Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. State and federal environmental regulatory requirements affect the economic viability of resources and will result in the retirement of a significant level of capacity resources by 2030. State and federal environmental policies also affect the viability of new resources and the cost of entry. State and federal subsidies for renewable generation have made new solar resources cost competitive with existing coal resources and contributed to the significant level of wind and solar resources entering the market.

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 February 13, 2023, the EPA issued a final rule reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[2] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.
- **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.[3] 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.[4] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP), to be known as the "Transport Rule," for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[5] The proposed FIP requirements would establish ozone season NO_X emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia. On January 6, 2023, the EPA proposed to lower the primary annual $PM_{2.5}$ standard to 9.0 to 10.0 µg/m³ from 12.0 µg/m³.[6]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[7] 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, emergency or supplemental power. RICE must be tested annually.[8] 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

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 *Natioal Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 87 Fed. Reg. 7624.

3 CAA § 110(a)(2)(D)(i)(I).

4 *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).

5 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA-HQ-OAR-2021-0668; FRL 8670-01-OAR, 87 Fed. Reg. 20036 (April 6, 2022).

6 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 88 Fed. Reg. 5558 (January 27, 2023).

7 *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).

8 See 40 CFR § 63.6640(f).

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 June 30, 2022, the Supreme Court held that Section 111(d) of the CAA did not provide authority under the major questions doctrine to regulate carbon emissions in the manner proposed.[9] Both the EPA's Affordable Clean Energy (ACE) rule and the Clean Power Plan (CPP), which were promulgated under Section 111(d) of the CAA, are expected to be vacated on remand.
- **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.[10]
- **Waters of the United States.** On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[11] The rule will become effective on March 20, 2023.
- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[12] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

9 *West Virginia v. EPA*, No. 20-1530 (S. Ct. of the U.S.).
10 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).
11 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. [EPA-HQ-OW-2021-0602; FRL-6027.4-01-OW, 88 Fed. Reg. 3004 (January 18, 2023)
12 42 U.S.C. §§ 6901 *et seq.*

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.[13] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[14] [15] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania. The auction price in the March 8, 2023 RGGI auction was $12.50 per short ton, or $13.78 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.45 per MWh or 70.9 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 74.8 percent for a new combined cycle (CC) unit and $43.09 per MWh or 82.4 percent for a new coal plant (CP) for the first three months of 2023.

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 March 31, 2023, Delaware,

13 "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>.
14 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* 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/> .
15 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).

Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.

- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $7.2 billion over the seven year period from 2014 through 2020, an average annual RPS compliance cost of $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.[16]

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 March 31, 2023, 96.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.8 percent of coal steam MW 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 5.8 percent of total generation in PJM for the first three months of 2023. RPS Tier I generation was 7.4 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM for the first three months of 2023. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.
- PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2023, Tier I generation in PJM met only 58.4 percent of the Tier I RPS requirements.

16 The 2020 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.

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. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. 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 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: 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.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated subsidies have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources, and the retirement of emitting 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, including supporting some emitting resources, 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.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. 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.

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. 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.

Existing 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 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 $16.69 per tonne in Ohio to $35.62 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $81.62 per tonne in Pennsylvania to $842.51 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2023 of $13.78 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[17] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[18] The impact of

17 "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>.

18 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.05290995 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2022 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

an $800 per tonne carbon price would be $269.59 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.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. 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 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. The results of the analysis 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.

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 seven year period from 2014 through 2020 for the nine jurisdictions that had RPS was $1.0 billion, or a total of $7.2 billion over seven years. The RPS compliance cost for 2020, the most recent year for which there is almost complete data, was $1.5 billion.[19] 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 $3.5 billion per year if the carbon price were $12.50 per short ton and emissions levels were five percent below 2021 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 $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 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 $12.50 per short ton would be about $2.3 billion. The costs of a carbon price

19 The 2020 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.

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.[20]

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.[21] [22]

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.[23] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

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 February 15, 2023, the EPA issued a final action reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[24] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and restores the basis for the MATS rule.[25] Restoration of the appropriate and necessary finding removes the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On April 3, 2023, the EPA proposed to strengthen and update the MATS rule to reflect recent developments in control technologies and the performance of coal fired plants.[26] The core proposal would revise the (non Hg) PM emission standard, from 0.030 to 0.010 lbs/MMBtu.[27] The EPA believes that the tighter standard could affect up to nine percent of U.S. coal units not already planning to retire.[28] The EPA projects that about 500 MW of coal fired capacity would become uneconomic to maintain by 2028 as a result of the proposed update.[29]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with particulate matter (PM) and ozone national ambient air quality standards (NAAQS).[30] Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

20 For more details, see the *2022 State of the Market Report for PJM*, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."
21 42 U.S.C. § 7401 et seq. (2000).
22 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.
23 42 U.S.C. §§ 6901 *et seq.*
24 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 88 Fed. Reg. 13956 (March 6, 2023).
25 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 (May 22, 2020).
26 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794.
27 *Id.* at 51–52.
28 *Id.*
29 *Id.* at 119.
30 The particulate matter (PM) regulated under the CAA is classified as either PM_{10}, which refers to PM less than 10 microns, and $PM_{2.5}$, which refers PM less than 2.5 microns. $PM_{2.5}$ is referred to as fine particular matter and poses the greatest risk to health. Examples of $PM_{2.5}$ include combustion particles, metals, and organic compounds.

On January 6, 2023, the EPA proposed to lower the primary annual $PM_{2.5}$ standard to 9.0 to 10.0 µg/m³ from 12.0 µg/m³.[31] The proposal does not change other $PM_{2.5}$ standards. The proposal responds to the directive in Executive Order 13990 for review of a 2020 Particulate Matter NAAQS Decision that left $PM_{2.5}$ standards unchanged.

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 emissions and 2006 fine particle emission NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[32] the EPA finalized increases to the good neighbor obligations (i.e. reduced allowable emissions) under the 2008 ozone NAAQS for 12 states.[33] 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."[34] 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.[35] 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.[36] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NO_x Ozone Season Group 2 Trading Program.[37] [38]

On March 15, 2023, the EPA finalized Federal Implementation Plan (FIP) requirements for 23 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[39] The rule resolves the CAA good neighbor obligations of the affected states. The FIP requirements establish ozone season NO_X emissions budgets for electric generating units in the following PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia. The list of PJM jurisdictions excludes North Carolina, the District of Columbia, Tennessee and Delaware. Electric generating units in the indicated states would be required to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program that was previously established in the 2021 CSAPR Update.

The EPA's emissions budgets for each PJM state for each ozone season for 2023 through 2029, and beyond are shown in Table 8-1.

Table 8-1 CSAPR NO_x ozone season group 3 state budgets: 2023 through 2029[40]

	Emissions Budget (Tons)							
PJM State	2023	2024	2025	2026	2027	2028	2029	2030+
Illinois	7,474	7,325	7,325	5,889*	5,363*	4,555*	4,050*	*
Indiana	12,440	11,413	11,413	8,410*	8,135*	7,280*	5,808*	*
Kentucky	13,601	12,999	12,472	10,190*	7,908*	7,837*	7,392*	*
Maryland	1,206	1,206	1,206	842*	842*	842*	842*	*
Michigan	10,727	10,275	10,275	6,743*	5,691*	5,691*	4,656*	*
New Jersey	773	773	773	773*	773*	773*	773*	*
Ohio	9,110	7,929	7,929	7929*	7,929*	6,911*	6,409*	*
Pennsylvania	8,138	8,138	8,138	7,512*	7,158*	7,158*	4,828*	*
Virginia	3,143	2,756	2,756	2,565*	2,373*	2,373*	1,951*	*
West Virginia	13,791	11,958	11,958	10,818*	9,678*	9,678*	9,678*	*

*The budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

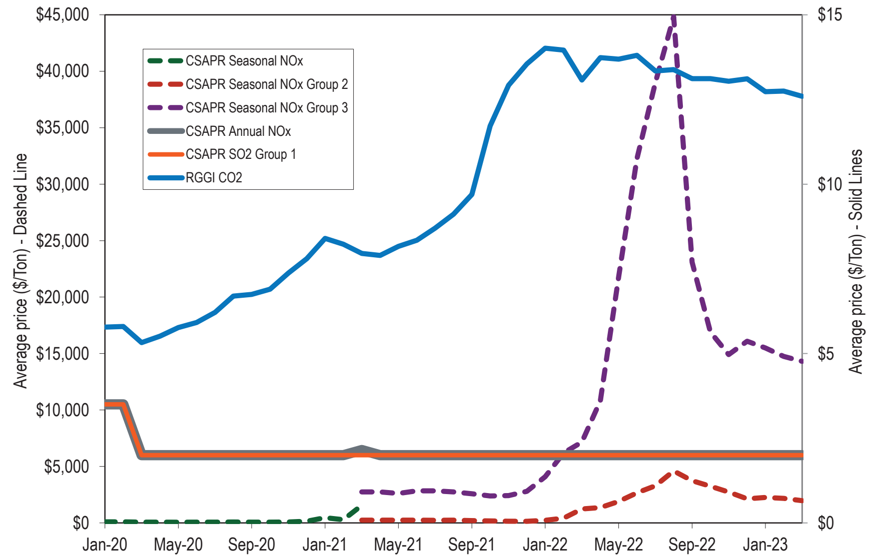
31 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter*. Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 88 Fed. Reg. 5558 (January 27, 2023).
32 Wisconsin v. EPA, 938 F.3d 303, 318-20 (D.C. Cir. 2019).
33 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
34 *Id.* at 23066.
35 *Id.* at 23085-23086.
36 *Id.* at 23121.
37 *Id.*
38 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>
39 See *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.
40 *Id.* at 35 (Table I.B-1).

Figure 8-1 shows average, monthly settled prices for NO_x and SO_2 emissions allowances including CSAPR related allowances for January 2020 through March 2023. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first three months of 2023, CSAPR annual NO_X prices were the same on average as the price in the first three months of 2022. The group 2 CSAPR Seasonal NO_X price averaged $2,130 in the first three months of 2023, a 239.9 percent increase over the group 2 CSAPR Seasonal NO_X price for the first three months of 2022.[41] The group 3 CSAPR Seasonal NO_X price averaged $14,849 in the first three months of 2023, a 155.4 percent increase over the group 3 CSAPR Seasonal NO_X price for the first three months of 2022.[42] The components of real-time LMP analysis shows that NO_x cost contributed $0.00 to the load-weighted average real-time LMP in the first three months of 2023, compared to $0.19 in first three months of 2022.[43] CO_2 cost contributed $1.61 to the load-weighted average real-time LMP in the first three months of 2023, compared to $1.68 in first three months of 2022.[44]

41 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.
42 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.
43 See Components of LMP in 2023 Quarterly State of the Market Report for PJM: January through March, Section 3: Energy Market.
44 Id.

Figure 8-1 Spot monthly average emission price comparison: January 2020 through March 2023



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.[45] 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.[46]

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

45 42 U.S.C § 7470 et seq.
46 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.

considers whether any identified increase is also a "significant net emission increase."

On April 21, 2022, the EPA issued for public input a draft technical non regulatory white paper on control techniques and measures that could reduce GHG emissions from new stationary CTs.[47]

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.[48] 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. 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.[49] [50]

Executive Order 14057 requires the federal government to achieve "100 percent carbon pollution-free electricity on a net annual basis by 2030, including 50 percent 24/7 carbon pollution-free electricity by 2030."[51]

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."[52] 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,

47 The draft white paper can be accessed here: <https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf>.

48 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

49 See CAA § 111.

50 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.

51 See Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, Section 102(a)(i), Executive Order 14057 (December 8, 2021), <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/?utm_medium=email&utm_source=govDelivery>.

52 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).

and were based on inputs that were not peer reviewed.[53] 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, established an Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases. The group developed estimates for the social cost of carbon (SCC), the social cost of nitrous oxide (SCN), and the social cost of methane (SCM). The cost estimates will 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. On July 27, 2022, the U.S. District Court for the Western District of Louisiana enjoined reliance on the IWG's SCC estimates.[54] On April 3, 2023, the U.S. Court of Appeals for the Fifth Circuit dismissed the challenge for lack of standing and vacated the injunction, explaining that agencies' use of the estimates is discretionary and the alleged harms are conjectural.[55]

The EPA has been using the IWG's interim value for SCC of $51 per metric ton of CO_2. In a proposed rule reforming standards for reducing emissions of GHGs from the Crude Oil and Natural Gas source category, the EPA proposes increasing that value to $190.[56] Support for the increase was included in a report attached to the proposed rule that is now subject to public comment.[57]

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).[58] Effective March 15, 2021, the EPA revised the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[59]

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).[60] [61] 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.[62] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[63] The Rule defines WOTUS to include: (i) traditional navigable waters, the territorial seas, and interstate waters; (ii) impoundments of WOTUS; (iii) tributaries to traditional navigable waters, the territorial seas, interstate waters, impoundments when the tributaries meet either the relatively permanent standard or the significant nexus standard; (iv) wetlands, including jurisdictional adjacent wetlands; and (v) intrastate lakes and ponds, streams, or wetlands that meet either the relatively permanent standard or the significant nexus standard.[64] The rule became effective on March 20, 2023, except that, due to preliminary injunctions issued in court proceedings challenging the rule, the rule did not become effective in 26 states, including PJM states Indiana, Ohio, Tennessee, Virginia, West Virginia, and Kentucky.

53 *Id.*
54 *See* Louisiana v. Biden, Order, Civ. No. 2:21-CV-1074-JDC-KK (July 27, 2022).
55 *See* Louisiana v. Biden, Case No. 2:21-CV-1074, slip. op. (5th Cir. April 3, 2023) at 8–15.
56 *See Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, EPA Docket No. EPA–HQ–OAR–2021–0317; FRL–8510–04–OAR, 87 Fed. Reg. 74702 (December 6, 2022).
57 *See Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, EPA Docket ID No. EPA-HQ-OAR-2021-0317 (September 2022).
58 *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.
59 *Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories*, EPA–HQ–OAR–2013–0495; FRL–10019–30– OAR, 86 Fed. Reg. 2542 (Jan. 13, 2018) ("2021 GHG NSR").
60 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.*").
61 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
62 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).
63 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. EPA–HQ–OW–2021–0602; FRL–6027.4–01–OW, 88 Fed. Reg. 3004 (January 18, 2023)
64 *See id.* at 3005–6.

The scope of the CWA expanded 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.[65] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[66] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[67] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[68] Additional litigation or administrative action may clarify the functional discharge analysis.[69] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[70]

Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[71]

Executive Order 13990 called for review and improvement of the existing 2020 Steam Electric Reconsideration Rule. The EPA intends to issue a proposed rule in the fall of 2022 to strengthen certain discharge limits applicable to steam generating units.[72]

On June 9, 2022, the EPA proposed the Water Quality Certification Improvement Rule (WQCIR), which would expand the grounds on which states may condition or block, projects in federal permit proceedings.[73] The WQCIR would provide each state certifying agency a role in determining the "reasonable period of time" to review the request and encourage their adoption of an "activity as a whole" analytical approach that would consider the impacts of the entire project rather than just the specific discharge needing certification.[74]

The EPA is currently implementing its 2015 and 2020 rules.[75] [76] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[77] Some owners have already indicated an intent to close generating units based on the discharge limits in the 2020 Rule.

The EPA is now implementing its Effluent Guidelines. The EPA has also proposed to tighten those guidelines.[78] The Effluent Guidelines establish effluent limitations and pretreatment standards applicable to steam electric generating units. Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or retiring their units by 2028.[79]

65 Slip. Op. No. 18-260 (April 23, 2020).
66 *Id.*
67 *Id.* at 1.
68 *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.").
69 *Id.*
70 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
71 See 40 CFR Part 423. For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
72 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021).
73 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
74 *Id.* at 35343-35349.
75 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015).
76 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
77 *Id.* at 64652.
78 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021); *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020); *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015) (collectively "Effluent Guidelines").
79 85 Fed. Reg. 64650, 64679-82.

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[80] 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.

On April 17 2015, the EPA published a rule under Subtitle D of 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.[81] 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 the EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[82]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[83]

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 an 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 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.[84]

On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[85] 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.[86] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented."[87] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[88] [89] 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

80 42 U.S.C. §§ 6901 *et seq.*

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

82 The Water Infrastructure Improvements for the Nation Act (WIIN Act).

83 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).

84 Utility Solid Waste Activities Group, et al. v. EPA, 901 F.3d 414 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).

85 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).

86 *Id.* at 53516-53517, 53536.

87 *Id.* at 53546; 40 CFR § 257.103(f)(1).

88 *Id.* at 65942.

89 A number of plants in PJM timely filed for extensions.

a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[90]

The EPA has under review 16 completed applications from PJM plants for extensions of the deadline for compliance with the Revised CCRR. The EPA has proposed action on three applications.

On November 18, 2022, the EPA issued a final denial of the application of the General James M. Gavin Plant (2,600 MW) located in the PJM footprint in Cheshire, Ohio (Gavin).[91] The EPA required the Gavin Plant to stop receiving waste at its bottom ash pond no later than April 12, 2023, or such later date as the EPA establishes to address demonstrated electric grid reliability issues.[92] The Gavin Plant has upgraded its facilities and is now in compliance with requirements to close its bottom ash pond, and will continue operating.

On January 11, 2022, the EPA proposed to deny the application of the Clifty Creek Power Plant (1,300 MW) owned by Ohio Valley Electric Corp. (OVEC) and located in the PJM footprint in Madison, Indiana (Clifty Creek).[93] The EPA proposes that both Clifty Creek cease receipt of waste and initiate closure of its surface impoundment no later than 135 days from the date of the EPA's final decision.[94] The EPA provides the potential for an extension for such period that PJM may determine that Clifty Creek is needed for reliability and the EPA agrees is appropriate.[95]

On January 25, 2023, the EPA proposed to deny the application of the Conemaugh Generating Station (1,872 MW) located in the PJM footprint in New Florence, Pennsylvania.[96] The comment period for the proposed denial ended March 10, 2023. The EPA proposes that Conemaugh cease receipt of waste into the Ash Filter Ponds A, B, C, and D and initiate closure no later than 135 days from the date of EPA's final decision (or such later date as EPA determines is necessary to address grid reliability).[97] The EPA provides the potential for an extension for such period that PJM may determine that Conemaugh is needed for reliability and the EPA agrees is appropriate.[98]

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.[99] 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 its own CCR permit program.

State Environmental Regulation

State Coal Ash Regulations

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. On July 1, 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[100] Dominion is currently developing plans to remove coal ash ponds at power stations in the Chesapeake Bay Watershed. The removed coal ash must 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.

Table 8-2 shows the compliance status of affected units with Virginia Solid Waste Management Regulations:[101]

90 *Id.*
91 Denial of Alternative Closure Deadline for General James M. Gavin Plant, Cheshire, Ohio, Docket No.: EPA-HQ-OLEM-2021-0590 (November 18, 2022) ("Gavin Denial Order").
92 87 Fed. Reg. 72989 (November 28, 2022).
93 Proposed Denial of Alternative Closure Deadline for Clifty Creek Power Station, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0587 (January 11, 2022) ("Clifty Creek Proposed Denial Order").
94 Clifty Creek Proposed Denial Order at 77.
95 Clifty Creek Proposed Denial Order at 76-77.
96 Proposed Denial of Alternate Liner Demonstration Application for Conemaugh Generating Station, New Florence, Pennsylvania, Docket No. EPA-HQ-OLEM-2021-0281 (January 25, 2023}) ("Conemaugh Proposed Denial Order").
97 Conemaugh Proposed Denial Order at 50.
98 Conemaugh Proposed Denial Order at 49-50.
99 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Federal CCR Permit Program*, EPA-HQ-OLEM-2019-0361, FRL-10003-82-OLEM, 85 Fed. Reg. 9940 (February 20, 2020).
100 Va. Code § 10.1-1402.03.
101 Virginia Department of Environmental Quality website: https://www.deq.virginia.gov/permits-regulations/permits/waste/coal.

Table 8-2 Compliance status of affected units with Virginia Solid Waste Management Regulations

Plant	CCR Compliance Status
Bremo Bluff Power Station	As of April 2020, ash has been removed from the East and West Ponds. Plans for closure by removal of ash from the remaining North Pond impoundment are under development and will be addressed by the Virginia DEQ in a separate future permitting action.
Chesapeake Energy Center	The facility is currently developing plans for closure by removal of ash from the landfill, historical area, and impoundment.
Chesterfield Power Station	Dominion Energy Virginia submitted the required solid waste permit application for closure by removal and groundwater monitoring of the Upper and Lower Ash Ponds in February 2020, and it is currently under review. The application outlines the removal of ash to either an offsite permitted landfill or offsite beneficial reuse. The application estimates that it will take approximately 13 years to complete closure by removal activities.
Clinch River Power Station	The ash pond was closed and capped prior to January 1, 2019. Clinch River Plant ceased burning coal in 2015 and no longer produces CCR material. The Plant now uses natural gas as fuel. All units are currently being monitored and maintained in post-closure care.
Clover Power Station	The station also has had a permitted CCR landfill since 1993. The permit is currently under revision to incorporate EPA CCR Rule requirements applicable to existing landfills.
Possum Point	As of June 2019, ash has been removed from Ponds A, B, C, and E. Plans for closure by removal of ash from the remaining impoundment (Pond D) are under development. Closure by removal of Pond D will be addressed in a future and separate DEQ permitting action.

Effective April 21, 2021, in response to a statutory mandate,[102] the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[103] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The rules include a permitting program intended to meet federal standards.[104] The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[105] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[106]

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 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.[107] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[108] 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.[109]

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[110]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, Illinois Governor J.B. Pritzker signed the Climate and Equitable Jobs Act (CEJA). CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month

102 Ill. Public Act 101-171 (a.k.a. SB 09).
103 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
104 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).
105 In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments, No. R 2020-019 (March 30, 2020) at 3 (Proposed New 35 Ill. Adm. Code 845z0.
106 *Id.*
107 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/>.
108 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>.
109 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>.
110 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."

basis.[111] [112] The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO2e and co-pollutants.[113] [114] New investor owned, gas-fired units will have emissions caps after three years of operation. The resultant emissions caps are very low for some units and higher for others. More than 10,000 MW of capacity are currently affected, most of which have requested that the MMU calculate a unit specific opportunity cost. The MMU calculates opportunity costs for units that make requests and provide required data.

The CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may elect to receive either the battery subsidies or to sell premium RECs for $30 each.

- **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.

111 Letter of John J. Kim, Director, Illinois Environmental Protection Agency, to Dr. Joseph Bowring, Market Monitor (January 21, 2022) ("IEPA January 21st Letter") <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IL_EPA_CEJA_Response_to_the_IMM_20220121.pdf>.

112 The IEPA January 21st Letter explains: "All of this information is already reported to USEPA by sources subject to Section k-5, per 40 CFR Part 98, and Illinois does not intend for any changes in existing methodologies in that regard. Specifically, Part 98.2(a)(1) requires Part 98 reporting of sources that are subject to Part 75. CO2e emissions are calculated using Equation A-1 from 40 CFR 98.2(b)(4), and emissions data for specific contributing pollutants are taken from a combination of CEMS data and other measurement or estimation methods. Part 98.3 requires reporting of CO2, CH4, N2O, and each fluorinated GHG. This covers all pollutants used to calculate CO2e that would be emitted by sources subject to Section k-5. Part 75.13 requires use of CO2 CEMS or alternate methods that are acceptable continuous monitoring methods detailed in Appendices F and G to Part 75. Part 98 Tables C-1 and C-2 have default values for CH4, N2O, and other GHGs, based on fuel type, that sources should continue to use for requirements pursuant to Section k-5; they are essentially considered to be continuous parameter monitoring based on fuel consumption."

113 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.

114 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.

- **New Jersey Control and Prohibition of Carbon Dioxide Emissions.** On December 2, 2022, New Jersey implemented rules restricting new power plants to CO_2 emissions less 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.[115] The rule limits existing electric generating units to no more than 1,700 lbs of CO_2 per megawatt hour of the gross energy input, by January 1, 2024, to no more than 1,300 pounds per megawatt hour by 2027, and to no more than 1,000 power per megawatt hour by 2035.
- **Climate Solutions Now Act of 2022.** One April 8, 2022, Maryland enacted a requirement for reduction of statewide greenhouse gas emissions by 60 percent from 2006 levels by 2031 and net-zero emissions by 2045.[116]
- **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.

Some states have enacted legislation in 2022 or have pending legislation in 2022 designed to reduce or eliminate greenhouse gas and other emissions, summarized in Table 8-3.

115 See N.J.A.C. 7:27F.

116 See Maryland SB 528.

Table 8-3 Summary of environmental regulatory activity impacting PJM resources by jurisdiction

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware		No current activity.
Illinois	HB 2178	2023-2024, 103rd General Assembly: Repeals the Energy Transition Act, the Energy Community Reinvestment Act, the Community Energy, Climate, and Jobs Planning Act, and the Illinois Clean Energy Jobs and Justice Fund Act.
Indiana		No current activity.
Kentucky		No current activity.
Maryland		No current activity.
Michigan		No current activity.
New Jersey	AB 3079	2022-2023 Reg. Sess.: Requires, by energy year 2050, all electric power sold in NJ by each electric power supplier and basic generation service provider to be from zero-carbon sources.
	SB 2185	2022-2023 Reg. Sess.: Requires BPU to develop program to incentivize installation of new energy storage systems.
	SB 1170/AB 1440	2022-2023 Reg. Sess.: Requires that all new residential and commercial developments be zero energy ready and that developers to offer zero energy construction.
	AB 1744	2022-2023 Reg. Sess.: Revises law concerning Class I and solar renewable energy portfolio standards, solar renewable energy certificates, and net metering.
	SCR 17	2022-2023 Reg. Sess.: Amends Constitution to prohibit construction of new fossil fuel power plants.
	SB 1384	2022-2023 Reg. Sess.: Establishes Nuclear Power Advisory Commission.
	AB 4782	2022-2023 Reg. Sess.: Increases the goal for the annual capacity of solar energy projects to be developed under the permanent Community Solar Energy Program from 50 to 500 megawatts per year.
	AB 4658	2022-2023 Reg. Sess.: Revises State renewable energy portfolio standards.
North Carolina		No current activity.
Ohio		No current activity.
Pennsylvania		No current activity.
Tennessee		No current activity.
Virginia	HB 2197	2023, Regular Session: Virginia Electric Utility Regulation Act: renewable energy; eligible sources for renewable energy portfolio standard program. Provides that for the purpose of the Virginia Electric Utility Regulation Act, renewable energy includes energy from advanced nuclear technology or hydrogen. The bill classifies electric-generating resources that generate electric energy derived from advanced nuclear technology or hydrogen located in the Commonwealth or physically located within the PJM region as renewable energy portfolio standard program sources.
	HB 2311	2023, Regular Session: Virginia Electric Utility Regulation Act; renewable energy; eligible sources for renewable energy portfolio standard program. Provides that for the purpose of the Virginia Electric Utility Regulation Act, renewable energy includes energy from nuclear and hydrogen power. The bill provides electric-generating resources that generate electric energy derived from nuclear or hydrogen power located in the Commonwealth or physically located within the PJM region as a renewable energy portfolio standard program source.
	HB 1670	2023, Regular Session: Virginia Electric Utility Regulation Act. Provides that, in lieu of the triennial review proceedings required under current law, Dominion Energy Virginia, beginning in 2023, will be subject to biennial reviews of their rates, terms, and conditions for generation, distribution, and transmission services. The bill also prohibits an investor-owned incumbent electric utility from permanently retiring an electric power generation facility from service after July 1, 2023, without first obtaining the approval of the Commission and a finding by the Commission that the retirement determination, after consideration of the impact of the proposed retirement on reliability or security of electric service to customers, is reasonable and prudent. Such prohibition does not apply to early retirement determinations identified by the utility in an integrated resource plan filed with the Commission by July 1, 2023. Virginia Electric Utility Regulation Act. Provides that, in lieu of the triennial review proceedings required under current law, Dominion Energy Virginia, beginning in 2023, will be subject to biennial reviews of their rates, terms, and conditions for generation, distribution, and transmission services. The bill also prohibits an investor-owned incumbent electric utility from permanently retiring an electric power generation facility from service after July 1, 2023, without first obtaining the approval of the Commission and a finding by the Commission that the retirement determination, after consideration of the impact of the proposed retirement on reliability or security of electric service to customers, is reasonable and prudent. Such prohibition does not apply to early retirement determinations identified by the utility in an integrated resource plan filed with the Commission by July 1, 2023.
	HB 2444/SB 1441	2023, Regular Session: Requires the VSCC, in conducting its review of requests for cost recovery by a Phase II Utility for costs associated with generating facilities utilizing energy derived from offshore wind, to give due consideration to the economic development benefits.
Washington, D.C.		No current activity.
West Virginia	HB 2175	2023, Regular Session: The purpose of this bill is to limit the number of permits to construct wind power plants, wind power farms, or “windmills” for power generally in West Virginia; to provide that for each new wind powered facility built in West Virginia, there is an offset in the amount of taxes paid by new and existing coal fired power plants; and to ensure that coal remains the primary source of power in West Virginia during emergency weather events.

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.[117] 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.[118] 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.[119]

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.[120]

Delaware, Maryland, New Jersey, and Virginia are members of RGGI. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[121] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[122] [123] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania.

Table 8-4 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 nine auctions of the 5th control period.[124] [125] The clearing price for the auction held March 8, 2023 was $12.50 per allowance (equal to one short ton of CO_2).[126] The March auction clearing price decreased 3.8 percent from the last auction clearing price of $12.99 in December 2022.

117 Va. HB 1526/SB 851.
118 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
119 *Id.*
120 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>.
121 "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>.
122 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* 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/>.
123 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).
124 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.
125 The December 2021 auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $13.00 per ton. The auctions on March 5, 2014, September 3, 2015, and December 1, 2021 are the only auctions that included CRRs.
126 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th and 5th Control Periods[127]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	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 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	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
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594
December 7, 2022	$12.99	22,233,203		22,233,203	$14.32	20,169,628		20,169,628
March 8, 2023	$12.50	21,522,877		21,522,877	$13.78	19,525,231		19,525,231

The RGGI auction held on March 8, 2023, generated $269.0 million in auction revenue. RGGI auctions have generated $6.2 billion in auction revenue since 2008.[128] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2020 reporting year, have invested $3.0 billion, 79.0 percent of revenues auction revenues.[129] The $3.0 billion of investment includes 53 percent on energy efficiency, 14 percent on clean and renewable energy, 8 percent on greenhouse gas abatement, 16 percent on direct bill assistance, 3 percent on beneficial electrification, 6 percent on administration and 1 percent on RGGI, Inc.[130]

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 2021 CO_2 emission levels and the RGGI clearing price for the March 2023 auction ranges from $1.9 billion per year to $3.5 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[131] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2021 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 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2021 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.[132]

127 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results> (Accessed October 17, 2022).
128 See Auction Results at <https://www.rggi.org/>.
129 *The Investment of RGGI Proceeds in 2020*, The Regional Greenhouse Gas Initiative (RGGI) at 14, May 2022, <https://www.rggi.org/investments/proceeds-investments>.
130 *Id.* at 13.
131 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.
132 "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>.

Table 8-5 Estimated CO_2 allowance revenue at March 2023 RGGI price level[133] [134]

		Estimated CO_2 allowance revenue ($ millions), carbon price $12.50 per short ton					
Jurisdiction	2021 power generation CO_2 emissions (short tons)	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Delaware	1,569,515.5	$18.6	$17.7	$16.7	$15.7	$14.7	$9.8
Illinois	20,545,590.8	$244.0	$231.1	$218.3	$205.5	$192.6	$128.4
Indiana	27,066,021.8	$321.4	$304.5	$287.6	$270.7	$253.7	$169.2
Kentucky	23,972,416.9	$284.7	$269.7	$254.7	$239.7	$224.7	$149.8
Maryland	10,527,468.1	$125.0	$118.4	$111.9	$105.3	$98.7	$65.8
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	8,424,107.9	$100.0	$94.8	$89.5	$84.2	$79.0	$52.7
North Carolina	61,960.5	$0.7	$0.7	$0.7	$0.6	$0.6	$0.4
Ohio	62,670,551.1	$744.2	$705.0	$665.9	$626.7	$587.5	$391.7
Pennsylvania	67,579,691.3	$802.5	$760.3	$718.0	$675.8	$633.6	$422.4
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	22,491,149.9	$267.1	$253.0	$239.0	$224.9	$210.9	$140.6
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	51,728,460.2	$614.3	$581.9	$549.6	$517.3	$485.0	$323.3
Total	296,636,934.0	$3,522.6	$3,337.2	$3,151.8	$2,966.4	$2,781.0	$1,854.0

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-6 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 2023 compliance year is the third year of the fifth control period.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[135] [136] The first adjustment removed 57.5 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.[137] 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.[138] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[139] The base emissions cap for each of the next five years will be reduced by 19.1 million allowances. The percent change columns in Table 8-6 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[140] The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.[141] Figure 8-2 shows the adjusted carbon budgets for the RGGI states. The RGGI clearing price since 2014 has been on average 194.7 percent higher than the prices prior to the emission cap adjustments.

133 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

134 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.

135 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

136 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

137 "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>.

138 Id.

139 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

140 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the RGGI cap for 2020 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 is treated analogously.

141 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.

Table 8-6 RGGI emissions cap history[142 143 144]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009	1st	$2.77	188,076,976		188,076,976	
2010		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012	2nd	$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		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015	3rd	$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		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018	4th	$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		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021	5th	$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022		$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023		$12.50	112,457,784	(3.1%)	93,367,454	(3.8%)

Figure 8-2 RGGI adjusted carbon budgets by state[145]

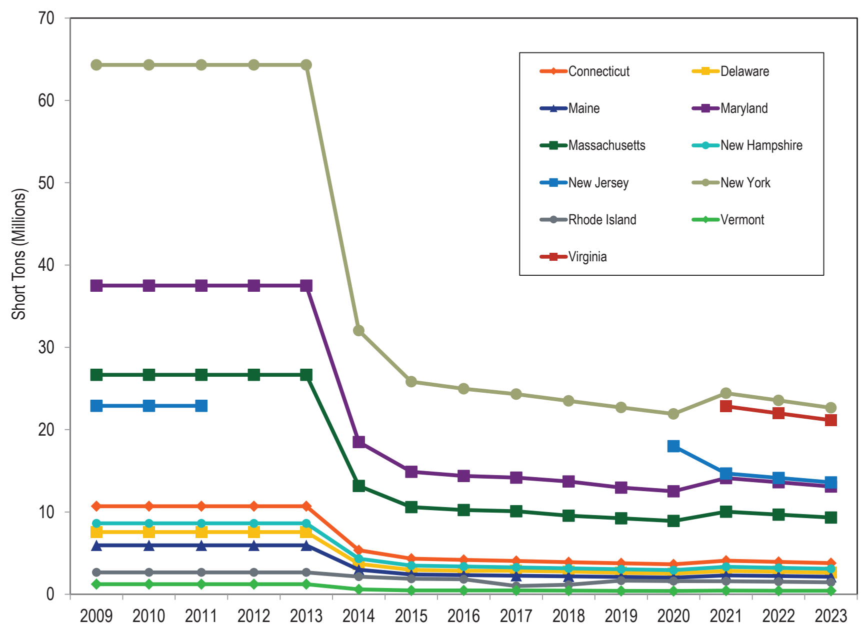


Table 8-7 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. Allowance revenues to states would be $1.5 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2021.

142 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed, October 18, 2022).

143 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>.

144 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.

145 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed October 18, 2022).

Table 8-7 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Jurisdiction	Carbon Price ($ per short ton)				$10.00	
Delaware	$14.9	$14.1	$13.3	$12.6	$11.8	$7.8
Illinois	$195.2	$184.9	$174.6	$164.4	$154.1	$102.7
Indiana	$257.1	$243.6	$230.1	$216.5	$203.0	$135.3
Kentucky	$227.7	$215.8	$203.8	$191.8	$179.8	$119.9
Maryland	$100.0	$94.7	$89.5	$84.2	$79.0	$52.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$80.0	$75.8	$71.6	$67.4	$63.2	$42.1
North Carolina	$0.6	$0.6	$0.5	$0.5	$0.5	$0.3
Ohio	$595.4	$564.0	$532.7	$501.4	$470.0	$313.4
Pennsylvania	$642.0	$608.2	$574.4	$540.6	$506.8	$337.9
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$213.7	$202.4	$191.2	$179.9	$168.7	$112.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$491.4	$465.6	$439.7	$413.8	$388.0	$258.6
Total	$2,818.1	$2,669.7	$2,521.4	$2,373.1	$2,224.8	$1,483.2
	Carbon Price ($ per short ton)				$25.00	
Delaware	$37.3	$35.3	$33.4	$31.4	$29.4	$19.6
Illinois	$488.0	$462.3	$436.6	$410.9	$385.2	$256.8
Indiana	$642.8	$609.0	$575.2	$541.3	$507.5	$338.3
Kentucky	$569.3	$539.4	$509.4	$479.4	$449.5	$299.7
Maryland	$250.0	$236.9	$223.7	$210.5	$197.4	$131.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$200.1	$189.5	$179.0	$168.5	$158.0	$105.3
North Carolina	$1.5	$1.4	$1.3	$1.2	$1.2	$0.8
Ohio	$1,488.4	$1,410.1	$1,331.7	$1,253.4	$1,175.1	$783.4
Pennsylvania	$1,605.0	$1,520.5	$1,436.1	$1,351.6	$1,267.1	$844.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$534.2	$506.1	$477.9	$449.8	$421.7	$281.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,228.6	$1,163.9	$1,099.2	$1,034.6	$969.9	$646.6
Total	$7,045.1	$6,674.3	$6,303.5	$5,932.7	$5,561.9	$3,708.0
	Carbon Price ($ per short ton)				$50.00	
Delaware	$74.6	$70.6	$66.7	$62.8	$58.9	$39.2
Illinois	$975.9	$924.6	$873.2	$821.8	$770.5	$513.6
Indiana	$1,285.6	$1,218.0	$1,150.3	$1,082.6	$1,015.0	$676.7
Kentucky	$1,138.7	$1,078.8	$1,018.8	$958.9	$899.0	$599.3
Maryland	$500.1	$473.7	$447.4	$421.1	$394.8	$263.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$400.1	$379.1	$358.0	$337.0	$315.9	$210.6
North Carolina	$2.9	$2.8	$2.6	$2.5	$2.3	$1.5
Ohio	$2,976.9	$2,820.2	$2,663.5	$2,506.8	$2,350.1	$1,566.8
Pennsylvania	$3,210.0	$3,041.1	$2,872.1	$2,703.2	$2,534.2	$1,689.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,068.3	$1,012.1	$955.9	$899.6	$843.4	$562.3
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,457.1	$2,327.8	$2,198.5	$2,069.1	$1,939.8	$1,293.2
Total	$14,090.3	$13,348.7	$12,607.1	$11,865.5	$11,123.9	$7,415.9

Table 8-8 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $25.00 per tonne, the PJM load-weighted average LMP in the first three months of 2023 would have increased by 5.4 percent.[146]

Table 8-8 Estimated impact of carbon price on LMP: January through March, 2022 and 2023

		2022 (Jan - Mar)			2023 (Jan - Mar)		
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	$54.13	$52.09	(3.8%)	$30.28	$29.23	(3.5%)
Scenario 2	$10.00	$54.13	$53.27	(1.6%)	$30.28	$29.90	(1.2%)
Scenario 3	$15.00	$54.13	$54.45	0.6%	$30.28	$30.58	1.0%
Scenario 4	$25.00	$54.13	$56.82	5.0%	$30.28	$31.92	5.4%
Scenario 5	$50.00	$54.13	$62.74	15.9%	$30.28	$35.28	16.5%

Table 8-9 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[147] [148] 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 $43.15 per MWh for a new coal plant (CP). Table 8-11 and Table 8-12 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-9 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	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.68	$3.37	$5.05	$16.85	$33.70	$67.40	$134.79
CP	$4.31	$8.62	$12.93	$43.09	$86.18	$172.36	$344.73

Table 8-9 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 $187.78 per credit in the first three months of 2023. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. The carbon price implied by the SREC price is slightly less than $400 per tonne. Table 8-9 shows that if the MWh produced by the solar resource resulted in avoiding the production of one MWh from a CT, the value of carbon reduction implied by an SREC price of $195.58 is a carbon price of $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 $24.45 per MWh.

Applying this method to Tier I and Class I REC and SREC price histories yields the implied carbon prices in Table 8-10. The carbon price implied by the average REC price during the first three months of 2023 in Ohio is $16.69 per tonne which is $2.91 per tonne higher than the RGGI auction price of $13.78 per tonne on March 8, 2023. The carbon price implied by the average price for Washington, DC RECs during the first three months of 2023 is $21.87 per tonne. The implied carbon prices for Virginia, Maryland, New Jersey and Pennsylvania RECs exceed the RGGI clearing price by at least $10 per tonne, and are well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[149] 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.

146 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>.

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

148 Prices reflect carbon emissions rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

149 "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>.

Table 8-10 Implied carbon price based on REC and SREC prices: 2014 through March 2023

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jurisdiction with Tier I or Class I REC										
Delaware	$35.28	$32.01	$33.01	$10.29	$11.60	$16.10	$19.94			
Maryland	$28.54	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$27.15	$30.09	$35.50
New Jersey	$21.10	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$26.85	$28.38	$35.62
Ohio	$10.19	$8.54	$5.30	$6.29	$11.21	$14.04	$16.33	$16.39	$16.45	$16.69
Pennsylvania	$26.74	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$26.44	$29.76	$35.12
Virginia								$20.56	$21.21	$24.21
Washington, D.C.		$3.20	$4.05	$4.90	$4.69	$5.52	$12.55	$15.87	$19.24	$21.87
Jurisdiction with Solar REC										
Delaware	$117.60	$85.66	$86.75	$35.80	$17.38					
Maryland	$293.59	$251.99	$183.64	$128.05	$87.27	$84.19	$101.68	$120.95	$108.77	$96.56
New Jersey	$327.20	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$409.69	$420.80	$384.05
Ohio	$82.56	$45.25	$36.26	$31.92	$21.73	$26.65				
Pennsylvania	$76.13	$67.09	$55.22	$43.97	$28.16	$51.65	$63.80	$73.78	$85.62	$81.62
Washington, D.C.	$960.35	$997.05	$996.49	$868.79	$842.89	$851.39	$869.41	$843.90	$843.80	$842.51
Regional Greenhouse Gas Initiative										
RGGI clearing price	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59	$14.84	$13.78

Table 8-11 Carbon price for natural gas fired generators[150]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
6,000	$3.17	$4.76	$6.35	$7.94	$9.52	$11.11	$12.70	$14.29	$15.87	$17.46	$19.05
6,500	$3.44	$5.16	$6.88	$8.60	$10.32	$12.04	$13.76	$15.48	$17.20	$18.92	$20.63
7,000	$3.70	$5.56	$7.41	$9.26	$11.11	$12.96	$14.81	$16.67	$18.52	$20.37	$22.22
7,500	$3.97	$5.95	$7.94	$9.92	$11.90	$13.89	$15.87	$17.86	$19.84	$21.83	$23.81
8,000	$4.23	$6.35	$8.47	$10.58	$12.70	$14.81	$16.93	$19.05	$21.16	$23.28	$25.40
8,500	$4.50	$6.75	$8.99	$11.24	$13.49	$15.74	$17.99	$20.24	$22.49	$24.74	$26.98
9,000	$4.76	$7.14	$9.52	$11.90	$14.29	$16.67	$19.05	$21.43	$23.81	$26.19	$28.57
9,500	$5.03	$7.54	$10.05	$12.57	$15.08	$17.59	$20.11	$22.62	$25.13	$27.65	$30.16
10,000	$5.29	$7.94	$10.58	$13.23	$15.87	$18.52	$21.16	$23.81	$26.45	$29.10	$31.75
10,500	$5.56	$8.33	$11.11	$13.89	$16.67	$19.44	$22.22	$25.00	$27.78	$30.56	$33.33
11,000	$5.82	$8.73	$11.64	$14.55	$17.46	$20.37	$23.28	$26.19	$29.10	$32.01	$34.92
11,500	$6.08	$9.13	$12.17	$15.21	$18.25	$21.30	$24.34	$27.38	$30.42	$33.47	$36.51
12,000	$6.35	$9.52	$12.70	$15.87	$19.05	$22.22	$25.40	$28.57	$31.75	$34.92	$38.10
12,500	$6.61	$9.92	$13.23	$16.53	$19.84	$23.15	$26.45	$29.76	$33.07	$36.38	$39.68
13,000	$6.88	$10.32	$13.76	$17.20	$20.63	$24.07	$27.51	$30.95	$34.39	$37.83	$41.27
13,500	$7.14	$10.71	$14.29	$17.86	$21.43	$25.00	$28.57	$32.14	$35.71	$39.29	$42.86
14,000	$7.41	$11.11	$14.81	$18.52	$22.22	$25.93	$29.63	$33.33	$37.04	$40.74	$44.44
14,500	$7.67	$11.51	$15.34	$19.18	$23.02	$26.85	$30.69	$34.52	$38.36	$42.20	$46.03
15,000	$7.94	$11.90	$15.87	$19.84	$23.81	$27.78	$31.75	$35.71	$39.68	$43.65	$47.62

150 Prices reflect carbon emission rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

Table 8-12 Carbon price for coal fired generators[151]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.58	$16.77	$20.96	$25.16	$29.35	$33.54	$37.73	$41.93	$46.12	$50.31
9,500	$8.85	$13.28	$17.70	$22.13	$26.55	$30.98	$35.40	$39.83	$44.26	$48.68	$53.11
10,000	$9.32	$13.98	$18.63	$23.29	$27.95	$32.61	$37.27	$41.93	$46.58	$51.24	$55.90
10,500	$9.78	$14.67	$19.57	$24.46	$29.35	$34.24	$39.13	$44.02	$48.91	$53.81	$58.70
11,000	$10.25	$15.37	$20.50	$25.62	$30.75	$35.87	$40.99	$46.12	$51.24	$56.37	$61.49
11,500	$10.71	$16.07	$21.43	$26.79	$32.14	$37.50	$42.86	$48.22	$53.57	$58.93	$64.29
12,000	$11.18	$16.77	$22.36	$27.95	$33.54	$39.13	$44.72	$50.31	$55.90	$61.49	$67.08
12,500	$11.65	$17.47	$23.29	$29.12	$34.94	$40.76	$46.58	$52.41	$58.23	$64.05	$69.88
13,000	$12.11	$18.17	$24.22	$30.28	$36.34	$42.39	$48.45	$54.50	$60.56	$66.62	$72.67
13,500	$12.58	$18.87	$25.16	$31.44	$37.73	$44.02	$50.31	$56.60	$62.89	$69.18	$75.47
14,000	$13.04	$19.57	$26.09	$32.61	$39.13	$45.65	$52.18	$58.70	$65.22	$71.74	$78.26
14,500	$13.51	$20.26	$27.02	$33.77	$40.53	$47.28	$54.04	$60.79	$67.55	$74.30	$81.06
15,000	$13.98	$20.96	$27.95	$34.94	$41.93	$48.91	$55.90	$62.89	$69.88	$76.87	$83.85
15,500	$14.44	$21.66	$28.88	$36.10	$43.32	$50.54	$57.77	$64.99	$72.21	$79.43	$86.65
16,000	$14.91	$22.36	$29.81	$37.27	$44.72	$52.18	$59.63	$67.08	$74.54	$81.99	$89.44
16,500	$15.37	$23.06	$30.75	$38.43	$46.12	$53.81	$61.49	$69.18	$76.87	$84.55	$92.24
17,000	$15.84	$23.76	$31.68	$39.60	$47.52	$55.44	$63.36	$71.27	$79.19	$87.11	$95.03
17,500	$16.30	$24.46	$32.61	$40.76	$48.91	$57.07	$65.22	$73.37	$81.52	$89.68	$97.83
18,000	$16.77	$25.16	$33.54	$41.93	$50.31	$58.70	$67.08	$75.47	$83.85	$92.24	$100.62

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 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).[152] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of March 31, 2023, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of March 31, 2023, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties. 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.[153]

As of March 31, 2023, Kentucky, Tennessee and West Virginia had 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

151 Prices reflect carbon emission rates for refined coal in *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

152 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed April 18, 2023).

153 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

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.[154]

Beginning in March 2023, RECs for GATS generators will be hourly time stamped certificates.[155] Prior to March 2023, PJM EIS issued RECs based on how much a generator produced in a month.

Table 8-13 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.

Table 8-13 Renewable and alternative energy standards of PJM jurisdictions: 2022 to 2032[156 157]

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delaware	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%
Illinois	20.50%	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%
Maryland	32.60%	34.45%	36.35%	38.25%	41.00%	44.75%	46.50%	53.00%	53.50%	53.50%	53.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%	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%	12.50%
Ohio	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	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%	18.00%
Virginia (Phase I utilities)	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%
Virginia (Phase II utilities)	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%
Washington, DC	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021 in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-14 for details.

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.[158] 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.[159] Additional details are provided in Table 8-14.

154 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
155 "PJM EIS to Produce Energy Certificates Hourly", PJM Environmental Information Services (February 13, 2023) <https://www.pjm-eis.com/-/media/about-pjm/newsroom/2023-releases/20230213-pjm-eis-to-produce-energy-certificates-hourly.ashx>.
156 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
157 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.
158 *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>.
159 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[160] 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.[161] [162] 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.[163] 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.

On May 18, 2021, Maryland enacted legislation doubling the limit on net metered capacity from 1,500 to 3,000 MW.[164] The legislation is expected to boost the installation of distribution level solar power.

160 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
161 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).
162 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
163 N.J. S. 2314/A. 3723.
164 Md. Code Ann § 7-306(d) & 7-306.2(g) (HB 569).

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.[165] Through the SREC-II program, the BPU distribute solar renewable certificates to qualifying solar power facilities. The legislation includes incentives for at least 1,500 MW of behind the meter solar facilities and 750 MW of community solar by 2026. It also includes a new competitive solicitation process to incentivize at least 1,500 MW of large-scale solar power facilities by 2026, and develops siting criteria for large-scale solar projects.

165 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-14 Recent changes in RPS rules[166] [167] [168] [169] [170] [171] [172]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
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.[173]

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).[174] 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

166 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
167 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
168 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>.
169 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
170 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>.
171 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
172 *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>.
173 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.
174 N.J. S. 2314/A. 3723.

MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[175] 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.[176] [177]

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Orsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[178] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[179] Both projects are expected to become operational before the end of 2026.[180] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Orsted, and U.S. Wind's 248 MW project.[181]

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.[182] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[183]

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.[184] 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 8-15 shows the Tier I standards for PJM states.[185] All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.[186]

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2022 to 2032

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Maryland	30.10%	31.95%	33.85%	35.75%	38.50%	42.25%	44.00%	50.50%	51.00%	51.00%	51.00%
New Jersey	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%	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%	8.00%
Washington, DC	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%

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.[187]

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

175 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.
176 BPU Docket No. QO18080851.
177 "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>.
178 "Orsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-16-gw-in-maryland-offshore-tender-766237/>.
179 *Id.*
180 *Id.*
181 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).
182 "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>.
183 "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>.
184 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.
185 This includes New Jersey's Class I renewable standard.
186 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).
187 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.

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 March 31, 2023. Tier I REC prices are lower than SREC prices. Several states have more stringent geographical restrictions for SRECs and higher alternative compliance payments (ACP) than for RECs. For example, the average SREC price for the first three months of 2023 in Washington, DC was $411.94 and the average Tier I REC price for the first three months of 2023 in Washington, DC was $10.69. The DC RPS requires SRECs to be sourced from within DC while Tier I RECs may be sourced from anywhere within the PJM footprint. Also the DC solar ACP is $500 per SREC compared to $50 per REC for Tier I compliance.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through March 2023

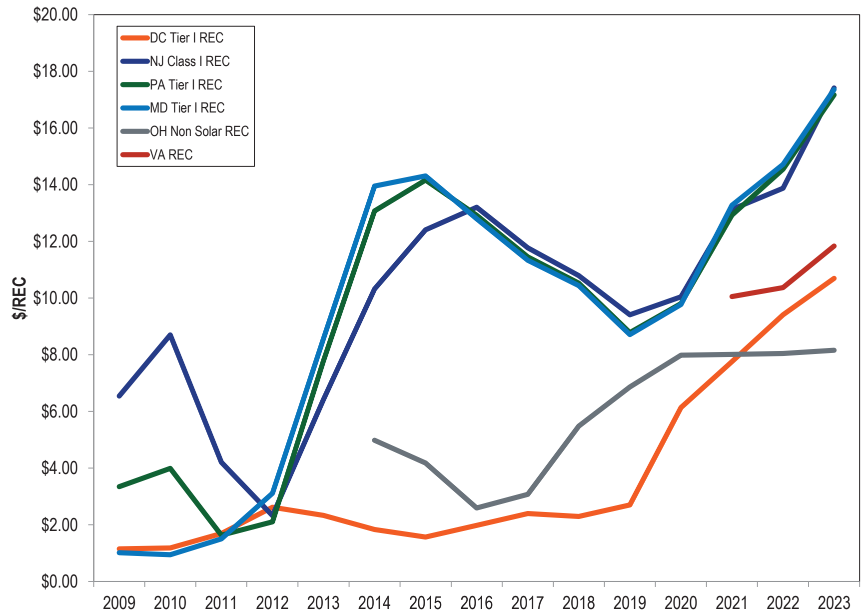


Figure 8-4 and Table 8-16 show the fulfillment of Tier I equivalent RPS requirement for 2017 through 2022 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[188] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon 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 Illinois RPS, beginning in 2019, is 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 8-16 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, Virginia imported

188 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed April 18, 2023). The timing of the REC retirement reports varies by state and the 2022 reporting year data may be incomplete for some states.

80.2 percent of the RECs used to satisfy the RPS in 2021, its first year with a mandatory RPS, and 80.7 percent of the Virginia's 2021 RECs were carbon free. Ohio met its RPS target using 85.9 percent imported RECs, and 14.1 percent State RECs for the 2021 compliance year. Ohio met its RPS target using 75.0 percent noncarbon producing RECs, and 25.0 percent carbon producing RECs for the 2021 compliance year. Illinois met its RPS target using 19.0 percent imported RECs, and 81.0 percent State RECs for the 2021 compliance year. Illinois met its RPS target using 100.0 percent noncarbon producing RECs for the 2019, 2020 and 2021 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2017 through 2022

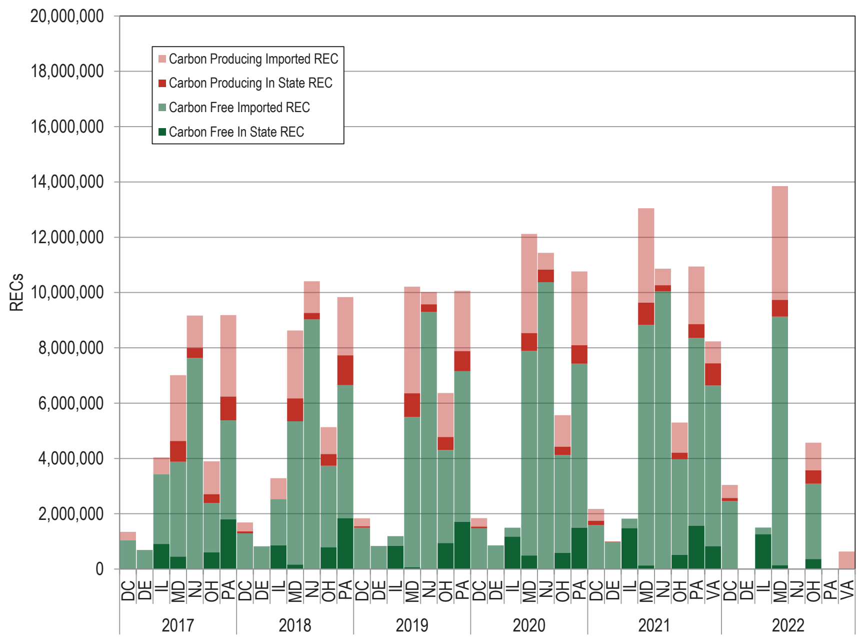


Table 8-16 State fulfillment of Tier I equivalent RPS: 2017 through 2022

		Carbon Free REC		Carbon Producing REC	
Year	REC Type	In State	Import	In State	Import
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	0.9%	99.1%	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	0.1%	90.6%	4.0%	5.3%
	PA Tier I	13.9%	55.1%	6.2%	24.8%
2021	DE New Eligible	0.3%	99.0%	0.7%	0.0%
	DC Tier I	0.0%	72.9%	7.4%	19.7%
	OH Renewable Energy Source	9.6%	65.3%	4.4%	20.6%
	IL Renewable	81.0%	19.0%	0.0%	0.0%
	MD Tier I	1.0%	66.7%	6.1%	26.1%
	NJ Class I	0.1%	92.3%	2.0%	5.5%
	PA Tier I	14.4%	62.0%	4.6%	19.1%
	VA Renewable	10.1%	70.6%	9.7%	9.6%
2022	DE New Eligible				
	DC Tier I	0.0%	80.8%	3.7%	15.5%
	OH Renewable Energy Source	8.0%	59.5%	10.6%	21.9%
	IL Renewable	83.8%	16.2%	0.0%	0.0%
	MD Tier I	1.0%	64.9%	4.4%	29.7%
	NJ Class I	0.0%	0.0%	0.0%	100.0%
	PA Tier I	35.3%	55.1%	2.5%	7.1%
	VA Renewable	0.0%	0.5%	0.0%	99.5%

Table 8-17 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 8-17 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-17 are included in the total RPS requirements presented in Table 8-13. 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.[189]

Table 8-17 Additional renewable standards of PJM jurisdictions: 2022 to 2032

Jurisdiction	Type of Standard	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Maryland	Off Shore Wind	1.36%	2.03%	0.14%	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.00%	0.05%	0.15%	0.25%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%	1.00%
Maryland	Tier 2	2.50%	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%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (GWh)	900	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%	10.00%

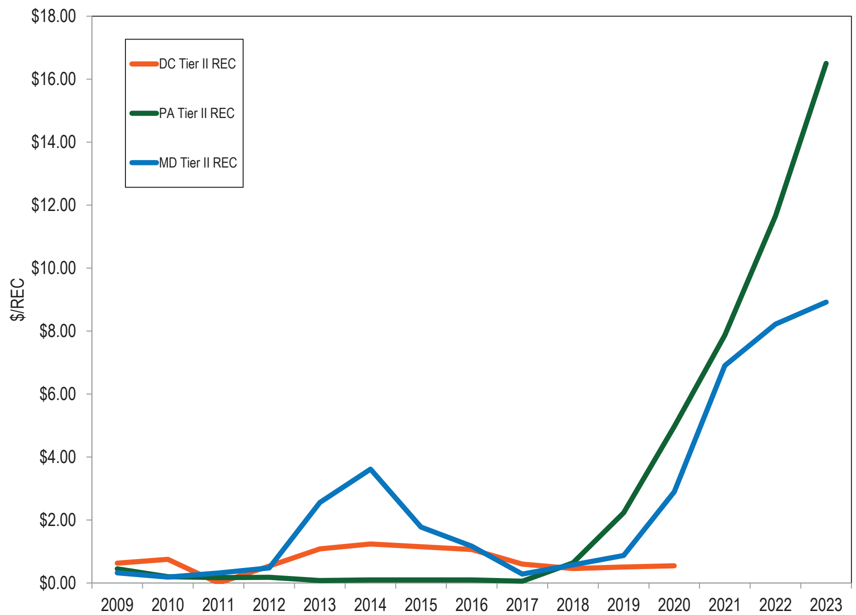
Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009, through March 31, 2023. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2023.[190] The average Pennsylvania Tier II REC price for the first three months of 2023 was $16.50, 55.9 percent higher than the average price over the first three months of 2022. The average New Jersey Class II REC price for the first three months of 2023 was $16.46, 53.9 percent higher than the average price for the first three months of 2022. The average Maryland Tier II REC price for the first three months of 2023 was $8.92, 6.0 percent higher than the average price over the first three months of 2022.[191]

189 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>.

190 The District of Columbia dropped Tier II RECs from their RPS in 2021.

191 Tier II REC price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through March 2023



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-13 and Table 8-15 but must be met by solar RECs (SRECs). Table 8-18 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, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs beginning with the 2021/2022 Delivery Year.[192] 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.[193] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[194] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[195] 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. Ohio, Michigan and 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.[196] 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.[197] 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.[198]

192 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.

193 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).

194 "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>.

195 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.

196 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

197 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>.

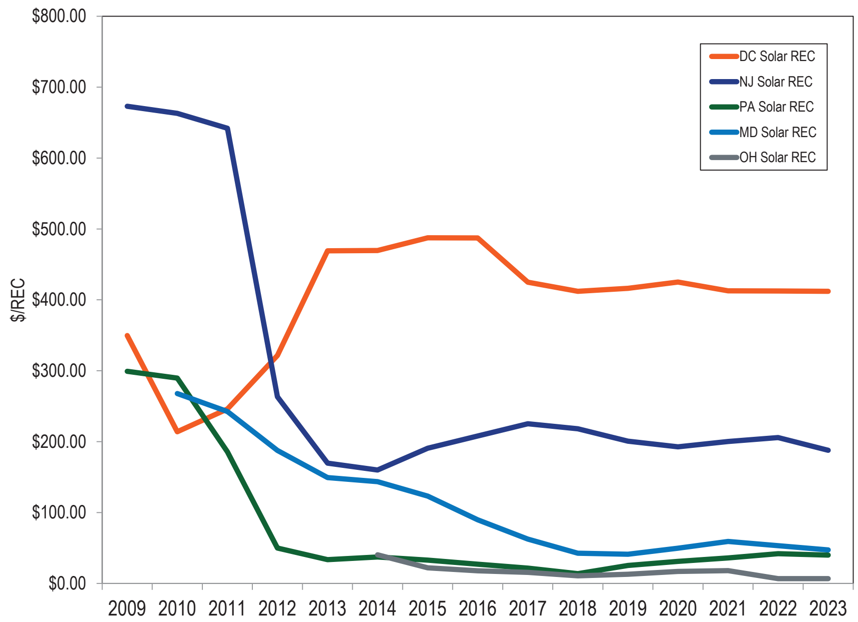
198 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2022 to 2032[199]

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delaware	2.75%	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750
Maryland	5.50%	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%
New Jersey	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%	1.40%	1.10%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, DC	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%

Figure 8-6 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through March 31, 2023. The average NJ SREC price was $187.78 for the first three months of 2023. The limited supply of solar facilities in Washington, DC compared to the RPS requirement results in higher SREC prices. The average Washington, DC SREC price was $411.94 per SREC for the first three months of 2023.[200]

Figure 8-6 Average SREC price by jurisdiction: 2009 through March 2023



199 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.
200 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com> (Accessed April 18, 2022).

Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states' solar requirement for 2017 through 2022.[201] 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 8-19 shows the percent of imported and local SRECs used to meet the RPS requirements. Since 2020, all SRECs used for RPS compliance in Illinois, Maryland, Pennsylvania and New Jersey have been sourced from in state solar generators.

Figure 8-7 State fulfillment of Solar RPS: 2017 through 2022

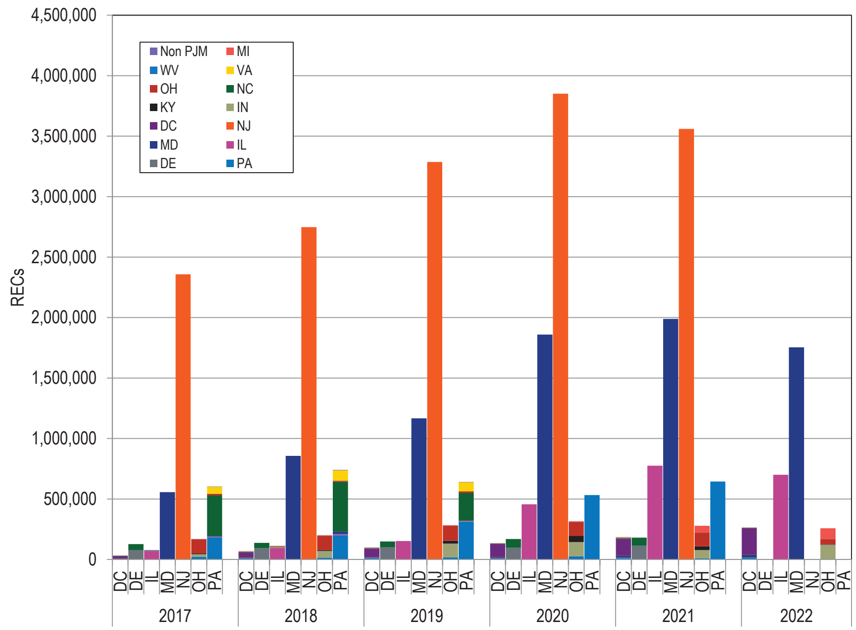


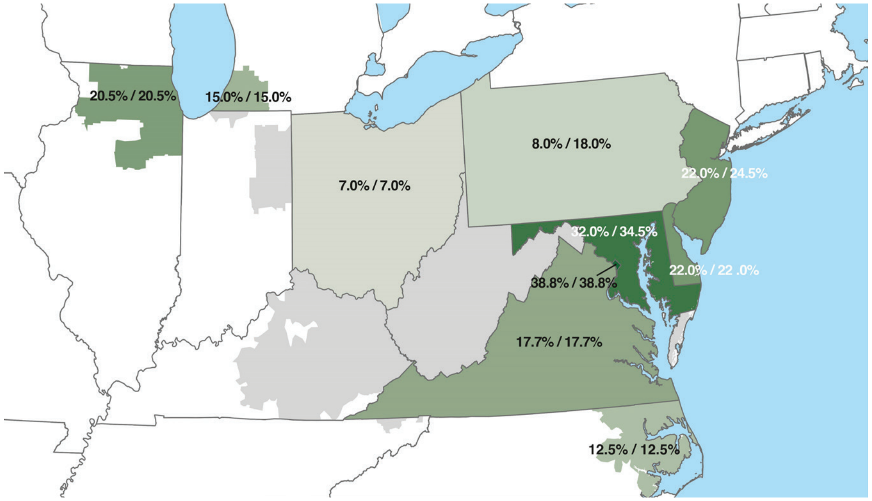
Table 8-19 State fulfillment of Solar RPS: 2017 through 2022

		In State SREC	Import SREC
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.6%	12.4%
	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	82.9%	17.1%
	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	67.8%	32.2%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.6%	56.4%
	PA Solar	48.8%	51.2%
2020	DC Solar	81.5%	18.5%
	DE Solar Eligible	56.7%	43.3%
	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%
2021	DC Solar	78.0%	22.0%
	DE Solar Eligible	62.3%	37.7%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%
	PA Solar	100.0%	0.0%
2022	DC Solar	81.9%	18.1%
	DE Solar Eligible		
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar		
	OH Solar Renewable Energy Source	17.4%	82.6%
	PA Solar	100.0%	0.0%

201 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed January 23, 2023). The timing of the REC retirement reports varies by state and the 2021 reporting year data may be incomplete for some states.

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: 2023[202]



Under the existing state renewable portfolio standards, 16.2 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first three months of 2023. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, large scale hydro, solid waste and waste coal resources. In the first three months of 2023, only 8.1 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 8-20. If the proportion of load among states remains constant, 25.5 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 13.8 percent of PJM load should have been served by Tier I or renewable energy resources in in the first three months of 2023. In the first three months of 2023, only 5.8 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 three months of 2023,

202 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.

and LSEs purchased RECs from non PJM resources (e.g. behind the meter rooftop solar) and RECs from resources outside the PJM footprint (Table 8-21). 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, 23.1 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 8-20 shows generation by jurisdiction and resource type for the first three months of 2023. Wind generation accounted for 9,928.7 GWh of the 15,102.2 Tier I GWh, or 65.7 percent. As shown in Table 8-20, 18,946.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 79.7 percent. Wind and solar generation (noncarbon producing) was 5.8 percent of total generation in PJM in the first three months of 2023. Tier I generation was 7.4 percent of total generation in PJM and Tier II was 1.9 percent of total generation in PJM in the first three months of 2023. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 4,199.7 GWh, or 22.2 percent of the total Tier I and Tier II generation.

Table 8-20 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through March, 2023

	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	11.0	0.0	0.0	16.3	0.0	27.4	0.0	0.0	0.0	0.0	0.0	27.4
Illinois	0.0	19.0	0.0	0.0	1.9	4,525.1	4,546.1	0.0	0.0	0.0	0.0	0.0	4,546.1
Indiana	0.0	0.2	0.0	10.6	116.8	2,180.8	2,308.4	0.0	0.0	0.0	0.0	0.0	2,308.4
Kentucky	0.0	0.0	55.8	15.3	18.9	0.0	90.0	0.0	0.0	0.0	0.0	0.0	90.0
Maryland	0.0	10.8	0.0	0.0	131.1	237.1	379.0	0.0	0.0	130.2	0.0	130.2	509.2
Michigan	0.0	14.8	0.0	17.1	1.0	0.0	32.8	0.0	0.0	0.0	0.0	0.0	32.8
New Jersey	0.0	34.5	3.6	0.0	168.7	3.7	210.5	67.0	0.0	292.2	0.0	359.2	569.7
North Carolina	0.0	0.0	137.0	0.0	401.4	170.9	709.3	0.0	0.0	0.0	0.0	0.0	709.3
Ohio	0.0	28.0	232.8	0.0	159.3	929.1	1,349.2	0.0	0.0	0.0	0.0	0.0	1,349.2
Pennsylvania	0.0	89.7	1,602.5	8.8	51.8	1,185.1	2,937.8	578.3	0.0	380.9	1,226.8	2,186.0	5,123.8
Tennessee	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
Virginia	297.5	113.8	264.0	19.6	870.5	15.6	1,581.0	567.5	271.2	174.5	0.0	1,013.3	2,594.3
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	7.6	235.3	0.0	6.5	681.3	930.6	0.0	0.0	0.0	155.4	155.4	1,086.0
Total	297.5	329.4	2,531.0	71.3	1,944.3	9,928.7	15,102.2	1,212.8	271.2	977.8	1,382.2	3,844.0	18,946.2

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2023, Tier I generation in PJM met only 58.4 percent of the Tier I RPS requirements. Table 8-21 compares each state's RPS requirement for the first three months of 2023 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 101.1 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 99.1 percent of the Tier I RPS requirement and 59.0 percent of the Tier II RPS requirement. North Carolina generation was in excess of the RPS requirement but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation in PJM states to meet 58.4 percent of the Tier I RPS requirement and 85.3 percent of the Tier II RPS requirement for the first three months of 2023.

Table 8-21 RPS Requirements and Generation by RPS Eligible Resources: January through March, 2023

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	27.4	634.2	4.3%	0.0	0.0	
Illinois	4,546.1	4,498.8	101.1%	0.0	0.0	
Indiana	2,308.4	0.0		0.0	0.0	
Kentucky	90.0	0.0		0.0	0.0	
Maryland	379.0	4,804.3	7.9%	130.2	375.9	34.6%
Michigan	32.8	166.4	19.7%	0.0	0.0	
New Jersey	210.5	3,742.2	5.6%	359.2	425.3	84.5%
North Carolina	709.3	130.2	544.7%	0.0	0.0	
Ohio	1,349.2	2,633.1	51.2%	0.0	0.0	
Pennsylvania	2,937.8	2,964.0	99.1%	2,186.0	3,705.0	59.0%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	1,581.0	5,453.3	29.0%	1,013.3	0.0	
Washington, D.C.	0.0	814.1	0.0%	0.0	0.0	
West Virginia	930.6	0.0		155.4	0.0	
Total	15,102.2	25,840.7	58.4%	3,844.0	4,506.2	85.3%

Table 8-22 shows the summer installed capacity rating of Tier I and Tier II wholesale capacity 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 the unit is operating using the fuel listed as Tier I or Tier II. Virginia has the largest amount of solar capacity in PJM, 2,841.1 MW, or 40.7 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,122.1 MW, or 73.9 percent of the total wind capacity.

Under the pre ELCC rules that remain in effect until the start of the 2023/2024 delivery year, 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.[203] As of March 31, 2022, the derated capacity with capacity obligations in the PJM Capacity Market totaled 3,501.1 MW for wind generators and 2,790.5 MW for solar generators. This compares to installed wind capacity of 10,995.8 MW and installed solar capacity of 6,985.3 MW in Table 8-22. Wind generators have higher derating factors during the winter months (November through April) because PJM rules make winter capacity interconnection rights (CIRs) available. 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.[204]

203 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
204 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017. PJM has removed this document from its web page.

Table 8-22 Renewable capacity by jurisdiction (MW): March 31, 2023

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	Waste Heat	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	13.0	0.0	50.0	0.0	0.0	0.0	0.0	1,868.1
Illinois	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	4,726.1	4,750.1
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	454.2	0.0	0.0	0.0	2,350.5	2,816.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	69.6	0.0	0.0	0.0	0.0	202.3
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	69.0	0.0	0.0	486.5	128.2	0.0	0.0	243.7	947.3
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	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	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	33.9	0.0	0.0	0.0	0.0	453.0	739.8	204.6	0.0	0.0	4.5	1,446.7
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,331.6	0.0	0.0	0.0	208.0	1,864.6
Ohio	0.0	1,020.0	194.4	30.4	0.0	1.0	136.0	0.0	0.0	798.9	0.0	0.0	134.0	1,045.6	3,360.3
Pennsylvania	54.0	0.0	1,387.3	122.0	1,300.0	0.0	0.0	0.0	1,269.0	170.9	209.3	1,347.0	0.0	1,457.2	7,316.7
Tennessee	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	0.0
Virginia	241.9	585.0	436.4	127.7	0.0	88.0	17.0	0.0	5,386.0	2,841.1	123.0	0.0	0.0	12.0	9,858.1
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	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	0.0	802.3	1,145.2
PJM Total	295.9	1,605.0	2,718.7	380.1	3,097.0	89.0	222.0	13.0	7,108.0	6,985.3	665.0	1,443.0	134.0	10,995.8	35,751.8

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[205] For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels is 38.0 percent and the ELCC rating for solar generators with tracking panels is 54.0 percent.

Table 8-23 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[206] 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 9,698.3 MW of which 3,290.5 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 GATS capacity located in jurisdictions outside PJM and all but 242.6 MW are eligible to produce RECs in at least one PJM jurisdiction.

205 Id.

206 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.

Table 8-23 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): March 31, 2023[207]

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	151.3	0.0	0.0	0.0	2.0	155.5
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	20.0	50.6	0.0	2.2	1,092.3	0.0	0.0	0.0	398.4	1,563.4
Indiana	0.0	0.0	0.0	0.0	0.0	47.2	0.0	1.3	175.8	0.0	0.0	94.6	180.0	498.9
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	0.0	39.3	0.0	0.0	0.0	0.0	917.3
Maryland	18.5	0.0	0.0	27.5	0.4	14.7	0.0	0.0	1,387.8	10.0	0.0	0.0	0.3	1,459.1
Michigan	31.0	0.0	0.0	0.0	17.2	16.6	0.0	4.8	113.9	0.0	0.0	0.0	87.4	270.8
Minnesota	0.0	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	23.5	0.0	15.4	3,290.5	0.0	0.0	0.0	3.1	3,332.5
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	800.4	0.0	0.0	0.0	1,283.1	0.0	0.0	0.0	0.0	2,235.0
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	49.3	303.2	0.0	0.0	34.0	53.3	558.9
Pennsylvania	62.2	109.7	0.8	0.0	56.5	45.2	22.1	100.0	692.6	0.2	474.2	57.6	3.2	1,624.3
South Carolina	0.0	0.0	0.0	0.0	31.5	29.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	152.6
Tennessee	0.0	0.0	0.0	0.0	411.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	411.6
Virginia	287.6	0.0	0.0	0.0	31.3	9.9	0.0	2.6	664.4	0.0	0.0	0.0	0.0	995.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	188.9	0.0	0.0	27.7	0.0	266.1
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	7.7	0.0	0.0	0.0	0.0	109.7
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	835.1	709.7	0.8	27.5	1,678.3	313.9	22.1	224.8	9,698.3	10.2	474.2	213.9	2,117.4	16,326.4

Renewable energy credits are related to the production and purchase of wholesale power, but are not, when they constitute a transaction separate from a wholesale sale of power, subject to FERC regulation.[208] 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. RECs revenues are included in net revenues in unit offers in the capacity market and the treatment of RECs in unit cost-based offers is included in unit fuel cost policies.

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.[209] This is equivalent to providing a REC price equal to three times its stated value per MWh.

207 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed July 20, 2022).
208 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).
209 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

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 8-24 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.

Table 8-24 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 8-25 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. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. 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 8-25 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 or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
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.

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 $228.00 per MWh.[210] 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. The most recent ACP for Pennsylvania solar is $82.90.[211] Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[212] Maryland reduced the solar ACP from $100 per credit to $80 per credit effective June 1, 2021.[213]

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.

Table 8-26 shows the alternative compliance standards for RPS in PJM jurisdictions.

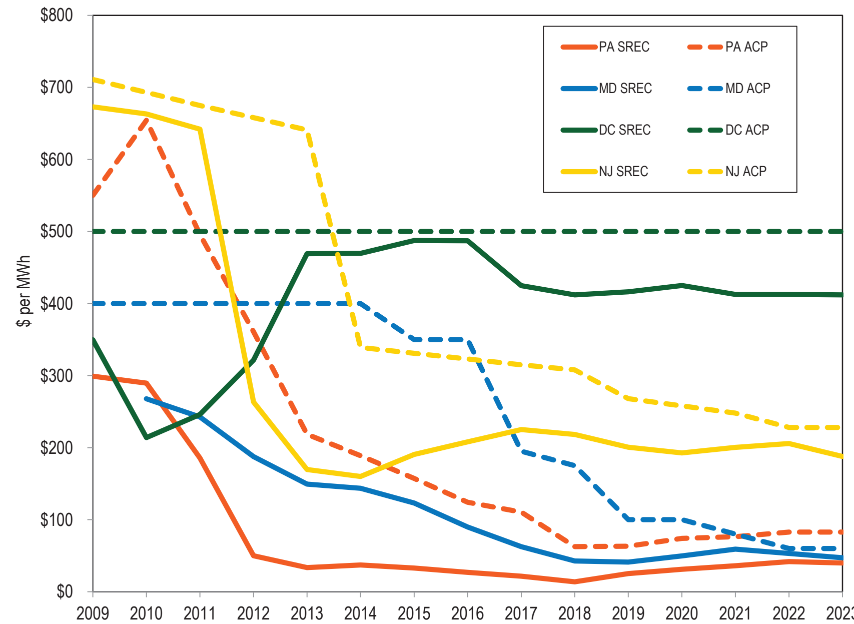
210 N.J. S. 2314/A. 3723.
211 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed October 20, 2022).
212 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
213 *Senate Bill 65 Electricity – 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 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of March 31, 2023[214 215]

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	$60.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$228.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$56.99		
Pennsylvania	$45.00	$45.00	$82.90
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 March 2023



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 2022 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in March of 2023.[216] Pennsylvania reported that the 694,980 SRECs, 10,891,729 Tier I RECs and 13,895,805 Tier II RECs were retired during the 2022 reporting

214 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/>.

215 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2021. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed January 26, 2022).

216 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2022," (March 2023), <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

year (June 1, 2021 through May 31, 2022). Supplier obligations for 598 SRECs, 11,999 Tier I RECs and 15,310 Tier II RECs required ACPs.

The Public Service Commission of the District of Columbia reported that 183,707 SRECs and 2,173,550 Tier I RECs were retired during the 2021 compliance year. The average price for solar RECs was $430.94. ACPs decreased from $8.2 million for 2020 to $5.7 million for 2021.[217]

The Public Service Commission of Maryland reported that 1,989,505 SRECs were retired in 2021, an increase of 7.0 percent over the 2020 level. Tier 1 REC retirements increased to 13,045,432, 7.7 percent higher than in 2020.[218] ACPs increased significantly, from $52,240 in 2020 to $77,129,013 for 2021, as a result of the requirement to purchase SRECs and a shortfall in available SRECs. [219] The ACP level in in 2020 was $52,240.

The Public Utilities Commission of Ohio reported that 6,023,768 RECs were retired in the 2020 compliance year, which is 4,000 RECs short of the RPS requirement. Alternative compliance payments were made due to the shortfall.[220]

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 740,604 credits for the compliance year ending May 31, 2021, with zero ACPs.[221] Delmarva Power satisfied their solar REC obligation of 150,262 credits with zero alternative compliance payments.

Prior to the 2017/2018 compliance 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 the 2017/2018 compliance year and ACPs for ComEd decreased to $74,148. The ACPs for ComEd in compliance year 2016/2017 totaled $40,575,311.[222]

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).[223] 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.[224]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2021.[225] Electric power suppliers retired 11,638,713 class I RECs and 1,803,748 class II RECs. Suppliers submitted 1,892 class I ACPs and 986 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,851,012 solar RECs and 12 SACPs were submitted at a cost of $248 per MWh. Additionally, 128,356 transition RECs were retired.[226]

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[227] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost of complying with RPS, as reported by the states, was $7.2 billion over the seven year period from 2014 through 2020 for the nine jurisdictions that had RPS and reported compliance costs.[228] The average RPS compliance cost per year

217 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2021," Public Service Commission of the District of Columbia (May 2, 2022), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
218 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2021," Public Service Commission of Maryland (November 29, 2022) at 8, <https://www.psc.state.md.us/commission-reports/>.
219 *Id.*
220 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio (November 2, 2021), <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
221 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2020–May 31, 2021," Delmarva Power, (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>
222 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
223 "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>.
224 "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>.
225 See RPS Report Summary 2005-2021, New Jersey's Clean Energy Program (May 17, 2022), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
226 "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>.
227 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
228 The actual PJM RPS compliance cost exceeds the reported $7.2 billion due to incomplete data. The compliance cost value for 2020 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

based on the reported compliance cost for the seven year period from 2014 through 2020 was $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.

Table 8-27 RPS Compliance Cost[229 230 231 232 233 234 235 236 237 238 239]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971	
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298	
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673	
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523			
Maryland	Total RPS	$104,056,879	$126,752,147	$135,232,457	$72,064,102	$84,874,724	$142,275,744	$223,218,944	$409,846,140
	Solar	$29,388,337	$39,062,714	$45,556,987	$21,276,834	$27,352,183	$57,824,616	$122,973,787	$221,296,225
	Tier I	$70,677,220	$85,070,001	$88,234,024	$50,099,228	$56,473,113	$84,333,097	$99,836,397	$187,579,231
	Tier II	$3,991,322	$2,619,432	$1,441,446	$688,040	$1,049,428	$118,031	$408,760	$970,684
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	$960,423,760	
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	$812,493,029	
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	$130,272,633	
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	$17,658,099	
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	$69,812,721	$81,752,397	
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0	
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,234,672	$81,752,397	
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	$182,995,718	$307,751,404
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	$24,764,538	$27,673,083
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	$100,528,434	$159,457,100
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	$57,702,746	$120,621,222
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701	$57,300,000	$65,000,000	
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914	$59,897,169	
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354	$5,102,831	
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733	$0	
PJM	Total RPS	$678,453,836	$888,414,253	$986,220,882	$925,472,176	$987,015,639	$1,164,589,372	$1,534,524,790	$717,597,544

229 Several states have not released compliance reports for 2020.
230 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
231 "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.
232 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.
233 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.
234 "RPS Report Summary 2005-2020," New Jersey's Clean Energy Program, April 13, 2021, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
235 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio, Nov. 2, 2021, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
236 "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>.
237 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2020," Public Service Commission of the District of Columbia, Executive Summary, May 3, 2021, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
238 "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.
239 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.[240] 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.[241] [242]

Table 8-28 shows SO_2 emission controls by fossil fuel fired units in PJM.[243] [244] [245] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[246] Of the current 51,733.2 MW of coal capacity in PJM, 49,671.0 MW of capacity, 96.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-28 SO_2 emission controls by fuel type (MW): March 31, 2023[247]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,671.0	2,062.2	51,733.2	96.0%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	0.0	67,784.6	67,784.6	0.0%
Other	325.0	3,500.0	3,825.0	8.5%
Total	49,996.0	77,953.2	127,949.2	39.1%

Table 8-29 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 51,733.2 MW of coal capacity in PJM, 51,604.2 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.[248]

Table 8-29 NO_X emission controls by fuel type (MW): As of March 31, 2023

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	51,604.2	129.0	51,733.2	99.8%
Diesel Oil	1,020.3	3,586.1	4,606.4	22.1%
Natural Gas	67,541.6	243.0	67,784.6	99.6%
Other	1,575.0	2,250.0	3,825.0	41.2%
Total	121,741.1	6,208.1	127,949.2	95.1%

Table 8-30 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (4.3 percent) and units with other fuel sources (51.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[249] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 51,733.2 MW of coal capacity in PJM, 51,648.2 MW of capacity, 99.8 percent, have some type of particulate emissions control technology.

Table 8-30 Particulate emission controls by fuel type (MW): As of March 31, 2023

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	51,648.2	85.0	51,733.2	99.8%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	2,912.0	64,872.6	67,784.6	4.3%
Other	1,972.0	1,853.0	3,825.0	51.6%
Total	56,532.2	71,417.0	127,949.2	44.2%

240 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
241 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> (Accessed May 7, 2020).
242 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 SO_2 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> (Accessed May 7, 2020)
243 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
244 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 2021.
245 The total MW are less than the 183,311.8 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> (Accessed March 4, 2022).
246 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
247 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.
248 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
249 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

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, all of the 108 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for either SO_2 or particulate emissions control, representing all of the 51,733.2 MW total coal capacity.

Emissions

Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the first quarter of 2023, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the first quarter of 2023.[250]

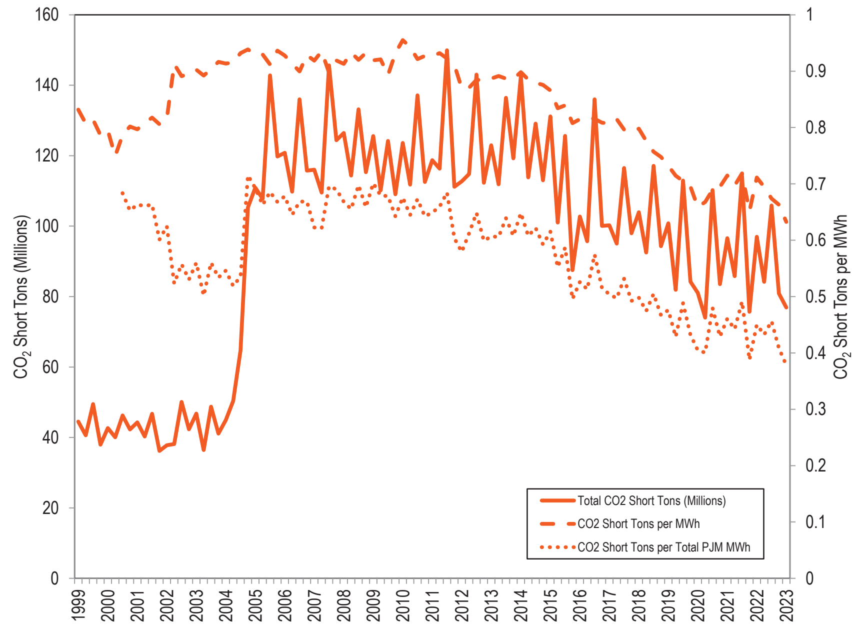
Figure 8-11 shows the total CO_2 emission in short tons on peak and off peak and the CO_2 emission rate in short tons per MWh for all CO_2 emitting units.

Table 8-31 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the third quarter of 2022.

Total PJM generation decreased from 215,415.1 GWh in the first quarter of 2022 to 203,326.4 GWh in the first quarter of 2023, while CO_2 produced decreased from 96,970.3 million short tons in the first quarter of 2022 to 76,894.7 million short tons in the first quarter of 2023.[251] The CO_2 emission rate averaged 0.70 short tons per MWh for all CO_2 emitting units in 2021, 0.69 short tons per MWh for all CO_2 emitting units in 2022, and 0.63 short tons per MWh for all CO_2 emitting units in the first three months of 2023.

250 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
251 See the *2021 Annual State of the Market Report for PJM*: Section 3: Energy Market, Table 3-10.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through March 2023[252 253]



In the first quarter of 2023, CO_2 emission rates were 0.63 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.63 for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[254]

252 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
253 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).
254 "The top 10 emitting power plants in America," <https://www.eenews.net/articles/the-top-10-emitting-power-plants-in-america/> (Accessed November 4, 2022).

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 March 2023[255]

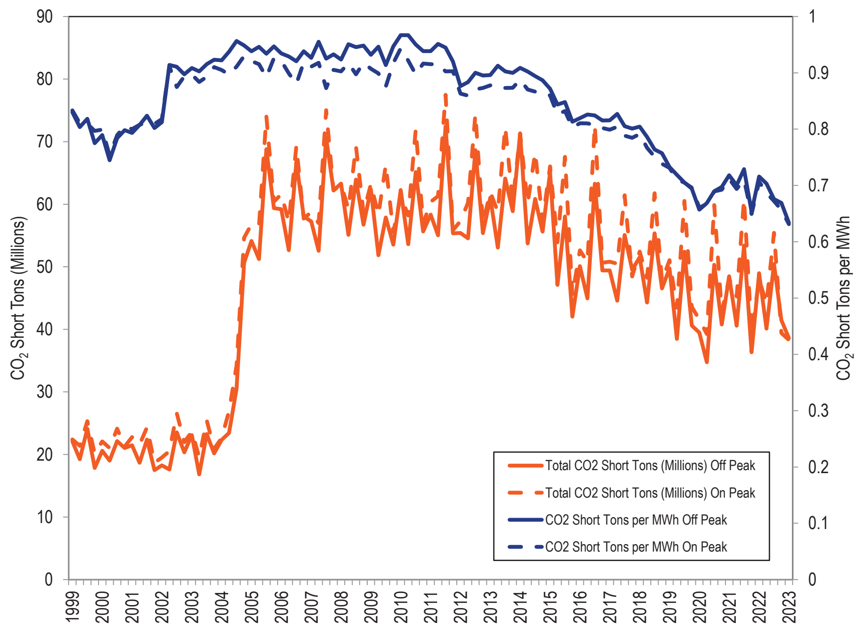


Table 8-31 Minimum and maximum CO_2 emissions per MWh: September 1999 through March 2023

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2023	1
	On Peak	0.63	2023	1
	Off Peak	0.63	2023	1
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the first quarter of 2023, the SO_2 emission rate was 0.000283 short tons per MWh for all SO_2 emitting units, and the NO_x emission rate was 0.000228 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the first quarter of 2023, SO_2 emission rates were 0.000280 short tons per MWh and 0.000286 short tons per MWh for all SO_2 units, for off and on peak hours. In the first quarter of 2023, NO_X emission rates were 0.000227 short tons per MWh and 0.000229 short tons per MWh for all NO_X emitting units, for off and on peak hours.

Table 8-32 shows the minimum and maximum SO_2 and NO_x emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the first quarter of 2023.

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 2023.[256 257]

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

256 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> (Accessed October 25, 2019).

257 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> (Accessed October 25, 2019).

Figure 8-12 SO_2 and NO_x emissions by quarter (thousands of short tons), by PJM units: January 1999 through March 2023[258]

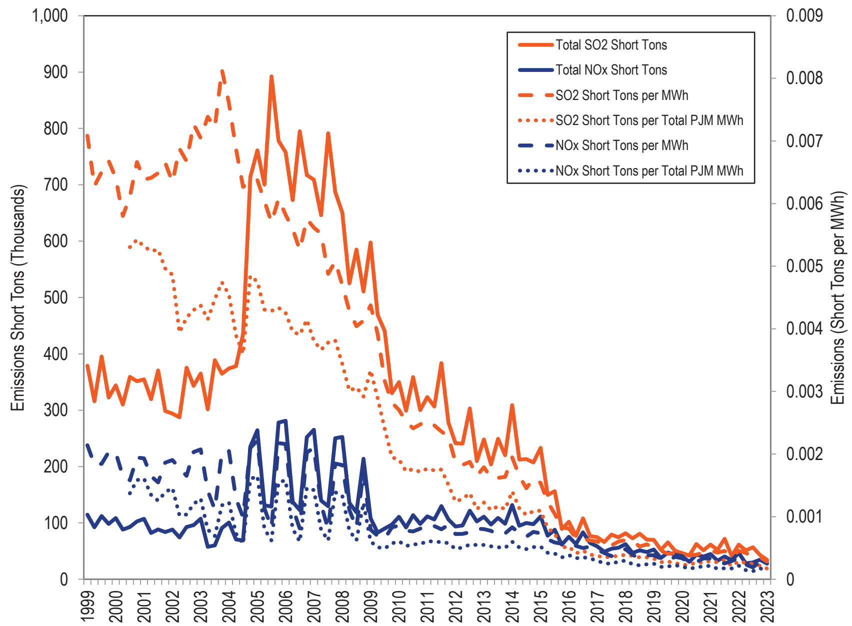


Figure 8-13 SO_2 and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through March 2023[259]

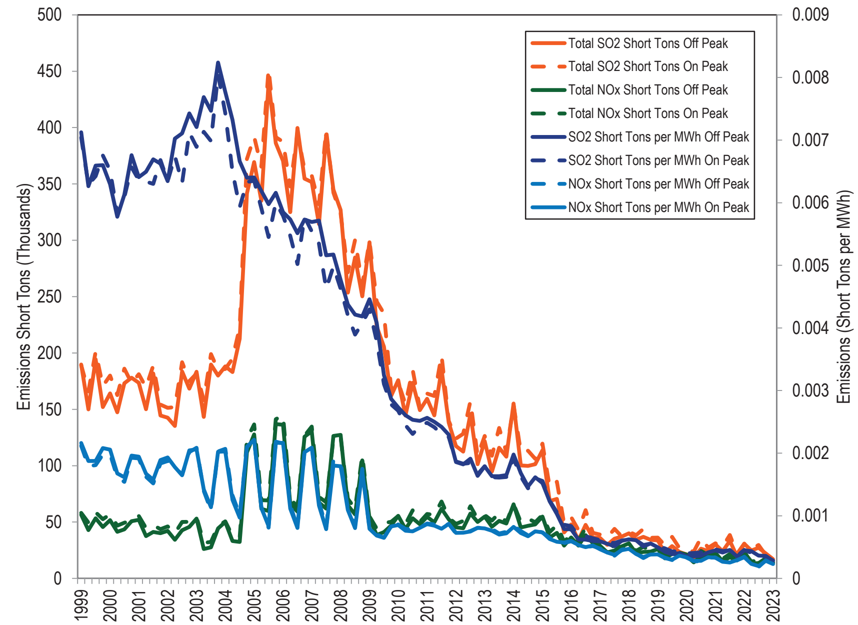


Table 8-32 Minimum and maximum SO_2 and NO_x emissions per MWh: September 1999 through March 2023

Emission Type			Short Tons per MWh	Year	Quarter
SO_2	Minimum	All hours	0.000	2023	1
		On Peak	0.000	2023	1
		Off Peak	0.000	2023	1
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NO_x	Minimum	All hours	0.000	2022	3
		On Peak	0.000	2022	3
		Off Peak	0.000	2022	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	2005	1

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

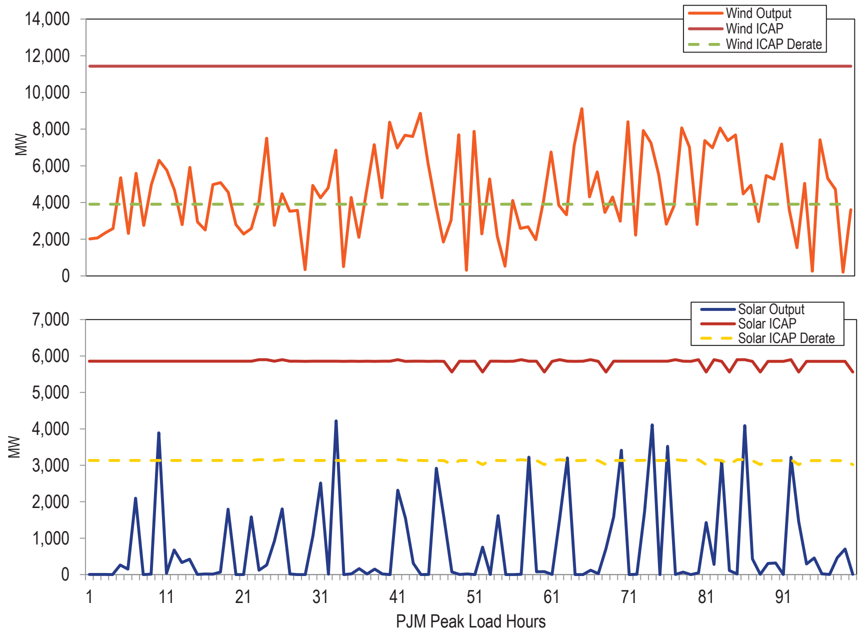
259 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

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 three months of 2023. In the first three months of 2023, 77 of the top 100 load hours in PJM are 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. 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 58 hours and below the derated ICAP for 42 hours of the top 100 load hours in the first three months of 2023. The wind capacity factor for the top 100 load hours in the first three months of 2023 was 39.8 percent. Wind output was above the derated ICAP for 1,232 hours and below the derated ICAP for 927 hours in the first three months of 2023. The wind capacity factor in the first three months of 2022 was 40.2 percent. Solar output was above the derated ICAP for 9 hours and below the derated ICAP for 91 hours of the top 100 load hours in the first three months of 2023. The solar capacity factor for the top 100 load hours in the first three months of 2023 was 12.7 percent. Solar output was above the derated ICAP for 242 hours and below the derated ICAP for 1,917 hours in the first three months of 2023. The solar capacity factor in the first three months of 2023 was 15.5 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through March, 2023



Wind Units

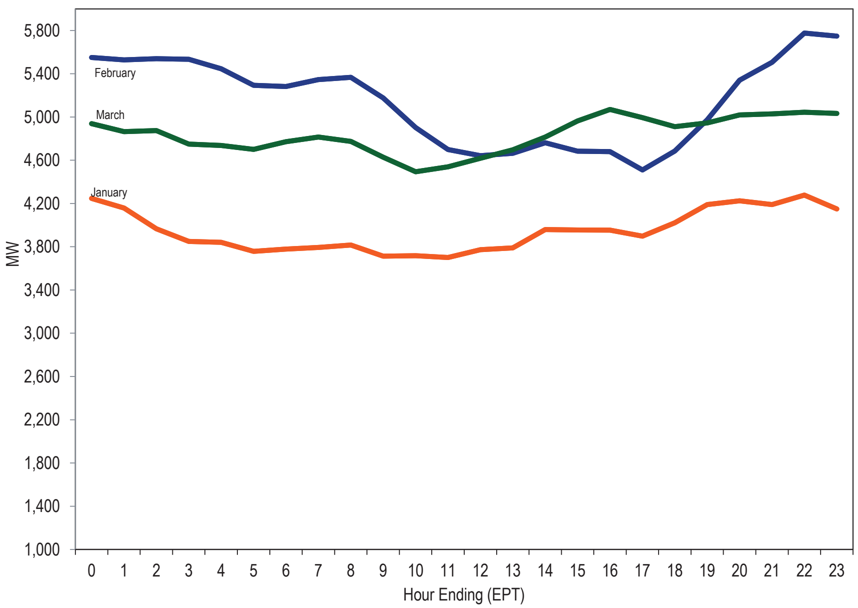
Table 8-33 shows the capacity factors of wind units in PJM. In the first three months of 2023, the capacity factor of wind units in PJM was 40.2 percent. Wind units that were capacity resources had a capacity factor of 40.4 percent and an installed capacity of 9,988.9 MW. Wind units that were energy only had a capacity factor of 39.1 percent and an installed capacity of 1,442.7 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.

Table 8-33 Capacity factor of wind units: January through March, 2023[260]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	39.1%	1,442.7
Capacity Resource	40.4%	9,988.9
All Units	40.2%	11,431.6

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for the first three months of 2023. The hour with the highest average output in the first three months of 2023, 5,776.6 MWh, occurred in February, and the hour with the lowest average output, 3,700.6 MWh, occurred in January. 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 March, 2023



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

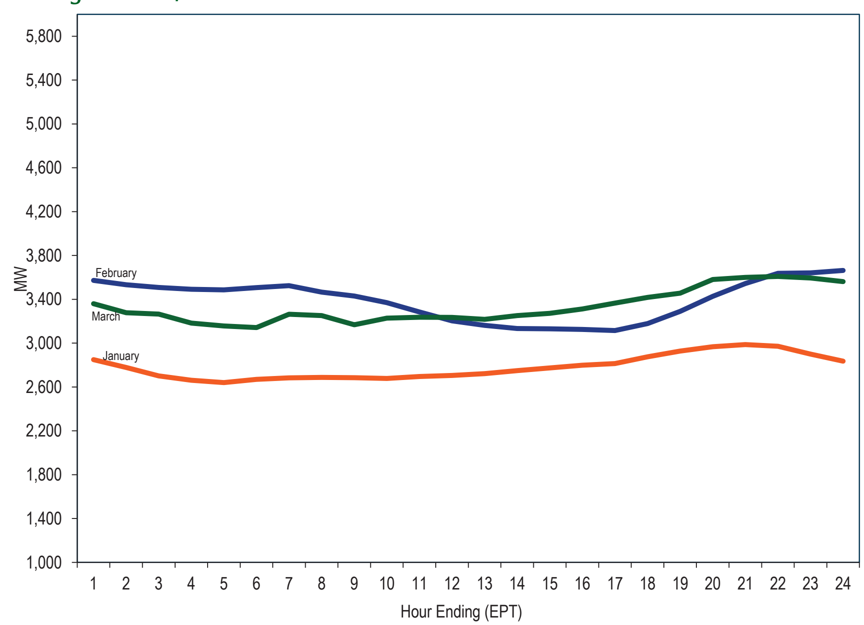
Table 8-34 shows the generation and capacity factor of wind units by month for the first three months of 2022 and 2023.

Table 8-34 Capacity factor of wind units in PJM by month: January through March, 2022 and 2023

	2022		2023	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	3,072,620.3	36.4%	2,913,720.6	34.3%
February	3,256,337.2	42.8%	3,440,914.0	44.8%
March	3,386,619.2	40.2%	3,574,026.7	42.1%

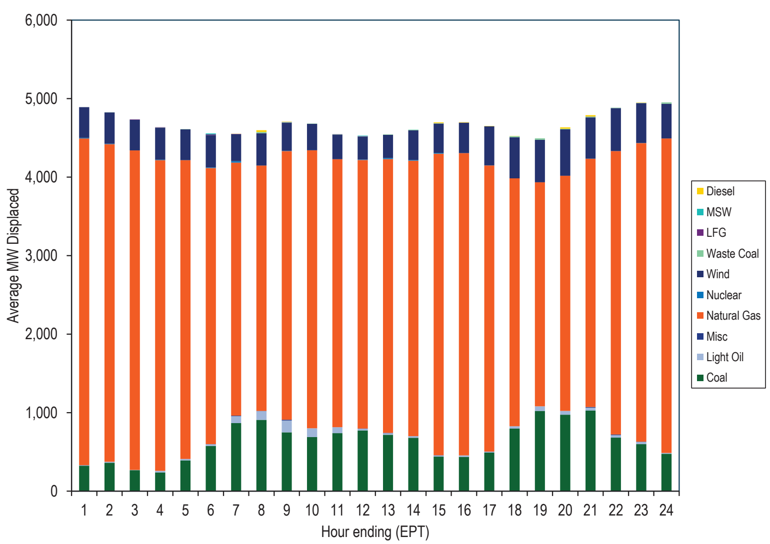
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units: January through March, 2023



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.[261] Figure 8-17 and Table 8-35 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 three months of 2023. 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 three months of 2023, the SCED dispatch instruction for marginal wind resources was to reduce output for 65.0 percent of the wind 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.

Figure 8-17 Marginal fuel at time of wind generation: January through March, 2023



261 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.

Table 8-35 Marginal fuel MW at time of wind generation: January through March, 2023

Hour	Coal	Light Oil	Misc	Natural Gas	Nuclear	Wind	Waste Coal	LFG	MSW	Diesel	Total
0	324.1	4.9	1.3	4,161.9	8.7	390.6	0.0	0.0	0.0	0.0	4,891.5
1	362.1	11.4	0.0	4,047.0	5.2	397.9	1.0	0.0	0.0	0.0	4,824.5
2	267.4	2.7	0.0	4,070.0	0.0	390.7	0.0	5.9	0.0	0.0	4,736.6
3	237.2	21.8	0.0	3,956.4	5.4	409.6	1.6	2.9	0.0	0.0	4,634.9
4	391.2	17.5	2.0	3,805.2	0.0	392.0	4.0	0.0	0.0	0.0	4,612.0
5	576.9	19.8	1.8	3,516.7	8.0	413.0	0.0	7.3	12.9	0.0	4,556.5
6	866.1	88.0	7.5	3,222.9	20.1	342.6	0.0	3.3	0.0	1.6	4,552.1
7	908.3	110.2	2.5	3,127.3	0.9	409.9	16.0	0.0	0.0	22.1	4,597.1
8	748.4	150.9	10.0	3,422.5	2.6	360.0	7.0	1.9	0.0	3.1	4,706.5
9	687.8	113.6	0.0	3,541.0	0.0	335.7	4.3	0.0	0.0	0.0	4,682.4
10	738.9	75.1	0.0	3,414.2	0.0	313.8	3.0	2.1	0.0	0.0	4,547.1
11	773.0	21.6	2.5	3,421.1	4.1	293.6	1.1	5.4	5.4	0.0	4,527.9
12	718.1	19.3	4.8	3,487.7	13.7	296.1	4.7	0.0	0.0	0.0	4,544.4
13	680.0	19.9	0.0	3,508.5	9.1	377.6	7.9	0.0	2.3	0.0	4,605.3
14	439.9	13.7	3.1	3,842.8	9.4	373.5	5.2	0.0	0.0	10.0	4,697.7
15	436.0	19.2	0.0	3,850.6	0.0	389.0	0.0	0.0	0.0	4.1	4,699.0
16	492.2	11.5	0.0	3,644.2	2.5	497.6	0.0	0.0	0.0	3.3	4,651.4
17	796.4	30.8	0.0	3,157.0	0.0	523.3	9.1	0.0	2.4	3.4	4,522.5
18	1,021.0	60.1	0.0	2,853.9	0.0	540.6	17.7	0.0	0.0	0.0	4,493.3
19	974.1	47.1	0.0	2,996.2	0.0	590.1	8.9	0.0	0.0	17.4	4,633.7
20	1,026.3	37.1	9.0	3,160.3	2.1	525.5	9.3	2.4	0.0	16.5	4,788.6
21	682.0	31.3	7.1	3,611.1	0.0	547.8	5.2	0.0	0.0	0.0	4,884.6
22	598.4	27.2	4.2	3,804.3	1.4	507.0	4.1	0.0	0.0	3.2	4,949.9
23	475.1	12.0	0.0	4,004.3	0.0	443.4	17.3	0.0	0.0	0.0	4,952.1
Average	634.2	40.3	2.3	3,567.8	3.9	419.2	5.3	1.3	1.0	3.5	4,678.8

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all and only PJM solar units that are in front of the meter. As shown in Table 8-22, there are 6,985.3 MW of solar capacity registered in GATS that are PJM units. As shown in Table 8-23, there are 9,698.3 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. The customers of these clusters 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 paying appropriate costs as a result of 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 8-36 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 15.5 percent for the first three months of 2023. Solar units that were capacity resources had a capacity factor of 15.6 percent and an installed capacity of 3,703.7 MW. Solar units that were energy only had a capacity factor of 15.4 percent and an installed capacity of 2,109.5 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.

Table 8-36 Capacity factor of solar units: January through March, 2023

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	15.4%	2,109.5
Capacity Resource	15.6%	3,703.7
All Units	15.5%	5,813.2

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 three months of 2023, 3,474.4 MW, occurred in March, and the hour with the lowest peak average output, 1,954.3 MW, occurred in January. 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 March, 2023

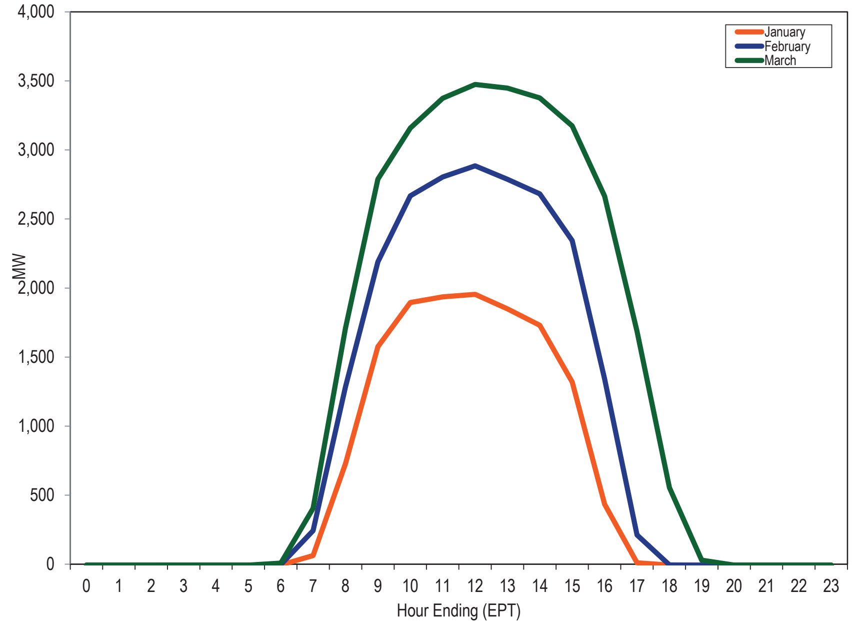


Table 8-37 shows the generation and capacity factor of solar units by month for the first three months of 2022 and 2023.

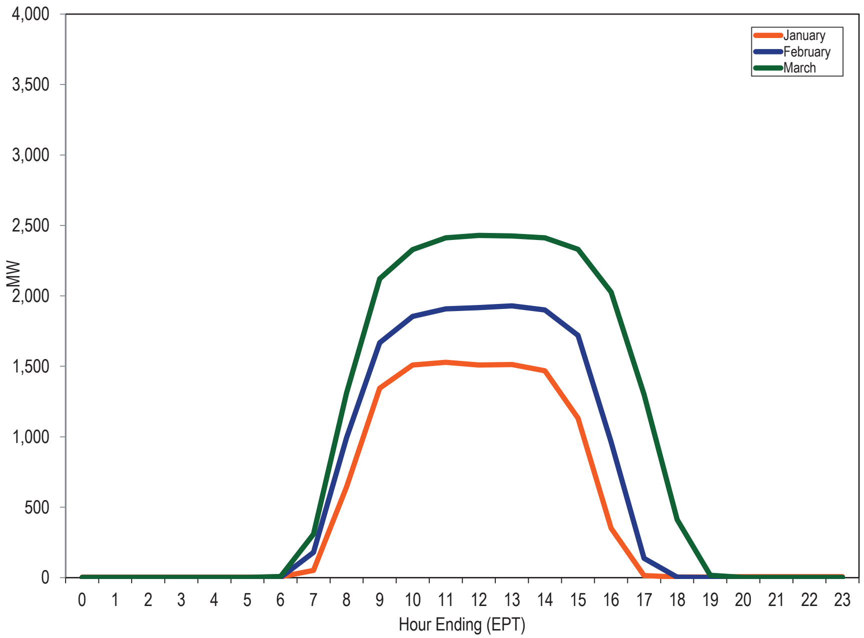
Table 8-37 Capacity factor of solar units by month: January through March, 2022 and 2023

	2022		2023	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	426,957.6	11.7%	417,821.3	9.9%
February	564,995.2	17.2%	598,407.5	15.2%
March	754,200.7	20.7%	928,052.2	21.2%

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.

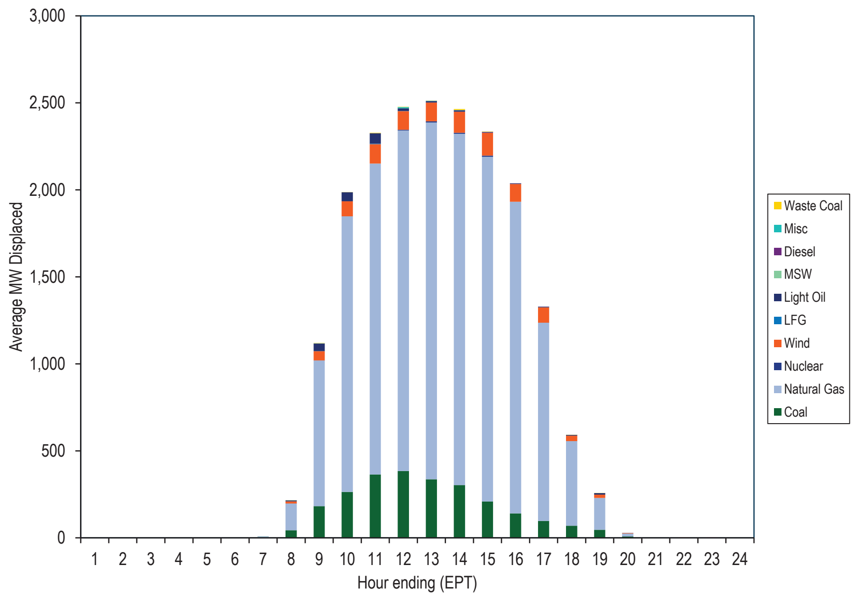
Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[262]

Figure 8-19 Average hourly day-ahead generation of solar units: January through March, 2023



Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, 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 solar generation output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when a solar unit is producing output.[263] Figure 8-20 and Table 8-38 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in the first three months of 2023. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In the first three months of 2023, there were no marginal solar units. When solar appears as the displaced fuel at times when solar 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 solar displaced by solar is thus overstated.

Figure 8-20 Marginal fuel at time of solar generation: January through March, 2023



262 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.

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

Table 8-38 Marginal fuel MW at time of solar generation: January through March, 2023

Hour	Coal	Natural Gas	Nuclear	Wind	LFG	Light Oil	MSW	Diesel	Misc	Waste Coal	Total
0	0.2	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
1	0.1	0.7	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.9
2	0.2	0.5	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.8
3	0.0	0.6	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.8
4	0.1	0.4	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.7
5	0.0	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
6	1.2	3.7	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	5.2
7	43.9	153.6	0.1	12.2	0.0	5.0	0.0	0.7	0.1	0.8	216.2
8	181.8	837.2	0.4	52.7	0.8	43.6	0.0	1.0	0.7	1.3	1,119.5
9	264.3	1,583.4	0.0	86.6	0.0	51.8	0.0	0.0	0.0	0.7	1,986.8
10	364.3	1,786.9	0.0	111.7	2.3	60.6	0.0	0.0	0.0	2.7	2,328.4
11	383.8	1,957.3	4.0	107.2	1.2	14.3	1.2	0.0	7.2	1.9	2,478.0
12	336.1	2,051.0	7.0	107.4	0.0	9.3	0.0	0.0	1.2	1.1	2,513.0
13	302.8	2,019.1	6.5	120.5	0.0	9.2	1.6	0.0	0.0	5.0	2,464.7
14	208.4	1,981.8	6.8	131.1	0.0	3.3	0.0	2.2	0.9	1.3	2,335.7
15	140.5	1,790.9	0.0	102.4	0.0	3.2	0.0	0.6	0.0	0.0	2,037.6
16	96.8	1,139.5	0.2	87.7	0.0	3.4	0.0	0.2	0.0	0.0	1,327.8
17	69.8	486.1	0.0	31.3	0.0	3.6	0.0	0.0	0.0	0.0	590.9
18	46.4	182.7	0.0	19.0	0.0	8.8	0.0	0.0	0.0	0.1	257.0
19	7.0	17.4	0.0	2.5	0.0	0.4	0.0	0.0	0.0	0.0	27.4
20	0.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
21	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
22	0.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
23	0.2	0.6	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	1.1
Average	102.0	666.5	1.0	40.6	0.2	9.0	0.1	0.2	0.4	0.6	820.7