# Environmental and Renewable Energy Regulations

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

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 particulate matter (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]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** Provisions exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs have been eliminated. As a result, the national emissions standards uniformly apply to all RICE.[3] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[4]
- **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 Units (the Clean Power Plan).[5] 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.[6] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[7]
- **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.[8]

### State Environmental Regulation

- **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 March 14, 2018, auction for the 2015–2018 compliance period was $3.79 per ton. The clearing price is equivalent to a price of $4.18 per metric tonne, the unit used in other carbon markets. The price decreased by $0.01 per ton, 0.3 percent, from $3.80 per ton from December 8, 2017, to $3.79 per ton for March 14, 2018.

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 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
4 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).
5 *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."
6 North Dakota v. EPA, et al., Order 15A793.
7 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).
8 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).

- **Carbon Price.** If the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

## 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 March 31, 2018, 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 effective February 3, 2015.[9]

## 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 March 31 2018, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce $SO_2$ emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.7 percent of fossil fuel fired capacity in PJM had $NO_X$ emission control technology.

## Renewable Generation

Total wind and solar generation was 3.7 percent of total generation in PJM for the first three months of 2018. Tier I generation was 5.2 percent of total generation in PJM and Tier II generation was 2.7 percent for the first three months of 2018.

9 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. 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.[10]

RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources 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

10 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.").

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 renewable resources by reducing the risks associated with lack of transparent market data.

The economic logic of RPS programs and the associated REC and SREC prices is not clear. The price of carbon implied by REC prices ranges from $4.07 per tonne in Washington, D.C. to $35.41 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $13.45 per tonne in Pennsylvania to $875.97 per tonne in Washington, D.C. The effective prices for carbon compare to the RGGI clearing price in March 2018 of $4.18 per tonne and to the social cost of carbon which is estimated in the range of $40 per tonne. The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $283.56 per MWh. The impact of a $40 per tonne carbon price would be $14.18 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

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 to limit carbon output, for example by incorporating a consistent 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 consistent 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 to the current wide range of implied carbon prices embedded in RPS programs 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 efficient markets 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. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

## 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.[11] [12]

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.

11 42 U.S.C. § 7401 et seq. (2000).

12 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.

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.[13] 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).[14]

The future of MATS is currently uncertain. 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.[15] The U.S. Supreme Court ruled in 2015 that "the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[16] The remand did not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.[17] 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."[18] The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[19] On April 28, 2017, the Court granted the EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[20]

## 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).[21] 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) then 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 emissions effective January 1, 2017.[22] 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.[23] 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

13 *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).

14 NSPS are promulgated under CAA § 111.

15 Michigan et al. v. EPA, Slip Op. No. 14-46.

16 135 S. Ct. 2699, 2712 (2015).

17 *See 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).

18 *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).

19 *See* Case No. 16-1127, et al.

20 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

21 Nitric Oxides ($NO_X$), Sulfur Dioxide ($SO_2$), Ozone ($O_3$), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

22 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.

23 CAA § 110(a)(2)(D)(i)(I).

ozone and fine particle and 2006 fine particle NAAQS.[24] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[25]

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.[26] Group 2 does not include any states in the PJM region.[27] 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[28] 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).[29] 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.[30] 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.[31] 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.[32] The EPA has removed North Carolina from the ozone season $NO_X$ trading program.[33] 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.

24 *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).

25 *Id.*

26 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.

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

28 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.

29 *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").

30 *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).

31 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.*

32 *Id.* at 74554.

33 *Id.* at 74507 n.13.

Table 8-1 Current and proposed CSAPR ozone season $NO_X$ budgets for electric generating units (before accounting for variability)[34]

| 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 |

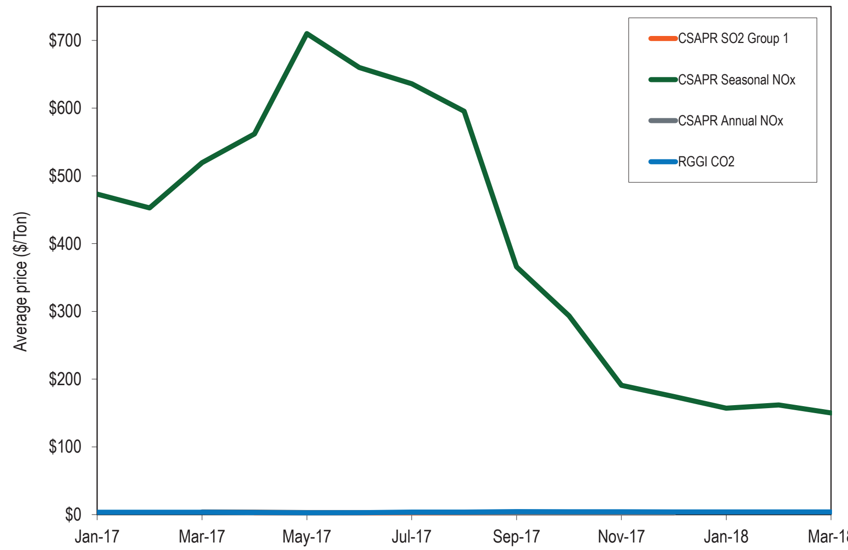
During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR $NO_X$ ozone season trading program by the start of the 2017 ozone season control period."[35] The EPA is concerned that "[w]ithout imposing a limit on the transitioned 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."[36] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[37]

Figure 8-1 shows average, monthly settled prices for $NO_X$, $CO_2$ and $SO_2$ emissions allowances including CSAPR related allowances for January 1, 2017 through March 31, 2018. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) $CO_2$ allowances.

In the first three months of 2018, CSAPR annual $NO_X$ prices were 38.2 percent lower than in the first three months of 2017. There were not any reported CSAPR Annual $NO_X$ cleared purchases for January or February 2017. The CSAPR Seasonal $NO_X$ price hit a peak of $710.12 in May 2017. The CSAPR Update resulted in fewer CSAPR Seasonal $NO_X$ allowances.[38]

34 CSAPR Update at 74567.
35 *Id.* at 74588.
36 *Id.*
37 *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.

Figure 8-1 Spot monthly average emission price comparison: January 2017 through March 2018[39]




## 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).[40] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power,

38 There were no reported cleared purchases for January through March, 2017 for CSAPR $SO_2$.
39 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).
40 *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").

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).[41]

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).[42]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[43] 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.

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.[44] As a result, the national emissions standards uniformly apply to all RICE.[45] 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."[46] 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.[47]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[48] 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."[49] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[50]

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 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.[51] [52]

41 *Id.*
42 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."
43 *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.
44 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).
45 *Id.*
46 DENREC v. EPA at 3, 20–21.
47 *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.
48 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
49 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).
50 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).
51 See CAA § 111.
52 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.

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."[53] 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.[54] 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.[55] [56] 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 (the Clean Power Plan).[57] 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.[58]

53 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).
54 *Id.*
55 *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>.
56 79 Fed. Reg. 1352 (January 8, 2014).
57 *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."
58 North Dakota v. EPA, et al., Order 15A793.

The future of the Clean Power Plan is currently uncertain. On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the EPA Act.[59] On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.[60]

## 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).

The CWA applies to the waters of the United States (WOTUS). The CWA defines WOTUS as "navigable waters."[61] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[62] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[63] The U.S. Supreme Court reversed the stay, but the EPA amended the 2015 Clean Water Rule to establish an applicability date of February 6, 2020.[64] The proposed rule would restore the pre 2015 rule to the code and the interpreting precedent applicable to the pre 2015 rule. As a result of the new applicability date, the pre 2015 rule is now in effect. The pre 2015 rule includes all navigable waters and waters with a "significant nexus" to such waters.[65]

EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

59 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).
60 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).
61 33 U.S.C. § 1362(7).
62 80 Fed. Reg. 37054 (June 29, 2015).
63 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.
64 *See Definition of "Waters of the United States"–Addition of an Applicability Date to 2015 Clean Water Rule*, Final Rule, EPA Docket No. EPA-HQ-OW-2017-0644, 83 Fed. Reg. 5200 (Feb. 6, 2018); National Assoc. of Mfg. v Dept. of Defense, No. 16-299 (S. Ct. Jan. 22, 2018).
65 Rapanos v. U.S., 547 U.S. 715 (2006).

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[66] 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 include 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 WOTUS and has a design intake flow of greater than two million gallons per day (mgd).[67]

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.

66 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. EPA issued a rule providing an expansive definition of "waters of the United States" in 2015 that the current administration has indicated intent to review. See Executive Order: Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the "Waters of the United States" Rule (February 28, 2017) referring to "*Clean Water Rule: Definition of 'Waters of the United States*,'" 80 Fed. Reg. 37054 (June 29, 2015).

67 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).

## Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[68]

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.[69] 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

68 42 U.S.C. §§ 6901 *et seq.*

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

restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

Table 8-2 describes the criteria and anticipated implementation dates.

### Table 8-2 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.[70] 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.[71] $NO_x$ emissions limits for coal units became effective December 15, 2012.[72] $NO_x$ emissions limits for other unit types became effective May 1, 2015.[73] As of December 31, 2017, 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.[74] 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.

Table 8-3 shows the HEDD emissions limits applicable to each unit type.

70 N.J.A.C. § 7:27-19.
71 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
72 N.J.A.C. § 7:27-19.4.
73 N.J.A.C. § 7:27-19.5.
74 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

Table 8-3 HEDD maximum $NO_X$ emission rates[75]

| 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).[76] 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.[77] 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.[78]

## 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.[79] On January 29, 2018, New Jersey Governor Phil Murphy signed an executive order to take all steps necessary to rejoin the RGGI program.[80] RGGI generates revenues for the participating states which have spent approximately 64 percent of revenues on energy efficiency, 16 percent on clean and renewable energy, 4 percent on greenhouse gas abatements and 10 percent on direct bill assistance.[81]

Table 8-4 shows the RGGI $CO_2$ auction clearing prices and quantities for the 2009–2011 compliance period auctions, the 2012–2014 compliance period auctions and 2015–2018 compliance period auctions held as of March 31, 2018, in short tons and metric tonnes.[82] Prices for auctions held March 14, 2018, were at \$3.79 per allowance (equal to one ton of $CO_2$), above the current price floor of \$2.21 for RGGI auctions.[83] 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 clearing price of \$3.80 in December 2017.

75 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.
76 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for $NO_X$ and $SO_2$ (CPS)).
77 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).
78 See *Id.*
79 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>.
80 *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.
81 RGGI. *The Investment of RGGI Proceeds in 2015*, The Regional Greenhouse Gas Initiative, <https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2015.pdf>. (October 2017).
82 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 auctions to use CRRs.
83 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 8-4 RGGI $CO_2$ allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2018 Compliance Periods[84]

| | 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 |
| March 8, 2017 | $3.00 | 14,371,300 | 14,371,300 | $3.31 | 13,037,428 | 13,037,428 |
| June 7, 2017 | $2.53 | 14,597,470 | 14,597,470 | $2.79 | 13,242,606 | 13,242,606 |
| September 8, 2017 | $4.35 | 14,371,585 | 14,371,585 | $4.80 | 13,037,686 | 13,037,686 |
| December 8, 2017 | $3.80 | 14,687,989 | 14,687,989 | $4.19 | 13,324,723 | 13,324,723 |
| March 14, 2018 | $3.79 | 13,553,767 | 13,553,767 | $4.18 | 12,295,774 | 12,295,774 |

84 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2018).

## 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.[85] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under 10 year contracts with select Illinois nuclear power plants.[86]

IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[87] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[88] 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."[89]

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.[90]

On February 14, 2017, the Electric Power Supply Association (EPSA) and others filed a complaint in the U.S. District Court for the Northern District of Illinois Eastern Division.[91] State defendants have filed a motion to dismiss and EPSA et al. have filed a motion for a stay. On April 24, 2017, the MMU filed an amicus curiae brief opposing the motion to dismiss and supporting the motion for a stay. The District Court granted the motion to dismiss on July 14, 2017. EPSA appealed to the U.S. Court of Appeals for the Seventh Circuit.

85 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>.
86 See IPAA § 1-75(d-5)(1).
87 See *id.*
88 See IPAA § 1-75(d-5)(1)(B).
89 See *id.*
90 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), <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 7, 2016) (reporting Exelon statement that Byron is "economically challenged"), <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.
91 Case No. 17-cv-01164.

On September 6, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

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.[92] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[93] 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 program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[94] 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.[95] In a decision issued July 25, 2017, the District Court dismissed the case. The Coalition for Competitive Electricity appealed to the U.S. Court of Appeals for the Second Circuit. On October 23, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

## 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 fulfill 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 March 31, 2018, 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 March 31 2018, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

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.[96]

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.[97]

92 OATT Attachment DD § 5.14(h).
93 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).
94 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).
95 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).
96 See the Indiana Utility Regulatory Commission's "2017 Annual Report," at 37 (Oct. 2017) <http://www.in.gov/iurc/files/IURC%20annual%20report%20web.pdf>.
97 See Enr. Com. Sub. For H. B. No. 2001.

Table 8-5 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. Washington, DC will require 38 percent of load to be served by renewable resources in 2029, 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.[98] On December 15, 2016, the Michigan State Senate approved Senate Bill 438 (S.B. 438) which increased the Michigan RPS percent requirements. The previous version of the bill required that 10 percent of retail electric load in Michigan be served by renewable and alternative energy resources in 2015 and subsequent years. S.B. 438 increased the percent of retail electric load to be served by renewable and alternative energy resources in Michigan to be 12.5 percent in 2019 and 2020 and 15 percent in 2021 and subsequent years.[99] In February 2017, the Maryland State House approved House Bill 1106 which increased the total RPS requirement from 20 percent by 2022 to 25 percent by 2020.

### Table 8-5 Renewable standards of PJM jurisdictions: 2018 to 2029[100]

| Jurisdiction with RPS | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Delaware | 17.50% | 19.00% | 20.00% | 21.00% | 22.00% | 23.00% | 24.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% |
| Illinois | 13.00% | 14.50% | 16.00% | 17.50% | 19.00% | 20.50% | 22.00% | 23.50% | 25.00% | 25.00% | 25.00% | 25.00% |
| Maryland | 18.30% | 20.40% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% | 25.00% |
| Michigan | 10.00% | 12.50% | 12.50% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% | 15.00% |
| New Jersey | 18.03% | 19.97% | 21.91% | 23.85% | 23.94% | 24.03% | 24.12% | 24.21% | 24.30% | 24.39% | 24.48% | 24.48% |
| North Carolina | 10.00% | 10.00% | 10.00% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% | 12.50% |
| Ohio | 4.50% | 5.50% | 6.50% | 7.50% | 8.50% | 9.50% | 10.50% | 11.50% | 12.50% | 12.50% | 12.50% | 12.50% |
| Pennsylvania | 14.70% | 15.20% | 15.70% | 18.00% | 18.00% | 18.00% | 18.00% | 18.00% | 18.00% | 18.00% | 18.00% | 18.00% |
| Washington, D.C. | 16.50% | 18.00% | 20.00% | 20.00% | 20.00% | 20.00% | 23.00% | 26.00% | 29.00% | 32.00% | 35.00% | 38.00% |
| **Jurisdiction with Voluntary Standard** | | | | | | | | | | | | |
| Indiana | 4.00% | 7.00% | 7.00% | 7.00% | 7.00% | 7.00% | 7.00% | 10.00% | 10.00% | 10.00% | 10.00% | 0.00% |
| Virginia | 7.00% | 7.00% | 7.00% | 7.00% | 12.00% | 12.00% | 12.00% | 15.00% | 15.00% | 15.00% | 15.00% | 0.00% |
| **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.

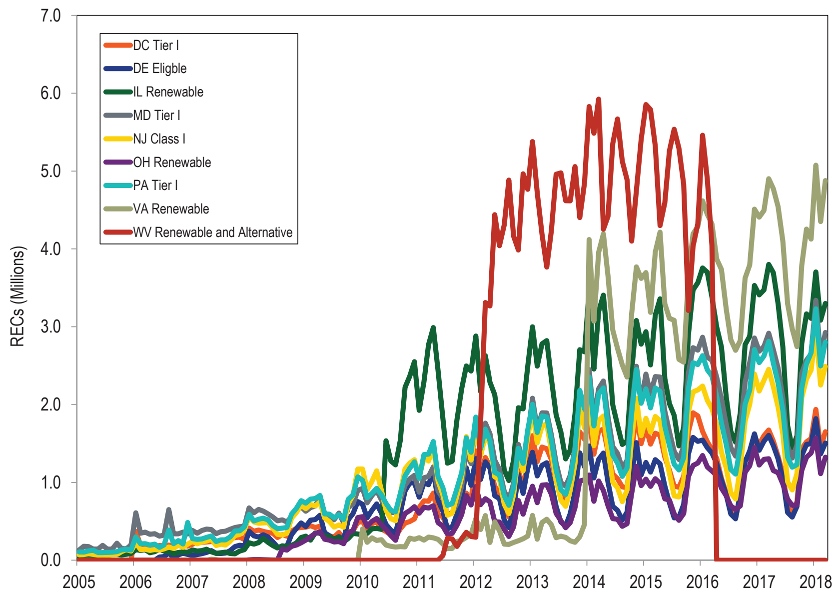
RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs typically have a shelf life of five years until they cannot be used to satisfy a state's RPS requirement.

Figure 8-2 shows the number of RECs eligible monthly by state for January 1, 2005, through March 31, 2018.[101] The figure includes Tier I or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania

98 See Council of the District of Columbia. B21-0650—Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed April 26, 2018).
99 See Michigan Legislature. Senate Bill 0438 (2015) <http://legislature.mi.gov/doc.aspx?2015-SB-0438> (Accessed April 26, 2018).
100 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
101 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed April 26, 2018).

classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and Wester Virginia classify these RECs as renewable or eligible. West Virginia repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard.

### Figure 8-2 Number of RECs eligible monthly by state: January 2005 through March 2018




The REC prices are 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.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through March 31, 2018. Tier I REC prices are lower than SREC prices.

### Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through March 2018

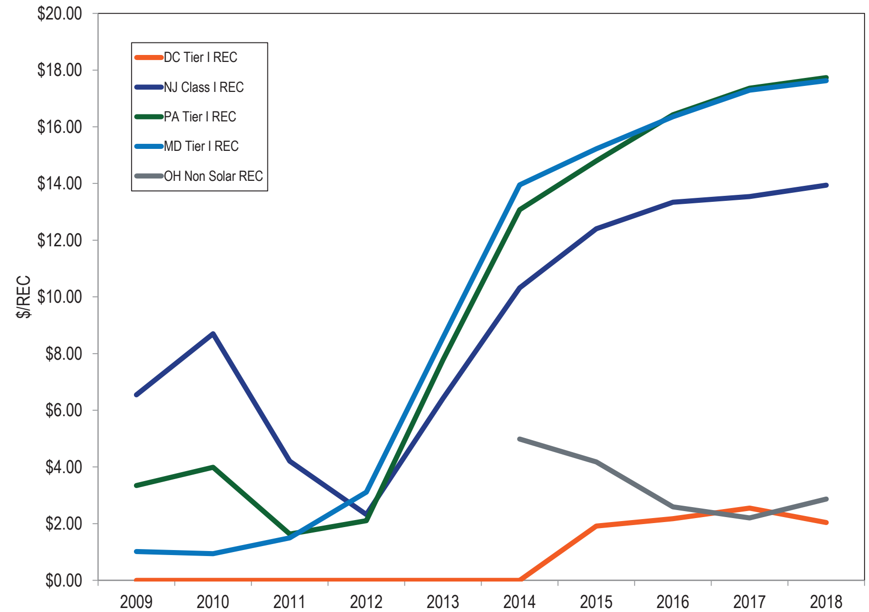


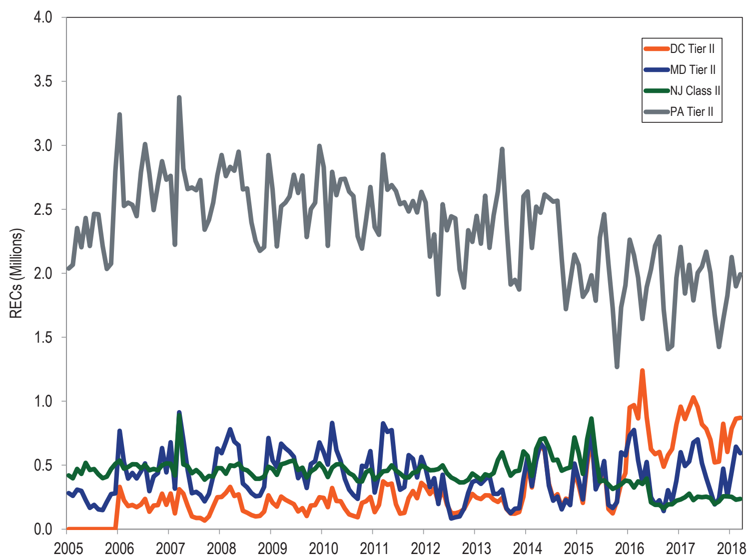

Table 8-6 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-6 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-6 are included in the total RPS requirements presented in Table 8-5. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 9.75 percent of load served in 2018 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.

## Table 8-6 Additional renewable standards of PJM jurisdictions: 2018 to 2029

| Jurisdiction | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Illinois | Wind Requirement | 9.75% | 10.88% | 12.00% | 13.13% | 14.25% | 15.38% | 16.50% | 17.63% | 18.75% | 18.75% | 18.75% | 18.75% |
| Illinois | Distributed Generation | 0.13% | 0.15% | 0.16% | 0.18% | 0.19% | 0.21% | 0.22% | 0.24% | 0.25% | 0.25% | 0.25% | 0.25% |
| Maryland | Tier II Standard | 2.50% | 0.00% | 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% |
| North Carolina | Swine Waste | 0.14% | 0.14% | 0.14% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% |
| North Carolina | Poultry Waste (in GWh) | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| Pennsylvania | Tier II Standard | 8.20% | 8.20% | 8.20% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% | 10.00% |
| Washington, D.C. | Tier II Standard | 1.00% | 0.50% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

Figure 8-4 shows the number of Tier II RECs eligible monthly by state for January 1, 2005 through March 31, 2018.[102] The figure includes Tier II or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

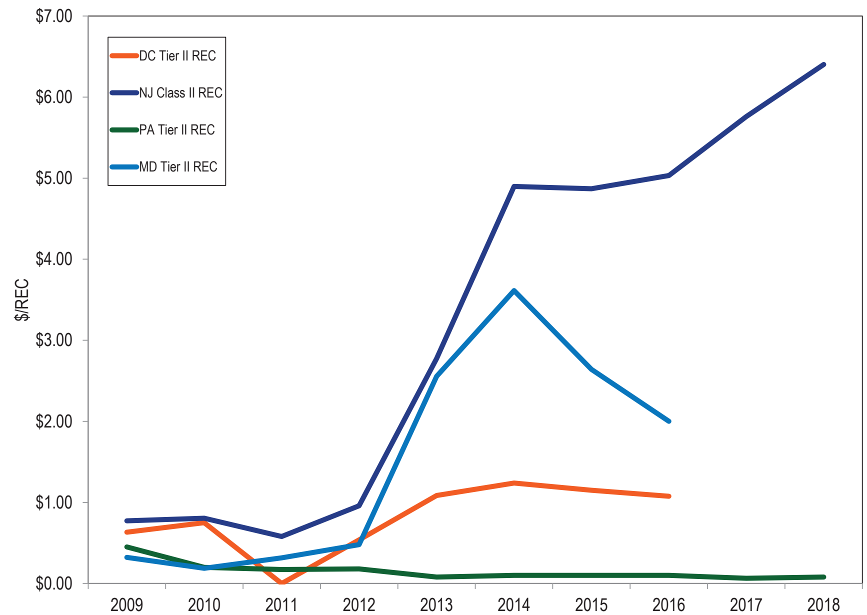
### Figure 8-4 Number of Tier II RECs eligible monthly by state: January 2005 through March 2018




102 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed April 26, 2018).

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009 through March 31, 2018. Pennsylvania had the lowest average Tier II REC prices at $0.08 per REC while New Jersey had the highest average Tier II REC prices at $6.40 per REC.[103]

### Figure 8-5 Average Tier II REC price by jurisdiction: January 2009 through March 2018[104]




103 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed April 26, 2018). There were not any reported cleared purchases for January 1, through March 31, 2018, for DC Tier II REC or MD Tier II RECs.

104 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 23, 2018). There were not any reported cleared purchases for January 1, through March 31, 2017 for DC Tier II REC, PA Tier II REC or MD Tier II RECs.

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-5 but must be met by solar RECs (SRECs) only. Table 8-7 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 2017, New Jersey has the most stringent solar standard in PJM, requiring that 3.0 percent of retail electricity sales within the state be served by solar resources. As Table 8-7 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.

### Table 8-7 Solar renewable standards by percent of electric load for PJM jurisdictions: 2018 to 2029

| Jurisdiction with RPS | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Delaware | 1.75% | 2.00% | 2.25% | 2.50% | 2.75% | 3.00% | 3.25% | 3.50% | 3.50% | 3.50% | 3.50% | 3.50% |
| Illinois | 0.78% | 0.87% | 0.96% | 1.05% | 1.14% | 1.23% | 1.32% | 1.41% | 1.50% | 1.50% | 1.50% | 1.50% |
| Maryland | 1.50% | 1.95% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |
| Michigan | No Minimum Solar Requirement | | | | | | | | | | | |
| New Jersey | 3.20% | 3.29% | 3.38% | 3.47% | 3.56% | 3.65% | 3.74% | 3.83% | 3.92% | 4.01% | 4.10% | 4.10% |
| North Carolina | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% | 0.20% |
| Ohio | 0.18% | 0.22% | 0.26% | 0.30% | 0.34% | 0.38% | 0.42% | 0.46% | 0.50% | 0.50% | 0.50% | 0.50% |
| Pennsylvania | 0.34% | 0.39% | 0.44% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% |
| Washington, D.C. | 1.15% | 1.35% | 1.58% | 1.85% | 2.18% | 2.50% | 2.60% | 2.85% | 3.15% | 3.45% | 3.75% | 4.10% |
| **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 | | | | | | | | | | | |

Figure 8-6 shows the number of SRECs eligible monthly by state for January 1, 2005 through March 31, 2018.[105]

## Figure 8-6 Number of SRECs eligible monthly by state: January 2005 through March 2018

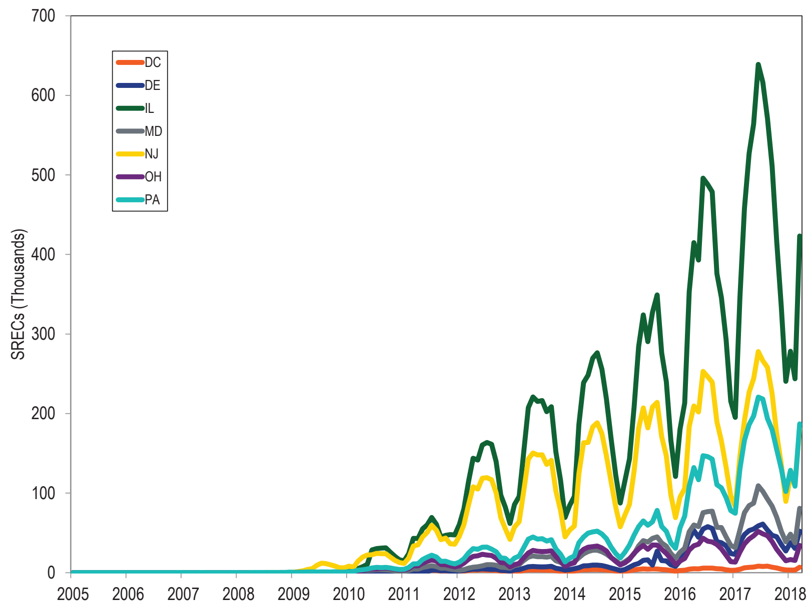



Figure 8-7 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009 through March 31, 2018. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from $673 per SREC in 2009 to $211 per SREC in the first three months of 2018. 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 $439 per SREC in the first three months of 2018.[106]

105 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed April 26, 2018).
106 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed April 26, 2018).

## Figure 8-7 Average SREC price by jurisdiction: January 2009 through March 2018

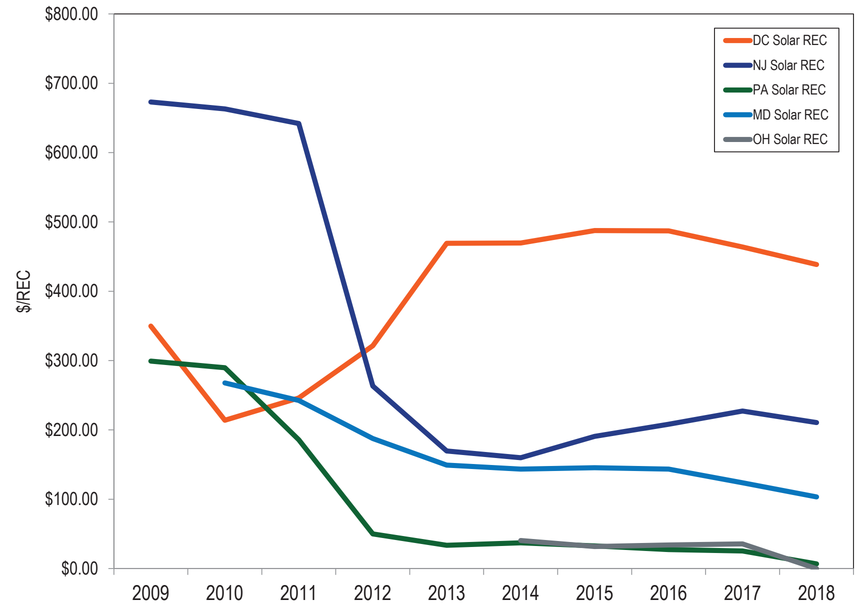
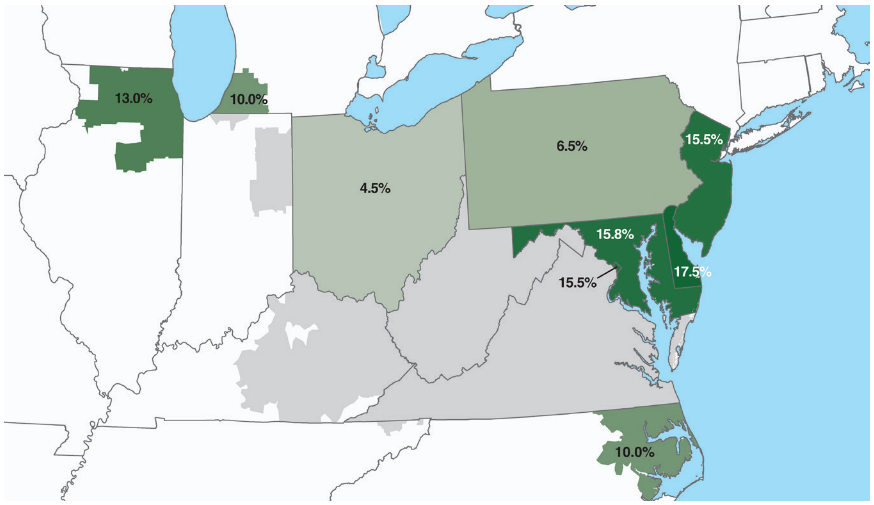
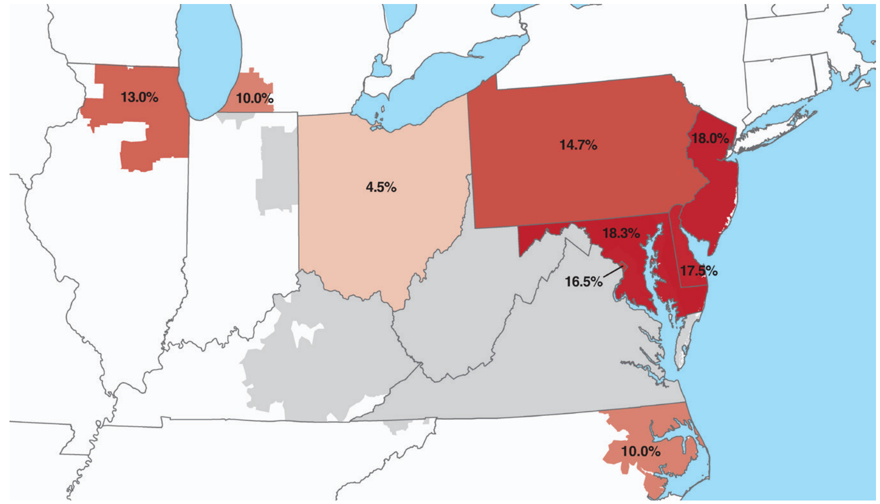



Figure 8-8 and Figure 8-9 show the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. Figure 8-8 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-8. Figure 8-9 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 gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. The 14.2 percent number in Figure 8-9 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

### Figure 8-8 Map of retail electric load shares under RPS - Tier I resources only: 2018




### Figure 8-9 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2018




Under the existing state renewable portfolio standards, approximately 9.3 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2018 and, if the proportion of load among states remains constant, 14.7 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 7.3 percent of PJM load must be served by Tier I renewables in 2018 and, if the proportion of load among states remains constant, 12.5 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 8-8 shows generation by jurisdiction and resource type for the first three months of 2018. Wind output was 7,395.3 GWh of 10,852.2 Tier I GWh, or 68.1 percent, in the PJM footprint. As shown in Table 8-8, 16,563.5 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 65.5 percent. Total wind and solar generation was 3.7 percent of total generation in PJM for the first three months of 2018. Tier I generation was 5.2 percent of total generation in PJM and Tier II was 2.7 percent of total generation for the first three months of 2018. Landfill gas, solid waste and waste coal were 4,980.2 GWh of renewable resource generation or 30.1 percent of the total Tier I and Tier II.

### Table 8-8 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through March, 2018

| | 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 | 8.4 | 0.0 | 0.0 | 0.0 | 8.4 | 0.0 | 0.0 | 0.0 | 0.0 | 8.4 |
| Illinois | 33.1 | 0.0 | 2.2 | 2,996.3 | 3,031.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3,031.6 |
| Indiana | 14.2 | 11.2 | 2.5 | 1,699.2 | 1,727.1 | 0.0 | 0.0 | 0.0 | 0.0 | 1,727.1 |
| Kentucky | 0.0 | 112.3 | 0.0 | 0.0 | 112.3 | 0.0 | 0.0 | 0.0 | 0.0 | 112.3 |
| Maryland | 18.8 | 602.8 | 32.6 | 182.4 | 836.7 | 0.0 | 161.0 | 0.0 | 161.0 | 997.7 |
| Michigan | 7.1 | 15.9 | 1.2 | 0.0 | 24.2 | 0.0 | 0.0 | 0.0 | 0.0 | 24.2 |
| New Jersey | 70.0 | 9.1 | 121.6 | 3.8 | 204.4 | 82.0 | 355.2 | 0.0 | 437.3 | 641.7 |
| North Carolina | 0.0 | 207.5 | 108.0 | 181.1 | 496.6 | 0.0 | 0.0 | 0.0 | 0.0 | 496.6 |
| Ohio | 90.0 | 37.7 | 0.2 | 544.2 | 672.1 | 0.0 | 0.0 | 0.0 | 0.0 | 672.1 |
| Pennsylvania | 199.1 | 900.7 | 4.7 | 1,174.6 | 2,279.1 | 437.4 | 298.6 | 2,186.6 | 2,922.6 | 5,201.7 |
| Tennessee | 0.0 | 172.7 | 0.0 | 0.0 | 172.7 | 0.0 | 0.0 | 0.0 | 0.0 | 172.7 |
| Virginia | 153.5 | 115.2 | 114.4 | 0.0 | 383.1 | 807.7 | 209.1 | 902.5 | 1,919.3 | 2,302.5 |
| 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 | 1.9 | 288.3 | 0.0 | 613.6 | 903.8 | 0.0 | 0.0 | 271.1 | 271.1 | 1,174.9 |
| Total | 596.0 | 2,473.4 | 387.5 | 7,395.3 | 10,852.2 | 1,327.2 | 1,024.0 | 3,360.2 | 5,711.3 | 16,563.5 |
| Percent of Renewable Generation | 3.6% | 14.9% | 2.3% | 44.6% | 65.5% | 8.0% | 6.2% | 20.3% | 34.5% | 100.0% |
| Percent of Total Generation | 0.3% | 1.2% | 0.2% | 3.5% | 5.2% | 0.6% | 0.5% | 1.6% | 2.7% | 7.9% |

Figure 8-10 shows the average hourly output by fuel type for January 1 through March 31 of 2014 through 2018. Tier I includes landfill gas, run-of-river hydro, solar and wind resources, as defined by the relevant states. Tier II includes pumped storage, solid waste and waste coal resources, as defined by the relevant states. Other includes biomass, miscellaneous, heavy oil, light oil, coal gas, propane, diesel, distributed generation, other biogas, kerosene and batteries.[107]

107 *2018 Quarterly State of the Market Report for PJM: January through March*, Section 3: Energy Market, Table 3-9.

### Figure 8-10 Average hourly output by fuel type: January through March, 2014 through 2018

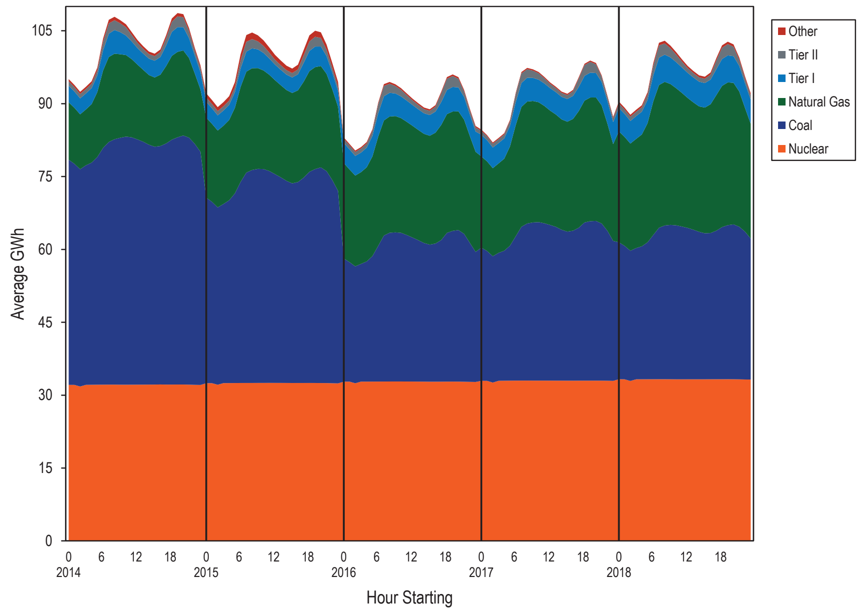



Table 8-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. 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, 502.6 MW, or 32.9 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2009 at $673 per REC, and in the first three months of 2018 are at $211 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,974.2 MW, or 61.1 percent of the total wind capacity.

Table 8-10 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 4,124.4 MW of which 1,821.7 MW is in New Jersey. These resources can 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.

### Table 8-9 PJM renewable capacity by jurisdiction (MW): March 31, 2018

| 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 | 49.3 | 360.0 | 0.0 | 0.0 | 0.0 | 9.0 | 0.0 | 0.0 | 3,152.2 | 3,570.5 |
| Indiana | 0.0 | 8.0 | 0.0 | 0.0 | 0.0 | 8.2 | 10.1 | 0.0 | 0.0 | 1,822.1 | 1,848.4 |
| 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 | 24.3 | 0.0 | 69.0 | 0.0 | 494.4 | 204.3 | 128.2 | 0.0 | 190.0 | 1,110.2 |
| Michigan | 0.0 | 8.0 | 0.0 | 0.0 | 0.0 | 13.9 | 4.6 | 0.0 | 0.0 | 0.0 | 26.5 |
| 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 | 502.6 | 162.0 | 0.0 | 4.5 | 1,211.3 |
| North Carolina | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 465.0 | 375.2 | 0.0 | 0.0 | 208.0 | 1,048.2 |
| Ohio | 9,910.0 | 68.2 | 0.0 | 156.0 | 0.0 | 119.1 | 1.1 | 0.0 | 0.0 | 569.8 | 10,824.2 |
| Pennsylvania | 0.0 | 201.8 | 2,346.0 | 0.0 | 1,269.0 | 893.3 | 19.5 | 261.8 | 1,611.0 | 1,367.2 | 7,969.6 |
| Tennessee | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 156.6 | 0.0 | 0.0 | 0.0 | 0.0 | 156.6 |
| Virginia | 0.0 | 134.1 | 0.0 | 17.0 | 5,166.2 | 350.5 | 401.3 | 123.0 | 585.0 | 0.0 | 6,777.1 |
| West Virginia | 0.0 | 5.4 | 0.0 | 0.0 | 0.0 | 257.9 | 0.0 | 0.0 | 165.0 | 686.3 | 1,114.6 |
| PJM Total | 9,910.0 | 584.8 | 4,503.0 | 255.0 | 6,888.2 | 2,936.3 | 1,527.8 | 675.0 | 2,361.0 | 8,146.0 | 37,787.1 |

### Table 8-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on March 31, 2018[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 | 141.5 | 0.0 | 141.5 |
| Arkansas | 0.0 | 0.0 | 0.0 | 0.0 | 18.0 | 0.0 | 0.0 | 0.0 | 0.0 | 18.0 |
| Delaware | 0.0 | 0.0 | 2.2 | 0.0 | 0.0 | 0.0 | 98.1 | 0.0 | 2.1 | 102.4 |
| Georgia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 85.1 | 258.9 | 0.0 | 344.0 |
| Illinois | 0.0 | 21.4 | 101.9 | 0.0 | 4.9 | 0.0 | 67.2 | 0.0 | 300.3 | 495.6 |
| Indiana | 0.0 | 0.0 | 49.6 | 0.0 | 5.2 | 94.6 | 66.6 | 0.0 | 180.0 | 395.9 |
| Iowa | 0.0 | 0.0 | 1.6 | 0.0 | 0.0 | 0.0 | 3.2 | 0.0 | 258.0 | 262.7 |
| Kentucky | 600.0 | 162.2 | 18.6 | 0.0 | 0.4 | 0.0 | 27.5 | 93.0 | 0.0 | 901.7 |
| Louisiana | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 129.2 | 0.0 | 129.2 |
| Maryland | 65.0 | 0.0 | 12.7 | 129.0 | 0.0 | 0.0 | 778.7 | 15.0 | 0.3 | 1,000.7 |
| Michigan | 55.0 | 1.3 | 4.8 | 0.0 | 0.0 | 0.0 | 3.2 | 31.0 | 0.0 | 95.3 |
| Missouri | 0.0 | 0.0 | 5.6 | 0.0 | 0.0 | 0.0 | 19.6 | 0.0 | 451.0 | 476.2 |
| New Jersey | 0.0 | 0.0 | 53.1 | 0.0 | 14.7 | 0.0 | 1,821.7 | 0.0 | 5.0 | 1,894.5 |
| New York | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 0.0 | 0.0 | 0.4 |
| North Carolina | 0.0 | 430.4 | 0.0 | 0.0 | 0.0 | 0.0 | 494.6 | 151.5 | 0.0 | 1,076.5 |
| North Dakota | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 360.0 | 360.0 |
| Ohio | 0.0 | 1.0 | 30.8 | 67.0 | 16.4 | 32.4 | 181.5 | 92.8 | 40.5 | 462.4 |
| Pennsylvania | 109.7 | 31.7 | 45.2 | 91.0 | 15.1 | 5.0 | 309.4 | 68.6 | 3.3 | 678.9 |
| South Carolina | 0.0 | 0.0 | 30.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 30.8 |
| Tennessee | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Texas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 57.7 | 0.0 | 57.7 |
| Virginia | 0.0 | 18.7 | 11.3 | 0.0 | 0.9 | 0.0 | 114.2 | 287.6 | 0.0 | 432.6 |
| West Virginia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.8 | 0.0 | 0.0 | 3.8 |
| Wisconsin | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 44.6 | 0.0 | 53.9 |
| District of Columbia | 0.0 | 0.0 | 0.0 | 0.0 | 14.4 | 0.0 | 49.2 | 0.0 | 0.0 | 63.6 |
| Total | 829.7 | 675.6 | 368.2 | 287.0 | 89.8 | 132.0 | 4,124.4 | 1,371.4 | 1,600.5 | 9,478.6 |

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[109] 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. FERC has found that such revenues can be appropriately considered in the rates established through the operation of wholesale organized markets.[110] 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.[111] 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.[112]

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 ultimately be traded. Table 8-11 shows the REC tracking systems used by each state within the PJM footprint.

108 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 8, 2018).

109 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we 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"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA… And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, … do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

110 See *ISO New England, Inc.*, 146 FERC ¶ 61,084 (2014) 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.").

111 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed March 6, 2018).

112 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.

### Table 8-11 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 8-12 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 added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard, be sourced from resources located within the PJM system.

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.

## Table 8-12 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 from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling. |
| 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 located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio. |
| Pennsylvania | Yes | RECs must be purchased from resources located within PJM. Additionally, all SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania. |
| 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. |

Table 8-13 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[113] [114] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

## Table 8-13 Carbon price per MWh by unit type

| | Carbon Price per MWh | | | | | | |
|---|---|---|---|---|---|---|---|
| Unit Type | Carbon $5/tonne | Carbon $10/tonne | Carbon $15/tonne | Carbon $50/tonne | Carbon $100/tonne | Carbon $200/tonne | Carbon $400/tonne |
| CT | $2.50 | $5.01 | $7.51 | $25.04 | $50.08 | $100.16 | $200.33 |
| CC | $1.77 | $3.54 | $5.32 | $17.72 | $35.45 | $70.89 | $141.78 |
| CP | $4.32 | $8.63 | $12.95 | $43.15 | $86.30 | $172.60 | $345.21 |

113 Heat rates from: *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, p 283, Table 7-4.
114 Carbon emissions rates from: *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed January 23, 2018).

Table 8-13 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the price of an SREC in New Jersey in first quarter of 2018 was $210.64 per MWh. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh produced by the solar resource resulted in avoiding the production of a MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price of approximately $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $25.04 per MWh.

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-14. The carbon price implied by the 2018 average REC price in Ohio of $5.73 per tonne is lower than the RGGI clearing price of $4.18 per tonne and lower than the social cost of carbon which is estimated in the range of $40 per tonne. The carbon price implied by the 2018 average

REC price in Washington, D.C. of $875.97 per tonne is multiples of the RGGI price and the social price of carbon. The carbon prices implied by REC prices in Maryland, New Jersey, and Pennsylvania for 2018 are also multiples of the RGGI clearing price. The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The prices implied by SREC prices are significantly greater than the prices implied by REC prices in each jurisdiction.

### Table 8-14 Implied carbon price based on REC and SREC prices: 2009 through 2018[115]

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Jurisdiction with Tier I or Class I REC** | Carbon Price ($ per Metric Tonne) Implied by REC Prices | | | | | | | | | |
| Delaware | | | | | $35.94 | $36.94 | $32.05 | $33.24 | $12.95 | |
| Maryland | $2.03 | $1.88 | $3.00 | $6.21 | $17.10 | $27.86 | $30.40 | $32.66 | $34.53 | $35.20 |
| New Jersey | $13.07 | $17.37 | $8.40 | $4.64 | $12.82 | $20.60 | $24.77 | $26.64 | $27.03 | $27.84 |
| Ohio | | | | | | $9.95 | $8.34 | $5.18 | $4.40 | $5.73 |
| Pennsylvania | $6.68 | $7.96 | $3.26 | $4.20 | $15.54 | $26.10 | $29.55 | $32.79 | $34.67 | $35.41 |
| Washington, D.C. | | | | | | | $3.83 | $4.35 | $5.09 | $4.07 |
| **Jurisdiction with Solar REC** | Carbon Price ($ per Metric Tonne) Implied by Solar REC Prices | | | | | | | | | |
| Delaware | | | | | | $114.81 | $83.63 | $85.71 | $42.45 | |
| Maryland | | $534.77 | $484.27 | $374.62 | $298.21 | $286.62 | $290.46 | $286.56 | $247.35 | $206.38 |
| New Jersey | $1,343.86 | $1,324.06 | $1,281.81 | $525.92 | $338.75 | $319.44 | $380.66 | $415.48 | $453.82 | $420.58 |
| Ohio | | | | | | $80.61 | $63.52 | $68.09 | $70.89 | |
| Pennsylvania | $597.38 | $578.30 | $370.81 | $99.69 | $66.92 | $74.33 | $65.50 | $54.58 | $50.81 | $13.45 |
| Washington, D.C. | $698.17 | $427.22 | $491.20 | $641.90 | $936.69 | $937.57 | $973.40 | $972.84 | $926.24 | $875.97 |
| **Regional Greenhouse Gas Initiative** | $CO_2$ Allowance Price ($ per Metric Tonne) | | | | | | | | | |
| RGGI clearing price | $3.06 | $2.12 | $2.08 | $2.13 | $3.22 | $5.21 | $6.72 | $4.93 | $3.77 | $4.18 |

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 the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $308.00 per MWh.[116] 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 plus the value of any solar rebates. 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.

115 The Delaware 2017 SREC price used in the derivation of the implied carbon price is the weighted average procurement price reported by the SREC Delaware Program <http://www.srecdelaware.com/documentation/>. All other SREC prices used in the derivation of the implied carbon price are average annual prices obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).

116 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 March 5, 2018).

Table 8-15 shows the alternative compliance standards for RPS in PJM jurisdictions.

### Table 8-15 Renewable alternative compliance payments in PJM jurisdictions: March 31, 2018[117] [118]

| 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 | $37.50 | $15.00 | $195.00 |
| Michigan | No specific penalties | | |
| New Jersey | $50.00 | | $308.00 |
| North Carolina | No specific penalties: At the discretion of the NC Utility Commission | | |
| Ohio | $50.24 | | $250.00 |
| Pennsylvania | $45.00 | $45.00 | 200% market value plus rebates |
| 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. The Pennsylvania Public Utility Commission issued their 2017 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 during the first quarter of 2018.[119] Pennsylvania reports that the 20,634,311 credits retired during the compliance year exceeded the amount required by the standards by 1,995 credits. Six alternative compliance payments were required to meet the Tier I standards and 14 alternative compliance payments were required to the meet the Tier II standards. The Public Service Commission of the District of Columbia published their 2017 compliance report on May 1, 2018.[120] The Public Service Commission reports that 1,645,545 credits were retired during the compliance year and there was a significant increase in compliance payments. Compliance payments were $26,571,010 for 2017, a 74.4 percent increase over the compliance payments for 2016. Solar standards contributed to the increase in compliance payments. Solar REC retirements in 2017 decreased 50.5 percent in 2017 with 30,765 solar RECs retired in 2017 and 62,173 retired in 2016.

117 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed February 7, 2018,).
118 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 7, 2018).
119 2017 "Annual Report – Alternative Energy Portfolio Standards Act of 2004", <http://www.pennaeps.com/reports/>.

## 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.[121] 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.[122] Of the current 61,231.1 MW of coal capacity in PJM, 57,260.0 MW of capacity, 93.5 percent, has some form

120 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017", Public Service Commission of the District of Columbia, <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.
121 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 5, 2018).
122 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 October 1, 2016).

of FGD (flue-gas desulfurization) technology to reduce $SO_2$ emissions. Table 8-16 shows $SO_2$ emission controls by fossil fuel fired units in PJM.[123] [124] [125]

### Table 8-16 $SO_2$ emission controls by fuel type (MW): March 31, 2018[126]

| | $SO_2$ Controlled | No $SO_2$ Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 57,260.0 | 3,971.1 | 61,231.1 | 93.5% |
| Diesel Oil | 0.0 | 5,949.6 | 5,949.6 | 0.0% |
| Natural Gas | 0.0 | 55,378.3 | 55,378.3 | 0.0% |
| Other | 325.0 | 4,920.7 | 5,245.7 | 6.2% |
| Total | 57,585.0 | 70,219.7 | 127,804.7 | 45.1% |

$NO_X$ emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 119,716.5 MW, 93.7 percent, of 127,804.7 MW of capacity in PJM, have emission controls for $NO_X$. Table 8-17 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.[127]

### Table 8-17 $NO_X$ emission controls by fuel type (MW): as of March 31, 2018

| | $NO_x$ Controlled | No $NO_x$ Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 60,387.3 | 843.8 | 61,231.1 | 98.6% |
| Diesel Oil | 2,207.6 | 3,742.0 | 5,949.6 | 37.1% |
| Natural Gas | 54,321.9 | 1,056.4 | 55,378.3 | 98.1% |
| Other | 2,799.7 | 2,446.0 | 5,245.7 | 53.4% |
| Total | 119,716.5 | 8,088.2 | 127,804.7 | 93.7% |

123 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 5, 2018).
124 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.
125 The total MW for each fuel type are less than the 183,837.0 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 5, 2018).
126 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.
127 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed March 5, 2018).

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.[128] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-18 shows particulate emission controls by unit type in PJM. In PJM, 60,897.1 MW out of 61,231.1 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of March 31, 2018. 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.[129] Currently, 140 of the 154 coal steam units have baghouse or FGD technology installed, representing 55,045.0 MW out of the 61,231.1 MW total coal capacity, or 89.9 percent.

### Table 8-18 Particulate emission controls by fuel type (MW): as of March 31, 2018

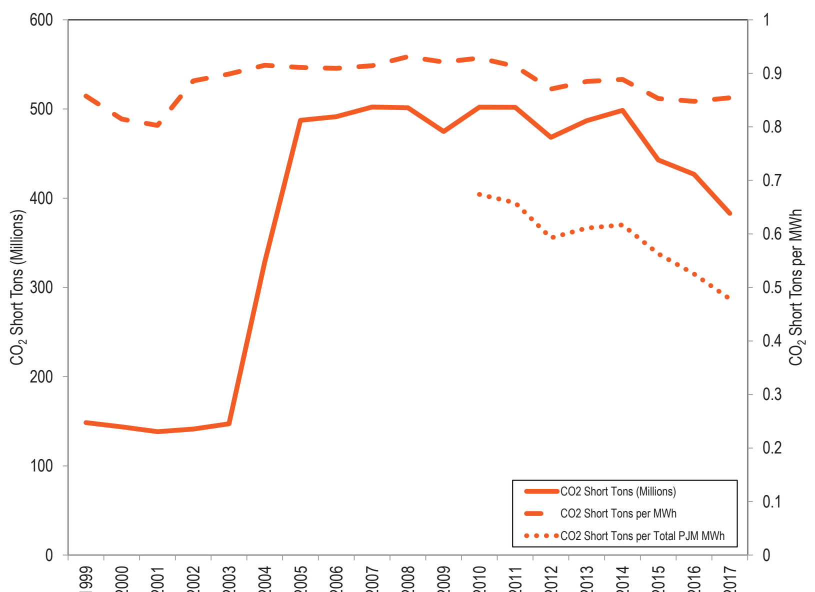
| | Particulate Controlled | No Particulate Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 60,897.1 | 334.0 | 61,231.1 | 99.5% |
| Diesel Oil | 0.0 | 5,949.6 | 5,949.6 | 0.0% |
| Natural Gas | 2,786.0 | 52,592.3 | 55,378.3 | 5.0% |
| Other | 3,102.0 | 2,143.7 | 5,245.7 | 59.1% |
| Total | 66,785.1 | 61,019.6 | 127,804.7 | 52.3% |

Figure 8-11 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 to 2017, as well as the $CO_2$ short ton emissions per MWh of total generation within PJM for 2010 to 2017.[130] [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 2008. In 2017, $CO_2$ emissions were 0.85 short tons per MWh. Total PJM generation decreased from 812,536.3 GWh in 2016 to 800,192.4 GWh in 2017, while $CO_2$ produced

128 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed March 5, 2018).
129 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 5, 2018).
130 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
131 Emissions data for the first three months was not yet available at the time of this report.

decreased from 426.8 million tons in 2016 to 383.1 million tons in 2017.[132] The reduction in $CO_2$ emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-12 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 2017. 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 2001, 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 0.80 short tons per MWh in 2001, and a maximum of 0.92 short tons per MWh in 2008. In 2017, $CO_2$ emissions were 0.87 short tons per MWh and 0.84 short tons per MWh for off and on peak hours.

### Figure 8-11 $CO_2$ emissions by year (millions of short tons), by PJM units: 1999 through 2017[133]




132 See *2017 State of the Market Report for PJM*, Section 3: Energy Market, Table 3-9.

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

### Figure 8-12 $CO_2$ emissions during on and off peak hours by year (millions of short tons), by PJM units: 1999 through 2017[134]

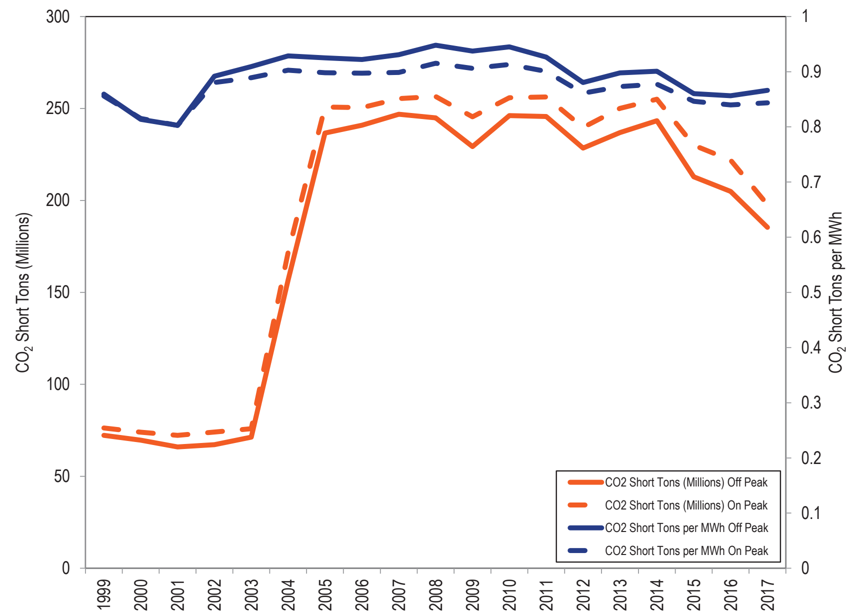


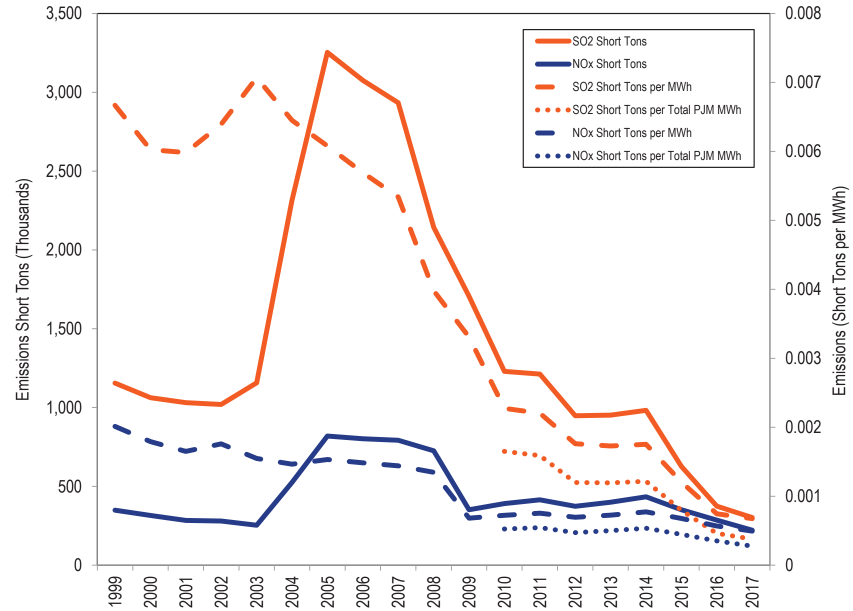

Figure 8-13 shows the total $SO_2$ and $NO_X$ short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all $SO_2$ and $NO_X$ emitting units, for each year from 1999 to 2017, as well as the $SO_2$ and $NO_X$ short ton emissions per MWh of total generation within PJM for 2010 to 2017. Since 1999 the amount of $SO_2$ produced per MWh was at a minimum of 0.000675 short tons per MWh in 2017, and a maximum of 0.007069 short tons per MWh in 2003. Since 1999, the amount of $NO_X$ produced per MWh was at a minimum of 0.000495 short tons per MWh in 2017, and a maximum of 0.002013 short tons per MWh in 1999. In 2017, $SO_2$ emissions were 0.000675 short tons per MWh and $NO_X$ emissions were 0.000495 short tons per MWh. The consistent decline in $SO_2$ and $NO_X$

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

emissions starting in 2006 is the result of a decline in the use of coal from 2006 to 2017.

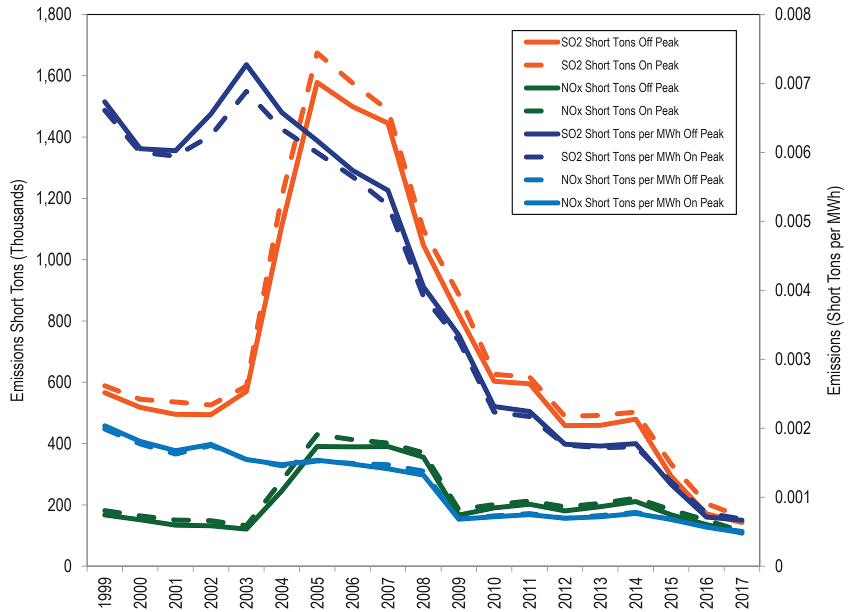
Figure 8-14 shows the total on peak hour and off peak hour $SO_2$ and $NO_X$ short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all $SO_2$ and $NO_X$ emitting units, for each year from 1999 to 2017. Since 1999 the amount of $SO_2$ produced per MWh during off peak hours was at a minimum of 0.000666 short tons per MWh in 2017, and a maximum of 0.007271 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 0.000683 short tons per MWh in 2017, and a maximum of 0.006884 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 0.000505 short tons per MWh in 2017, and a maximum of 0.001987 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 0.000486 short tons per MWh in 2017, and a maximum of 0.002037 short tons per MWh in 1999. In 2017, $SO_2$ emissions were 0.000666 short tons per MWh and 0.000683 short tons per MWh for off and on peak hours. In 2017, $NO_X$ emissions were 0.000505 short tons per MWh and 0.000486 short tons per MWh for off and on peak hours.

Figure 8-13 $SO_2$ and $NO_X$ emissions by year (thousands of short tons), by PJM units: 1999 through 2017[135]




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

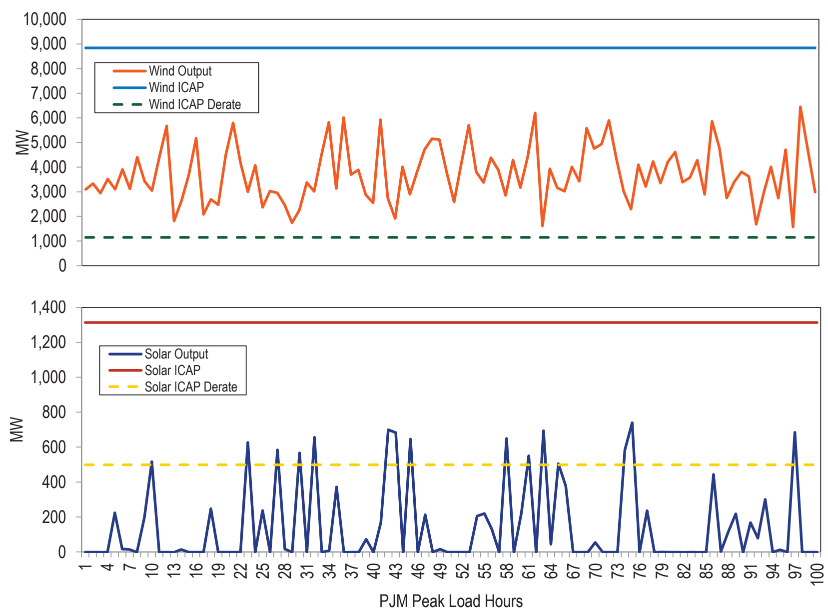
Figure 8-14 $SO_2$ and $NO_x$ emissions during on and off peak hours by year (thousands of short tons), by PJM units: 1999 through 2017[136]




## 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 8-15 shows the wind and solar output during the top 100 load hours in PJM for the first three months of 2018. The top 100 load hours in PJM during the first three months of 2018, 62 are within PJM defined peak load periods. 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 all 100 hours and below the derated ICAP for 0hours of the top 100 peak load hours of the first three months of 2018. Wind output was above the derated ICAP 1,981 hours and below the derated ICAP for 178 hours for the first three months of 2018. The wind capacity factor for the top 100 peak load hours of the first three months of 2018 is 42.1 percent. Solar output was above the derated ICAP for 15 hours and below the derated ICAP for 85 hours of the top 100 peak load hours of the first three months of 2018. Solar output was above the derated ICAP 367 hours and below the derated ICAP for 1,792 hours for the first three months of 2018. The solar capacity factor for the top 100 peak load hours of the first three months of 2018 is 10.6 percent.

Figure 8-15 Wind and solar output during the top 100 peak load hours in PJM: January through March, 2018




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

## Wind Units

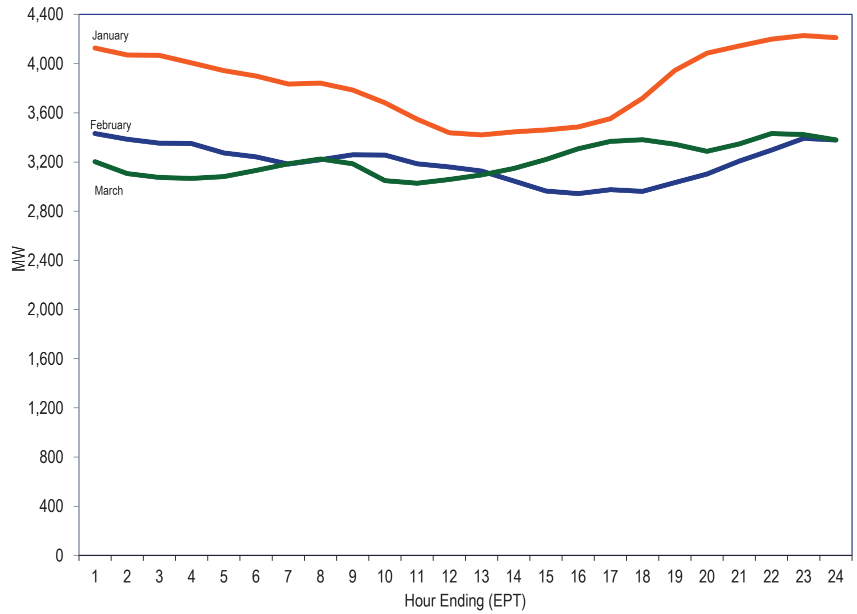
Table 8-19 shows the capacity factor of wind units in PJM. In the first three months of 2018, the capacity factor of wind units in PJM was 43.6 percent. Wind units that were capacity resources had a capacity factor of 43.2 percent and an installed capacity of 7,569 MW. Wind units that were classified as energy only had a capacity factor of 47.4 percent and an installed capacity of 895 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 8-19 Capacity factor of wind units in PJM: January through March, 2018[138]

| Type of Resource | Capacity Factor | Installed Capacity (MW) |
|---|---|---|
| Energy-Only Resource | 47.4% | 895 |
| Capacity Resource | 43.2% | 7,569 |
| All Units | 43.6% | 8,463 |

Figure 8-16 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through March 31, 2018. The hour with the highest average output, 4,228 MW, occurred in January, and the hour with the lowest average output, 2,944 MW, occurred in February. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

### Figure 8-16 Average hourly real-time generation of wind units in PJM: January through March, 2018




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.

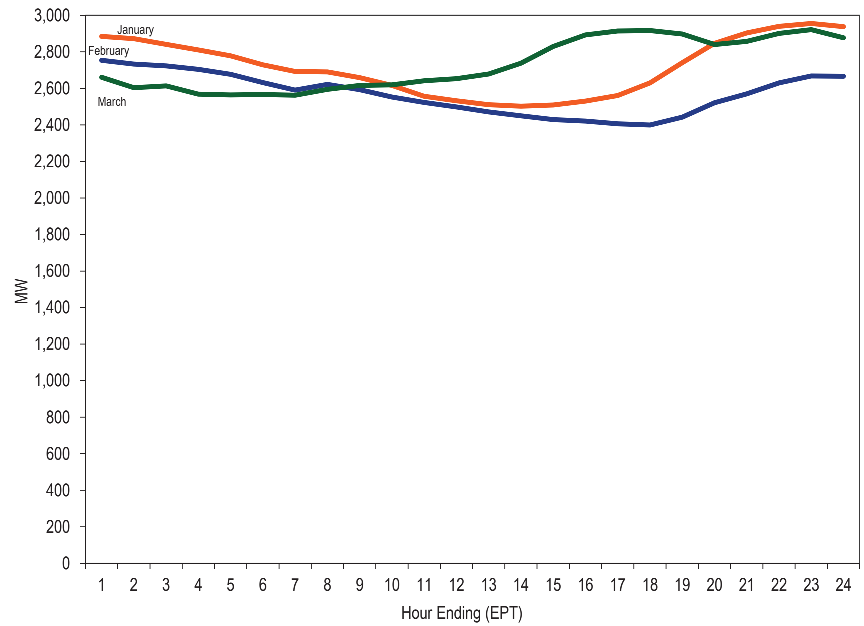
Table 8-20 shows the generation and capacity factor of wind units in each month of January 1, 2017 through March 31, 2018.

### Table 8-20 Capacity factor of wind units in PJM by month: January 2017 through March 2018

| | 2017 | | 2018 | |
|---|---|---|---|---|
| Month | Generation (MWh) | Capacity Factor | Generation (MWh) | Capacity Factor |
| January | 2,016,120.9 | 37.8% | 2,856,292.5 | 48.3% |
| February | 2,178,159.8 | 44.4% | 2,148,206.1 | 40.4% |
| March | 2,299,037.1 | 42.5% | 2,387,719.3 | 41.7% |
| April | 2,071,212.0 | 39.8% | | |
| May | 1,824,269.0 | 34.7% | | |
| June | 1,456,609.5 | 28.6% | | |
| July | 809,478.9 | 16.9% | | |
| August | 689,983.0 | 15.0% | | |
| September | 908,311.6 | 19.0% | | |
| October | 1,916,644.9 | 35.6% | | |
| November | 2,197,021.1 | 40.2% | | |
| December | 2,149,119.8 | 42.0% | | |
| Annual | 20,515,967.5 | 33.4% | 7,392,217.9 | 43.6% |

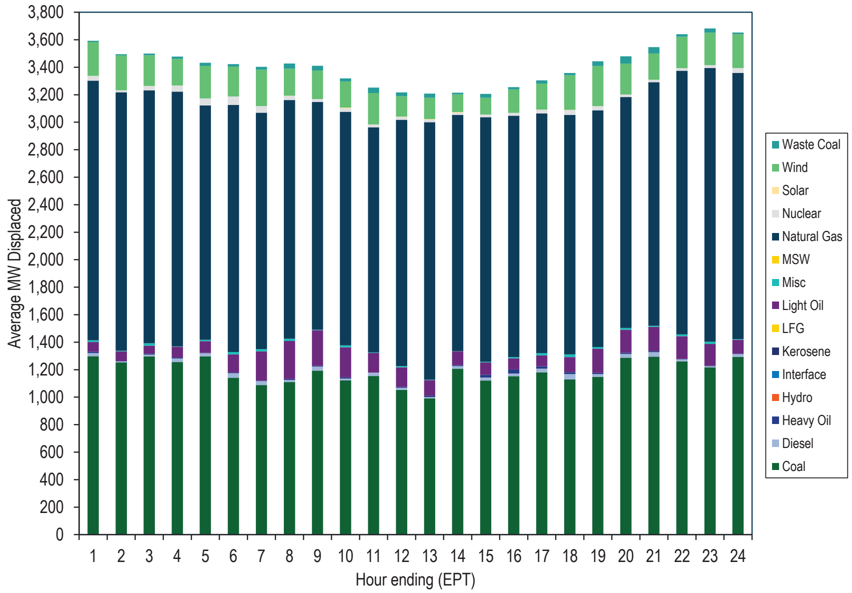
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer noncapacity related wind energy at their discretion. Figure 8-17 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.

### Figure 8-17 Average hourly day-ahead generation of wind units in PJM: January through March, 2018




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 8-18 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first three months of 2018. 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 8-18 Marginal fuel at time of wind generation in PJM: January through March, 2018




## 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 8-10, there are 3,959.8 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 8-21 shows the capacity factor of solar units in PJM. In the first three months of 2018, the capacity factor of solar units in PJM was 17.5 percent. Solar units that were capacity resources had a capacity factor of 17.9 percent and an installed capacity of 1,114 MW. Solar units that were classified as energy only had a capacity factor of 15.0 percent and an installed capacity of 199 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 8-21 Capacity factor of solar units in PJM: January 1 through March 31, 2018

| Type of Resource | Capacity Factor | Installed Capacity (MW) |
|---|---|---|
| Energy-Only Resource | 15.0% | 199 |
| Capacity Resource | 17.9% | 1,114 |
| All Units | 17.5% | 1,313 |

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-19 shows the average hourly real-time generation of solar units in PJM, by month. 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 8-19 Average hourly real-time generation of solar units in PJM: January through March, 2018

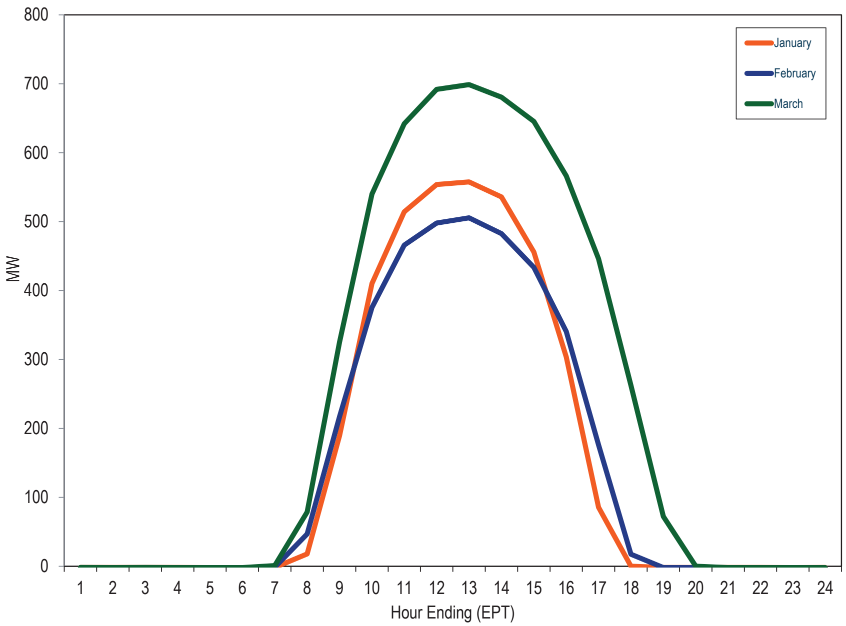



Table 8-22 shows the generation and capacity factor of solar units in each month of January 1, 2017 through March 31, 2018.

Table 8-22 Capacity factor of solar units in PJM by month: January 2017 through March 2018

| | 2017 | | 2018 | |
|---|---|---|---|---|
| Month | Generation (MWh) | Capacity Factor | Generation (MWh) | Capacity Factor |
| January | 47,456.3 | 11.6% | 100,302.6 | 15.7% |
| February | 84,111.1 | 21.7% | 88,853.0 | 14.5% |
| March | 109,498.1 | 25.0% | 155,528.4 | 22.8% |
| April | 121,835.3 | 27.5% | | |
| May | 127,944.3 | 26.9% | | |
| June | 146,226.0 | 30.5% | | |
| July | 144,300.0 | 28.6% | | |
| August | 133,780.1 | 26.3% | | |
| September | 125,731.7 | 25.4% | | |
| October | 104,658.9 | 19.1% | | |
| November | 90,442.5 | 16.3% | | |
| December | 61,707.8 | 12.0% | | |
| Annual | 1,297,692.0 | 22.5% | 344,684.0 | 17.9% |

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 noncapacity related solar energy at their discretion. Figure 8-20 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.

**Figure 8-20 Average hourly day-ahead generation of solar units in PJM: January through March, 2018**