Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Environmental Protection Agency ("EPA") has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM Energy Market.

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 units. Federal and state renewable energy mandates and associated incentives 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 significant impacts on PJM wholesale markets.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) 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.[1]
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[2] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[3]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs.[4] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency demand response programs to operate for additional hours have been eliminated.[5] Zero hours are exempt.[6] As a result, the national emissions standards uniformly apply to all RICE.[7] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[8]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating

1 *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 No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

2 CAA § 110(a)(2)(D)(i)(I).

3 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").

4 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *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, 78 Fed. Reg. 9403 (January 30, 2013).

5 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

6 *Id.*

7 *Id.*

8 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

Units (the Clean Power Plan).[9] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[10]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[11] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[12] New Jersey's HEDD rule, 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.[13]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS") that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[14]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the December 7, 2016, auction for the 2015-2017 compliance period was $3.55 per ton. The clearing price is equivalent to a price of $3.91 per metric tonne, the unit used in other carbon markets.

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[15]

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On December 31, 2016, 89.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.4 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

9 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

10 North Dakota v. EPA, et al., Order 15A793.

11 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

12 N.J.A.C. § 7:27-19.

13 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

14 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

15 See Enr. Com. Sub. For H. B. No. 2001.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[16]

RECs, federal investment tax credits and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The same is true for nuclear power credits, ZECs (zero emissions credits). The credits provide an incentive to make negative energy offers and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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. It would be preferable to have a single, transparent market for RECs operated by PJM that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying resources by reducing the risks associated with lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensure 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.

PJM markets could also provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition.

16 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is "in connection with" or "affects" jurisdictional rates or charges.").

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[17 18] The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

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.

On December 21, 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.[19] The rule established a compliance deadline of April 16, 2015.

In a related EPA rule also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required 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 (PM).[20]

On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[21] The remand did not stay MATS and had no effect on the implementation of MATS. On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[22] This action supplies the initial cost determination that the U.S. Supreme Court found lacking, and which was the sole basis for remand. The rule has been effective since April 14, 2016, and remains effective.

Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[23] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2

17 42 U.S.C. § 7401 et seq. (2000).
18 The 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.
19 *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 No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).
20 NSPS are promulgated under CAA § 111.
21 Michigan et al. v. EPA, Slip Op. No. 14-46.
22 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
23 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

emissions effective January 1, 2017. The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[24] The CSAPR requires 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. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[25] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[26]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[27] Group 2 does not include any states in the PJM region.[28] Group 1 states must reduce both annual SO_2 and NO_x emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[29] NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_x emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 ("CSAPR Update").[30] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_x emissions level was lowered to 0.075 ppm from 0.08 in 1997.[31] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[32] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_x from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[33] The EPA has removed North Carolina from the ozone season NO_x trading

24 CAA § 110(a)(2)(D)(i)(I).

25 *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"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).

26 *Id.*

27 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

28 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

29 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM (PM*2.5*) measures less than 2.5 microns across.

30 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (–Oct. 26, 2016) ("CSAPR Update").

31 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

32 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

33 *Id.* at 74554.

program.[34] Table 8-1 shows the revised reduced NO_X emissions budgets for each PJM affected state. Table 8-1 also shows the assurance level, which is a hard cap on emissions, meaning that emissions above the assurance cannot be covered by emissions allowances, even if available.

Table 8-1 Current and proposed CSAPR ozone season NO_X budgets for electric generating units (before accounting for variability)[35]

State	2017 CSAPR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Assurance Level (Tons)
Illinois	14,601	17,667
Indiana	23,303	28,197
Kentucky	21,115	25,549
Maryland	3,828	4,632
Michigan	17,023	20,598
New Jersey	2,062	19,094
Ohio	19,522	23,622
Pennsylvania	17,952	21,722
Tennessee	7,736	9,361
Virginia	9,223	11,160
West Virginia	17,815	21,556

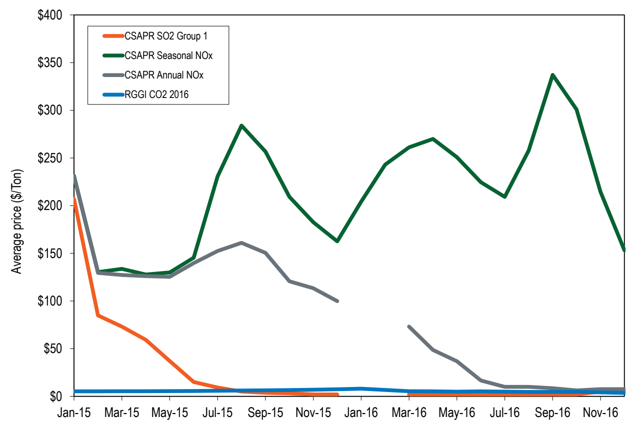
During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR NO_X ozone season trading program by the start of the 2017 ozone season control period."[36] The EPA is concerned that "[w]ithout imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive ozone seasons."[37] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[38]

Compliance with CSAPR's Phase 1 emissions budgets is required in 2015 and 2016 and with CSAPR's Phase 2 emissions in 2017 and beyond.[39]

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for 2015 and 2016. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In 2016, CSAPR annual NO_X prices were 83.9 percent lower than in 2015. The CSAPR annual NO_X price was $230.50 in January 2015, the first month that CSAPR was effective, and has decreased steadily since then. There were not any reported cleared purchases for January or February 2016 for CSAPR Annual NO_X. The CSAPR Seasonal NO_X price hit a peak of $337.14 in September 2016. The CSAPR Update resulted in fewer CSAPR Seasonal NO_X allowances. The average price of CSAPR SO_2 in 2016 was $2.70 compared to the average price of $41.78 for CSAPR SO_2 in 2015.[40]

Figure 8-1 Spot monthly average emission price comparison: 2015 through 2016[41]



34 *Id.* at 74507 n.13.
35 CSAPR Update at 74567.
36 *Id.* at 74588.
37 *Id.*
38 *Id.* at 74560. The EPA states: "The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or 'true-up')s for the 2016 ozone season program is completed." *Id.*
39 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
40 There were not any reported cleared purchases for January or February 2016 for CSAPR SO_2 or CSAPR Annual NO_X.
41 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[42] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including 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) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[43]

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 whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[44]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[45] The proposed rule would have allowed owners and operators of emergency stationary internal 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 rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.[46]

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[47] As a result, the national emissions standards uniformly apply to all RICE.[48] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[49] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[50]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[51] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[52] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[53]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

The MMU is currently taking steps to ensure resource portfolios remain in compliance. The MMU contacted all

42 *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, 78 Fed. Reg. 6674 (January 30, 2013) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." 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 ("2010 RICH NESHAP Rule").

43 *Id.*

44 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

45 *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.

46 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that use behind the meter generators will maintain emergency status and not have to curtail during pre-emergency events, unlike other demand resources. This matter remains pending.

47 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *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, 78 Fed. Reg. 9403 (January 30, 2013).

48 *Id.*

49 DENREC v. EPA at 3, 20–21.

50 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.

51 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

52 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

53 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

CSPs with Demand Resources using diesel fuel to ensure compliance is met among all PJM resources.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[54] [55]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[56] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[57] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[58] [59] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("CPE Guidelines" or Clean Power Plan).[60] On February 6, 2016, the U.S. Supreme Court issued a stay on the CPE Guidelines that will prevent them from taking effect until judicial review is completed.[61] An appeal is pending before the U.S. Court of Appeals for the District of Columbia Circuit, and a decision there may be appealed to the U.S. Supreme Court. The status of CPE Guidelines is uncertain with the transition to a new administration.

States would have flexibility to meet the Clean Power Plan's GHG goals, including through participation in multistate CO_2 credit trading programs.

The CPE Guidelines set state by state rate and mass based CO_2 emissions targets.[62] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2022 and the final goals effective 2030.[63] The CPE Guidelines anticipate that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 32 percent below the level of emissions in 2005.[64]

The EPA has calculated rate and mass-based goals based on EGU emissions rates for each state.[65] The EPA uses three building blocks to calculate state goals.[66] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[67]

To calculate state interim and final goals, the EPA assumes the following building blocks: (i) heat rate improvement of 2.1–3.4 percent (depending upon the region) at affected EGUs; (ii) displacement of generation

54 See CAA § 111.

55 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 the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. 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. 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). 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. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

56 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (August 8, 2016).

57 *Id.*

58 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

59 79 Fed. Reg. 1352 (January 8, 2014).

60 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

61 North Dakota v. EPA, 136 S. Ct. 999 (2016).

62 *Id.* at 1560. A rate-based goal is measured in pounds of CO_2 per megawatt hour (lbs/MWh); a mass-based goal is measured in total short tons of CO_2 emissions.

63 *Id.* at 1559.

64 *Id.* at 34839.

65 A mass-based goal is expressed as maximum number of tons of CO_2 that may be emitted over a time period, while a rate-based goal is expressed as a number of pounds of CO_2 per MWh.

66 *Id.* at 1559.

67 *Id.* at 1559–1560.

from lower emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units; and (iii) displacement of generation from new zero emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.[68]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-2.

Table 8-2 Interim and final targets for CO_2 emissions goals for PJM states (Short Tons of CO_2)[69]

Jurisdiction	2020 Interim New Source Complements (Short Tons of CO_2)	2030 Final New Source Complements (Short Tons of CO_2)	2020 Interim Mass Goal (Short Tons CO_2)	2030 Final Final Goal (Short Tons CO_2)
Delaware	78,842	69,561	5,141,711	4,781,386
District of Columbia	NA	NA	NA	NA
Illinois	818,349	722,018	75,619,224	67,119,174
Indiana	939,343	828,769	86,556,407	76,942,604
Kentucky	752,454	663,880	72,065,256	63,790,001
Maryland	170,930	150,809	16,380,325	14,498,436
Michigan	623,651	550,239	53,680,801	48,094,302
New Jersey	313,526	276,619	17,739,906	16,876,364
North Carolina	692,091	610,623	57,678,116	51,876,856
Ohio	949,997	838,170	83,476,510	74,607,975
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Tennessee	358,838	316,598	32,143,698	28,664,994
Virginia	450,039	397,063	30,030,110	27,830,174
West Virginia	602,940	531,966	58,686,029	51,857,307
Total	8,008,336	7,065,645	689,786,255	617,871,210

The difference in goals reflects different evaluation of state specific factors, referred to as building blocks, including heat rate improvements, dispatch among affected EGUs, expanded use of less carbon-intensive generating capacity and demand-side energy efficiency.[70] The essence of the approach is that the baseline is set by the current opportunity in a state to achieve additional CO_2 emissions reductions. No credit is given for prior steps that states have taken, some more than others, to achieve CO_2 emissions reductions.

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[71] The CPE Guidelines would not require states to implement the building blocks in their plan, but would require states to meet the goals through an approach included in an EPA-approved plan.

States could implement a state measures approach, which involves a state "adopt[ing] a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable."[72] States could choose from market-based trading programs, emissions performance standards, renewable portfolio standards (RPS), energy efficiency resource standards (EERS), and other demand-side energy efficiency programs.[73]

The CPE Guidelines recognize that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlight the Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act of 2006.[74] Each of these programs would require significant changes in order to comply with the approach in the CPE Guidelines. The trading rules could remain, but new regional goals and compliance deadlines that equal or exceed the state goals and compliance deadlines set in the CPE Guidelines would be needed. The rules would also take into account that the CPE Guidelines rely on reduced emissions from EGUs to reach state goals and does not count non-EGU offsets towards meeting those goals.[75]

The CPE Guidelines permit states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[76]

Federal Regulation of Environmental Impacts on Water

Water cooling systems at steam electric power generating stations are subject to regulation under the Clean Water Act (CWA).

EPA regulations of discharges from steam electric power generating stations are set forth in the Generating

68 *Id.* 1559.
69 The District of Columbia has no affected EGUs and is not subject to the CPE Guidelines (at 1560).
70 CPE Guidelines 1559–1560.
71 *Id.*
72 *Id.* at 1560.
73 *Id.* at 898.
74 *Id.* at 1560.
75 *Id.* at 34910.
76 *Id.* at 1560.

Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[77] Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits included limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from waters of the United States and has a design intake flow of greater than two million gallons per day (mgd).[78]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[79]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[80] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

77 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

78 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

79 42 U.S.C. §§ 6901 *et seq.*

80 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

Table 8-3 describes the criteria and anticipated implementation dates.

Table 8-3 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

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 reason 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.[81] New Jersey's HEDD rule, 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.[82] NO_x emissions limits for coal units became effective December 15, 2012.[83] NO_x emissions limits for other unit types became effective May 1, 2015.[84] As of December 31, 2016, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[85] In total 37 NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

81 N.J.A.C. § 7:27–19.

82 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

83 N.J.A.C. § 7:27-19.4.

84 N.J.A.C. § 7:27-19.5.

85 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

Table 8-4 shows the HEDD emissions limits applicable to each unit type.

Table 8-4 HEDD maximum NO_X emission rates[86]

Fuel and Unit Type	NO_X 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

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[87] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[88] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[89]

State Regulation of Greenhouse Gas Emissions

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.[90] RGGI generates revenues for the participating states which have spent approximately 57 percent of revenues to date on energy efficiency, 15 percent on clean and renewable energy, 8 percent on greenhouse gas abatements and 15 percent on direct bill assistance.[91]

Table 8-5 shows the RGGI CO_2 auction clearing prices and quantities for the 2009-2011 compliance period auctions, the 2012-2014 compliance period auctions and 2015-2017 compliance period auctions held as of December 31, 2016, in short tons and metric tonnes. Prices for auctions held December 7, 2016, for the 2015-2017 compliance period were at $3.55 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[92] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction of $4.54 in September 2016. The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auction to use CRRs.

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

87 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

88 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).

89 See *Id.*

90 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>.

91 *Investment of RGGI Proceeds Through 2014*, The Regional Greenhouse Gas Initiative, <http://rggi.org/docs/ProceedsReport/RGGI_Proceeds_FactSheet_2014.pdf> (Accessed January 20, 2017).

92 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Table 8-5 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[93]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459

Zero Emissions Credits (ZEC) Programs

On December 7, 2016, the State of Illinois enacted legislation that, among other things, provides subsidies, known as zero emission credits (ZECs), for certain existing nuclear-powered generation units that indicated they would otherwise retire.[94] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under ten year contracts with select Illinois nuclear power plants.[95] IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[96] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[97] The base price is reduced by the amount that "the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016."[98]

The revenues provided by the ZEC legislation are expected to forestall the retirement of a specific PJM nuclear unit in Illinois, the Quad Cities Generating Station.[99]

The ZEC legislation creates subsidies for existing units that create the same price suppressive effects as subsidies for new entry that are addressed by the Minimum Offer Price Rule.[100] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[101] The MMU's proposed modification of the MOPR rules would, if in place, apply to nuclear units receiving subsidies. Such subsidies may otherwise result in noncompetitive offers in PJM markets that would be addressed on a unit specific basis.

A similar issue has arisen in New York, where the New York Public Service Commission ("New York PSC") established a program requiring the purchase of ZEC credits from specific nuclear facilities in upstate New York. The constitutionality of the New York PSC's

93 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 20, 2017).
94 See Illinois 99th Gen. Assemb., S.B. 2814 (Dec. 7, 2016), which can be accessed at: <http://www.ilga.gov/legislation/99/SB/09900SB2814lv.htm>. The Governor of Illinois signed the ZEC legislation, amending the Illinois Power Agency Act ("IPAA"), on December 7, 2016; see also ICC, et al., Potential Nuclear Power Plant Closings in Illinois (Jan. 5, 2015), which can be accessed at: <http://www.ilga.gov/reports/special/report_potential%20nuclear%20power%20plant%20closings%20in%20il.pdf>.
95 See IPAA § 1-75(d-5)(1).
96 See *id.*
97 See IPAA § 1-75(d-5)(1)(B).
98 See *id.*
99 See Ted Caddell, RTO Insider "Exelon's Crane Reports 'Monumental Year,'" (Feb. 8, 2017); Exelon, Press Release, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants" (June 2, 2016) (citing "lack of progress on Illinois energy legislation" as a key factor), which can be accessed at: <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 6, 2016) (reporting Exelon statement that Byron is "economically challenged"), which can be accessed at: <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.
100 OATT Attachment DD § 5.14(h).
101 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).

program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[102] On January 9, 2017, the MMU filed an amicus curiae brief supporting plaintiffs on the grounds that the ZEC subsidies interfere with the operation of wholesale power markets in New York and have price suppressive effects in the energy markets in PJM.[103]

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfil these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of December 31, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of December 31, 2016, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

102 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).

103 Brief of Amicus Curiae of Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM, USDC SDNY Case No. 1:16-cv-08164-VEC (Jan. 9, 2017).

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[104]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[105]

Table 8-6 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year. In 2014, Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Washington, DC will require 35.0 percent of load to be served by renewable resources in 2028, the highest standard of PJM jurisdictions. In October 2016, the Council of the District of Columbia passed legislation that expanded the District's RPS program and increased the percent of retail load in the District that must be served by clean energy resources to 50 percent by 2032.[106]

104 See the Indiana Utility Regulatory Commission's "2016 Annual Report." P 34 <http://www.in.gov/iurc/files/Annual%20Report%202016%20WEB%20version.pdf> (Accessed March 7, 2017).

105 See Enr. Com. Sub. For H. B. No. 2001.

106 See B21-0650 – Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed January 18, 2017).

Table 8-6 Renewable standards of PJM jurisdictions: 2016 to 2028[107]

Jurisdiction with RPS		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware		14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%
Illinois		10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%
Maryland		15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	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%	10.00%	10.00%
New Jersey		14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%	24.21%	24.30%	24.39%	24.48%
North Carolina		6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio		2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%
Pennsylvania		13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.		13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%
Jurisdiction with Voluntary Standard														
Indiana		4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%
Virginia		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%
Jurisdiction with No Standard														
Kentucky	No Renewable Portfolio Standard													
Tennessee	No Renewable Portfolio Standard													
West Virginia	No Renewable Portfolio Standard													

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM states with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Though there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources.

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In Delaware, Illinois, North Carolina, and Ohio, eligible technologies are for the most part identical to Tier I resources. Michigan is the only state with an RPS that does not classify eligible technologies into tiers and also permits technologies that differ markedly from those classified as Tier I resources in states that do classify technologies. Michigan's RPS includes coal gasification, industrial cogeneration, and coal with carbon capture and storage as eligible technologies.

Table 8-7 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-7 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in are included in the total RPS requirements presented in Table 8-6. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 7.50 percent of load served in 2016 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or "Class 2" standards, which allow specific technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2021, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste.

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

Table 8-7 Additional renewable standards of PJM jurisdictions: 2016 to 2028

Jurisdiction		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-6 but must be met by solar RECs (SRECs) only. Table 8-8 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdictions' RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2016, New Jersey had the most stringent solar standard in PJM, requiring that 2.45 percent of retail electricity sales within the state be served by solar resources. As Table 8-8 shows, by 2028, New Jersey will continue to have the most stringent standard, requiring that at least 4.10 percent of load be served by solar.

Figure 8-2 and Figure 8-3 show the percent of retail electric load that must be served by Tier I resources and Tier 2 Resources in each PJM jurisdiction with a mandatory RPS. Figure 8-2 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-2. Figure 8-3 shows the percent of retail load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. Like all other PJM states with mandatory RPS, the Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated

Table 8-8 Solar renewable standards by percent of electric load for PJM jurisdictions: 2016 to 2028

Jurisdiction with RPS		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware		1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%
Illinois		0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Maryland		0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Minimum Solar Requirement													
New Jersey		2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%	3.83%	3.92%	4.01%	4.10%
North Carolina		0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio		0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%
Pennsylvania		0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.		0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%
Jurisdiction with Voluntary Standard														
Indiana	No Minimum Solar Requirement													
Virginia	No Minimum Solar Requirement													
Jurisdiction with No Standard														
Kentucky	No Renewable Portfolio Standard													
Tennessee	No Renewable Portfolio Standard													
West Virginia	No Renewable Portfolio Standard													

gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. The 13.7 percent number in Figure 8-3 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-2 Map of retail electric load shares under RPS – Tier I resources only: 2016

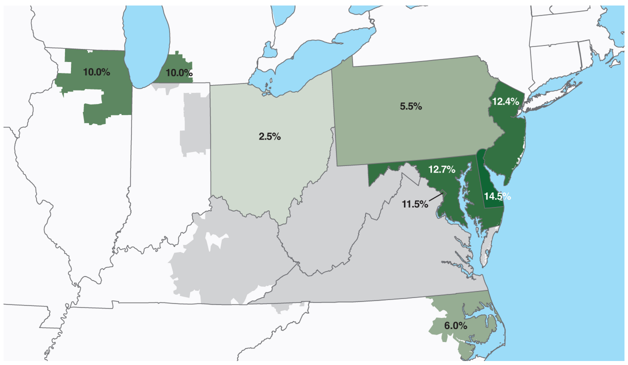
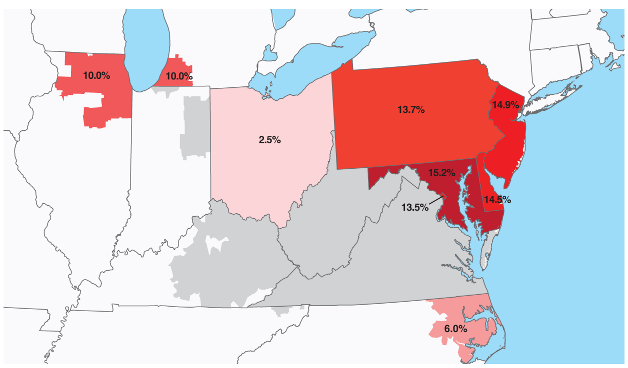


Figure 8-3 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2016



Under the existing state renewable portfolio standards, approximately 7.7 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2016 and, if the proportion of load among states remains constant, 14.4 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 5.6 percent of PJM load must be served by Tier I renewables in 2016 and, if the proportion of load among states remains constant, 9.0 percent of PJM load must be served by Tier I renewables in 2028 under defined RPS rules.

In jurisdictions with RPS, load serving entities must either generate power from eligible technologies identified in their jurisdictions' RPS or purchase RECs from resources classified as eligible technologies. Table 8-9 shows renewable resource generation by jurisdiction and resource type for 2016. Wind output was 15,755.3 GWh of 25,556.9 Tier I GWh, or 61.0 percent, in the PJM footprint. As shown in Table 8-9, 46,412.3 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 57.1 percent. Total renewable generation was 5.7 percent of total generation in PJM for 2016. Landfill gas, solid waste and waste coal were 19,907.8 GWh of renewable resource generation or 42.9 percent of the total Tier I and Tier II.

Table 8-9 Renewable resource generation by jurisdiction and renewable resource type (GWh): 2016

	Tier I					Tier II				
Jurisdiction	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	40.4	0.0	0.0	0.0	40.4	0.0	0.0	0.0	0.0	40.4
Illinois	113.4	0.0	14.2	6,811.6	6,939.1	0.0	0.0	0.0	0.0	6,939.1
Indiana	57.1	0.0	7.2	4,298.4	4,362.7	0.0	0.0	0.0	0.0	4,362.7
Kentucky	0.0	418.8	0.0	0.0	418.8	0.0	0.0	0.0	0.0	418.8
Maryland	100.2	1,380.4	104.3	525.3	2,110.2	0.0	669.5	0.0	669.5	2,779.7
Michigan	22.1	0.0	0.4	0.0	22.6	0.0	0.0	0.0	0.0	22.6
New Jersey	290.0	8.2	509.7	11.6	819.4	521.4	1,430.4	0.0	1,951.8	2,771.2
North Carolina	0.0	761.6	319.5	7.7	1,088.8	0.0	0.0	0.0	0.0	1,088.8
Ohio	350.9	478.9	1.2	1,172.2	2,003.3	0.0	0.0	0.0	0.0	2,003.3
Pennsylvania	664.4	2,009.4	27.3	3,344.5	6,045.5	1,819.2	1,254.6	7,451.0	10,524.8	16,570.3
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	537.7	915.8	26.0	0.0	1,479.5	2,479.1	785.4	3,497.3	6,761.7	8,241.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	1,174.3	0.0	0.0	1,174.3	0.0	0.0	0.0	0.0	1,174.3
Total	2,176.2	7,147.2	1,009.8	16,171.3	26,504.5	4,819.7	4,139.8	10,948.3	19,907.8	46,412.3
Percent of Renewable Generation	4.7%	15.4%	2.2%	34.8%	57.1%	10.4%	8.9%	23.6%	42.9%	100.0%
Percent of Total Generation	0.3%	0.9%	0.1%	2.0%	3.3%	0.6%	0.5%	1.3%	2.5%	5.7%

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. New Jersey has the largest amount of solar capacity in PJM, 397.2 MW, or 54.9 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2009 at $673 per REC, and in 2016 are at $205 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,448.7 MW, or 61.0 percent of the total wind capacity.

Table 8-10 PJM renewable capacity by jurisdiction (MW): December 31, 2016

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	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	59.3	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,846.4	2,914.7
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	1,602.4	1,628.7
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	166.0	0.0	0.0	0.0	0.0	166.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.4	79.8	128.2	0.0	190.0	986.5
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.5	397.2	162.0	0.0	4.5	1,105.8
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	207.1	0.0	0.0	0.0	559.6
Ohio	11,080.0	63.4	0.0	156.0	0.0	119.1	1.1	0.0	0.0	403.0	11,822.6
Pennsylvania	0.0	208.0	2,346.0	0.0	1,269.0	893.3	19.5	345.8	1,611.0	1,337.7	8,030.3
Tennessee	0.0	0.0	0.0	0.0	0.0	52.0	0.0	50.0	0.0	0.0	102.0
Virginia	0.0	222.1	0.0	17.0	5,166.2	350.5	0.0	444.9	585.0	0.0	6,785.7
West Virginia	0.0	2.2	0.0	0.0	0.0	257.9	0.0	0.0	165.0	583.3	1,008.4
PJM Total	11,080.0	681.8	4,143.0	255.0	6,888.2	2,719.2	723.8	1,130.9	2,361.0	7,298.2	37,281.1

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 3,047.0 MW of which 1,417.4 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. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions. This includes both solar generation located inside PJM but not PJM units, and generation connected to other RTOs outside PJM.

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on December 31, 2016[108]

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Alabama	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.5	0.0	87.5
Arkansas	0.0	135.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	153.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	77.9	0.0	2.1	82.2
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	38.7	258.9	0.0	297.6
Illinois	0.0	21.4	91.9	0.0	0.6	0.0	39.5	0.0	300.5	453.9
Indiana	0.0	0.0	43.2	0.0	5.2	234.6	22.1	0.0	180.0	485.1
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	476.7	479.8
Kentucky	600.0	86.2	18.6	0.0	0.4	0.0	16.3	93.0	0.0	814.5
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	0.0	63.0
Maryland	65.0	0.0	11.7	129.0	0.0	0.0	592.5	15.0	0.3	813.5
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	3.0	31.0	0.0	93.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	451.0	451.2
New Jersey	0.0	0.0	53.1	0.0	8.3	0.0	1,417.4	0.0	5.0	1,483.8
New York	0.0	158.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	159.1
North Carolina	0.0	242.5	12.0	0.0	0.0	0.0	412.7	151.5	0.0	818.7
North Dakota	0.0	0.0	360.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0
Ohio	0.0	1.0	33.6	92.6	16.4	32.4	130.0	109.3	35.1	450.4
Pennsylvania	109.7	31.7	45.2	91.0	13.2	5.0	239.6	68.6	3.3	607.2
Tennessee	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	18.2	12.1	0.0	0.5	0.0	20.9	287.6	0.0	339.2
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	0.0	3.3
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	28.9	0.0	0.0	28.9
Total	829.7	756.9	686.8	312.6	62.5	272.0	3,047.0	1,267.7	1,454.0	8,689.2

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 revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. The FERC has found that such costs can be appropriately considered in the rates established through the operation of wholesale organized markets.[109] This decision is an important recognition of the integration of the RECs markets and the other PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[110] This is equivalent to providing a REC price equal to three times its stated value per MWh. 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.[111]

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must

108 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 3, 2017).

109 See 146 FERC ¶ 61,084 at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. [footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition. We also find that ISO-NE's use of an inflation rate in determining the price of Renewable Energy Credits is a reasonable estimate of Renewable Energy Credits for the 2018-2019 Capacity Commitment Period.").

110 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed October 19, 2016).

111 GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

ultimately be traded. Table 8-12 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-12 REC Tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		
Virginia	PJM-GATS			

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-13 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with states' standards to be generated by in-state resources. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions.

Pennsylvania requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint. Virginia requires that every load serving entity that chooses to participate in its voluntary renewable energy standard purchase RECs from the control area or RTO in which it is located. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs typically have a shelf life of five years until they cannot be used to satisfy a state's RPS requirement. The REC price figures take the average price for each vintage of REC, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available.

Table 8-13 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or resources located in a control area synchronized with PJM.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are either located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in state contiguous to Ohio has been deemed deliverable into the state of Ohio. If a renewable resource is located outside of this range, then it must demonstrate deliverabilty to the Public Utilities Commission of Ohio.
Pennsylvania	No	RECs must be purchased from resources located anywhere within PJM.
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.

Figure 8-4 shows the average solar REC (SREC) price by jurisdiction for 2009 through 2016. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from $673 per SREC in 2009 to $205 per SREC in 2016. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $488 per SREC in 2016.[112]

Figure 8-4 Average SREC price by jurisdiction: 2009 through 2016

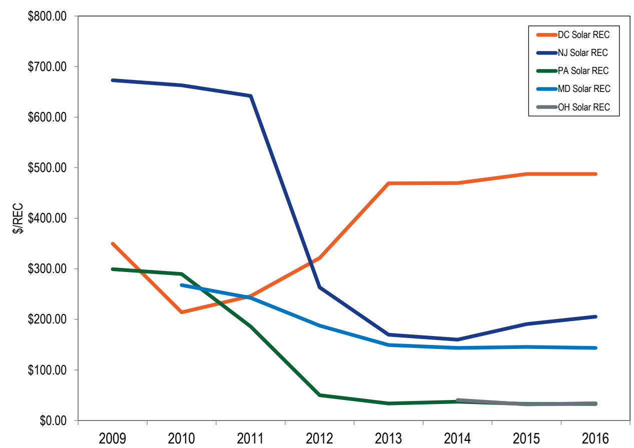
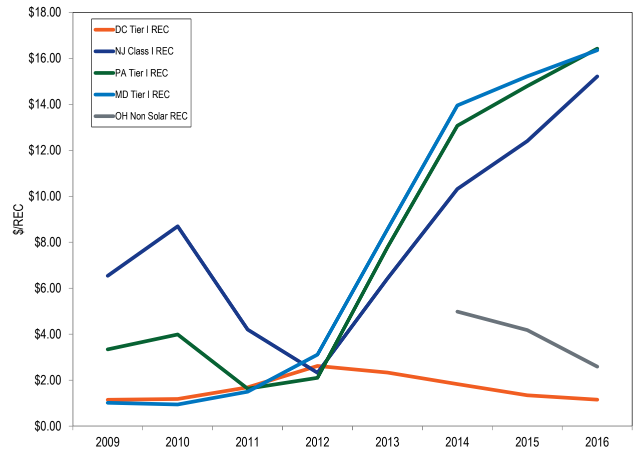


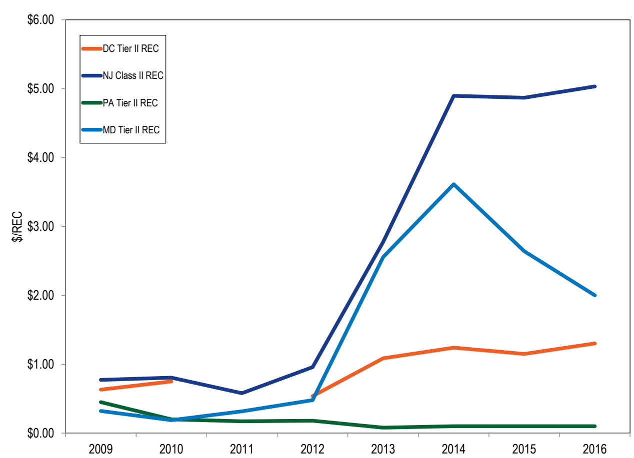
Figure 8-5 shows the average Tier I REC price by jurisdiction from 2009 through 2016. Tier I REC prices are lower than SREC prices. Ohio and Pennsylvania had the lowest SREC prices at $34 per SREC and $33 per SREC in 2016 while Pennsylvania had the highest Tier I REC prices at $16 per REC in 2016.[113]

Figure 8-5 Average Tier I REC price by jurisdiction: 2009 through 2016



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-6 shows the average Tier II REC price by jurisdiction for 2009 through 2016. DC had the lowest Tier II REC prices at $1.15 per REC while New Jersey had the highest Tier II REC prices at $5.03 per REC.[114]

Figure 8-6 Average Tier II REC price by jurisdiction: 2009 through 2016



PJM jurisdictions have various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between

112 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).

113 Tier I REC price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).

114 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 20, 2017).

the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $323.00 per MWh.[115] 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. For all states with an alternative compliance payment, the alternative compliance payment creates a cap on REC prices. Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. In Michigan and North Carolina, there are no pre-established values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-14 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-14 Renewable alternative compliance payments in PJM jurisdictions: As of December 31, 2016[116 117]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$40.00	$15.00	$350.00
Michigan	No specific penalties		
New Jersey	$50.00		$323.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$49.75		$300.00
Pennsylvania	$45.00	$45.00	200% market value
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission. In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public. The RPS compliance reports are released with a lag of up to three years. It is therefore impossible to know the current level of RPS compliance in PJM jurisdictions. As of December 31, 2016, compliance reports for the year 2015 are available for Delaware, Illinois, Michigan, New Jersey, North Carolina, Pennsylvania, Washington, D.C.[118 119] The RPS compliance report for the year 2014 is available for Ohio. The RPS compliance report for the year 2013 is available for Maryland.[120]

One jurisdiction where RPS compliance costs have raised concerns is the District of Columbia. According to the District of Columbia Public Service Commission's 2015 annual RPS compliance report, electric retailers have been able to meet the allotted standards for Tier I and II resources but have struggled to meet the standard for solar resources. Due to a combination of insufficient supply of eligible solar resources in the District and increasing percentages of load that must be served by solar resources, total solar alternative compliance payments in the District of Columbia have increased from $0.70 million in 2013 to $19.9 million in 2015.[121]

115 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/Policies for Renewables & Efficiency, "Solar Renewables Energy Certificates (SRECs)," <http://programs.dsireusa.org/system/program/detail/5687> (Accessed January 20, 2017).

116 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed January 20, 2017).

117 See "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 20, 2017).

118 RPS compliance reports are available on jurisdictions' public utilities commissions' websites.

119 The Lawrence Berkeley National Laboratory, a subsidiary of the US Department of Energy, actively keeps track of compliance reports and data on their website. See the report "U.S. Renewables Portfolio Standards: 2016 Annual Status Report (PDF)" and "RPS Compliance Data (XLSX)" available on their website. <https://emp.lbl.gov/projects/renewables-portfolio> (Accessed January 18, 2017).

120 The Clean Energy States Alliance tracks all completed RPS compliance reports on their website: <http://cesa.org/projects/state-federal-rps-collaborative/state-rps-annual-reports-and-compliance-reports/#MD> (Accessed January 23, 2017).

121 See the Public Service Commission of the District of Columbia's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015." <http://www.dcpsc.org/getmedia/901b3c18-4859-435d-ae1a-ca296584c26b/aharris_542016_831_1_FC_-_945_-_2016_-_E_-_REPORT.aspx> (Accessed January 20, 2017).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[122] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[123] Of the current 64,015.1 MW of coal capacity in PJM, 57,212.0 MW of capacity, 89.4 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[124] [125] [126]

Table 8-15 SO_2 emission controls by fuel type (MW): as of December 31, 2016[127]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	57,212.0	6,803.1	64,015.1	89.4%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	0.0	52,518.3	52,518.3	0.0%
Other	325.0	4,920.7	5,245.7	6.2%
Total	57,537.0	70,242.7	127,779.7	45.0%

NO_X emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 119,374.0 MW, 93.4 percent, of 127,779.7 MW of capacity in PJM, have emission controls for NO_X. Table 8-16 shows NO_X emission controls by unit type in PJM. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_X compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[128]

Table 8-16 NO_X emission controls by fuel type (MW), as of December 31, 2016

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	63,075.8	939.3	64,015.1	98.5%
Diesel Oil	2,207.6	3,793.0	6,000.6	36.8%
Natural Gas	51,290.9	1,227.4	52,518.3	97.7%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	119,374.0	8,405.7	127,779.7	93.4%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[129] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 63,681.1MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of December 31, 2016. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR to meet the state and federal emissions limits established by the MATS EPA regulations.[130] Currently, 142 of the 171 coal steam units have baghouse or FGD technology installed, representing 55,683.0 MW out of the 63,681.1 MW total coal capacity, or 87.4 percent.

Table 8-17 Particulate emission controls by fuel type (MW), as of December 31, 2016

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	63,681.1	334.0	64,015.1	99.5%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	538.0	51,980.3	52,518.3	1.0%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	67,321.1	60,458.6	127,779.7	52.7%

Figure 8-7 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for each year from 1999

122 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 7, 2016).

123 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A Section 72.2" <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed March 7, 2016).

124 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 7, 2016).

125 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year.

126 The total MW for each fuel type are less than the 182,449.1 reported in Section 5: Capacity, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed March 7, 2016).

127 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.

128 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed March 7, 2016).

129 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed March 7, 2016).

130 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed March 7, 2016).

to 2016, as well as the CO_2 short ton emissions per MWh of total generation within PJM from 2004 to 2016.[131] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.80 short tons per MWh in 2001, and a maximum of 0.93 short tons per MWh in 2010. In 2016, CO_2 emissions were 0.84 short tons per MWh. Total PJM generation increased from 786,698.5 GWh in 2015 to 812,544.1 GWh in 2016, while CO_2 produced decreased from 484.5 million tons in 2015 to 353.1 million tons in 2016.[132] The reduction in CO_2 emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-8 shows the total on peak hour and off peak hour CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for each year from 1999 to 2016. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.80 short tons per MWh in 2016, and a maximum of 0.95 short tons per MWh in 2008. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.78 short tons per MWh in 2016, and a maximum of 0.92 short tons per MWh in 2008. In 2016, CO_2 emissions were 0.80 short tons per MWh and 0.78 short tons per MWh for off and on peak hours.

Figure 8-7 CO_2 emissions by year (millions of short tons), by PJM units: 1999 through 2016[133]

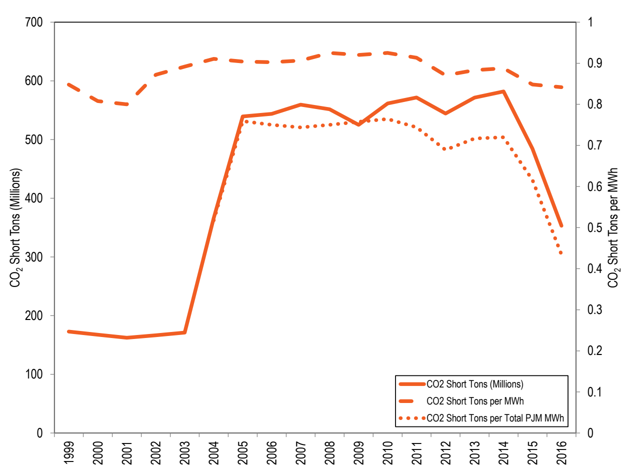


Figure 8-8 CO_2 emissions during on and off peak hours by year (millions of short tons), by PJM units: 1999 through 2016[134]

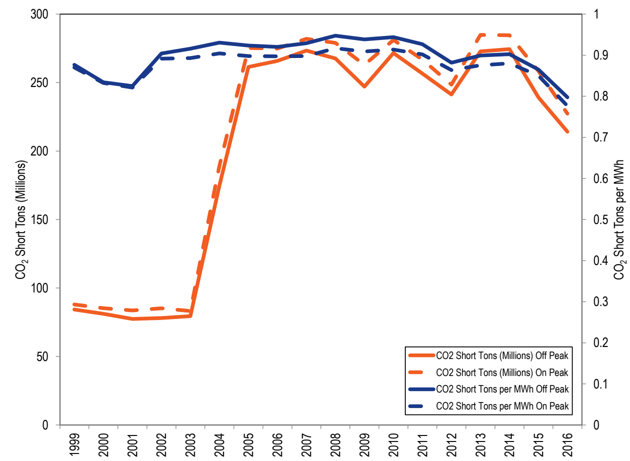


Figure 8-9 shows the total SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for each year from 1999 to 2016, as well as the SO_2 and NO_X short ton emissions per MWh of total generation within PJM from 2004 to 2016. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000732 short tons per MWh in 2016, and a maximum of 0.006336 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh was at a minimum of 0.000572 short tons per MWh in 2016, and a maximum of 0.001972 short tons per MWh in 1999. In 2016, SO_2 emissions were 0.000732 short tons per MWh and NO_X emissions were 0.000572 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal from 2006 to 2016.

Figure 8-10 shows the total on peak hour and off peak hour SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for each year from 1999 to 2016. Since 1999 the amount of SO_2 produced per MWh during off peak hours was at a minimum of 0.000723 short tons per MWh in 2016, and a maximum of 0.006654 short tons per MWh in 2003. Since 1999 the amount of SO_2 produced per MWh during on peak hours was at a minimum of

131 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
132 See Table 3-8, Section 3.
133 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
134 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

0.000774 short tons per MWh in 2016, and a maximum of 0.006326 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh during off peak hours was at a minimum of 0.000603 short tons per MWh in 2016, and a maximum of 0.001993 short tons per MWh in 1999. Since 1999, the amount of NO_X produced per MWh during on peak hours was at a minimum of 0.000609 short tons per MWh in 2016, and a maximum of 0.002037 short tons per MWh in 1999. In 2016, SO_2 emissions were 0.000723 short tons per MWh and 0.000774 short tons per MWh for off and on peak hours. In 2016, NO_X emissions were 0.000603 short tons per MWh and 0.000609 short tons per MWh for off and on peak hours.

Figure 8-9 SO_2 and NO_X emissions by year (thousands of short tons), by PJM units: 1999 through 2016[135]

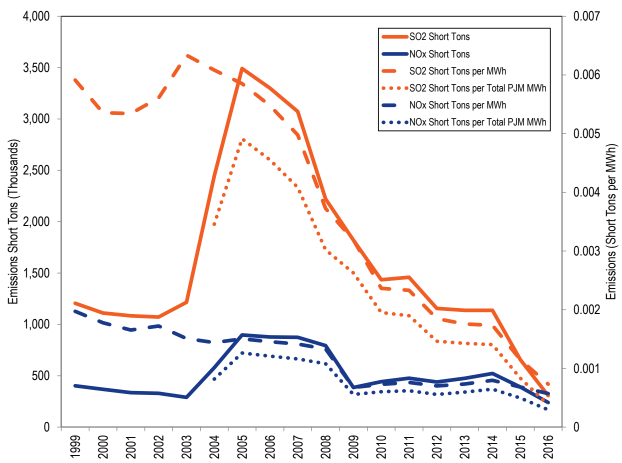
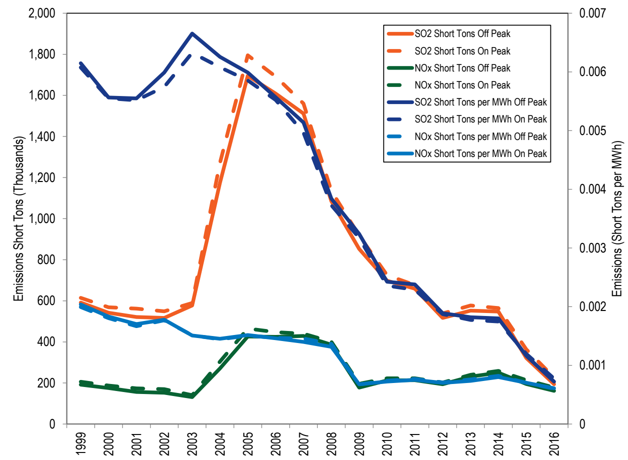


Figure 8-10 SO_2 and NO_X emissions during on and off peak hours by year (thousands of short tons), by PJM units: 1999 through 2016[136]



Wind and Solar Peak Hour Output

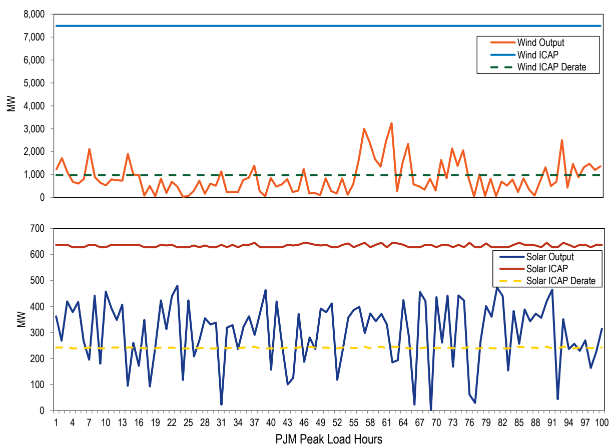
The capacity of solar and wind resources are derated for the PJM capacity market based on expected performance during high load hours. Figure 8-11 shows the wind and solar output during the top 100 load hours in PJM for 2016. The top 100 load hours in PJM during 2016 did not fall entirely within PJM defined peak load periods. There were 89 hours during PJM defined peak periods and 11 hours during PJM defined off peak periods. All top 100 peak load hours in 2016 occurred during the months of July, August and September. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total ICAP of wind and solar PJM resources derated to 13 and 38 percent. The actual output of the wind and solar resources during the top 100 peak load hours are above and below the derated values. Wind output was above the derated ICAP for 31 hours and below the derated ICAP for 69 hours of the top 100 peak load hours of 2016. Wind output was above the derated ICAP 6,288 hours and below the derated ICAP for 2,496 hours for the entire year. The wind capacity factor for the top 100 peak load hours of 2016 is 11.4 percent. Solar output was above the derated ICAP for 71 hours and below the derated ICAP for 29 hours of the top 100 peak load hours of 2016. Solar output was above the derated ICAP 1,940 hours and below the derated ICAP

135 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

136 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

for 6,844 hours for the entire year. The solar capacity factor for the top 100 peak load hours of 2016 is 47.5 percent.

Figure 8-11 Wind and solar output during the top 100 peak load hours in PJM: 2016



Wind Units

Table 8-18 shows the capacity factor of wind units in PJM. In 2016, the capacity factor of wind units in PJM was 28.1 percent. Wind units that were capacity resources had a capacity factor of 28.7 percent and an installed capacity of 6,668 MW. Wind units that were classified as energy only had a capacity factor of 21.5 percent and an installed capacity of 1,111 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[137]

Table 8-18 Capacity factor of wind units in PJM: 2016[138]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.5%	1,111
Capacity Resource	28.7%	6,668
All Units	28.1%	7,779

Figure 8-12 shows the average hourly real-time generation of wind units in PJM, by month for 2016. The hour with the highest average output, 3,322.9 MW, occurred in December, and the hour with the lowest average output, 500.9 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-12 Average hourly real-time generation of wind units in PJM: 2016

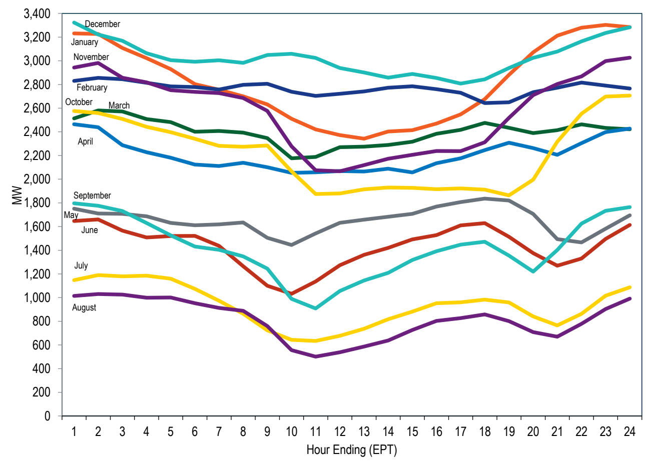


Table 8-19 shows the generation and capacity factor of wind units in each month of 2015 through 2016.

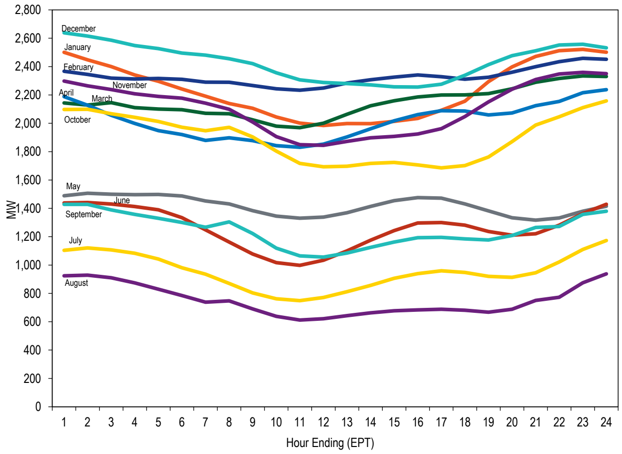
Table 8-19 Capacity factor of wind units in PJM by month: 2015 through 2016

	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,664,426.8	33.9%	2,095,618.0	40.5%
February	1,511,093.1	34.1%	1,925,470.3	39.8%
March	1,701,249.6	34.7%	1,781,561.4	34.5%
April	1,641,965.0	34.5%	1,587,976.6	31.7%
May	1,209,088.5	24.6%	1,230,631.9	23.6%
June	955,156.7	20.1%	1,029,071.2	19.7%
July	639,381.7	13.0%	691,689.6	12.8%
August	623,873.6	12.4%	603,498.4	11.2%
September	846,505.6	17.3%	1,017,658.6	19.5%
October	1,756,221.4	34.8%	1,647,392.1	30.5%
November	2,023,340.0	41.3%	1,851,353.3	34.7%
December	2,037,436.4	39.8%	2,254,119.4	39.4%
Annual	16,609,738.2	28.3%	17,716,040.8	28.1%

Wind units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer noncapacity related wind energy at their discretion. Figure 8-13 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

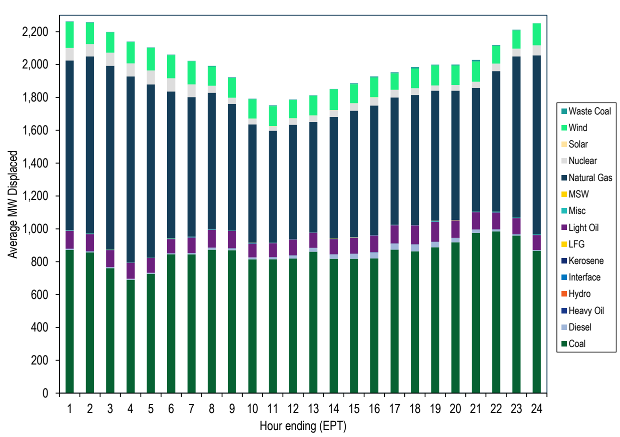
137 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
138 Capacity factor is calculated based on online date of the resource.

Figure 8-13 Average hourly day-ahead generation of wind units in PJM: 2016



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 depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-14 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2016. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 8-14 Marginal fuel at time of wind generation in PJM: 2016



Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-11, there are 3,047.0 MW capacity of solar registered in GATS that are not PJM capacity or energy resources. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to escape their proper financial responsibility through badly designed rules, such as rules for netting.

Table 8-20 shows the capacity factor of solar units in PJM. In 2016, the capacity factor of solar units in PJM was 18.3 percent. Solar units that were capacity resources had a capacity factor of 18.4 percent and an installed capacity of 552 MW. Solar units that were classified as energy only had a capacity factor of 17.6 percent and an installed capacity of 182 MW. Solar capacity in RPM is derated to 38 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[139]

Table 8-20 Capacity factor of wind units in PJM: 2016

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	17.6%	182
Capacity Resource	18.4%	552
All Units	18.3%	734

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-15 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation was highest in June, the month with the highest average hour, 400.6 MW, compared to 645 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

139 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

Figure 8-15 Average hourly real-time generation of solar units in PJM: 2016

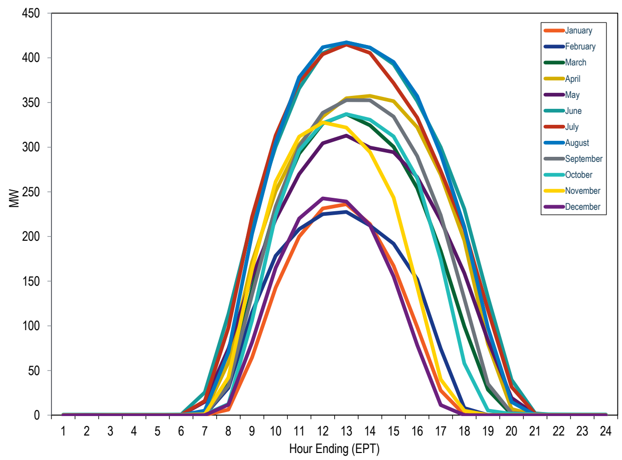


Figure 8-16 Average hourly day-ahead generation of solar units in PJM: 2016

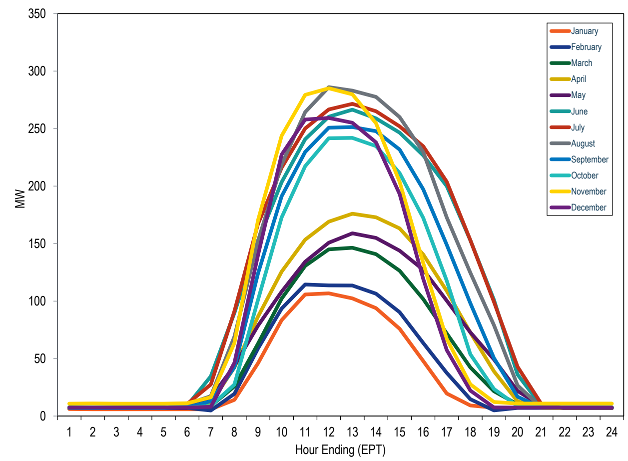


Table 8-21 shows the generation and capacity factor of solar units in each month of 2015 through 2016.

Table 8-21 Capacity factor of solar units in PJM by month: 2015 through 2016

	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	19,969.1	8.6%	38,858.7	10.8%
February	27,836.9	13.1%	43,770.8	12.6%
March	33,353.5	13.6%	73,745.6	19.1%
April	46,307.8	19.5%	85,867.1	22.8%
May	54,641.7	22.2%	77,453.7	19.8%
June	46,659.5	19.3%	101,147.1	26.0%
July	53,800.1	21.5%	101,146.3	25.1%
August	54,975.1	22.0%	99,167.5	24.5%
September	43,878.9	18.1%	74,093.9	18.7%
October	38,640.7	15.4%	67,357.0	16.4%
November	28,899.6	11.9%	57,259.6	14.4%
December	21,570.6	7.4%	38,424.5	9.4%
Annual	470,533.4	16.0%	858,291.9	18.4%

Solar units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Solar units may offer non-capacity related solar energy at their discretion. Figure 8-16 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[140]

140 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.