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 affected offer behavior in the capacity market. Expectations about the cost and life of such investments and about future capacity and energy prices have affected retirement decisions. The markets have also provided incentives for new, lower emission units to enter.

Environmental requirements and initiatives at both the federal and state levels, 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 resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

Overview

Federal Environmental Regulation

- **MATS.** 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] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[2] The list of coal steam units subject to MATS, however, remains in place.[3] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS. The EPA's May 22, 2020, finding is under review pursuant to Executive Order 13990.
- **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.[4] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[5]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[6] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup,

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 (Feb. 16, 2012).

2 *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA–HQ–OAR–2018–0794, 85 Fed. Reg. 31286.

3 *Id.* at 31291.

4 CAA § 110(a)(2)(D)(i)(I).

5 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).

6 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA–HQ–OAR–2018–0048; FRL–9997–95–OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

emergency or supplemental power. RICE must be tested annually.[7] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan (CPP), which ACE had replaced.[8] Neither the ACE nor CPP is currently effective.

- **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.[9]

- **Waters of the United States.** On June 9, 2021, the EPA and the Department of the Army concluded their review pursuant to Executive Order 13990 and announced their intention to initiate a new rulemaking process and develop a new definition of Waters of the United States that restores and improves upon the protections in place prior to the 2015. As a result of recent Court action, the pre 2015 regulatory regime for interpreting WOTUS is now effective.

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[10] The EPA has proposed significant changes to the implementing regulations.

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 Jersey, New York, Rhode Island, Vermont and Virginia that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[11] Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join.[12] [13] The auction price in the September 8, 2021, auction was $9.30 per short ton, or $10.25 per metric tonne.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.52 per MWh or 70.5 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 70.8 percent for a new combined cycle (CC) unit and $43.15 per MWh or 136.2 percent for a new coal plant (CP) for January through September, 2021.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring 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 September 30, 2021, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. Indiana has voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.

7 See 40 CFR § 63.6640(f).
8 American Lung Association et al. v. EPA, No. 19-1140.
9 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).
10 42 U.S.C. §§ 6901 *et seq.*
11 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
12 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.
13 Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $5.6 billion over the six year period from 2014 through 2019, an average annual RPS compliance cost of $936.7 million. The compliance cost for 2019, the most recent year with almost complete data, was $1.2 billion.[14]

Emissions Controls in PJM Markets

- **Regulations.** 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.
- **Emissions Controls.** In PJM, as of September 30, 2021, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.8 percent of coal steam MW had some type of particulate control, and 94.6 percent of fossil fuel fired capacity had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.0 percent of total generation in PJM in the first nine months of 2021. RPS Tier I generation was 5.4 percent of total generation in PJM and RPS Tier II generation was 2.2 percent of total generation in PJM in the first nine months of 2021. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.

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.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. 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.[15] The MMU recommends that

14 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

15 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.").

the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. 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. FERC's recent MOPR order addressed these impacts.

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 the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to states in order to permit states to consider the development of a multistate framework: for RECs markets; for potential agreement on carbon pricing including the distribution of carbon revenues; and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $9.52 per tonne in Washington, DC to $19.38 per tonne in Maryland. The price of carbon implied by SREC prices ranges from $68.49 per tonne in Pennsylvania to $872.95 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in June 2021 of $10.25 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[16] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.71 per MWh.[17] The impact of an $800 per tonne carbon price would be $267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

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 offers 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 ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

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

16 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

17 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. Such modeling information would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state. This would permit states to make critical decisions about carbon pricing. For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price 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.

The annual average cost of complying with RPS over the six year period from 2014 through 2019 for the nine jurisdictions that had RPS was $936.7 million, or a total of $5.6 billion over six years. The RPS compliance cost for 2019, the most recent year for which there is almost complete data, was $1.2 billion.[18] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $3.1 billion per year if the carbon price were $9.30 per short ton and emissions levels were five percent below 2020 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $16.6 billion if the carbon price were $50 per short ton and emission levels were five percent below 2020 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $9.30 per short ton would be about $2.1 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[19]

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.[20 21]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[22] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

18 The 2019 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

19 For more details, see the *2019 State of the Market Report for PJM*, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."

20 42 U.S.C. § 7401 et seq. (2000).

21 The EPA defines a "major source" 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.

22 42 U.S.C. §§ 6901 *et seq.*

The EPA's actions have affected 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.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.

On May 22, 2020, the EPA published a rule finalizing its Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.[23] The EPA determined that the estimated cost to coal and oil fired power plants of complying with the MATS rule in 2015 outweighed the estimated quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions in 2015.[24] The EPA determined that based on analysis of costs versus benefits it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.[25] [26] The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.[27] Removal of the appropriate and necessary finding creates the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On January 20, 2021, an executive order was issued stating national objectives "to listen to the science; to improve public health and protect our environment; to ensure access to clean air and water; to limit exposure to dangerous chemicals and pesticides; to hold polluters accountable, including those who disproportionately harm communities of color and low-income communities; to reduce greenhouse gas emissions; to bolster resilience to the impacts of climate change; to restore and expand our national treasures and monuments; and to prioritize both environmental justice and the creation of the well-paying union jobs necessary to deliver on these goals" ("Executive Order 13990").[28] The order directs government agencies to immediately review, and as appropriate and consistent with applicable law, "take action to address the promulgation of Federal regulations and other actions during the last 4 years that conflict with these important national objectives, and to immediately commence work to confront the climate crisis."[29] The May 22, 2021, supplemental finding on MATS is an action specified for review.[30]

On April 9, 2020, the EPA finalized a rule establishing a new sub category in the MATS with less stringent requirements for units fueled by eastern bituminous refuse coal, waste coal.[31] The rule allows four refuse coal plants, Grant Town Power Plant (Unit 1A and 1 B (40 MW each)) in West Virginia; and Colver Power Project (110 MW), Ebensburg Power Plant (50 MW), and Scrubgrass Generating Co. (Units 1 and 2 (42 MW each)) in Pennsylvania; to emit higher levels of acid gases and SO_2.[32] The EPA stated that it was concerned that units would close and leave coal refuse piles, which are prone to smoldering and emit uncontrolled acid gases and other HAP.[33]

CAA: NAAQS/CSAPR

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,

23 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA–HQ–OAR–2018–0794, 85 Fed. Reg. 31286.

24 *Id.* at 31299.

25 Michigan v. EPA, 135 S.Ct. 2699 (2015) (reversed EPA determination that cost does not have to be read into the definition of "appropriate").

26 85 Fed. Reg. at 31288.

27 *Id.* at 31291. The EPA explains (*id.*): "The Court's holding in *New Jersey* [517 F.3d 574 (D.C. Cir. 2008)] plainly states that CAA section 112(c)(9) 'unambiguously limit[s] EPA's discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.' 517 F.3d 574, 583 (D.C. Cir. 2008)."

28 *See* President Joseph R. Biden Jr., Executive Order 13990 re "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" ("Executive Order 13990").

29 *Id.* (Sec. 1).

30 *Id.* at Sec. 2(iv).

31 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Subcategory of Certain Existing Electric Utility Steam Generating Units Firing Eastern Bituminous Coal Refuse for Emissions of Acid Gas Hazardous Air Pollutants*, Docket No. EPA–HQ–OAR–2018–0794, 85 Fed. Reg. 20838 (April 15, 2020).

32 *Id.* at 20841.

33 *Id.* at 20847.

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).

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. 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. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[34]

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[35] the EPA finalized increases to the good neighbor obligations (i.e. reduced allowable emissions) under the 2008 ozone NAAQS for 12 states.[36] Eleven of the affected states are PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The EPA determined that Tennessee's emissions budget "fully eliminated the state's significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS."[37] For the remaining PJM states, projected 2021 emissions were found to contribute at or above a threshold of 1 percent of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.[38] Starting with the 2021 ozone season for emissions trading under CSAPR, the new FIPs require power plants in the affected states (also including Louisiana and New York) to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program.[39] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NOx Ozone Season Group 2 Trading Program.[40 41]

The EPA's new emissions budgets for each PJM state for each ozone season for 2021 through 2024, and beyond are shown in Table 8-1. Table 8-1 also includes the states budgets that would have been in effect had the rules not been revised.

Table 8-1 CSAPR NO_X ozone season group 3 state budgets: 2021 through 2024[42 43]

	Emissions Budget (Tons)							
	Budget without revised rule				Revised Budget			
PJM State	2021	2022	2023	2024+	2021	2022	2023	2024+
Illinois	9,368	9,368	8,413	8,292	9,102	9,102	8,179	8,059
Indiana	15,856	15,383	15,357	12,232	13,051	12,582	12,553	9,564
Kentucky	15,588	15,588	15,588	15,588	15,300	14,051	14,051	14,051
Maryland	1,501	1,267	1,267	1,350	1,499	1,266	1,266	1,348
Michigan	13,898	13,459	11,182	10,968	12,727	12,290	9,975	9,786
New Jersey	1,346	1,346	1,346	1,346	1,253	1,253	1,253	1,253
Ohio	15,829	15,927	15,927	15,927	9,690	9,773	9,773	9,773
Pennsylvania	11,896	11,896	11,896	11,896	8,379	8,373	8,373	8,373
Virginia	4,664	4,274	4,361	4,025	4,516	3,897	3,980	3,663
West Virginia	15,165	15,165	15,165	15,165	13,334	12,884	12,884	12,884

Figure 8-1 shows average, monthly settled prices for NO_X and SO_2 emissions allowances including CSAPR related allowances for 2020 and the first nine months of 2021. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first nine months of 2021, CSAPR annual NO_X prices were 1.1 percent higher on average than in the first nine months of 2020. In the first nine months of 2020, CSAPR Seasonal NO_X prices were on average $68.02 per

34 Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland. See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285. On May 15, 2020, the Court denied an appeal of the EPA decision filed by Maryland, except that the Court agreed that EPA did not sufficiently support its rejection based on the cost effectiveness of Maryland's request that two waste coal plants, Cambria Cogeneration (Pa.) and Grant Town Cogen (W.Va.), be required to operate selective noncatalytic reduction (SNCR) controls, and remanded the decision. Maryland v. Wheeler, Case No. 18-1285 (D.C. Cir May 19, 2020).

35 Wisconsin v. EPA, 938 F.3d 303, 318–20 (D.C. Cir. 2019).

36 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).

37 *Id.* at 23066.

38 *Id.* at 23085–23086.

39 *Id.* at 23121.

40 *Id.*

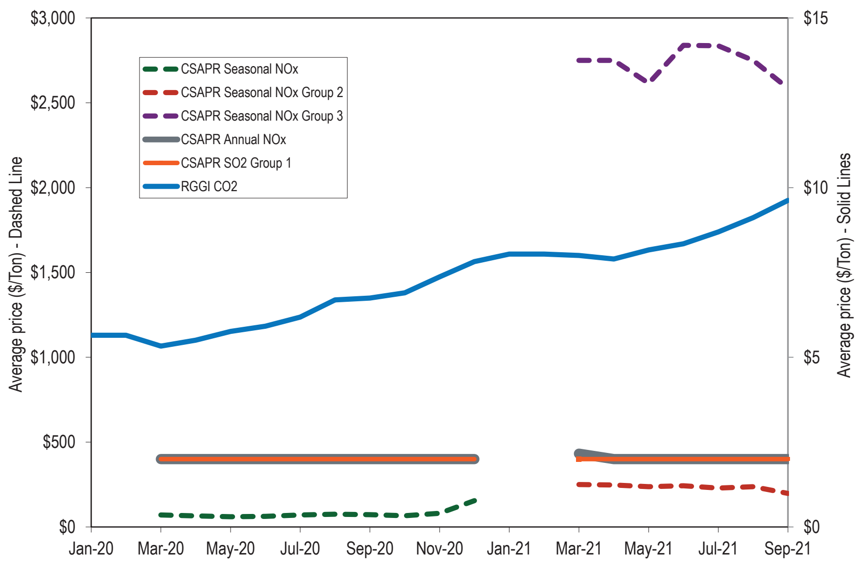
41 On April 30, 2021, the MMU sent a market message to PJM market participants explaining how to account for the changes in cost-based offers. *See* "CSAPR Ozone Season Changes," <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CSAPR_Ozone_Season_Changes_20210430.pdf>

42 *Id.* at 23123–23124 (Table VII.C.2–1–4).

43 *See* "State Budgets under the Revised Cross-State Air Pollution Rule Update," EPA, <https://www.epa.gov/csapr/state-budgets-under-revised-cross-state-air-pollution-rule-update>.

credit. The CSAPR Seasonal NO_x price for group 2 states averaged $234.49 in the first nine months of 2021, a 244.7 percent increase over the CSAPR Seasonal NO_x price for the first nine months of 2020.[44] The CSAPR Seasonal NO_x price for group 3 states averaged $2,732.15 in the first nine months of 2021, a 3,916.6 percent increase over the CSAPR Seasonal NO_x price for the first nine months of 2020.[45] The components of LMP analysis in Table 3-64 shows that NO_x cost contributed $0.25 to the load-weighted average LMP for the first nine months of 2021. In 2020, the NO_x cost contributed $0.01 to the load-weighted average LMP through the first nine months.

Figure 8-1 Spot monthly average emission price comparison: January 2020 through September 2021



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[46] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[47]

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second part considers whether any identified increase is also a "significant net emission increase."

On August 1, 2019, the EPA proposed revisions to the NSR permitting program under which, both emissions increases and decreases from a major modification would be considered in the first part of the NSR applicability test.[48] Under the revised rule the need for a permit and associated investments in pollution controls would be more frequently avoided than under the current rule.

On March 25, 2020, the EPA released a memorandum changing the EPA's longstanding interpretation of "begin actual construction" under the NSR preconstruction permitting regulations.[49] [50] EPA policy has been to preclude almost every physical onsite construction activity that is of a permanent nature prior to issuance of a permit. Under the new interpretation, which focuses on the statutory meaning of "emissions unit,"[51] the policy precludes only the construction of the emissions unit. The EPA clarified that the costs and consequences of pre permit construction are risks born by the owner/operators if no permit issues, or issues without the expected terms or conditions. The new interpretation significantly expands the scope of activity that an owner/

44 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.

45 Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia participate in the CSAPR NO_x Ozone Season Group 3 Trading Program.

46 42 U.S.C § 7470 et seq.

47 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

48 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

49 See Anne L. Idsal, Principal Deputy Assistant Administrator, Memorandum re Interpretation of "Begin Actual Construction" Under the New Source Review Preconstruction Permitting Regulations" ("March 25th Memo").

50 See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).

51 40 CFR § 52.21(b)(7) ("any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit…").

operator willing to assume the risks may undertake prior to receiving an NSR permit when constructing a project that will include an emissions unit.

CAA: RICE

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). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[52] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios.

52 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf>.

Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations.

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[53] [54]

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.”[55] 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.[56] 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.

Executive Order 13990, Section 6, establishes an Interagency Working Group on the Social Cost of Greenhouse Gases. The group is tasked to develop estimates in the form of monetized damages for the “social cost of carbon” (SCC), the “social cost of nitrous oxide” (SCN), and the “social cost of methane” (SCM), associated with incremental increases in greenhouse gas emissions.

53 See CAA § 111.

54 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 (Dec. 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.

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

56 *Id.*

The cost estimates would be used by EPA and other agencies to determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses of regulatory and other actions.

Effective October 23, 2015, the EPA placed national limits on the amount of CO_2 that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).[57] On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[58]

On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced. On February 12, 2021, the EPA issued a memo stating that as a result of the court vacating ACE without reinstating the Clean Power Plan ("CPP"), there are no effective regulations under CAA section 111(d) with respect to greenhouse gas emissions from electric generating units at this time, and states are not currently required to submit plans.[59] The memo also noted: "ongoing changes in electricity generation mean that the emission reduction goals that the CPP set for 2030 have already been achieved."[60]

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[61] [62] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[63] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

October 22, 2019, a new rule that would have defined WOTUS more narrowly was vacated by the U.S. District Court District of Arizona.[64] [65] The new rule was never implemented.

The EPA now interprets, in light of the Court action, WOTUS consistent with the pre 2015 regulatory regime until further notice. Such definition includes as WOTUS: (i) territorial seas, usable in interstate commerce; (ii) tributaries; (iii) lakes and ponds, and impoundments of jurisdictional waters; and (iv) adjacent wetlands.[66] Such definition excludes, among other things: (i) ground water; (ii) artificial lakes and ponds, including water storage reservoirs [etc.], so long as those artificial lakes and ponds are not impoundments of jurisdictional waters; and (iii) waste treatment systems.[67]

On June 9, 2021, the EPA and the Department of the Army concluded their review pursuant to Order 13990 of the NWPR and announced their intention to initiate a new rulemaking process that maintains the protections in place under the pre 2015 regulatory regime and develops a new definition of WOTUS.[68] The scope of the CWA has expanded and the precise definition of WOTUS has become less important as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[69] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[70] This holding invalidates the EPA's recent interpretive statement intended to establish a bright line

57 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) ("2015 GHG NSR Rule"); 40 CFR Part 60, subpart TTTT.

58 *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA–HQ–OAR–2013–0495; FRL–9987–85– OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) ("2018 Proposed Rev. GHG NSR").

59 *See* Joseph Goffman, Acting Assistant Administrator, EPA, Memo re Status of Affordable Clean Energy Rule and Clean Power Plan (February 12, 2021).

60 *Id.*, citing "Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," EPA-452/R-19-003 (June 2019), at 2-14 to 2-15.

61 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

62 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."

63 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

64 See *The Navigable Waters Protection Rule: Definition of "Waters of the United States,"* EPA Docket No. EPA–HQ–OW–2018–0149, 85 Fed. Reg. 22250 ({___}).

65 See Pascua Yaqui Tribe v. U.S. EPA, No. CV-20-00266-TUC-RM, __ F.Supp.3d __ (USDC Ariz. 2021).

66 See 40 CFR 230.3(s); 40 CFR § 120.2.

67 *Id.*

68 EPA News Release, "EPA, Army Announce Intent to Revise Definition of WOTUS."

69 Slip. Op. No. 18-260 (April 23, 2020).

70 *Id.*

rule excluding all releases of pollutants to groundwater from the permitting program.[71] The EPA may not interpret the CWA to require a direct discharge.[72] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[73] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[74] Additional litigation or administrative action may clarify the functional discharge analysis.[75] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[76]

Discharges and Intakes

The EPA regulates discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[77]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[78] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. 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.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[79] 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.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[80]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[81]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above

71 *See Interpretive Statement on Application of the Clean Water Act National Pollutant Discharge Elimination System Program to Releases of Pollutants From a Point Source to Groundwater*, 84 Fed. Reg. 16810 (April 23, 2019).
72 Slip. Op. No. 18-260 at 5.
73 *Id.* at 1.
74 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").
75 *Id.*
76 *See id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
77 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
78 42 U.S.C. §§ 6901 *et seq.*
79 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
80 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
81 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[82] On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[83] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[84] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented."[85] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[86] [87] Upon receipt of required documentation satisfying certain criteria, the EPA could grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[88]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.[89] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of a coal ash permitting program.

82 Utility Solid Waste Activities Group, et al. v. EPA, No. 15-1219 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18–1289 (D.C. Cir. March 13, 2019).
83 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA–HQ–OLEM–2019–0172; FRL–10002– 02–OLEM, 85 Fed. Reg. 53516 (August 28, 2020).
84 *Id.* at 53516–53517, 53536.
85 *Id.* at 53546.
86 *Id.* at 65942.
87 A number of plants in PJM timely filed for extensions.
88 *Id.*
89 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Federal CCR Permit Program*, 85 Fed. Reg. 9940 (Feb. 20, 2020).

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions.[90] In 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[91] Effective July 1, 2019, coal ash ponds at power stations in the Chesapeake Bay Watershed had to be closed by removal of coal ash. The removed coal ash either had to be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

On March 30, 2020, in response to a statutory mandate,[92] the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[93] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The proposed rules include a permitting program and are intended to meet federal standards.[94] Presumably the rules, once finalized, would be the basis for an application under RCRA allowing the Illinois EPA to also administer the federal regulatory program. The Illinois EPA has identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[95] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[96]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments

90 The following Virginia power stations host coal ash ponds: Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, Clinch River Plant and Possum Point Power Station, owned by Dominion Energy; and Glen Lyn Plant, owned by Appalachian Power.
91 Va. Code § 10.1-1402.03.
92 Ill. Public Act 101-171 (a.k.a. SB 09).
93 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
94 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845) ("Proposed Illinois CCR Rules").
95 Proposed Illinois Rules at 3.
96 *Id.* at 3.

are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluent guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[97] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[98] Dickerson Generating Station was retired effective August 13, 2020. The Chalk Point coal units were retired effective June 1, 2021. On June 9, 2021, GenOn reported that it would retire its Morgantown coal fired unit by May 31, 2022, five years earlier than previously announced.[99]

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[100]

- **New Jersey HEDD.** 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. 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.
- **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). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

State Regulation of Greenhouse Gas Emissions

Clean Energy Standards

- In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[101] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[102] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[103]

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[104]

97 See Potomac Riverkeeper Network, Press Release, "Maryland Proposes to Reject Effort to Delay Pollution Reductions" (Posted April 4, 2020), <https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>.
98 See "GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant" (May 15, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>.
99 See "GenOn Holdings, LLC Announces Retirement of Three Coal-Fired Power Plants" (June 9, 2021) <https://www.genon.com/genon-news/genon-holdings-llc-announces-retirement-of-three-coal-fired-power-plants>.
100 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."
101 Va. HB 1526/SB 851.
102 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
103 *Id.*
104 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>.

Delaware, Maryland, New Jersey and Virginia are the only PJM states that are members of RGGI. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[105] Virginia joined RGGI on January 1, 2021.

Pennsylvania plans to join RGGI on January 1, 2022. Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.[106] The Pennsylvania Environmental Quality Board (EQB), on September 15, 2020, approved a draft regulation developed by the DEP that governs Pennsylvania's entry into RGGI in 2022.[107] The DEP announced on September 1, 2021 that the Independent Regulatory Review Commission approved the regulation for RGGI participation beginning January 1, 2022.[108] The Pennsylvania state senate passed, with a veto proof majority of 32-18, a resolution on October 27, 2021, disapproving Pennsylvania's RGGI rule.[109] The resolution will now go to the Pennsylvania house. If the resolution passes, the question becomes whether an expected veto from Governor Wolf would survive a vote to override it.[110] If enacted, the CO_2 Budget Trading Program is likely to be challenged in court. At this time, it is not known whether and when the CO_2 Budget Trading Program would become effective in Pennsylvania.

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period, the 4th control period, and the first three auctions of the 5th control period.[111] [112] The clearing price for the auction held September 8, 2021 was $9.30 per allowance (equal to one short ton of CO_2).[113] The September auction clearing price increased 16.7 percent over the last auction clearing price of $7.97 in June 2021.

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th and 5th Control Periods[114]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
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
June 13, 2018	$4.02	13,771,025	13,771,025	$4.43	12,492,867	12,492,867
September 9, 2018	$4.50	13,590,107	13,590,107	$4.96	12,328,741	12,328,741
December 5, 2018	$5.35	13,360,649	13,360,649	$5.90	12,120,580	12,120,580
March 13, 2019	$5.27	12,883,436	12,883,436	$5.81	11,687,660	11,687,660
June 5, 2019	$5.62	13,221,453	13,221,453	$6.19	11,994,304	11,994,304
September 4, 2019	$5.20	13,116,447	13,116,447	$5.73	11,899,044	11,899,044
December 4, 2019	$5.61	13,116,444	13,116,444	$6.18	11,899,041	11,899,041
March 11, 2020	$5.65	16,208,347	16,208,347	$6.23	14,703,969	14,703,969
June 3, 2020	$5.75	16,336,298	16,336,298	$6.34	14,820,045	14,820,045
September 2, 2020	$6.82	16,192,785	16,192,785	$7.52	14,689,852	14,689,852
December 2, 2020	$7.41	16,237,495	16,237,495	$8.17	14,730,412	14,730,412
March 3, 2021	$7.60	23,467,261	23,467,261	$8.38	21,289,147	21,289,147
June 2, 2021	$7.97	22,987,719	22,987,719	$8.79	20,854,114	20,854,114
September 8, 2021	$9.30	22,911,423	22,911,423	$10.25	20,784,899	20,784,899

The RGGI auction held on September 8, 2021, generated 213.1 million in auction revenue. RGGI auctions have generated $4.4 billion in auction revenue since 2008.[115] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2019 reporting year, have spent approximately 54 percent of the revenue on energy efficiency, 14 percent on

105 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
106 Executive Order No. 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor (Oct. 3, 2019), <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.
107 "Environmental Quality Board Approves Proposed Climate Change Regulation," DEP Newsroom, (September 15, 2020) <https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21865&typeid=1>.
108 "Independent Regulatory Review Commission Approves CO2 Budget Final Rulemaking," DEP Newsroom (September 1, 2021) <https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21997&typeid=1>.
109 "Senate moves to block key part of Wolf's climate plan," McDevitt, Rachael, State Impact Pennsylvania <https://stateimpact.npr.org/pennsylvania/2021/10/27/senate-moves-to-block-key-part-of-wolfs-climate-plan/>.
110 Governor Wolf successfully vetoed Pa. H.B. 2025 proposed in 2020, which would have restricted the Governor's authority to join RGGI.
111 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023.
112 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.
113 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).
114 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results>.
115 See Auction Results at <https://www.rggi.org/>.

clean and renewable energy, 10 percent on greenhouse gas abatement and 15 percent on direct bill assistance.[116]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2020 CO_2 emission levels and the RGGI clearing price for the June 2021 auction ranges from $1.6 billion per year to $3.1 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[117] Table 8-3 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2020 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-3 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2020 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[118]

Table 8-3 Estimated CO_2 allowance revenue at September 2021 RGGI price level[119] [120]

		Estimated CO_2 allowance revenue ($ millions), carbon price $9.30 per short ton					
Jurisdiction	2020 power generation CO_2 emissions (short tons)	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
Delaware	2,055,837.3	$18.2	$17.2	$16.3	$15.3	$14.3	$9.6
Illinois	18,801,034.9	$166.1	$157.4	$148.6	$139.9	$131.1	$87.4
Indiana	32,618,816.1	$288.2	$273.0	$257.9	$242.7	$227.5	$151.7
Kentucky	28,595,734.2	$252.6	$239.3	$226.0	$212.8	$199.5	$133.0
Maryland	10,160,364.6	$89.8	$85.0	$80.3	$75.6	$70.9	$47.2
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	11,765,032.5	$103.9	$98.5	$93.0	$87.5	$82.1	$54.7
North Carolina	40,388.7	$0.4	$0.3	$0.3	$0.3	$0.3	$0.2
Ohio	80,279,155.3	$709.3	$671.9	$634.6	$597.3	$559.9	$373.3
Pennsylvania	77,857,196.9	$687.9	$651.7	$615.5	$579.3	$543.1	$362.0
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	32,755,841.7	$289.4	$274.2	$258.9	$243.7	$228.5	$152.3
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	53,818,573.2	$475.5	$450.5	$425.4	$400.4	$375.4	$250.3
Total	348,747,975.2	$3,081.2	$2,919.0	$2,756.9	$2,594.7	$2,432.5	$1,621.7

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-4 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2021 compliance year is the first year of the fifth control period.

RGGI recently announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[121] [122] The first adjustment removed 57.5 million allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[123] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[124] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[125] The base emissions cap for each of the next five years will be reduced by 19.1 allowances.

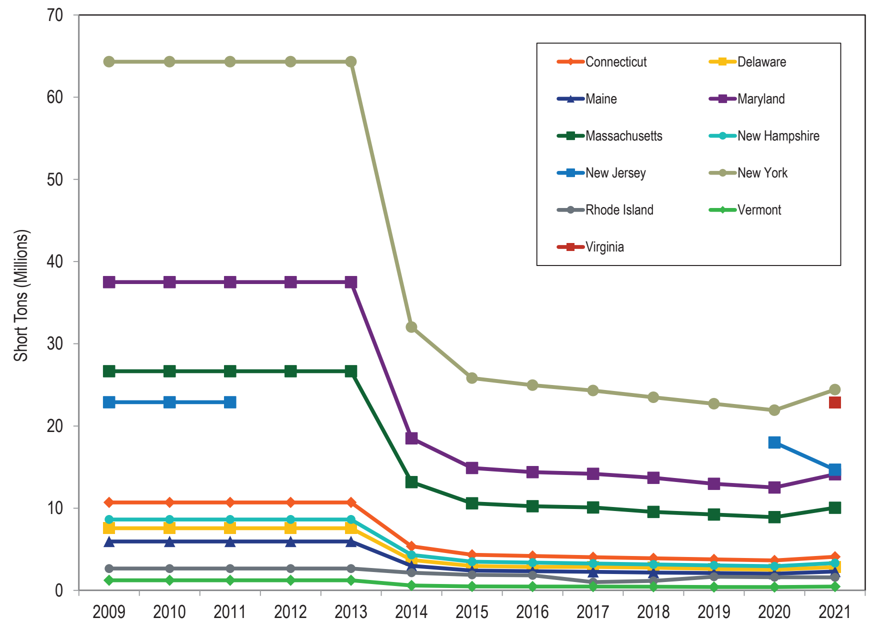
116 *The Investment of RGGI Proceeds in 2019*, The Regional Greenhouse Gas Initiative (RGGI), June 2021, <https://www.rggi.org/investments/proceeds-investments>.
117 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.
118 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.
119 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.
120 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.
121 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
122 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.
123 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.
124 Id.
125 "Third Adjustment for Banked Allowances Announcement", Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

The percent change columns in Table 8-4 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[126] The adjusted emissions cap for 2021 marks the first year the adjusted carbon emissions cap has increased since the start of RGGI.[127] Figure 8-2 shows the adjusted carbon budgets for the RGGI states. All states, with the exception of New Jersey, have a higher 2021 adjusted carbon budget relative to the corresponding 2020 budget. The RGGI clearing price since 2014 has been on average 126.6 percent higher than the prices prior to the emission cap adjustments.

Table 8-4 RGGI emissions cap history[128 129 130]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009		$2.77	188,076,976		188,076,976	
2010		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011	1st	$1.89	188,076,976	0.0%	188,076,976	0.0%
2012		$1.93	165,184,246	0.0%	165,184,246	0.0%
2013		$2.92	165,184,246	0.0%	165,184,246	0.0%
2014	2nd	$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017	3rd	$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020	4th	$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021		$8.28	119,767,784	(3.9%)	100,677,454	4.5%
2022			116,112,784	(3.1%)	97,022,454	(3.6%)
2023	5th		112,457,784	(3.1%)	93,367,454	(3.8%)

Figure 8-2 RGGI adjusted carbon budgets by state[131]



If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-5 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $16.6 billion if the carbon price were $50 per short ton and emission levels were five percent below 2020 levels. Allowance revenues to states would be $1.7 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2020.

126 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the percent changes from 2019 to 2020 do not reflect the impact of New Jersey rejoining RGGI.
127 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.
128 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution>.
129 RGGI budgets for 2022 and 2023 are found in a RGGI press release, "Third Adjustment for Banked Allowances Announcement," March 15, 2021 <https://www.rggi.org/news-releases/rggi-releases>.
130 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

131 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution>.

Table 8-5 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
Jurisdiction	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
	Carbon Price ($ per short ton)				$10.00	
Delaware	$19.5	$18.5	$17.5	$16.4	$15.4	$10.3
Illinois	$178.6	$169.2	$159.8	$150.4	$141.0	$94.0
Indiana	$309.9	$293.6	$277.3	$261.0	$244.6	$163.1
Kentucky	$271.7	$257.4	$243.1	$228.8	$214.5	$143.0
Maryland	$96.5	$91.4	$86.4	$81.3	$76.2	$50.8
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$111.8	$105.9	$100.0	$94.1	$88.2	$58.8
North Carolina	$0.4	$0.4	$0.3	$0.3	$0.3	$0.2
Ohio	$762.7	$722.5	$682.4	$642.2	$602.1	$401.4
Pennsylvania	$739.6	$700.7	$661.8	$622.9	$583.9	$389.3
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$311.2	$294.8	$278.4	$262.0	$245.7	$163.8
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$511.3	$484.4	$457.5	$430.5	$403.6	$269.1
Total	$3,313.1	$3,138.7	$2,964.4	$2,790.0	$2,615.6	$1,743.7
	Carbon Price ($ per short ton)				$25.00	
Delaware	$48.8	$46.3	$43.7	$41.1	$38.5	$25.7
Illinois	$446.5	$423.0	$399.5	$376.0	$352.5	$235.0
Indiana	$774.7	$733.9	$693.1	$652.4	$611.6	$407.7
Kentucky	$679.1	$643.4	$607.7	$571.9	$536.2	$357.4
Maryland	$241.3	$228.6	$215.9	$203.2	$190.5	$127.0
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$279.4	$264.7	$250.0	$235.3	$220.6	$147.1
North Carolina	$1.0	$0.9	$0.9	$0.8	$0.8	$0.5
Ohio	$1,906.6	$1,806.3	$1,705.9	$1,605.6	$1,505.2	$1,003.5
Pennsylvania	$1,849.1	$1,751.8	$1,654.5	$1,557.1	$1,459.8	$973.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$778.0	$737.0	$696.1	$655.1	$614.2	$409.4
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,278.2	$1,210.9	$1,143.6	$1,076.4	$1,009.1	$672.7
Total	$8,282.8	$7,846.8	$7,410.9	$6,975.0	$6,539.0	$4,359.3
	Carbon Price ($ per short ton)				$50.00	
Delaware	$97.7	$92.5	$87.4	$82.2	$77.1	$51.4
Illinois	$893.0	$846.0	$799.0	$752.0	$705.0	$470.0
Indiana	$1,549.4	$1,467.8	$1,386.3	$1,304.8	$1,223.2	$815.5
Kentucky	$1,358.3	$1,286.8	$1,215.3	$1,143.8	$1,072.3	$714.9
Maryland	$482.6	$457.2	$431.8	$406.4	$381.0	$254.0
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$558.8	$529.4	$500.0	$470.6	$441.2	$294.1
North Carolina	$1.9	$1.8	$1.7	$1.6	$1.5	$1.0
Ohio	$3,813.3	$3,612.6	$3,411.9	$3,211.2	$3,010.5	$2,007.0
Pennsylvania	$3,698.2	$3,503.6	$3,308.9	$3,114.3	$2,919.6	$1,946.4
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,555.9	$1,474.0	$1,392.1	$1,310.2	$1,228.3	$818.9
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,556.4	$2,421.8	$2,287.3	$2,152.7	$2,018.2	$1,345.5
Total	$16,565.5	$15,693.7	$14,821.8	$13,949.9	$13,078.0	$8,718.7

Table 8-6 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $10.00 per tonne, the PJM load-weighted, average LMP in the first nine months of 2021 would have increased by 6.4 percent.[132]

Table 8-6 Estimated impact of carbon price on LMP: January through September, 2020 and 2021

		2020 (Jan - Sep)			2021 (Jan - Sep)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$21.23	$22.85	7.6%	$35.68	$36.03	1.0%
Scenario 2	$10.00	$21.23	$24.67	16.2%	$35.68	$37.96	6.4%
Scenario 3	$15.00	$21.23	$26.49	24.8%	$35.68	$39.88	11.8%
Scenario 4	$25.00	$21.23	$30.13	41.9%	$35.68	$43.73	22.6%
Scenario 5	$50.00	$21.23	$39.23	84.8%	$35.68	$53.34	49.5%

Table 8-7 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[133] [134] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-7 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	$2.45	$4.90	$7.36	$24.52	$49.04	$98.08	$196.17
CC	$1.67	$3.34	$5.01	$16.71	$33.41	$66.83	$133.65
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-7 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $190.85 per credit in the first nine months of 2021. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If

132 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

133 Heat rates from: *2021 State of the Market Report for PJM: January through June*, Section 7: Net Revenue, Table 7-3.

134 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>.

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 slightly less than $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 $24.52 per MWh.

Applying this method to tier I and class I REC and SREC price histories yields the implied carbon prices in Table 8-8. The carbon price implied by the average REC price during the first nine months of 2021 in Washington, DC is $9.52 per tonne which is $0.73 per tonne lower than the September 8, 2021 RGGI clearing price of $10.25 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[135] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

Table 8-8 Implied carbon price based on REC and SREC prices: 2009 through 2021[136]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per tonne) Implied by REC Prices**												
Delaware					$34.15	$35.17	$31.91	$32.91	$10.26	$11.57	$16.05	$19.88	
Maryland	$2.07	$1.92	$3.06	$6.34	$17.46	$28.45	$29.18	$26.09	$23.12	$21.28	$17.76	$19.26	$19.38
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.01	$19.19	$19.82	$19.36
Ohio						$10.16	$8.52	$5.29	$6.27	$11.17	$14.00	$15.68	$17.66
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$28.88	$26.35	$23.35	$21.47	$17.91	$19.35	$19.01
Washington, D.C.							$3.19	$4.04	$4.88	$4.68	$5.50	$7.44	$9.52
Jurisdiction with Solar REC	**Carbon Price ($ per tonne) Implied by Solar REC Prices**												
Delaware						$117.25	$85.40	$86.48	$35.70	$17.33			
Maryland		$546.11	$494.54	$382.57	$304.54	$292.70	$251.23	$183.09	$127.67	$87.00	$83.93	$98.06	$113.64
New Jersey	$1,372.37	$1,352.15	$1,309.00	$537.08	$345.94	$326.21	$388.73	$424.21	$459.21	$445.00	$409.08	$389.72	$389.17
Ohio						$82.32	$45.12	$36.15	$31.82	$21.67	$26.57		
Pennsylvania	$610.05	$590.57	$378.67	$101.80	$68.34	$75.90	$66.89	$55.06	$43.84	$28.07	$51.50	$62.52	$68.49
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$840.35	$848.82	$871.73	$872.95
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per tonne)**												
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$9.13

State Renewable Portfolio Standards

Ten of 14 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 requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are 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

135 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.
136 There were no trades in 2018 and 2019 for Ohio SRECs available in the Evomarkets data.

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 must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[137] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2021, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2021, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties.[138] Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[139]

As of September 30, 2021, Kentucky, Tennessee and West Virginia have no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[140]

Table 8-9 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.

137 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home>.
138 Effective January 1, 2021 the Virginia voluntary RPS is being replaced with a mandatory RPS.
139 See the Indiana Utility Regulatory Commission's "2020 Annual Report," at 41 (Oct. 2020) <https://www.in.gov/iurc/2981.htm>.
140 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

Table 8-9 Renewable and alternative energy standards of PJM jurisdictions: 2021 to 2030[141] [142]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	21.00%	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%
Illinois	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	33.30%	32.60%	34.40%	36.20%	38.00%	40.50%	44.00%	45.50%	50.00%	52.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)	14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard										
Indiana	7.00%	7.00%	7.00%	7.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jurisdiction with No Standard										
Kentucky	No Renewable Portfolio Standard									
Tennessee	No Renewable Portfolio Standard									
West Virginia	No Renewable Portfolio Standard									

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50.0 percent renewable by 2030.[143] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill 65 reduced the penalty for solar non compliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[144] Additional details are provided in Table 8-10.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[145] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[146] [147] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[148] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030. Table 8-10 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

141 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
142 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.
143 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
144 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
145 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
146 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
147 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
148 N.J. S. 2314/A. 3723.

Table 8-10 Recent changes in RPS rules[149] [150] [151] [152] [153] [154]

Jurisdiction	Legislation	Effective Date	Summary of changes
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[155] On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[156] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[157] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.[158] [159]

In 2017, the Maryland Public Service Commission announced two awards of ORECs to two commercial wind projects, Deepwater Wind's 120-MW Skipjack Wind Farm and U.S. Wind's 248-MW project. Deepwater Wind has since been acquired by Orsted.[160] These project awards are the first under Maryland's 2010 OREC program.

149 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
150 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
151 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
152 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
153 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
154 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
155 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
156 N.J. S. 2314/A. 3723.
157 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.
158 BPU Docket No. QO18080851.
159 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.
160 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[161] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[162]

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 jurisdictions 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.[163] Although 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. Table 8-11 shows the Tier I standards for PJM states.[164] All eligible technologies for the RPS standards in Table 8-11 satisfy the EIA definition of renewable energy.[165]

Table 8-11 Tier I / Class I renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	30.80%	30.10%	31.90%	33.70%	35.50%	38.00%	41.50%	43.00%	47.50%	50.00%
New Jersey	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[166]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, 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 September 30, 2021. Tier I REC prices are lower than SREC prices. For example, the average SREC price in Washington, DC in the first nine months of 2021 was $428.11 and the average Tier I price in Washington, DC in first nine months of 2021 was $4.67.

161 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.

162 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.

163 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

164 This includes New Jersey's Class I renewable standard.

165 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home>.

166 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through September 2021

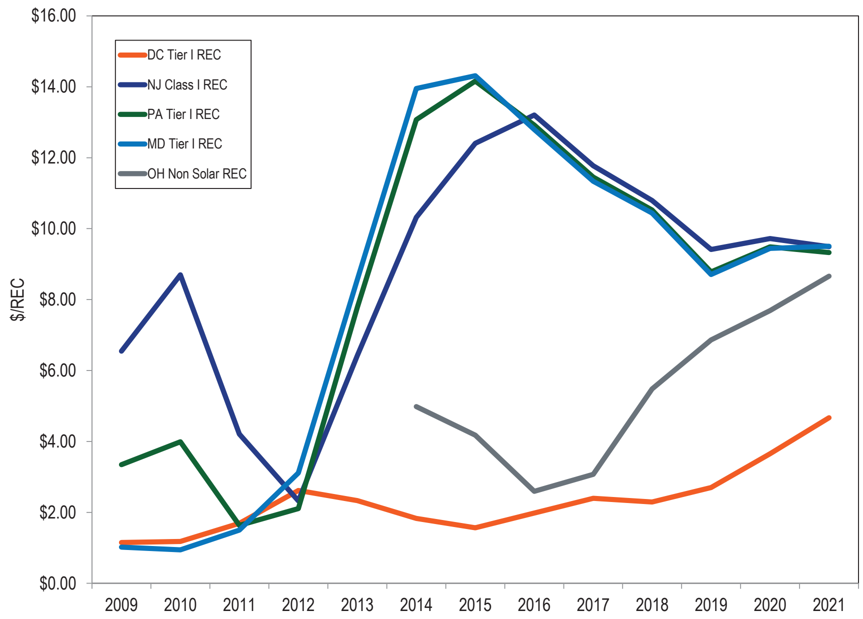
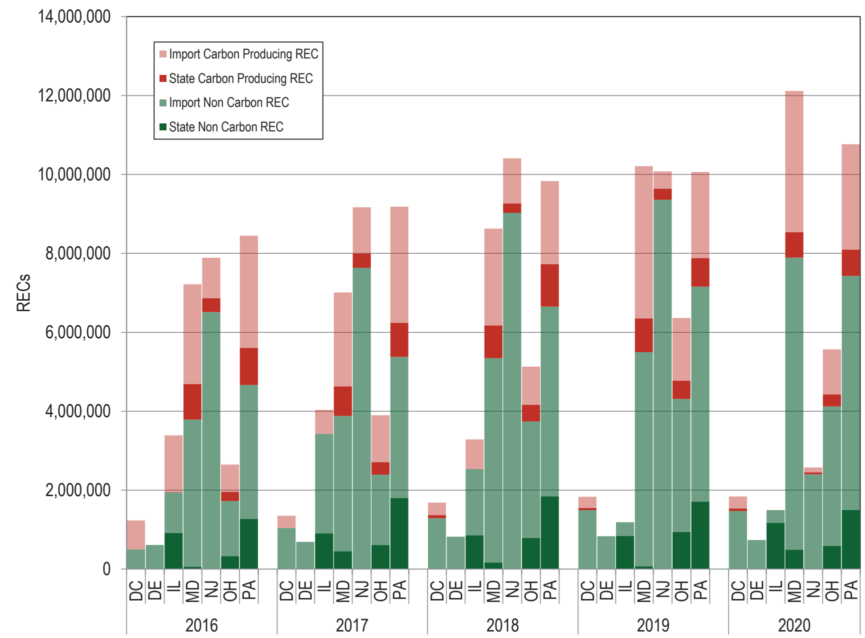


Figure 8-4 and Table 8-12 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2020 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[167] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Delaware (DE) New Eligible requirement and the Illinois RPS, beginning in 2019, are fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-12 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Pennsylvania met its Tier I target using 79.9 percent imported RECs, and 20.1 percent State RECs for the 2020 compliance year. Pennsylvania met its Tier I target using 69.0 percent noncarbon producing RECs, and 31.0 percent carbon producing RECs for the 2020 compliance year. Illinois met its Tier I target using 29.5 percent imported RECs, and 70.5 percent State RECs for the 2019 compliance year. Illinois met its Tier I target using 100.0 percent noncarbon producing RECs for the 2019 compliance year.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2016 through 2020



167 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 22, 2021). The timing of the REC retirement reports varies by state and the 2020 reporting year data is incomplete for several states.

Table 8-12 State fulfillment of Tier I equivalent RPS: 2016 through 2020

Year	REC Type	State Non Carbon REC	Import Non Carbon REC	State Carbon Producing REC	Import Carbon Producing REC
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%
2019	DE New Eligible	0.3%	99.7%	0.0%	0.0%
	DC Tier I	0.0%	81.5%	2.8%	15.7%
	OH Renewable Energy Source	14.7%	53.0%	7.3%	25.0%
	IL Renewable	70.5%	29.5%	0.0%	0.0%
	MD Tier I	0.7%	53.2%	8.4%	37.8%
	NJ Class I	0.1%	92.7%	2.8%	4.4%
	PA Tier I	17.0%	54.2%	7.2%	21.7%
2020	DE New Eligible	0.0%	100.0%	0.0%	0.0%
	DC Tier I	0.0%	80.1%	3.3%	16.6%
	OH Renewable Energy Source	10.5%	63.5%	5.5%	20.5%
	IL Renewable	78.3%	21.7%	0.0%	0.0%
	MD Tier I	4.1%	61.1%	5.3%	29.6%
	NJ Class I	0.0%	93.1%	2.0%	4.9%
	PA Tier I	13.9%	55.1%	6.2%	24.8%

Table 8-13 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-13 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-13 are included in the total RPS requirements presented in Table 8-9. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, 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 in 2020. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[168]

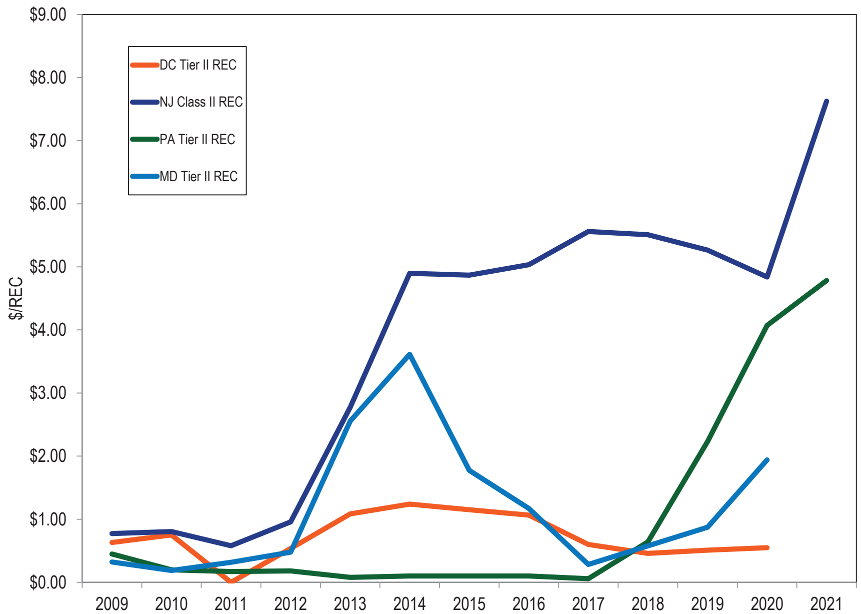
168 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2, <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

Table 8-13 Additional renewable standards of PJM jurisdictions: 2021 to 2030

Jurisdiction	Type of Standard	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	Off Shore Wind	1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.94%	1.94%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	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%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

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 September 30, 2021. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2021. In the first nine months of 2021, the average Pennsylvania Tier II REC price was $4.78 and the average New Jersey Class II REC price was $7.63.[169]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through September 2021



169 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com>.

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-9 and Table 8-11 but must be met by solar RECs (SRECs) only. Table 8-14 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have or have had requirements for the proportion of load to be served by solar. New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[170] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[171] The new program establishes a 15 year fixed priced Transition REC (TREC). Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[172] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[173] The Delaware General Assembly passed new RPS legislation on February 10, 2021 that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[174]

Table 8-14 Solar renewable standards by percent of electric load for PJM jurisdictions: 2021 to 2030[175]

Jurisdiction with RPS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.50%	2.75%	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%
Illinois (RECs)	2,000,000	2,000,000	2,000,000	2,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	4,000,000
Maryland	7.50%	5.50%	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%
Michigan	No Minimum Solar Requirement									
New Jersey	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	No Minimum Solar Requirement									
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
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									

170 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).
171 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
172 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
173 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
174 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
175 The Illinois solar standard currently requires 2 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 099-0906, June 1, 2017.

Figure 8-6 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2021. The average NJ SREC prices dropped from $673 per SREC in 2009 to $191 per SREC in the first nine months of 2021. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price was $428 per SREC for the first nine months of 2021.[176]

Figure 8-6 Average SREC price by jurisdiction: 2009 through September 2021

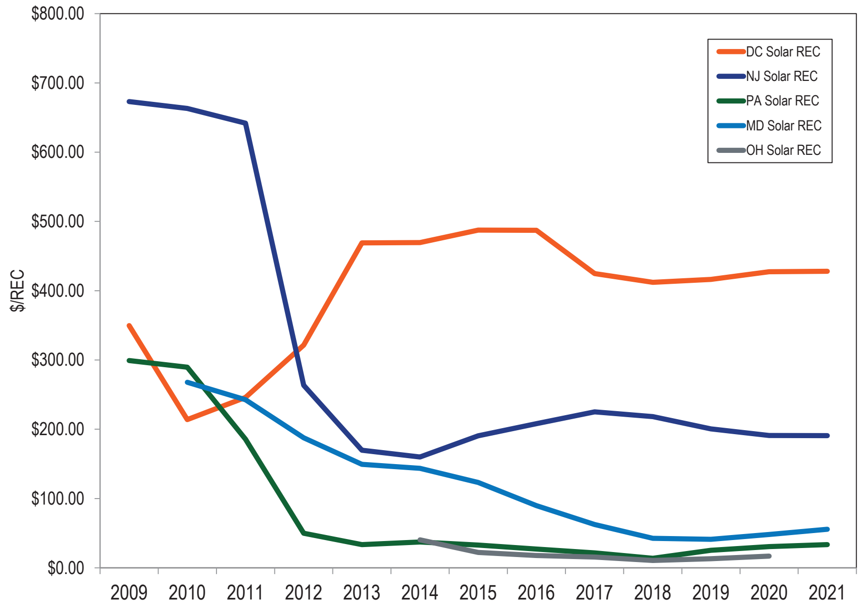
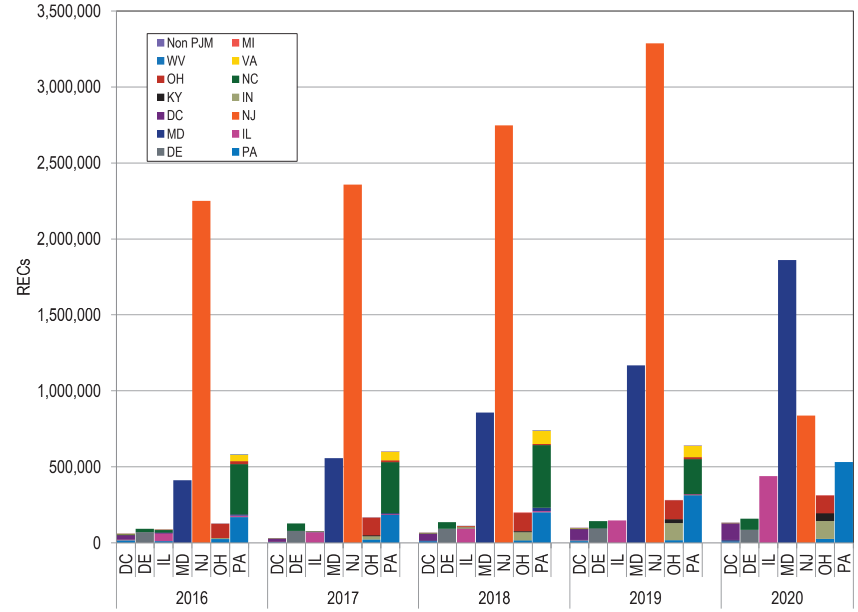


Figure 8-7 and Table 8-15 shows where the SRECs originated that are used to satisfy the states' solar requirement by retiring RECs for 2016 through 2020.[177] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-15 shows the percent of imported and local SRECs used to meet the RPS requirements. Illinois, Maryland, New Jersey and Pennsylvania met their solar requirements using 100 percent in-state SRECs in 2020.

Figure 8-7 State fulfillment of Solar RPS: 2016 through 2020



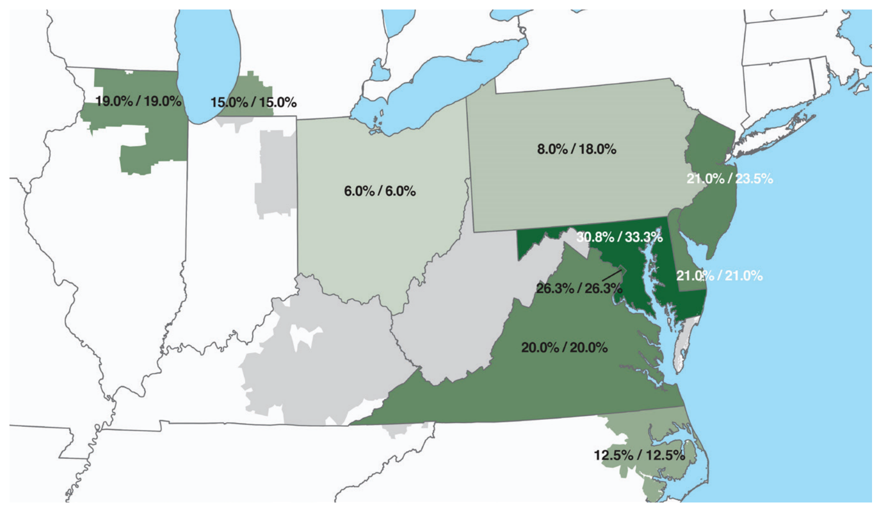
176 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com>.
177 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>. The timing of the REC retirement reports varies by state and the 2020 reporting year data is incomplete for several states.

Table 8-15 State fulfillment of Solar RPS: 2016 through 2020

		State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	DE Solar Eligible	76.5%	23.5%
	IL Solar Renewable	56.1%	43.9%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	73.3%	26.7%
	PA Solar	29.1%	70.9%
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.5%	12.5%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	69.0%	31.0%
	PA Solar	30.6%	69.4%
2018	DC Solar	67.4%	32.6%
	DE Solar Eligible	67.7%	32.3%
	IL Solar Renewable	82.8%	17.2%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%
	PA Solar	27.1%	72.9%
2019	DC Solar	72.4%	27.6%
	DE Solar Eligible	66.4%	33.6%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.5%	56.5%
	PA Solar	48.8%	51.2%
2020	DC Solar	81.5%	18.5%
	DE Solar Eligible	54.0%	46.0%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%
	PA Solar	100.0%	0.0%

Figure 8-8 shows 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. For each state in Figure 8-8, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. 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. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of 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 – Renewable / Alternative Energy resources: 2021[178]



178 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

Under the existing state renewable portfolio standards, 15.9 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2021. Tier I resources consist of landfill gas, run of river hydro, wind and solar resources. Tier II resources consist of pumped storage, solid waste and waste coal resources. In the first nine months of 2021, 7.6 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-16. If the proportion of load among states remains constant, 28.6 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 13.5 percent of PJM load should have been served by Tier I or renewable energy resources in the first nine months of 2021. In the first nine months of 2021, 5.4 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the state renewable requirements for the first nine months of 2021, and LSEs purchased RECs from outside the PJM footprint. LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 26.2 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-16 shows generation by jurisdiction and resource type for the first nine months of 2021. Wind output was 19,862.2 GWh of 34,587.3 Tier I GWh, or 57.4 percent, in the PJM footprint. As shown in Table 8-16, 48,374.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 71.5 percent. Total wind and solar generation (noncarbon producing) was 4.0 percent of total generation in PJM for the first nine months of 2021. Tier I generation was 5.4 percent of total generation in PJM and Tier II was 2.2 percent of total generation in PJM for the first nine months of 2021. Biofuel, landfill gas, solid waste and waste coal (carbon producing) accounted for 10,125.7 GWh, or 20.9 percent of the total Tier I and Tier II generation.

Table 8-16 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2021

	Tier I							Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	38.3	0.0	0.0	0.0	0.0	38.3	0.0	0.0	0.0	0.0	0.0	38.3
Illinois	0.0	110.9	0.0	0.0	11.5	9,152.9	9,275.2	0.0	0.0	0.0	0.0	0.0	9,275.2
Indiana	0.0	15.0	0.0	18.4	37.5	3,945.6	4,016.6	0.0	0.0	0.0	0.0	0.0	4,016.6
Kentucky	0.0	0.0	248.6	70.7	0.0	0.0	319.3	0.0	0.0	0.0	0.0	0.0	319.3
Maryland	0.0	33.3	0.0	0.0	420.6	408.9	862.8	0.0	0.0	513.5	0.0	513.5	1,376.3
Michigan	0.0	50.9	0.0	40.0	4.9	0.0	95.8	0.0	0.0	0.0	0.0	0.0	95.8
New Jersey	0.0	97.7	16.0	0.0	710.8	6.9	831.4	211.9	0.0	1,019.1	0.0	1,231.1	2,062.4
North Carolina	0.0	0.0	532.1	0.0	1,662.1	359.1	2,553.3	0.0	0.0	0.0	0.0	0.0	2,553.3
Ohio	0.0	247.5	851.2	0.0	481.8	1,795.8	3,376.4	0.0	0.0	0.0	0.0	0.0	3,376.4
Pennsylvania	0.0	331.1	3,806.3	18.0	195.9	2,427.1	6,778.4	1,836.4	0.0	1,173.2	4,069.9	7,079.5	13,857.9
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	998.1	0.0	0.0	998.1	998.1
Virginia	927.6	368.0	841.5	56.7	1,764.2	632.6	4,590.6	2,005.3	854.3	630.0	0.0	3,489.6	8,080.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	24.4	664.0	0.0	27.5	1,133.2	1,849.2	0.0	0.0	0.0	475.2	475.2	2,324.3
Total	927.6	1,317.2	6,959.6	203.8	5,316.9	19,862.2	34,587.3	4,053.6	1,852.5	3,335.9	4,545.0	13,786.9	48,374.2

Table 8-17 shows the summer installed capacity rating of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. 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. Virginia has the largest amount of solar capacity in PJM, 1,590.0 MW, or 35.8 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 9,379.3 MW, or 87.8 percent of the total wind capacity.

On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators, based on the effective load carrying capability (ELCC) method.[179] The MMU opposed the ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented data, among other issues, but does not oppose the ELCC approach in concept and when done correctly.[180] [181]

Under the pre ELCC rules a generator's capacity value was derated from the installed capacity level by multiplying the generator's net maximum capability by a derating factor. The derating factor was either based on the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of the pre ELCC method was to obtain a MW value the generator can reliably produce during the summer peak hours.[182] As of October 1, 2021, the derated capacity with capacity obligations in the PJM Capacity Market totaled 1,522.9 MW for wind generators and 1,779.5 MW for solar generators. This compares to installed wind capacity of 10,682.3 MW and installed solar capacity of 4,437.5 MW in Table 8-17. PJM posts class average capacity factors for wind and solar generators. There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.[183]

Table 8-17 Renewable capacity by jurisdiction (MW): September 30, 2021

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	0.0	0.0	39.2	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	4,526.1	4,574.3
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	30.1	0.0	0.0	2,350.5	2,392.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.7
Maryland	0.0	0.0	0.4	22.3	0.0	0.0	69.0	0.0	0.0	371.5	128.2	0.0	245.2	836.6
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	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	0.0	11.0	61.1	0.0	0.0	0.0	0.0	453.0	685.3	204.6	0.0	4.5	1,419.4
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,180.1	0.0	0.0	208.0	1,713.1
Ohio	0.0	2,320.0	194.4	58.2	0.0	1.0	136.0	0.0	0.0	416.1	0.0	0.0	1,045.6	4,171.3
Pennsylvania	54.0	0.0	1,387.3	125.2	1,300.0	0.0	0.0	0.0	1,269.0	121.8	209.3	1,347.0	1,457.2	7,270.7
Tennessee	50.0	0.0	296.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	346.6
Virginia	241.9	585.0	436.4	127.7	0.0	88.0	17.0	0.0	5,386.0	1,590.0	123.0	0.0	12.0	8,606.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	29.1	0.0	96.0	687.3	1,030.2
PJM Total	345.9	2,905.0	3,015.6	465.0	3,097.0	89.0	222.0	13.0	7,108.0	4,437.5	665.0	1,443.0	10,682.3	34,488.4

179 See 176 FERC ¶ 61,056.
180 *In Docket ER21-278-000, see* Comments and Motions of the Independent Market Monitor for PJM, (November 20, 2020); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (December 18, 2020); Comments and Motions of the Independent Market Monitor for PJM (March 22, 2021); Answer and motion for Leave to Answer of the Independent Market Monitor for PJM (April 29, 2021)
181 *In Docket ER21-2043, see* Comments of the Independent Market Monitor for PJM (June 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 9, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM (July 20, 2021);
182 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
183 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017 <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[184]

Table 8-18 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[185] These resources are not PJM resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 8,152.7 MW of which 2,842.3 MW are in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 1,774.7 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 54.0 MW of capacity registered with GATS located in Alabama.

Table 8-18 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): September 30, 2021[186]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas/ Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	130.3	0.0	0.0	0.0	2.0	134.5
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.0	21.4	55.4	0.0	2.1	780.8	0.0	0.0	0.0	598.4	1,458.0
Indiana	0.0	0.0	0.0	0.0	0.0	48.0	0.0	5.2	137.3	0.0	0.0	94.6	180.0	465.1
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	336.8	340.5
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.4	39.2	0.0	0.0	0.0	0.0	917.6
Maryland	3.8	65.0	0.0	2.2	0.0	14.7	0.0	0.0	1,213.1	10.0	0.0	0.0	0.3	1,309.1
Michigan	31.0	0.0	0.0	0.0	1.3	16.6	0.0	4.8	111.9	0.0	0.0	0.0	80.6	246.2
Minnesota		0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	0.0	0.0	0.0	45.8	0.0	14.8	2,842.3	0.0	0.0	0.0	4.7	2,907.6
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
North Carolina	151.5	0.0	0.0	0.0	520.4	0.0	0.0	0.0	1,259.6	0.0	0.0	0.0	0.0	1,931.5
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.0	6.6	19.7	0.0	61.1	257.3	0.0	0.0	33.0	54.7	525.3
Pennsylvania	62.2	109.7	0.8	0.0	31.5	45.2	21.1	100.0	525.1	0.2	204.2	57.6	3.2	1,160.8
South Carolina	0.0	0.0	0.0	0.0	0.0	30.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	122.1
Tennessee	0.0	0.0	0.0	0.0	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.6
Virginia	287.6	0.0	0.0	0.0	30.8	11.3	0.0	2.6	399.7	0.0	0.0	0.0	0.0	732.0
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	144.1	0.0	0.0	13.5	0.0	207.0
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	4.7	0.0	0.0	0.0	0.0	106.7
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	44.7
Total	820.5	774.7	0.8	2.2	1,014.4	344.1	21.1	240.3	8,152.7	10.2	204.2	198.7	2,313.7	14,097.8

184 Id.
185 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. 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.
186 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS>.

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.[187] 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.

Delaware, North Carolina, Michigan and Virginia allow various types of 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.[188] This is equivalent to providing a REC price equal to three times its stated value per MWh.

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 8-19 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

187 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).

188 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231>.

Table 8-19 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			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-20 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 each state's 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 to be sourced from resources located in Pennsylvania.

Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. 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 8-20 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 be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria.
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. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance 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 (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $238.00 per MWh.[189] Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates which was $74.00 per MWh for reporting year ending May 31, 2020. Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[190] Maryland reduced the solar ACP from $100 per credit to $80 per credit effective June 1, 2021.[191]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

189 N.J. S. 2314/A. 3723.
190 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
191 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

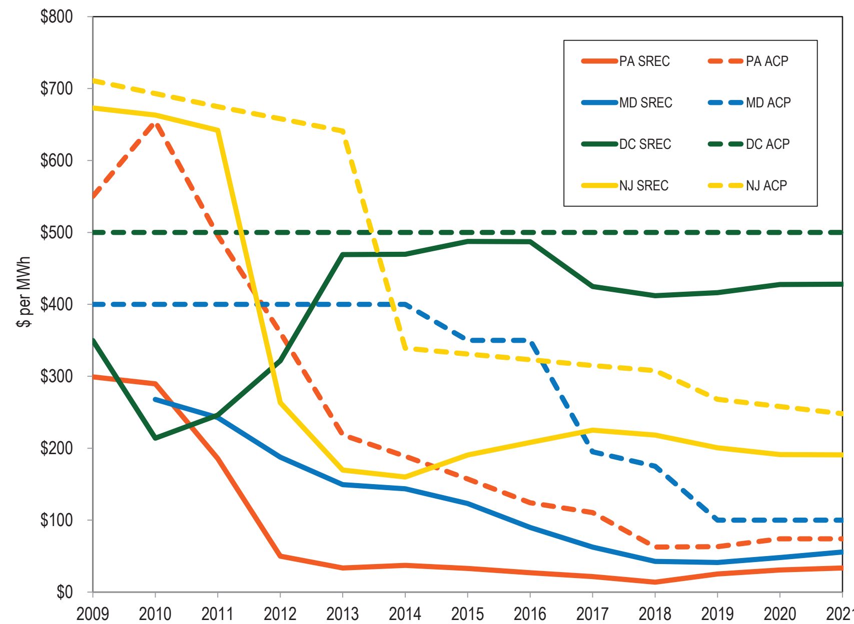
Table 8-21 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-21 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of September 30, 2021[192] [193]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$30.00	$15.00	$80.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$238.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$53.49		
Pennsylvania	$45.00	$45.00	$74.00
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.

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through September 2021



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 Pennsylvania Public Utility Commission issued their 2020 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in February of 2021.[194] Pennsylvania reported that the 614,926 SRECs, 10,086,046 Tier I RECs and 11,203,559 Tier II RECs were retired during the 2020 reporting year (June 1, 2019 through May 31, 2020). Supplier obligations for 1,435

192 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

193 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2020. See "Pricing," <https://www.pennaeps.com/reports/>.

194 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2020," (September 2020), <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf >.

SRECs, 34,737 Tier I RECs and 37,073 Tier II RECs were resolved through ACPs.

The Public Service Commission of the District of Columbia reported that 99,061 SRECs, 1,834,067 Tier I RECs and 54,953 Tier II RECs were retired during the 2019 compliance year. ACPs decreased from $18.7 million for 2018 to $12.1 million for 2019.[195]

The Public Service Commission of Maryland reported that 1,167,329 SRECs were retired in 2019, an increase of 36.2 percent over the 2018 level. Tier 1 REC retirements increased to 10,210,275, 18.3 percent higher than in 2018, and 55,879 Tier 2 RECs were retired in 2019, a 96.5 percent decrease below the 2018 level.[196] ACPs totaled $7.7 million for 2019, up from $67,797 in 2018.[197]

The Public Utilities Commission of Ohio reported that 6,367,089 nonsolar RECs were retired in the 2019 compliance year, which is less than the nonsolar REC obligation of 6,509,239 RECs; and 377,665 SRECs were retired in the 2019 compliance year, exceeding the SREC obligation of 271,176 SRECs.[198]

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 719,261 credits for the compliance year ending May 31, 2020, with zero ACPs.[199] Delmarva Power satisfied their solar REC obligation of 135,771 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through ACPs. This requirement was removed for 2017/2018 Delivery Year and ACPs for COMED decreased to $74,148. The 2016-2017 ACPs for COMED totaled $40,575,311.[200]

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).[201] Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.[202]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2020.[203] Electric power suppliers retired 10,078,927 class I RECs and 1,758,386 class II RECs. Twenty ACPs were submitted class I credits; 135 ACPs were submitted for class II. Electric power suppliers retired 3,287,327 solar RECs and 12 SACPs were submitted.

Table 8-22 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[204] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-22 is an estimate based on average REC prices and assigning the reported alternative compliance payments to the solar standard. The cost of complying with RPS, as reported by the states, was $5.6 billion over the six year period from 2014 through 2019 for the nine jurisdictions that had RPS and reported compliance costs.[205] The average RPS compliance cost per year

195 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2019," Public Service Commission of the District of Columbia (May 1, 2020), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
196 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (October 2020) at 9, <https://www.psc.state.md.us/commission-reports/>.
197 *Id.* at 9.
198 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2019," Public Utilities Commission of Ohio (April 7, 2021), <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
199 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2019–May 31, 2020," Delmarva Power, (Sept. 25, 2020), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>
200 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
201 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2019) at 38, <https://www.ncuc.net/Reps/reps.html>.
202 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.
203 See RPS Report Summary 2005-2020, New Jersey's Clean Energy Program (Apr. 13, 2021), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
204 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
205 The actual PJM RPS compliance cost exceeds the reported $4.4 billion since this total does not include a value for Delaware in 2014 and a value for Pennsylvania in 2018.

based on the reported compliance cost for the six year period from 2014 through 2019 was $936.7 million. The compliance cost for 2019, the most recent year with almost complete data, was $1.2 billion.

Table 8-22 RPS Compliance Cost[206,207,208,209,210,211,212,213,214,215,216]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523	
Maryland	Total RPS	$103,990,914	$126,727,632	$135,198,524	$72,009,070	$84,806,928	$134,545,520
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	$27,351,388	$55,166,116
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	$56,406,247	$79,320,505
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	$1,049,293	$58,899
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	$3,264,504	
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579	
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$67,922,688
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$58,344,639
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701	$57,300,000
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733
PJM	Total RPS	$678,387,871	$888,389,738	$986,186,949	$925,417,144	$986,947,843	$1,154,969,115

206 Several states that have compliance periods that align with the PJM capacity market have not released compliance reports for the period June 1, 2019 through May 31, 2020.
207 "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
208 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the COMED cost of RECs as given in Section 11, Table 2.
209 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Dec. 2019) at 8, <https://www.psc.state.md.us/commission-reports/>.
210 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
211 "RPS Report Summary 2005-2020," New Jersey's Clean Energy Program, April 13, 2021, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
212 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2019," Public Utilities Commission of Ohio, April 7, 2021, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
213 "2020 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, February 2021 <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf>.
214 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2019, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
215 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.
216 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[217] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[218] [219]

Table 8-23 shows SO_2 emission controls by fossil fuel fired units in PJM.[220] [221] [222] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[223] Of the current 55,226.2 MW of coal capacity in PJM, 51,659.9 MW of capacity, 93.5 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-23 SO_2 emission controls by fuel type (MW): September 30, 2021[224]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	51,659.9	3,566.3	55,226.2	93.5%
Diesel Oil	0.0	5,005.4	5,005.4	0.0%
Natural Gas	0.0	67,466.8	67,466.8	0.0%
Other	325.0	3,833.7	4,158.7	7.8%
Total	51,984.9	79,872.2	131,857.1	39.4%

Table 8-24 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 55,226.2 MW of coal capacity in PJM, 55,097.2 MW of capacity, 99.8 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[225]

Table 8-24 NO_X emission controls by fuel type (MW): As of September 30, 2021

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	55,097.2	129.0	55,226.2	99.8%
Diesel Oil	1,398.3	3,607.1	5,005.4	27.9%
Natural Gas	66,468.8	998.0	67,466.8	98.5%
Other	1,805.7	2,353.0	4,158.7	43.4%
Total	124,770.0	7,087.1	131,857.1	94.6%

Table 8-25 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8percent) in PJM have particulate controls, as well as a few natural gas units (4.3 percent) and units with other fuel sources (49.5 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[226] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 55,226.2 MW of coal capacity in PJM, 55,141.2 MW of capacity, 99.8 percent, have some type of particulate emissions control technology. In order to achieve compliance with MATS, 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. Currently, 106 of the 118 coal steam units have baghouse or FGD technology installed, representing 50,359.9 MW out of the 55,226.2 MW total coal capacity, or 91.2 percent.

217 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table>.
218 On April 16, 2020, the EPA issued a revised 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>.
219 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards,"<https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf>.
220 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/>.
221 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. The most recent complete set of emissions data is from the second quarter of 2020.
222 The total MW are less than the 184,622.7 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html>.
223 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>.
224 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.
225 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls>.
226 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf>.

Table 8-25 Particulate emission controls by fuel type (MW): As of September 30, 2021

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	55,141.2	85.0	55,226.2	99.8%
Diesel Oil	0.0	5,005.4	5,005.4	0.0%
Natural Gas	2,912.0	64,554.8	67,466.8	4.3%
Other	2,058.5	2,100.2	4,158.7	49.5%
Total	60,111.7	71,745.4	131,857.1	45.6%

Emissions

Figure 8-10 shows the total CO_2 emissions and the CO_2 emissions per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the third quarter of 2021. Figure 8-10 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2021.[227] [228] For the period from the first quarter of 1999 through the third quarter of 2021, the minimum CO_2 produced per MWh was 0.66 short tons per MWh in the first quarter of 2020, and the maximum was 0.96 short tons per MWh in the first quarter of 2010. Total PJM generation increased from 229,848.9 GWh in the third quarter of 2020 to 232,549.2 GWh in the third quarter of 2021, while CO_2 produced increased from 110.2 million short tons in the third quarter of 2020 to 114.2 million short tons in the third quarter of 2021.[229]

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through September 2021[230 231]

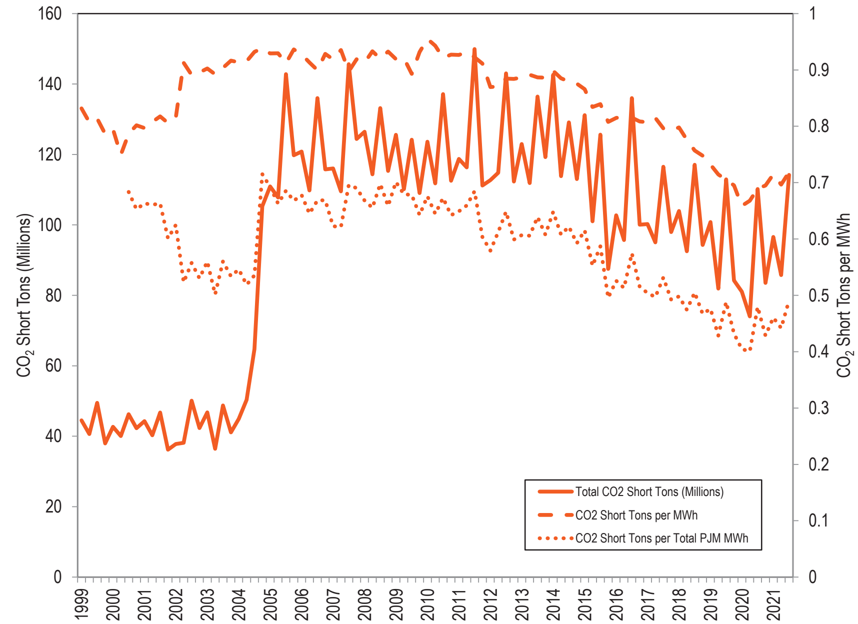


Figure 8-11 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since the first quarter of 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since the first quarter of 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.94 short tons per MWh in the first quarter of 2010.

227 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
228 Emissions data for the first quarter of 2021 was not yet finalized at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.
229 See the *2020 Quarterly State of the Market Report for PJM: January through March*, Section 3: Energy Market, Table 3-10.
230 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
231 In 2004 and 2005, PJM integrated the American Electric Power (AEP), COMED, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).

In the third quarter of 2021, CO_2 emissions were 0.73 short tons per MWh for off peak hours and 0.70 for on peak hours.

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through September 2021[232]

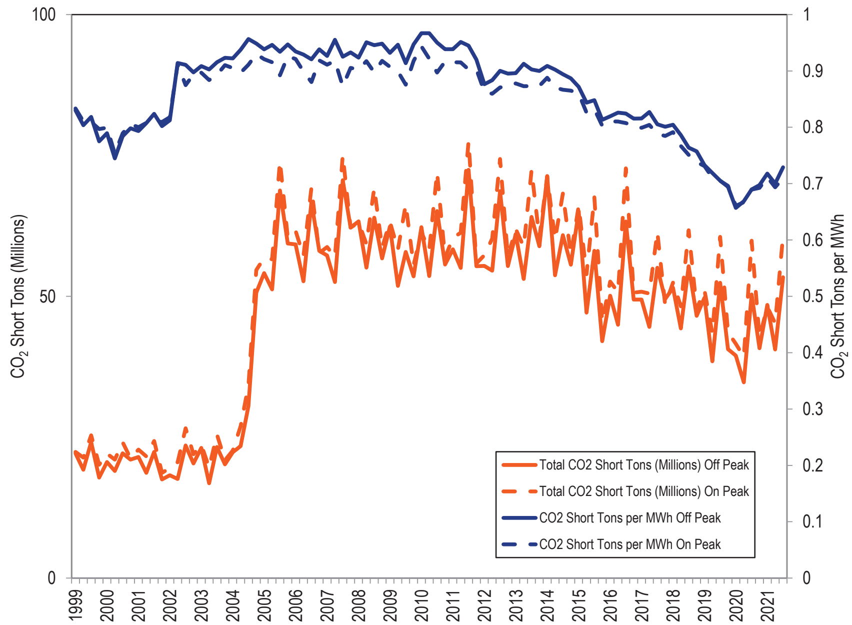


Figure 8-12 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum SO_2 produced per MWh was 0.000378 short tons per MWh in the first quarter of 2020, and the maximum was 0.008141 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum NO_X produced per MWh was at a 0.000254 short tons per MWh in the third quarter of 2021, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the third quarter of 2021, SO_2 emissions were 0.000452 short tons per MWh and NO_X emissions were 0.000254 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2021.[233] [234]

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: January 1999 through September 2021[235]

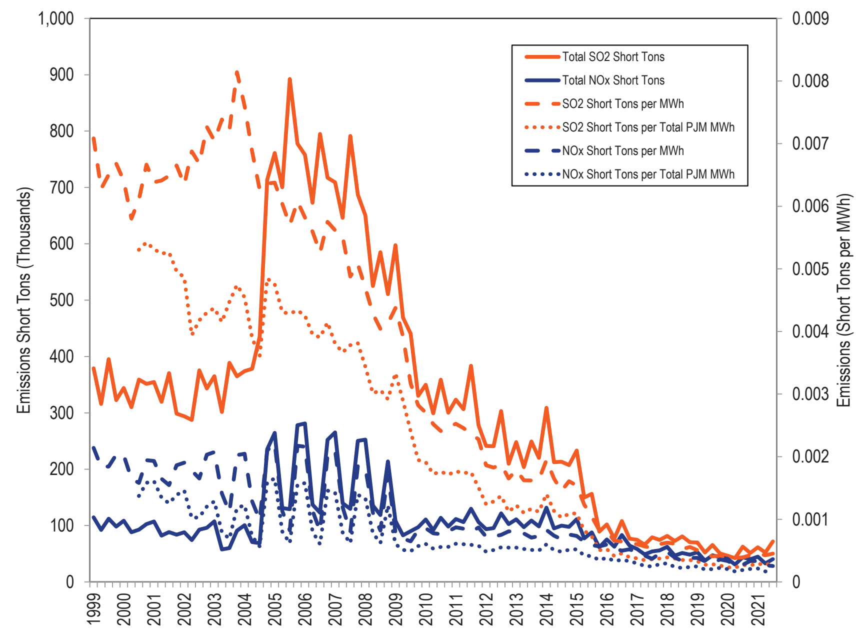


Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum SO_2 produced per MWh during off peak

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

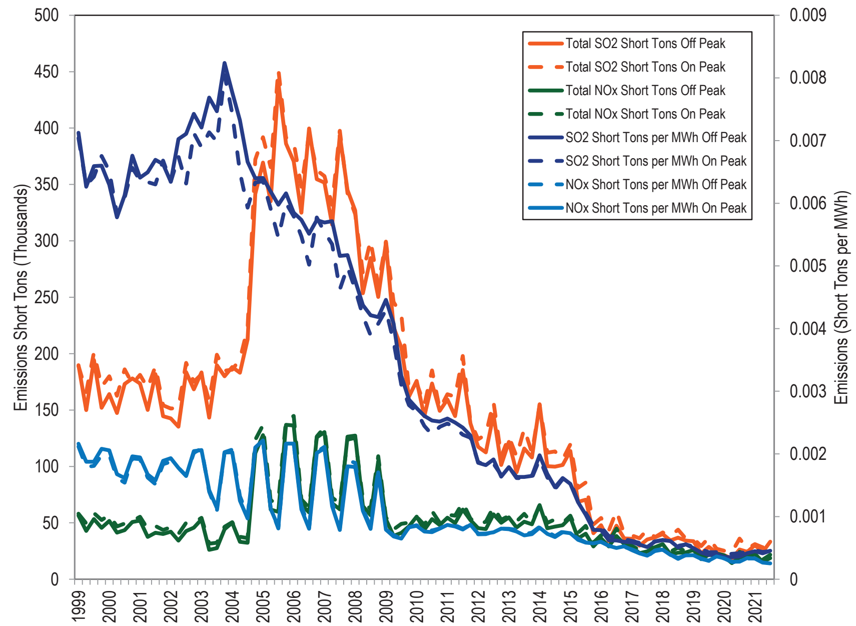
233 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752>.

234 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812>.

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

hours was 0.000352 short tons per MWh in the second quarter of 2020, and the maximum was 0.008239 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum SO_2 produced per MWh during on peak hours was 0.000402 short tons per MWh in the first quarter of 2020, and the maximum was 0.008048 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum NO_X produced per MWh during off peak hours was 0.000255 short tons per MWh in the third quarter of 2021, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. For the period from the first quarter of 1999 through the third quarter of 2021, the minimum NO_X produced per MWh during on peak hours was 0.000253 short tons per MWh in the third quarter of 2021 and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the third quarter of 2021, SO_2 emissions were 0.000454 short tons per MWh and 0.000450 short tons per MWh for off and on peak hours. In the third quarter of 2021, NO_X emissions were 0.000255 short tons per MWh and 0.000253 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through September 2021[236]



Renewable Energy Output

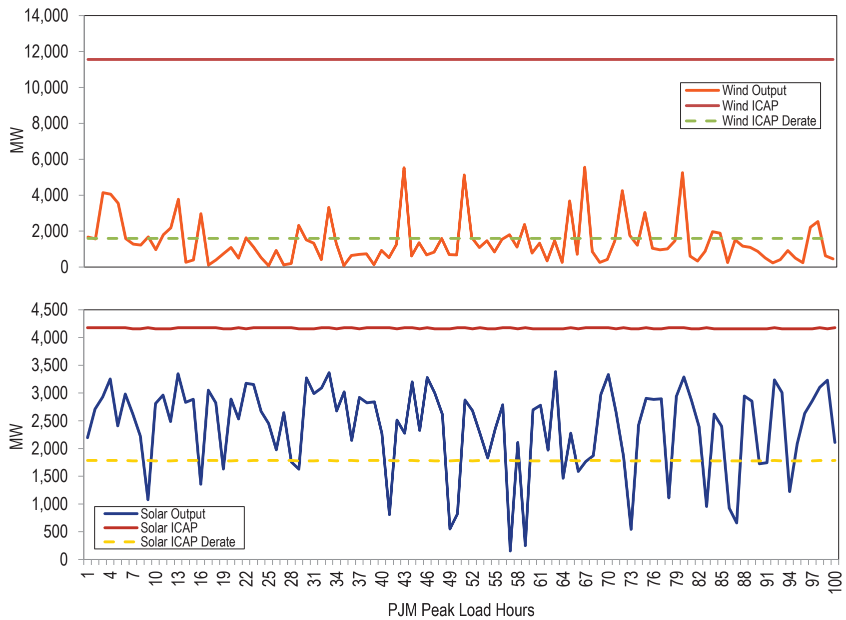
Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in the first nine months of 2021. The top 100 load hours in PJM in the first

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

nine months of 2021 are all PJM defined peak load hours. 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 capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.[237] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 27 hours and below the derated ICAP for 73 hours of the top 100 load hours in the first nine months of 2021. The wind capacity factor for the top 100 load hours in first nine months of 2021 was 12.2 percent. Wind output was above the derated ICAP for 4,364 hours and below the derated ICAP for 2,187 hours in the first nine months of 2021. The wind capacity factor in the first nine months of 2021 was 25.5 percent. Solar output was above the derated ICAP for 79 hours and below the derated ICAP for 21 hours of the top 100 load hours in the first nine months of 2021. The solar capacity factor for the top 100 load hours in the first nine months of 2021 was 57.3 percent. Solar output was above the derated ICAP for 1,836 hours and below the derated ICAP for 4,715 hours in the first nine months of 2021. The solar capacity factor in the first nine months of 2021 was 27.5 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through September, 2021



Wind Units

Table 8-26 shows the capacity factors of wind units in PJM. In the first nine months of 2021, the capacity factor of wind units in PJM was 25.5 percent. Wind units that were capacity resources had a capacity factor of 26.9 percent and an installed capacity of 10,119.3 MW. Wind units that were energy only had a capacity factor of 15.6 percent and an installed capacity of 1,447.7 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[238]

237 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors are 38.0 percent, 42 percent or 60.0 percent depending on installation type. PJM, Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

238 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

Table 8-26 Capacity factor of wind units: January through September 2021[239]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	15.6%	1,447.7
Capacity Resource	26.9%	10,119.3
All Units	25.5%	11,567.0

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for the first nine months of 2021. The hour with the highest average output in the first nine months of 2021, 942.7 MW, occurred in March, and the hour with the lowest average output, 942.7 MW, occurred in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units: January through September, 2021

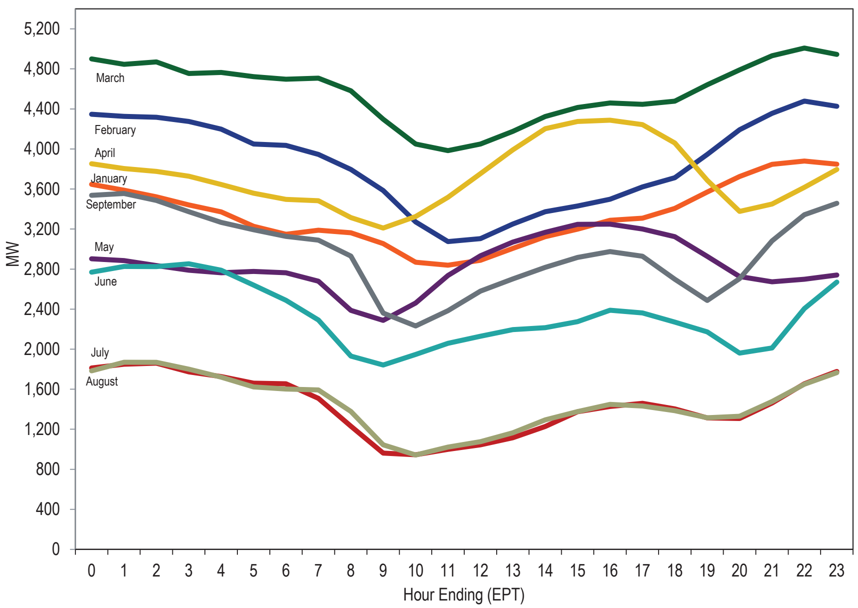


Table 8-27 shows the generation and capacity factor of wind units by month for 2020 and the first nine months of 2021.

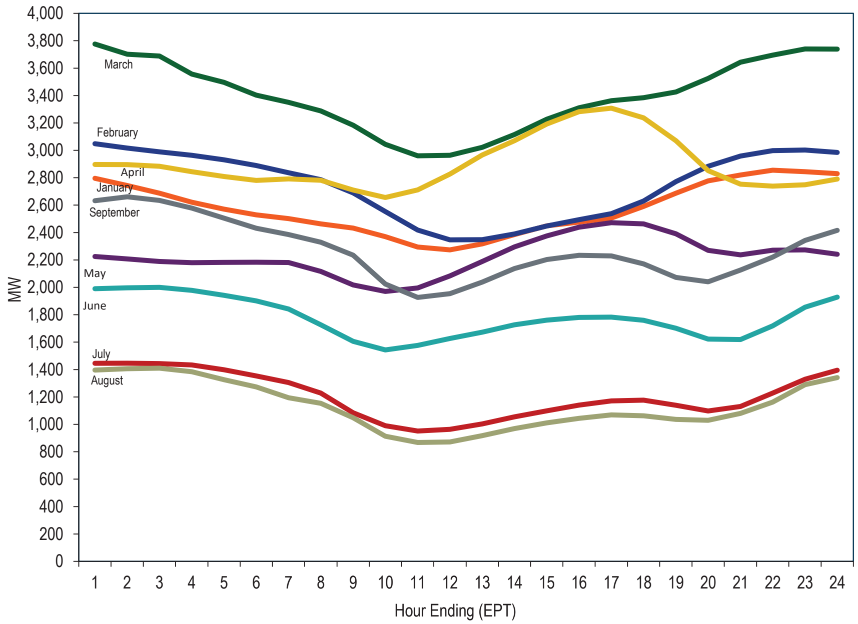
Table 8-27 Capacity factor of wind units in PJM by month: 2020 and January through September, 2021

	2020		2021	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,588,895.7	33.3%	2,486,383.6	29.4%
February	2,564,467.7	35.1%	2,595,187.7	33.4%
March	2,739,005.2	34.8%	3,399,080.7	39.6%
April	2,679,800.9	35.0%	2,684,454.5	32.3%
May	2,261,803.9	28.6%	2,110,377.3	24.5%
June	1,662,419.6	21.7%	1,691,536.1	20.3%
July	959,774.9	12.1%	1,073,252.3	12.5%
August	925,896.4	11.7%	1,087,078.7	12.6%
September	1,604,108.9	20.8%	2,137,750.7	25.7%
October	2,322,150.1	29.0%		
November	3,271,536.3	41.1%		
December	2,851,142.4	33.8%		
Annual	26,431,001.9	28.1%	19,265,101.5	25.5%

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. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

239 Capacity factor is calculated based on online date of the resource.

Figure 8-16 Average hourly day-ahead generation of wind units: January through September, 2021



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. 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 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.[240] Figure 8-17 and Table 8-28 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2021. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2021, the dispatch instruction for marginal wind resources was to reduce output for 57.8 percent of the unit intervals. 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, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

240 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Figure 8-17 Marginal fuel at time of wind generation: January through September, 2021

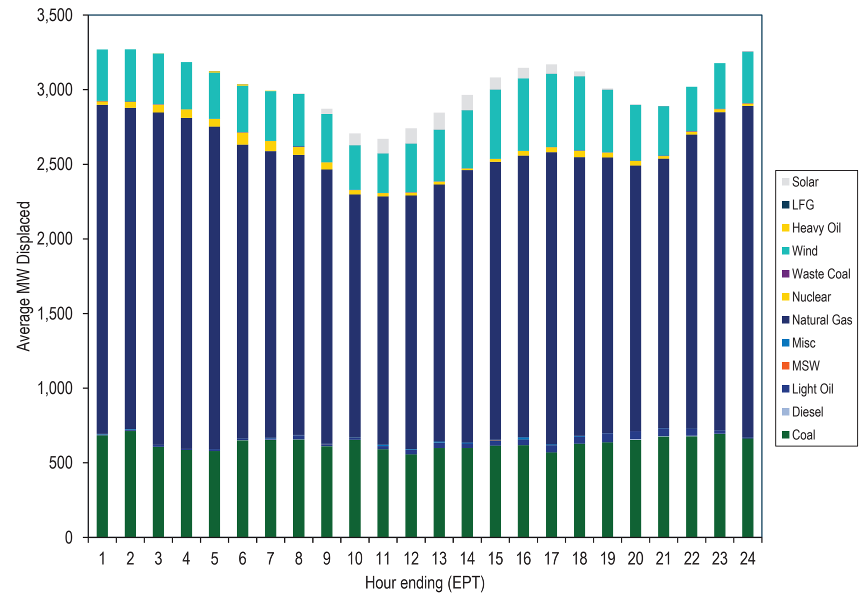


Table 8-28 Marginal fuel MW at time of wind generation: January through September, 2021

Hour	Coal	Diesel	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Heavy Oil	LFG	Solar	0	Total
0	683.7	0.7	3.4	0.8	5.5	2,205.0	22.5	2.9	345.2	0.0	0.0	0.0	0.0	3,269.7
1	713.4	0.3	5.7	0.0	5.6	2,153.4	40.5	2.2	349.0	0.0	0.0	0.0	0.0	3,270.2
2	607.5	0.0	12.6	0.0	0.0	2,227.4	52.4	2.4	339.8	0.9	0.0	0.0	0.0	3,243.0
3	585.7	0.0	7.7	0.0	0.0	2,217.1	57.2	0.7	316.0	0.0	0.0	0.0	0.0	3,184.4
4	578.8	0.0	13.1	0.0	0.5	2,160.1	51.2	1.4	309.4	8.6	0.4	0.0	0.0	3,123.4
5	650.2	2.6	9.8	0.0	0.6	1,967.9	80.7	3.8	311.6	8.6	0.9	0.0	0.0	3,036.5
6	653.4	2.0	9.2	0.0	2.9	1,920.2	68.2	1.3	332.6	3.3	0.0	0.0	0.0	2,993.1
7	655.2	2.6	26.0	0.7	2.0	1,876.7	52.5	3.8	351.7	0.0	0.0	5.2	0.0	2,976.6
8	611.5	0.7	11.6	1.0	2.7	1,838.1	46.8	1.7	323.2	0.0	0.0	34.8	0.0	2,872.1
9	654.4	0.0	12.3	0.7	1.8	1,628.5	29.3	2.6	298.0	0.0	0.1	79.0	0.0	2,706.7
10	590.7	0.0	21.4	0.0	9.5	1,663.6	21.8	0.7	264.3	0.0	0.7	97.7	0.0	2,670.4
11	556.9	0.0	29.2	0.0	5.2	1,699.3	19.4	3.3	325.3	0.0	0.1	102.6	0.0	2,741.3
12	598.8	0.0	34.2	1.0	8.8	1,721.6	19.2	2.2	345.7	0.0	0.8	114.3	0.0	2,846.6
13	599.0	0.0	29.8	0.0	6.3	1,825.8	10.6	2.2	388.3	0.0	0.2	102.8	0.0	2,965.1
14	615.0	0.5	30.9	3.1	4.8	1,862.6	18.7	0.8	464.0	0.0	0.2	81.5	0.0	3,082.2
15	618.7	0.0	36.9	0.4	14.5	1,887.2	31.5	1.3	485.5	0.0	0.0	71.0	0.0	3,146.9
16	569.9	0.0	46.9	0.8	5.5	1,958.5	32.7	1.5	490.8	0.0	0.5	62.2	0.0	3,169.3
17	628.5	0.3	47.3	0.0	5.1	1,866.7	42.7	2.5	496.3	0.0	0.7	32.6	0.0	3,122.6
18	637.5	0.0	59.8	0.0	1.9	1,846.7	32.2	2.1	419.2	0.0	1.2	7.9	0.0	3,008.6
19	653.7	4.5	54.2	0.1	0.0	1,778.6	31.6	1.6	373.0	0.0	1.5	0.0	0.0	2,898.9
20	676.0	3.6	50.9	0.0	1.5	1,806.1	16.6	3.7	329.8	0.0	1.3	0.0	0.0	2,889.5
21	677.9	3.8	47.6	0.0	0.3	1,969.1	19.9	4.2	296.5	0.0	0.0	0.0	0.0	3,019.1
22	694.2	0.8	20.9	0.0	1.0	2,132.4	19.8	2.9	306.0	0.0	0.0	0.0	0.0	3,178.0
23	662.8	0.0	6.7	0.0	1.6	2,220.2	15.4	3.3	343.6	0.0	2.0	0.0	0.0	3,255.5
Average	632.2	0.9	26.2	0.4	3.7	1,934.7	34.7	2.3	358.5	0.9	0.4	33.0	0.0	3,027.9

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 8-17, there are 4,437.5 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-18, there are 8,152.7 MW capacity of solar registered in GATS that are not PJM units. 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 avoid their proper financial responsibility through badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-29 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 27.5 percent in the first nine months of 2021. Solar units that were capacity resources had a capacity factor of 28.3 percent and an installed capacity of 3,638.7 MW. Solar units that were energy only had a capacity factor of 21.6 percent and an installed capacity of 843.4 MW. Solar capacity in RPM is derated to 38.0, 42.0 or 60.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[241]

241 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

Table 8-29 Capacity factor of solar units: January through September, 2021

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.6%	843.4
Capacity Resource	28.3%	3,638.7
All Units	27.5%	4,482.1

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output in the first nine months of 2021, 2,943.1 MW, occurred in July, and the hour with the lowest peak average output, 1,306.9 MW, occurred in February. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-18 Average hourly real-time generation of solar units: January through September, 2021

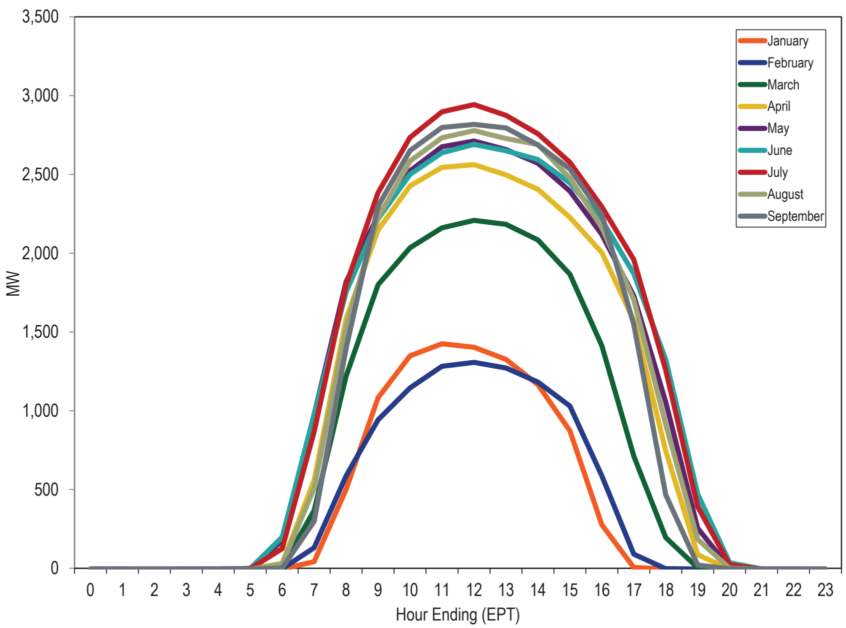


Table 8-30 shows the generation and capacity factor of solar units by month for 2020 and the first nine months of 2021.

Table 8-30 Capacity factor of solar units by month: 2020 and January through September, 2021

	2020		2021	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	172,790.6	14.4%	274,740.5	14.5%
February	192,610.6	17.1%	253,062.0	14.3%
March	268,220.8	21.7%	525,106.6	25.5%
April	339,791.0	28.0%	651,744.6	31.5%
May	371,098.3	29.0%	729,705.9	33.0%
June	386,657.7	30.9%	706,570.2	33.1%
July	419,087.1	31.6%	765,115.5	34.7%
August	325,962.2	24.5%	693,649.4	32.1%
September	289,608.7	18.3%	656,280.0	32.0%
October	282,855.9	15.1%		
November	272,656.3	15.7%		
December	217,925.0	12.6%		
Annual	3,539,264.3	21.0%	5,255,974.7	28.3%

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. Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[242]

242 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 8-19 Average hourly day-ahead generation of solar units: January through September, 2021