2)(D)(i)(I).

14 See 40 CFR Parts 50, 53, and 58.

15 *Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Sulfur*, 77 Fed. Reg. 20218 (April 3, 2012).

16 See EPA Docket No. EPA-HQ-OAR-2008-0699.

17 See EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

18 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708 (January 14, 2013) (“Final NESHAP RICE Rule”).

19 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295 , codified at 40 CFR Part 60 Subpart JJJJ.

20 *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.

combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The Market Monitoring Unit objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand side resources in the PJM markets nor for reliability.[21] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[22] Otherwise a 15-hour exception applies.[23] The exempted emergency demand response programs include Demand Resources in RPM.

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.[24] 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.[25] 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.[26]

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.[27] 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.[28]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[29] 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.[30] The U.S. Court of Appeals for the D.C. Circuit also upheld the Tailoring Rule in its June 26th decision.[31]

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.[32] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[33]

Effective August 13, 2012, the EPA implemented step 3.[34] 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.[35]

21 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

22 Final NESHAP RICE Rule at 31–24.

23 *Id.* at 31.

24 Massachusetts v. EPA, 549 U.S. 497.

25 *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).

26 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

27 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").

28 *Id.* at 31516.

29 *Id.*.

30 *Id.* at 31516.

31 Coalition for Responsible Regulation, Inc., et al. v. EPA.

32 *Id.*

33 *Id.* at 31520.

34 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).

35 *Id.* at 41055.

On March 27, 2012, the EPA proposed an emissions standard for CO_2 from new fossil-fired electric utility generating units.[36] 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)."[37] 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.[38] 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."[39]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the Clean Water Act (CWA).[40] A settlement in a Federal Court, as modified, obligates the EPA to issue a final rule no later than June 27, 2013.[41]

This rule seeks to protect aquatic life from being trapped on the screens that cover water intake structures over the cooling system at a generating facility (impingement) or drawn into the cooling system (entrainment).

The EPA would study facilities that draw 125 MGD or more of water to evaluate, in a process open to the public, the need for site specific controls to prevent entrainment, and, if there is such a need, the EPA would determine those controls.

The rule would require new or upgraded units to include or add technology equivalent to closed cycle cooling.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule,[42] which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[43]

New Jersey's HEDD rule will be implemented in two phases. For the first phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol)

36 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).

37 *Id.* at

38 *Id.* at 22392. EPA observes that PJM State Illinois, currently requires CCS for new coal generation.

39 *Id.* at 22406.

40 EPA, *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).

41 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010, *modified*, Second Amendment to Settlement Agreement among the Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, dated July 17, 2012.

42 N.J.A.C. § 7:27-19.

43 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include: installation of emissions controls at the HEDD unit or a non-HEDD unit; run-time limitations; commitment to use natural gas on HEDD units if dual fueled; implementation of energy efficiency, demand response or renewable energy measures; or other approved measures. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports. The second phase involves performance standards applicable after May 1, 2015. New, reconstructed or modified turbines must comply with State of the Art (SOTA), Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT) standards, as applicable. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates. On February 8, 2012, the Governor of New Jersey announced that no extension beyond the 2015 deadline would be granted.[44]

Table 7-1 shows the HEDD emissions limits applicable to each unit type.

Table 7-1 HEDD maximum NO_x emission rates[45]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI)[46] is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[47]

Under RGGI, each state has its own CO_2 Budget Trading Program implemented through state regulations based on a common set of rules that allow the nine 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.

A total of 14 auctions were held for 2009–2011 compliance period allowances, and 16 auctions have been held for 2012–2014 compliance period allowances.

Table 7-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional 16 auctions held only for the 2012-2014 compliance period held as of December 31, 2012. Prices for auctions held in 2012 for the 2012-2014 compliance period were $1.93 per allowance (equal to one ton of CO_2), which is the current price floor for RGGI auctions. The average 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 through November.

44 State of New Jersey, Press Release, "Governor Christie Continues Commitment to Clean Air with Aggressive Deadline for Power Plants to Reduce Emissions."

45 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

46 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

47 A similar regional initiative has organized under the Western Climate Initiative, Inc. (WCI). The first mover is the California Air Resources Board (ARB), which has organized a cap and trade program that was implemented 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.

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In 2012, NO_x prices were 75.6 percent lower than in 2011. SO_2 prices were 57.6 percent lower in 2012 than in 2011. Figure 7-1 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 and Maryland.

Figure 7-1 Spot monthly average emission price comparison: 2011 and 2012

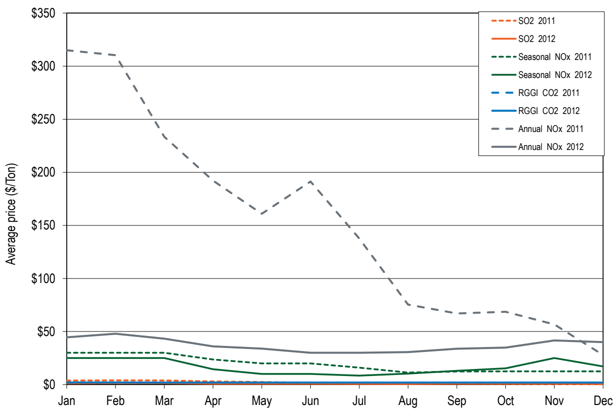


Table 7-2 RGGI CO_2 allowance auction prices and quantities (tons): 2009-2011 and 2012-2014 Compliance Periods[48]

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
December 5, 2012	$1.93	37,563,083	19,774,000

48 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed January 21, 2013).

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 December 31, 2012, Delaware, Illinois, 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.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2021. As shown in Table 7-3, New Jersey will require 22.5 percent of load to be served by renewable resources in 2022, 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 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 formally 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.

Table 7-3 Renewable standards of PJM jurisdictions to 2022[49,50]

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	8.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
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%

Table 7-4 Solar renewable standards of PJM jurisdictions to 2022

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%	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.10%	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	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										

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 7-3 but must be met by solar RECs (SRECs) 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.[51] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2012, the most stringent standard in PJM was Delaware's, requiring 0.40 percent of load to be served by solar resources. As Table 7-4 shows, by 2022, the most stringent standard will be New Jersey's which requires at least 3.56 percent of load to be served by solar.

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

50 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.

51 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. The standards shown in Table 7-5 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 4.50 percent in 2012 and escalating to 14.25 percent in 2022. Maryland, New Jersey, Pennsylvania[52], 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 2,928 GWh of solar generation by 2022 (Table 7-5).

Table 7-6 Renewable alternative compliance payments in PJM jurisdictions: 2012

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	Voluntary standard		
Illinois	$2.16		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$658.00
North Carolina	No specific penalties		
Ohio	$45.00		$350.00
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 7-5 Additional renewable standards of PJM jurisdictions to 2021

Jurisdiction		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	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%	0.00%
New Jersey	Solar Carve-Out (in GWh)	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928
North Carolina	Swine Waste	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	170	700	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%

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 $658 per MWh.[53] 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 7-6 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 7-7 shows generation by jurisdiction and renewable resource type in 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 12,633.6 GWh of 42,531.6 Tier I GWh, or 59.6 percent, in the PJM footprint. As shown in Table 7-7, 42,531.6 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 49.8 percent.

52 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.

53 See "New Jersey Renewables Portfolio Standard" <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed March 7, 2013).

Table 7-7 Renewable generation by jurisdiction and renewable resource type (GWh): 2012

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	61.4	0.0	0.0	0.0	0.0	0.0	0.0	61.4	122.8
Illinois	142.8	0.0	0.0	0.0	0.0	0.0	5,282.4	5,425.2	5,425.2
Indiana	0.0	0.0	34.7	0.0	0.0	0.0	2,638.6	2,673.3	2,673.3
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	93.9	0.0	1,653.5	10.8	604.8	0.0	299.3	2,057.5	2,662.3
Michigan	28.8	0.0	52.7	0.0	0.0	0.0	0.0	81.5	81.5
New Jersey	369.9	443.3	10.9	206.0	1,384.6	0.0	8.5	595.2	2,423.2
North Carolina	0.0	0.0	333.9	0.0	0.0	0.0	0.0	333.9	333.9
Ohio	236.1	0.0	400.2	1.5	0.0	0.0	960.5	1,598.3	1,598.3
Pennsylvania	875.0	1,538.6	1,971.2	5.5	1,718.6	8,545.3	2,069.9	4,921.6	16,724.2
Tennessee	0.0	0.0	0.0	0.0	317.9	0.0	0.0	0.0	317.9
Virginia	404.3	4,562.5	626.5	9.7	1,151.8	0.0	0.0	1,040.5	6,754.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	10.5	0.0	1,021.8	0.0	0.0	1,068.9	1,374.4	2,406.7	3,475.6
Total	2,222.8	6,544.5	6,105.3	233.5	5,177.6	9,614.3	12,633.6	21,195.2	42,531.6

Table 7-8 PJM renewable capacity by jurisdiction (MW), on December 31, 2012

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	2,454.4	2,547.3
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,253.2	1,261.4
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	40.1	109.0	0.0	120.0	1,099.8
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	186.8	191.1	0.0	7.5	875.9
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	4,706.5	45.9	125.5	37.0	0.0	178.0	1.1	0.0	0.0	500.0	5,594.0
Pennsylvania	35.0	222.0	2,366.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,863.7
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	13,340.5	591.4	4,986.5	99.6	5,493.0	2,481.5	248.8	926.1	1,552.2	6,549.2	36,268.8

Table 7-8 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[54] This capacity 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. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 27.6 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 188.8 MW, or 75.1 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,707.6 MW, or 56.6 percent of the total wind capacity.

Table 7-9 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not resources offered into PJM wholesale markets. This includes solar capacity of 1,110.6 MW of which 741.8 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 7-9 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.

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

Table 7-9 Renewable capacity by jurisdiction, non-PJM units registered in GATS[55,56] (MW), on December 31, 2012

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	30.2	0.0	0.1	30.3
Illinois	0.0	6.6	100.4	0.0	0.0	0.0	34.4	0.0	302.5	443.9
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.0	0.0	0.0	729.9
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	706.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	63.6	0.0	0.3	70.9
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	741.8	0.0	0.4	805.4
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	40.3	52.6	67.0	1.0	64.4	109.3	15.9	351.5
Pennsylvania	0.0	5.5	16.2	4.8	87.0	0.3	158.7	0.0	144.0	416.5
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.6	318.1	0.0	351.1
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	1.3
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	5.9	0.0	0.0	5.9
Total	655.0	140.3	285.9	57.4	833.1	24.6	1,110.6	560.0	609.3	4,276.2

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

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

Table 7-10 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2012

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	53,698.0	25,086.8	78,784.8	68.2%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,445.4	31,445.4	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	0.0	8,746.6	8,746.6	0.0%
Total	53,698.0	92,673.7	146,371.7	36.7%

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 78,784.8 MW of coal steam capacity in PJM, 53,698.0 MW of capacity, 68.2 percent, has some form of FGD technology. Table 7-10 shows emission controls by unit type, of fossil fuel units in PJM.[57]

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, 133,117.1 MW, or 90.9 percent, of 146,371.7 MW of capacity in PJM, have emission controls for NO_x. Table 7-11 shows NO_X emission controls by unit type of fossil fuel units in PJM. 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. 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 7-11 NO_x emission controls by unit type (MW), as of December 31, 2012

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,027.2	2,757.6	78,784.8	96.5%
Combined Cycle	26,831.1	201.0	27,032.1	99.3%
Combustion Turbine	25,888.0	5,557.4	31,445.4	82.3%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	4,370.8	4,375.8	8,746.6	50.0%
Total	133,117.1	13,254.6	146,371.7	90.9%

55 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.

56 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 01, 2013).

57 See "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed January 15, 2013)

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, 76,900.8 MW, 97.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-12 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 7-12 Particulate emission controls by unit type (MW), as of December 31, 2012

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	76,900.8	1,884.0	78,784.8	97.6%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,445.4	31,445.4	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	3,047.0	5,699.6	8,746.6	34.8%
Total	79,947.8	66,423.9	146,371.7	54.6%

Wind Units

Table 7-13 shows the capacity factor of wind units in PJM. In 2012, the capacity factor of wind units in PJM was 25.7 percent. Wind units that were capacity resources had a capacity factor of 26.6 percent and an installed capacity of 4,738 MW. Wind units that were classified as energy only had a capacity factor of 21.3 percent and an installed capacity of 1,811 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.[58]

Table 7-13 Capacity[59] factor[60] of wind units in PJM: 2012

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	21.3%	NA	1,811
Capacity Resource	26.6%	147.5%	4,738
All Units	25.7%	147.5%	6,549

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-14 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 872.4 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 4,971 separate five minute intervals, or 4.7 percent of all intervals. On average, 2,566.2 MW of wind were offered daily. Overall, wind units were marginal in 16,342 separate five minute intervals, or 15.5 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they provide 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 marginal cost minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-14 Wind resources in real time offering at a negative price in PJM: 2012

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	872.4	4,971	4.7%
All Wind	2,566.2	16,342	15.5%

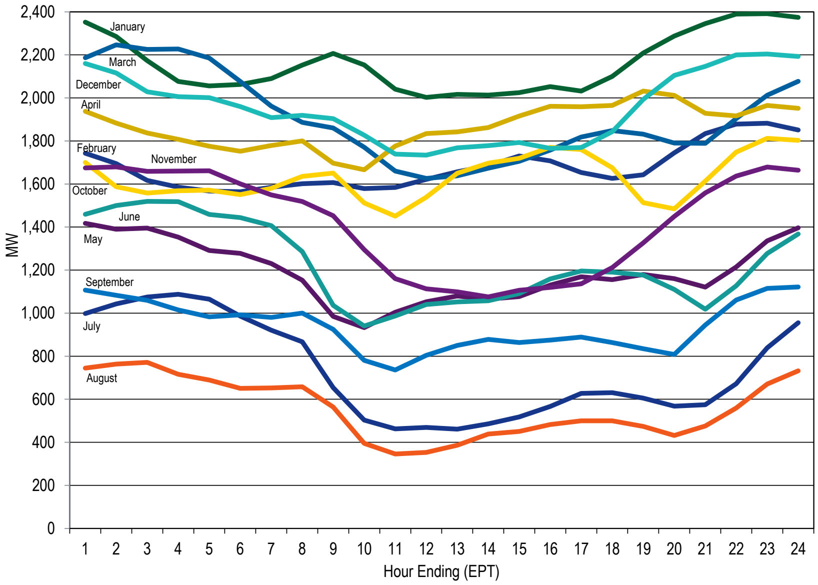
Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in January, March and December, and lowest in July and August. The highest average hour, 2,391.2 MW, occurred in January, and the lowest average hour, 345.4 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

58 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

59 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.

60 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.

Figure 7-2 Average hourly real-time generation of wind units in PJM: 2012



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 generation of wind units in PJM, by month.

Table 7-15 shows the generation and capacity factor of wind units in each month of 2011 and 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 in summer months. New wind farms came on line throughout 2012, and are included in this analysis as they were added.

Table 7-15 Capacity factor of wind units in PJM by month, 2011 and 2012[61]

	2011		2012	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	909,690.8	28.5%	1,608,349.8	41.9%
February	1,181,192.0	40.5%	1,167,011.9	32.4%
March	1,130,037.9	35.0%	1,416,278.0	35.6%
April	1,329,713.7	42.5%	1,345,643.3	34.7%
May	856,656.7	26.5%	885,583.1	21.6%
June	677,215.5	20.9%	882,597.0	22.2%
July	398,470.5	11.7%	546,676.9	13.3%
August	430,295.2	12.6%	415,544.2	10.1%
September	659,102.8	19.9%	677,039.5	16.9%
October	905,536.3	25.2%	1,213,664.0	27.7%
November	1,432,340.4	39.7%	1,022,628.8	22.9%
December	1,126,776.8	30.0%	1,452,588.7	31.1%
Annual	11,037,028.4	27.6%	12,633,605.2	25.7%

61 Capacity factor shown in Table 7-16 is based on all hours in 2012.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: 2012

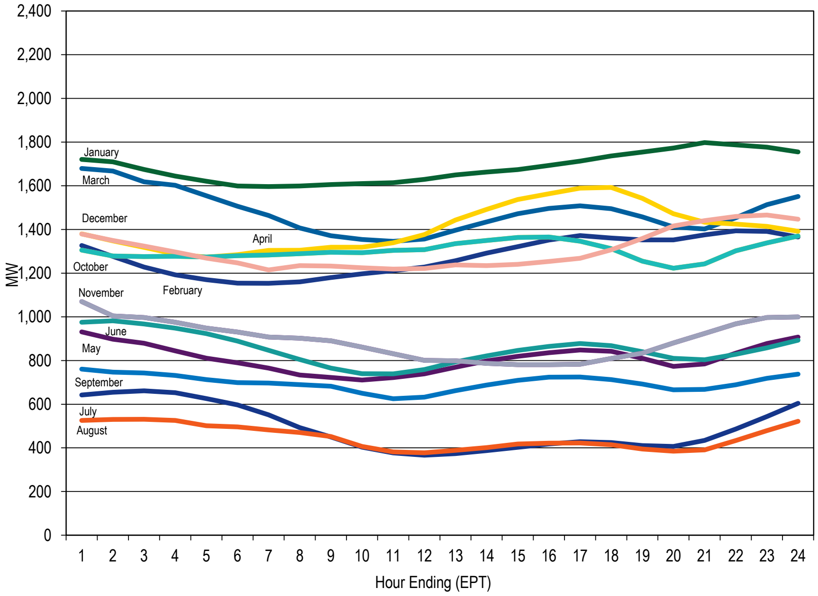
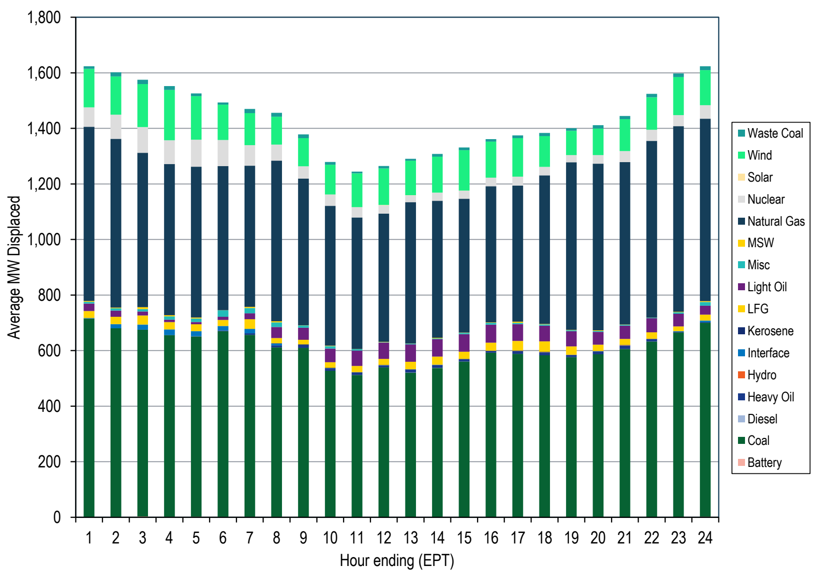


Figure 7-4 Marginal fuel at time of wind generation in PJM: 2012



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 through 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 376 MW lower from peak average output (0000 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.

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 month with the highest average hour, 109.2 MW, compared to 248.8 MW of solar installed capacity in PJM. In general, solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: 2012