

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. On April 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.³

- **Air Quality Standards (NO_x and SO₂ Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.⁴ (Transport Rule) On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.⁵ On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),⁶ which applies when no state implementation plan has been approved. On June 27, 2024, the Supreme Court of the United States granted a stay of the federal implementation plan pending judicial review.⁷ The effect of the stay is to eliminate the ozone season NO_x emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the state emissions budgets are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states.
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.⁸ NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain 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.⁹ RICE do not have to meet the same emissions standards if they are stationary emergency RICE. Environmental regulations allow stationary emergency RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response

¹ *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

² See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—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 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.

⁴ CAA § 110(a)(2)(D)(i)(I).

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

⁶ 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).

⁷ *Ohio v. EPA*, Slip Op. No. 23A349. (S. Ct. June 27, 2024)

⁸ *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).

⁹ See 40 CFR § 63.6640(f).

when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

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

- **Greenhouse Gas Emissions.** On April 25, 2024, the EPA issued a rule (called “Carbon Emissions Rule” in this report) taking four separate actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs):¹⁰ the rule repeals the Affordable Clean Energy (ACE) Rule; the rule finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; the rule revises the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; the rule revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.
- The proposed new source performance standards (NSPS) and emission guidelines reflect the application of the best system of emission reduction (BSER). The proposal includes emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs (including coal, oil or gas). For coal fired EGUs, compliance is required by January 1, 2030, with standards that vary based on whether the EGU commits to retire before 2032, 2035, 2040, or does not commit to retire before 2040.¹¹ The EPA proposes to repeal the Affordable Clean Energy Rule.¹²

¹⁰ See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA-HQ-OAR-2023-0072 (“Carbon Emissions Rule”).

¹¹ Carbon Emissions Rule at 33371–33373.

¹² Carbon Emissions Rule at 33243.

- **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.¹³
- **Waters of the United States.** On August 29, 2023, the EPA issued a final rule defining adjacent wetlands consistent with the Supreme Court holding that an adjacent wetland is “... a relatively permanent body of water connected to traditional interstate navigable waters ... and ... that the wetland has a continuous surface connection with that water.”¹⁴ The rule became effective on September 8, 2023.¹⁵
- **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. Since 2015, the EPA has 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. In March 2023, the EPA proposed to further strengthen regulation of effluent discharges.¹⁶
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.¹⁷ 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.

¹³ 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).

¹⁴ See Revised Definition of “Waters of the United States,” EPA-HQ-OW-2023-0346, 88 Fed. Reg. 61964 (September 8, 2023).

¹⁵ See *id.*

¹⁶ See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, 88 Fed. Reg. 18824 (March 29, 2023).

¹⁷ 42 U.S.C. §§ 6901 et seq.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO₂ emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that applies to power generation facilities. The RGGI auction price in the September 4, 2024, RGGI auction was \$25.75 per short ton, or \$28.38 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 mandated 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. The CEJA operating hour limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- **Carbon Price.** If the price of carbon were \$50.00 per metric tonne, short run marginal costs would have increased by \$24.45 per MWh or 80.3 percent for a new combustion turbine (CT) unit, \$16.85 per MWh or 90.5 percent for a new combined cycle (CC) unit and \$43.12 per MWh or 118.0 percent for a new coal plant (CP) for the first nine months of 2024.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2024, Delaware, 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 \$11.8 billion over the nine year period from 2014 through 2022, an average annual RPS compliance cost of \$1.3 billion. The compliance cost for 2022, the most recent year with almost complete data, was \$2.4 billion.¹⁸

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of September 30, 2024, 97.4 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO₂ 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 5.5 percent of total generation in PJM for the first nine months of 2024. RPS Tier I generation was 6.8 percent of total generation in PJM and RPS Tier II generation was 2.1 percent of total generation in PJM for the first nine months of 2024. Only Tier I generation is defined to be renewable but Tier I 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 nine months of 2023, Tier I generation from PJM generators met only 45.9 percent of the Tier I RPS requirements.

¹⁸ The 2022 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 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 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 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 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 stationary emergency 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, federal subsidies, 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.

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 \$13.93 per tonne in Ohio to \$62.59 per tonne in Virginia. The price of carbon implied by SREC prices ranges from \$74.84 per tonne in Pennsylvania to \$777.00 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2024 of \$28.38 per tonne and to the social cost of carbon which is estimated in the range of \$50 per tonne.^{19 20} 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.²¹ The impact of 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

¹⁹ "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>.

²⁰ A recent update by the EPA estimates the social cost of carbon emissions for 2030 to be between \$140 and \$380 per metric ton (2020 dollars). See Table ES.1 in Report on the Social Cost of Greenhouse Gases, U.S. Environmental Protection Agency (November 2023) <<https://www.epa.gov/environmental-economics/scghg>>.

²¹ The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 52.91 kg 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.

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 nine year period from 2014 through 2022 for the ten jurisdictions that had RPS was \$1.3 billion, or a total of \$11.8 billion over nine years. The RPS compliance cost for 2022, the most recent year for which there is almost complete data, was \$2.4 billion.²² 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 \$9.0 billion per year if the carbon price were \$25.75 per short ton and emissions levels were five percent below 2022 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 \$17.5 billion if the carbon price were \$50 per short ton and emission levels were five percent below 2022 levels. If only the current RPS states participated in a regional carbon market, the estimated

²² The 2022 compliance cost value for PJM states does not include Delaware, Michigan or North Carolina. Based on past data these states generally account for approximately 2.0 percent of the total RPS compliance cost of PJM states.

revenue returned to the states/customers from selling carbon allowances at \$25.75 per short ton would be about \$6.0 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.²³

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.^{24 25}

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.²⁶ 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.

²³ For more details, see the 2023 Annual State of the Market Report for PJM, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."

²⁴ 42 U.S.C. § 7401 et seq. (2000).

²⁵ 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.

²⁶ 42 U.S.C. §§ 6901 et seq.

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 antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, 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.²⁷ 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.²⁸ 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 24, 2024, the EPA finalized a strengthened and updated MATS rule reflecting recent developments in control technologies and the performance of coal fired plants.²⁹ The EPA allows plants to meet emissions requirements for non-HAP metals under an alternative fPM emission standard as a surrogate, and most use that approach.³⁰ The core proposal would revise the (non Hg) fPM emission standard, from 0.030 to 0.010 lbs/MMBtu.³¹ The EPA “does not project that any EGUs will retire in response to the standards promulgated in this final rule.”³²

²⁷ 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).

²⁸ 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).

²⁹ 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.

³⁰ *Id.* at 8.

³¹ *Id.* at 76.

³² *Id.* at 154.

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).³³ Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO₂, O₃ at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

On February 7, 2024, the EPA issued a final rule reducing the primary annual PM_{2.5} standard to 9.0 µg/m³ from 12.0 µg/m³.³⁴ The rule 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 SO₂ and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states. CSAPR 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*,³⁵ the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.³⁶ On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP) (at that time termed the Transport Rule) for 26 states that addresses the contribution of those states to problems in other states in attaining and

³³ The particulate matter (PM) regulated under the CAA is classified as either PM₁₀, which refers to PM less than 10 microns, and PM_{2.5}, which refers to PM less than 2.5 microns. PM_{2.5} is referred to as fine particulate matter and poses the greatest risk to health. Examples of PM_{2.5} include combustion particles, metals, and organic compounds.

³⁴ 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, 89 Fed. Reg. 16202 (March 6, 2024).

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

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

maintaining the 2015 Ozone NAAQS.³⁷ 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 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.³⁸ The FIP, also known as the Good Neighbor Plan, resolves the CAA good neighbor obligations of the affected states and applies when no state implementation plan has been approved. 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 2029³⁹

PJM State	Emissions Budget (Tons)							
	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	7,929*	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.

37 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).

38 See *Federal “Good Neighbor Plan” for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.

39 *Id.* at 35 (Table 1.B-1).

On June 27, 2024, the Supreme Court of the United States granted a stay of the FIP and therefore the EPA’s enforcement of CSAPR pending judicial review.⁴⁰ The effect of the stay is to eliminate the ozone season NO_x emissions budgets for electric generating units in the PJM states. Unless and until the stay is lifted, no federal implementation plan is effective in PJM states and the emissions budgets described in Table 8-1 are not effective. The EPA had previously rejected all proposed state implementation plans for PJM states.

Figure 8-1 shows average, monthly settled prices for NO_x and SO₂ emissions allowances including CSAPR related allowances for 2020 through September 2024. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO₂ allowances.

The RGGI CO₂ allowance price averaged \$20.71 in the first nine months of 2024, a 57.0 percent increase in comparison with the average price for the first nine months of 2023. The CSAPR annual NO_x allowance price averaged \$3.35 in the first nine months of 2024, a 67.4 percent increase in comparison with the average price for the first nine months of 2023. The group 2 CSAPR Seasonal NO_x allowance price averaged \$889.13 in the first nine months of 2024, a 40.2 percent decrease in comparison with the average price for the first nine months of 2023.⁴¹ The group 3 CSAPR Seasonal NO_x allowance price averaged \$1,008.64 in the first nine months of 2024, an 89.8 percent decrease in comparison to the average price for the first nine months of 2023.⁴² The components of real-time LMP analysis shows that NO_x cost contributed \$0.011 to the load-weighted average real-time LMP in the first nine months of 2024, compared to \$0.067 in the first nine months of 2023.⁴³ CO₂ cost (RGGI) contributed \$1.91 to the load-weighted average real-time LMP in the first nine months of 2024, compared to \$1.87 in the first nine months of 2023.⁴⁴

40 *Ohio v. EPA*, Slip Op. No. 23A349. (S. Ct. June 27, 2024)

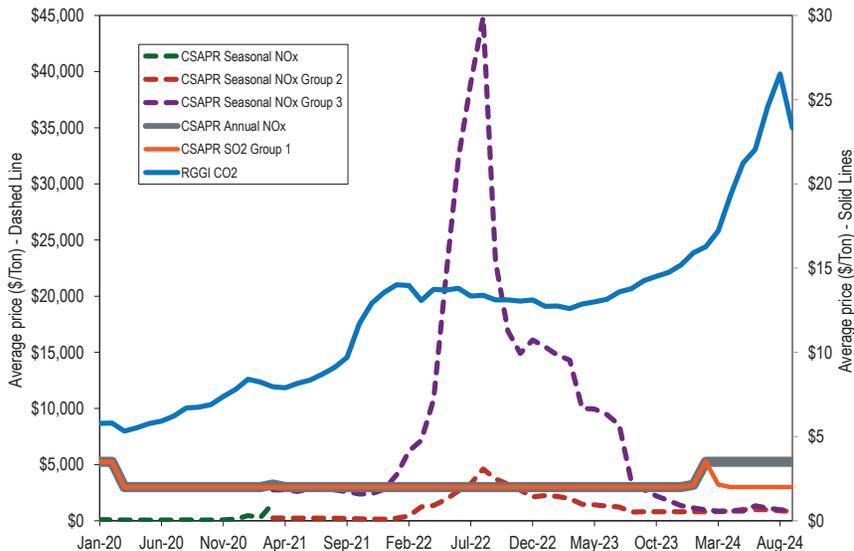
41 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.

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 *2024 Quarterly State of the Market Report for PJM: January through September*, Section 3: Energy Market.

44 *Id.*

Figure 8-1 Spot monthly average emission price comparison: 2020 through September 2024



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.”

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 the EPA emissions standards (stationary emergency 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.⁴⁷ 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. Some DR registrations reflect a participant’s reliance on behind the meter generation having environmental restrictions that limit the resource’s ability to operate only in emergency conditions. PJM’s DRHUB does not explicitly identify RICE generators, only whether it is an internal combustion engine. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does

⁴⁷ Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <<https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf>> (Accessed March 2, 2020).

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 CO₂ as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.^{48 49}

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.”⁵⁰

On April 25, 2024, the EPA finalized a rule taking four actions under CAA § 111(a)(1) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs) (“Carbon Emissions Rule”).⁵¹ The Carbon Emissions Rule repeals the Affordable Clean Energy (ACE) Rule; finalizes emission guidelines for GHG emissions from existing coal fired and oil/gas fired steam generating EGUs; revises the New Source Performance

⁴⁸ See CAA § 111.

⁴⁹ 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.

⁵⁰ 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](https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/)>.

⁵¹ See *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Proposed Rule, Docket No. EPA-HQ-OAR-2023-0072 (“Carbon Emissions Rule”).

Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs; and revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The rule deferred action on emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines.

The Carbon Emissions Rule creates subcategories of combustion turbines by capacity factor. For new combustion turbines, the final rule establishes three subcategories based on capacity factor. New base load turbines (greater than 40 percent capacity factor) are subject to an initial phase one standard based on efficient design and operation of combined cycle turbines; and a phase two standard based on 90 percent capture of CO₂ with a compliance deadline of January 1, 2032. New intermediate load turbines (20–40 percent capacity factor) are subject to a standard based on efficient design and operation of simple cycle turbines. New low load turbines (less than 20 percent capacity factor) are subject to a standard based on low-emitting fuel.⁵²

For existing coal-fired units, the Carbon Emissions Rule establishes subcategories based on continued operation past defined dates. Units that intend to operate on or after January 1, 2039, will have an emission rate limit based on application of carbon capture and sequestration/storage (CCS) with 90 percent capture, which they must meet on January 1, 2032. Units that have committed to cease operations by January 1, 2039, will have an emission rate limit based on 40 percent natural gas co-firing that they must meet on January 1, 2030. Units that demonstrate that they plan to permanently cease operation prior to January 1, 2032, will have no emission reduction obligations under the rule. The rule provides states the ability to provide a variance for individual existing units based on consideration of remaining useful life and other factors. The rule defines a required process, under which states have two years to submit plans to the EPA for review and approval. States may incorporate certain reliability related mechanisms into their plans: a short term reliability mechanism for units responding to declared grid

⁵² Carbon Emissions Rule states (at 435 ft. n.733): “For owners/operators of combustion turbines the lower emitting fuels requirement is defined to include fuels with an emissions rate of 160 lb CO₂/MMBtu or less. For owners/operators of steam generating units or IGCC facilities the EPA is requiring the use of the maximum amount of non-coal fuels available to the affected facility.”

emergencies, and a reliability assurance mechanism for units needed operate after the desired deactivation date.

On May 9, 2024, a coalition of PJM states including West Virginia, Indiana, Kentucky, Tennessee, Virginia, and 20 other states, filed a petition for review of the Carbon Emissions Rule by the United States Court of Appeals for the D.C. Circuit.⁵³ PJM joined other RTOs to file an amicus brief in support of petitioners, arguing that the result would result in premature retirements of fossil generation and threaten reliability.⁵⁴ The states also sought to stay implementation of the rule, but the motion for stay was denied by the U.S. Supreme Court by order issued October 4, 2024.⁵⁵ The petition remains pending at the D.C. Circuit.

On August 8, 2016, the U.S. Court of Appeals for the Seventh Circuit determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the “Social Costs of Carbon.”⁵⁶ The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer reviewed.⁵⁷ Although the decision applies only to the Department of Energy’s regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

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 the 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.⁵⁸ 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.⁵⁹

The EPA has been using the IWG’s interim value for SCC of \$51 per metric ton of CO₂. 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 \$190.⁶⁰ Support for the increase was included in a report attached to the proposed rule that is now subject to public comment.⁶¹

CWA: WOTUS Definition

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).⁶² ⁶³ 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.⁶⁴ Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

The scope of the CWA expanded as a result of an April 23, 2020, 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

⁵⁸ See *Louisiana v. Biden*, Order, Civ. No. 2:21-CV-1074-JDC-KK (July 27, 2022).

⁵⁹ See *Louisiana v. Biden*, Case No. 2:21-CV-1074, slip. op. (5th Cir. April 3, 2023) at 8–15.

⁶⁰ 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).

⁶¹ See *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, EPA Docket No. EPA-HQ-OAR-2021-0317 (September 2022).

⁶² 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.”).

⁶³ For more details, see the *2019 Annual State of the Market Report for PJM*, Volume II, Appendix H: “Environmental and Renewable Energy Regulations.”

⁶⁴ 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).

⁶⁵ 590 U.S. 165 (April 23, 2020).

⁶⁶ *Id.*

⁶⁷ *Id.* at 1.

⁵³ See *West Virginia, et al. v. EPA*, No. 24-1120, et al. (D.C. Circuit) at 1.

⁵⁴ See *Motion for Leave to File Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection LLC., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc., as Amicus Curiae in Support of Petitioners*, No. 24-1120, et al. (D.C. Circuit September 13, 2024).

⁵⁵ See *West Virginia, et al. v. EPA*, No. 24A95, et al.

⁵⁶ See *Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al.*, Case Nos. 14-2147, et al., Slip Op.

⁵⁷ *Id.*

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

On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.⁷¹ 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.⁷² 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.

On May 25, 2023, a decision of U.S. Supreme Court held that “jurisdiction over an adjacent wetland under the CWA requires “first, ... a relatively permanent body of water connected to traditional interstate navigable waters ... and second, that the wetland has a continuous surface connection with that water, making it difficult to determine where the ‘water’ ends and the ‘wetland’ begins.”⁷³ The Court’s definition of adjacent wetlands significantly reduced the range of waters meeting that definition compared to the range covered in the December 30, 2022 rule.

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 *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).

⁷² See *id.* at 3005-6.

⁷³ See *Sackett v. EPA*, Slip Op. 21-454.

On August 29, 2023, the EPA issued a final rule modifying its 2022 rule to define adjacent wetlands consistent with the Supreme Court holding, and it became effective on September 8, 2023.⁷⁴

CWA: 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.⁷⁵ The regulations, Effluent Limitations Guidelines and Standards (ELGs), are national industry-specific wastewater regulations based on the performance of demonstrated wastewater treatment technologies.

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.⁷⁶ 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.⁷⁷

The EPA has been implementing ELGs established in its 2015 and 2020 rules.⁷⁸ ⁷⁹ 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

⁷⁴ See *Revised Definition of “Waters of the United States [Conforming],”* Final Rule, Docket No. EPA-HQ-OW-2023-0346; FRL-11132-01-OW, 88 Fed. Reg. 61964 (September 8, 2023).

⁷⁵ See 40 CFR Part 423. For more details, see the *2019 Annual State of the Market Report for PJM*, Volume II, Appendix H: “Environmental and Renewable Energy Regulations.”

⁷⁶ See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).

⁷⁷ *Id.* at 35343-35349.

⁷⁸ 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).

⁷⁹ See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).

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, 2025.⁸⁰

Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or committing to retiring their units by 2028.⁸¹ On March 7, 2023, the EPA issued a direct final regulation extending the deadline from October 13, 2021, to June 27, 2023, for plants to opt in to the 2028 early retirement commitment.⁸²

Executive Order 13990 called for review and improvement of the 2020 Rule.

On April 25, 2024, pursuant to CWA, the EPA issued a rule strengthening the 2015 and 2020 ELGs for coal-fired power plants (“2024 Effluents Rule”).⁸³ The 2024 Effluents Rule would reduce discharges by an estimated 660–672 million pounds per year, including toxic and bioaccumulative pollutants, such as arsenic, lead, mercury, selenium, chromium, and cadmium.⁸⁴

This 2024 Effluents Rule establishes a zero discharge of pollutants limitation for three wastewaters generated at coal-fired power plants: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.⁸⁵ The regulation also establishes numeric discharge limitations for mercury and arsenic for combustion residual leachate (CRL) that is discharged through groundwater and for a fourth wastestream, called legacy wastewater, that is discharged from certain surface impoundments.⁸⁶ The regulation also eliminates less stringent requirements for two subcategories of facilities (high

flow facilities and low utilization energy generating units) that were contained in the 2020 regulation.⁸⁷

The 2024 Effluents Rule allows additional time for compliance for some plants that have installed, or are in the process of installing, additional treatment technologies to meet the 2015 and 2020 ELGs.⁸⁸ The rule allows some plants to continue to meet the 2015 and 2020 ELGs while they are in the process of closing and converting to use other fuels such as natural gas.⁸⁹

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.⁹⁰ 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.⁹¹ 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.⁹²

⁸⁰ *Id.* at 64652.

⁸¹ 85 Fed. Reg. 64650, 64679–82.

⁸² See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Initial Notification Date Extension*, EPA Docket No. EPA–HQ–OW–2009–0819; FRL–8794.1–02–OW, 88 Fed. Reg. 18440 (March 29, 2023); 40 CFR § 423.19(f) (1).

⁸³ See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. EPA–HQ–OW–2009–0819; FRL–8794–01–OW, 89 Fed. Reg. 40198 (May 9, 2024) (“2024 Effluents Rule”); CWA §§ 301, 304, 306, 307, 308, 402 et 501.

⁸⁴ *Id.* at 40198, 40203.

⁸⁵ *Id.* at 40198.

⁸⁶ *Id.* at 40252.

⁸⁷ *Id.* at 40200.

⁸⁸ *Id.*

⁸⁹ *Id.* at 40246.

⁹⁰ 42 U.S.C. §§ 6901 et seq.

⁹¹ See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

⁹² The Water Infrastructure Improvements for the Nation Act (WIIN Act).

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR (“2018 CCRR Revisions”) partly in response to the 2016 amendments.⁹³

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.⁹⁴

On July 29, 2020, the EPA finalized revisions to the CCR rule in compliance with the court orders (“Revised CCR”).⁹⁵ The Revised CCR 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

⁹³ 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).

⁹⁴ *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).

⁹⁵ 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).

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 CCR.⁹⁶

The EPA has or had under review 16 completed applications from PJM plants for extensions of the deadline for compliance with the Revised CCR. The EPA has proposed action on six applications.

On November 18, 2022, the EPA issued a final denial of the application of the General James M. Gavin Plant (2,600 MW) owned by Lightstone Generation LLC and located in the PJM footprint in Cheshire, Ohio (Gavin).⁹⁷ 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.⁹⁸ 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).⁹⁹ 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.¹⁰⁰ 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.¹⁰¹

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.¹⁰² The comment period for the proposed denial ended March 10, 2023. The EPA proposes that Conemaugh cease receipt of

⁹⁶ *Id.* at 53516-53517, 53536.

⁹⁷ 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”). A complaint requesting declaratory and injunctive relief is pending in federal district court. See *Gavin Power, LLC v. EPA*, Case No. 2:24cv41 (S.D. Ohio).

⁹⁸ 87 Fed. Reg. 72989 (November 28, 2022).

⁹⁹ 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”).

¹⁰⁰ Clifty Creek Proposed Denial Order at 77.

¹⁰¹ Clifty Creek Proposed Denial Order at 76-77.

¹⁰² 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”).

waste into the Ash Filter Ponds A, B, C, and D and initiate closure no later than 135 days from the date of the EPA's final decision (or such later date as the EPA determines is necessary to address grid reliability).¹⁰³ 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.¹⁰⁴

On June 23, 2023, the EPA proposed to deny the application of the Waukegan Generating Station owned by Midwest Generation, LLC (NRG), located in the PJM footprint in Waukegan, Illinois (Waukegan).¹⁰⁵ Waukegan retired all of its coal fired units as of May 31, 2022. Waukegan requested an extension to October 11, 2023, to discontinue receipt of CCR waste streams. The EPA would require the Waukegan Plant to stop receiving CCR waste no later than 135 days after a final decision.¹⁰⁶ The EPA provides the potential for an extension for such period that PJM may determine that Waukegan is needed for reliability and the EPA agrees is appropriate.¹⁰⁷ Although the application is denied, as a practical matter, Waukegan will not be required to discontinue receipt of CCR waste prior to its requested extension to October 11, 2023.

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in nonparticipating states, noticed February 20, 2020.¹⁰⁸ 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.¹⁰⁹ Dominion is 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:¹¹⁰

¹⁰³ Conemaugh Proposed Denial Order at 50.

¹⁰⁴ Conemaugh Proposed Denial Order at 49–50.

¹⁰⁵ Proposed Denial of Alternative Closure Deadline for Waukegan Generating Station, Docket No. EPA-HQ-OLEM-2023-0209 (June 23, 2023) ("Waukegan Proposed Denial Order").

¹⁰⁶ Waukegan Proposed Denial Order at 8.

¹⁰⁷ Waukegan Proposed Denial Order at 52–55.

¹⁰⁸ 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).

¹⁰⁹ Va. Code § 10.1-1402.03.

¹¹⁰ Virginia Department of Environmental Quality website: <<https://www.deq.virginia.gov/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,¹¹¹ the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.¹¹² 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.¹¹³ The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.¹¹⁴ The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.¹¹⁵

111 Ill. Public Act 101-171 (a.k.a. SB 09).

112 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.

113 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).

114 *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).

115 *Id.*

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).

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:¹¹⁶

- Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became law. 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.¹¹⁷ ¹¹⁸ 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.¹¹⁹ ¹²⁰ 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.

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

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

117 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/>> .

118 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Commonwealth Court of Pennsylvania Case No. 41 M.D. 2022 (November 1, 2023). On July 18, 2024, the Pennsylvania Supreme Court denied the appeal as moot. *Jessica Shirley v. Pennsylvania Legislative Reference Bureau*, Opinion, J-30B-2023 and J-30C-2023 (July 18, 2024).

119 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.

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

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 investments in emissions reductions 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.
- **New Jersey Control and Prohibition of Carbon Dioxide Emissions.** On December 2, 2022, New Jersey implemented rules restricting new power plants to CO₂ emissions less 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.¹²¹ The rule limits existing electric generating units to no more than 1,700 lbs of CO₂ 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 pounds 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 2045.¹²²
- **Illinois Air Quality Standards (NO_x, SO₂ and Hg).** The State of Illinois has promulgated its own standards for NO_x, SO₂ 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 proposed legislation in 2023 and in 2024 to date designed to reduce or eliminate greenhouse gas and other emissions. The proposed legislation is summarized in Table 8-3.

¹²¹ See N.J.A.C. 7:27F.
¹²² See Maryland SB 528.

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

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware	SB 265	152nd General Assembly: Enacted. The Delaware Energy Solutions Act of 2024 authorizes processes necessary to help meet the net zero goals of the Climate Change Solutions Act of 2023, facilitating a transition to carbon-free energy sources by (i) preparing for offshore wind if cost competitive, and (ii) increasing options for interconnecting renewable energy resources to the grid.
Illinois	HB 4734	103rd General Assembly: Amends the Environmental Protection Act. Extends deadlines for reduced or zero carbon dioxide emissions by 10 years for certain EGUs and large greenhouse gas-emitting units.
Indiana	HB 1382	2024 Reg. Sess.: Bill would replace provisions of the Indiana Code concerning the retirement, etc. of electric generation facilities. New provisions authorize the IURC to approve or deny the retirement of an electric generating unit, with a rebuttable presumption against retirement.
Kentucky		No current activity.
Maryland	HB 1315	2024 Reg. Sess.: Bill would require the PSC to consider certain factors before approving the premature retirement of a generation facility, establishing a rebuttable presumption that an electricity generation facility should not be prematurely retired, and prohibiting the PSC from approving an agreement related to the premature retirement of an electricity generation facility under certain circumstances.
Michigan		No current activity.
New Jersey	SB 222	2024-2025 Reg. Sess.: Bill would authorize regulation of greenhouse gas emissions under "Air Pollution Control Act (1954)" and "Global Warming Response Act."
	SB 220	2024-2025 Reg. Sess.: Bill would establish Nuclear Power Advisory Commission.
	SB 2816	2024-2025 Reg. Sess.: Requires electric public utilities to submit to BPU and to implement electric infrastructure improvement plans.
	SB 3308/A 4513	2024-2025 Reg. Sess.: Requires electric public utilities to implement certain improvements to the interconnection process for certain grid supply solar facilities.
North Carolina		No current activity.
Ohio		No current activity.
Pennsylvania	SB 1058	2023-2024 Reg. Sess.: Bill would provide for the abrogation of regulations relating to the CO2 Budget Trading Program.
	SB 1287	2023-2024 Reg. Sess.: An Act amending the Alternative Energy Portfolio Standards Act, further providing for alternative energy portfolio standards; providing for Zero Emissions Carbon Certificate Program, for solar photovoltaic technology requirements and for decarbonization; and establishing the ZEC Fund.
	SB 1191	2023-2024 Reg. Sess.: An Act establishing the Pennsylvania Climate Emissions Reduction Program, which, e.g., would establish a Pennsylvania-specific cap-and-invest program. It is proposed by the Governor as an alternative to RGGI participation.
Tennessee		No current activity.
Virginia	SB 557	2024 Reg. Sess.: Bill would provide that, for the purposes of the renewable energy portfolio standard, eligible sources include (i) hydrogen resources that are produced from zero-carbon generating facilities and (ii) zero-carbon nuclear generating facilities that were placed into service after July 1, 2024.
	HB 28	2024 Reg. Sess.: Bill would establish a moratorium, effective January 1, 2025, e.g., on any state approval required for electric generating facilities using fossil fuel.
	HB 1027	2024 Reg. Sess.: Under the bill, if the State Corporation Commission or an electric utility receives notice of any federal regulation that may threaten the production or supply of affordable, reliable, and secure energy within the Commonwealth, they will inform the Office of the Attorney General of such regulation within 30 days. The OAG must take any action necessary to defend the Commonwealth's interest in the production and supply of affordable, reliable, and secure energy, including filing an action in court or participating in administrative proceedings.
	SB 454	2024 Reg. Sess.: Bill would permit American Electric Power and Dominion Energy Virginia to petition the State Corporation Commission at any time for the approval of a rate adjustment clause for the recovery of project development costs for up to one small modular reactor facility.
	HB 109	2024 Reg. Sess.: Requires each incumbent electric utility that is a member that is in an RTO to submit an annual report recording all votes cast by the utility or its affiliates and a brief description explaining how each vote is in the public interest.
Washington, D.C.		No current activity.
West Virginia	HB 4712	2024 Reg. Sess.: Bill would limit the number of permits to construct wind power plants 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 2045.¹²³ 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.¹²⁴ 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.¹²⁵

Brandon Shores

In November 2020, Talen Energy entered into a settlement agreement with the Sierra Club pursuant to which Talen Energy agreed that it would cease the combustion of coal at the Brandon Shores units by December 31, 2025.¹²⁶ Talen notified PJM that it would retire the Brandon Shores units as of June 1, 2025. The agreement was conditioned on approval of any permits required to permit the Brandon Shores units to burn oil as an alternate fuel source.¹²⁷ In April 2023, PJM stated that it was informed by Talen Energy “for the first time, that although [Talen Energy] had previously been evaluating a conversion of the Brandon Shores units to fuel oil combustion, it has determined that such a conversion is uneconomic and does not justify operating after June 1, 2025.”¹²⁸ The Commission has approved the costs for the transmission upgrades to accommodate the retirement of Brandon Shores without replacement generation.¹²⁹ On April 18, 2024, Talen filed with the FERC for compensation under Part V (RMR).¹³⁰

¹²³ Va. HB 1526/SB 851.

¹²⁴ See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).

¹²⁵ *Id.*

¹²⁶ See Talen Energy Corp, Talen Energy Announces Transformational Move Toward a Sustainable, ESG-Focused Future (November 10, 2020), <<https://talenenergy.investorroom.com/2020-11-10-Talen-Energy-Announces-Transformational-Move-Toward-a-Sustainable-ESG-Focused-Future>>.

¹²⁷ See Maryland Dept. of Energy, Draft Part 70 Permit, which references permitting conversion of Brandon Shores Units 1 and 2 from coal to oil (June 29, 2022).

¹²⁸ Motion for Leave to Answer and Answer of PJM Interconnection, LLC, Docket Nos. ER23-2612-000 (October 3, 2023) at 11.

¹²⁹ See 185 FERC ¶ 61,107.

¹³⁰ See Docket No. ER24-1790-000.

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 CO₂ emissions from power generation facilities.¹³¹ Virginia withdrew from RGGI effective January 1, 2024.

Delaware, Maryland and New Jersey are members of RGGI, and Virginia was a member from January 1, 2021 through 2023. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.¹³² Virginia joined RGGI on January 1, 2021, and left RGGI on December 31, 2023. A court challenge to Virginia's leaving RGGI is pending.¹³³ Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.¹³⁴ A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania.

Table 8-4 shows the RGGI CO₂ auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period through the 5th control period, and the first year of the 6th control period.¹³⁶ The clearing price for the auction held September 4, 2024 was \$25.75 per allowance (equal to one short ton of CO₂).¹³⁷ The Cost Containment Reserve (CCR) for 2024 was exhausted in the first auction of the year and the September auction cleared well above the CCR trigger price of \$15.92 per allowance.¹³⁸ All RGGI auctions in 2024

¹³¹ 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>>.

¹³² “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>.

¹³³ See Floyd County Circuit Court, Virginia, Case No. CL23000173-00.

¹³⁴ 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/>>.

¹³⁵ 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).

¹³⁶ 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. The 6th control period covers 2024 through 2026.

¹³⁷ 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).

¹³⁸ RGGI auctions employ a price cap called the Cost Containment Reserve (CCR) trigger price. When demand for allowances exceeds the supply at the CCR trigger price, the auction is cleared by setting the price equal to the CCR trigger price and drawing on allowances that are held in reserve. In the March 2024 auction, the reserve allowances were not sufficient to meet the demand at the CCR trigger price and the auction cleared above the CCR trigger price. The December 2023 auction cleared at the CCR trigger price (\$14.88 per ton). The auctions on March 5, 2014, September 3, 2015, December 1, 2021 and December 6, 2023, are the only auctions that have cleared at the CCR trigger price.

cleared above the CCR trigger price. The September auction clearing price increased 22.4 percent from the last auction clearing price of \$21.03 in June 2024. The average RGGI auction price through the first nine months of 2024 was \$20.20 per allowance, a 55.0 percent increase over the average RGGI auction price through the first nine months of 2023.

Table 8-4 RGGI CO₂ allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th, 5th and 6th Control Periods¹³⁹

Auction Date	Short Tons				Metric Tonnes			
	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
June 7, 2023	\$12.73	22,026,639		22,026,639	\$14.03	19,982,237		19,982,237
September 6, 2023	\$13.85	21,948,358		21,948,358	\$15.27	19,911,221		19,911,221
December 6, 2023	\$14.88	22,090,709	5,565,291	27,656,000	\$16.40	20,040,360	5,048,749	25,089,108
March 13, 2024	\$16.00	15,855,879	8,416,278	24,272,157	\$17.64	14,384,216	7,635,121	22,019,337
June 5, 2024	\$21.03	16,053,188		16,053,188	\$23.18	14,563,211		14,563,211
September 4, 2024	\$25.75	15,943,608		15,943,608	\$28.38	14,463,802		14,463,802

¹³⁹ See Regional Greenhouse Gas Initiative, "Auction Results," <<https://www.rggi.org/auctions/auction-results>>.

The RGGI auction held on September 4, 2024, generated \$410.5 million in auction revenue. RGGI auctions have generated \$8.3 billion in auction revenue since 2008.¹⁴⁰ RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2022 reporting year, have invested \$4.0 billion, 68.3 percent of auction revenues.¹⁴¹ RGGI reports that 61 percent of the \$4.0 billion was invested in energy efficiency, six percent on clean and renewable energy, eight percent on greenhouse gas abatement, 15 percent on direct bill assistance, four percent on beneficial electrification, six percent on administration and one percent on RGGI, Inc.¹⁴²

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 2022 CO₂ emission levels and the RGGI clearing price for the September 2024 auction ranges from \$4.7 billion per year to \$9.0 billion per year depending on associated reductions in carbon emission levels (Table 8-5).¹⁴³ Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2022 CO₂ emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO₂ 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 2022 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 CO₂ emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.¹⁴⁴

Table 8-5 Estimated CO₂ allowance revenue at September 2024 RGGI price level^{145 146}

Jurisdiction	Estimated CO ₂ allowance revenue (\$ millions), carbon price \$25.75 per short ton						
	2022 power generation CO ₂ emissions (million short tons)	5 percent reduction below 2022 emission levels	10 percent reduction below 2022 emission levels	15 percent reduction below 2022 emission levels	20 percent reduction below 2022 emission levels	25 percent reduction below 2022 emission levels	50 percent reduction below 2022 emission levels
Delaware	2.3	\$55.5	\$52.6	\$49.7	\$46.8	\$43.8	\$29.2
Illinois	25.0	\$611.2	\$579.0	\$546.9	\$514.7	\$482.5	\$321.7
Indiana	36.0	\$880.9	\$834.5	\$788.1	\$741.8	\$695.4	\$463.6
Kentucky	33.5	\$819.5	\$776.4	\$733.2	\$690.1	\$647.0	\$431.3
Maryland	11.7	\$285.3	\$270.2	\$255.2	\$240.2	\$225.2	\$150.1
Michigan	1.3	\$31.0	\$29.3	\$27.7	\$26.1	\$24.4	\$16.3
New Jersey	12.0	\$293.8	\$278.3	\$262.9	\$247.4	\$231.9	\$154.6
North Carolina	0.1	\$3.0	\$2.8	\$2.7	\$2.5	\$2.3	\$1.6
Ohio	83.6	\$2,045.3	\$1,937.7	\$1,830.0	\$1,722.4	\$1,614.7	\$1,076.5
Pennsylvania	80.3	\$1,963.6	\$1,860.2	\$1,756.9	\$1,653.5	\$1,550.2	\$1,033.5
Tennessee	0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	27.3	\$667.2	\$632.1	\$597.0	\$561.9	\$526.7	\$351.2
Washington, D.C.	0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	55.3	\$1,352.3	\$1,281.1	\$1,209.9	\$1,138.8	\$1,067.6	\$711.7
Total	368.3	\$9,008.5	\$8,534.3	\$8,060.2	\$7,586.1	\$7,111.9	\$4,741.3

140 See Auction Results at <<https://www.rggi.org/>>.

141 *The Investment of RGGI Proceeds in 2022*, The Regional Greenhouse Gas Initiative (RGGI) at 16, July 2024, <<https://www.rggi.org/investments/proceeds-investments>>.

142 *Id.* at 15.

143 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.

144 "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>>.

145 The 2022 CO₂ emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from PJM generators.

146 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 8-5 do not reflect offset allowances.

The RGGI emissions cap (carbon budget) is the sum of CO₂ 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 2024 compliance year is the first year of the sixth control period.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.¹⁴⁷ ¹⁴⁸ The first adjustment removed 57.4 million allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.¹⁴⁹ 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 2020.¹⁵⁰ The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.¹⁵¹ 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.¹⁵² The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.¹⁵³ Figure 8-2 shows the adjusted carbon budgets (CO₂ emissions caps) for the RGGI states.

Table 8-6 RGGI emissions cap history¹⁵⁴ ¹⁵⁵

		RGGI Average Clearing Price (\$ per short ton)	RGGI Cap (short tons)	Percent Change in RGGI Cap	RGGI Adjusted Cap (short tons)	Percent Change in Adjusted Cap
2009		\$2.77	188,076,976		188,076,976	
2010	1st	\$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		\$1.93	165,184,246	0.0%	165,184,246	0.0%
2013	2nd	\$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		\$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	3rd	\$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		\$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	\$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		\$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022	5th	\$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023		\$13.58	112,457,784	(3.1%)	93,367,454	(3.8%)
2024	6th	\$20.20	84,162,784	(3.2%)	69,401,609	(3.9%)

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

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

149 "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>.

150 Id.

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

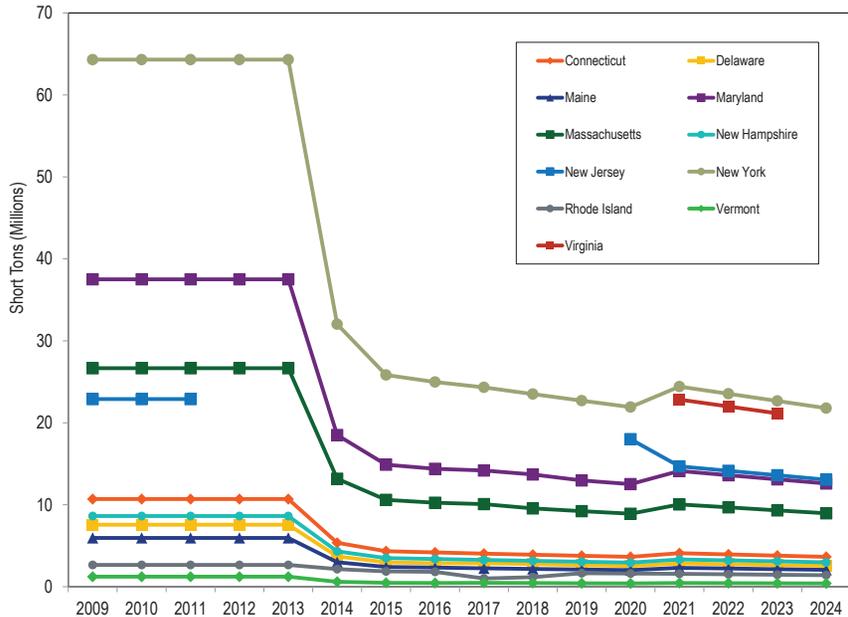
152 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the RGGI cap for 2020 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 and Virginia's withdrawal at the end of 2023 are treated analogously.

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

154 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <<https://www.rggi.org/allowance-tracking/allowance-distribution>> (Accessed April 30, 2024).

155 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.

Figure 8-2 RGGI adjusted carbon budgets by state¹⁵⁶



Carbon Pricing, State Revenues and Energy Market Prices

Table 8-7 shows the estimated allowance revenue for PJM states for carbon prices ranging from \$20 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 \$17.5 billion if the carbon price were \$50 per short ton and emission levels were five percent below 2022 levels. Allowance revenues to states would be \$3.7 billion if the carbon price were \$20 per short ton and emission levels were 50 percent below 2022.

¹⁵⁶ Data for the figure was collected from allowance distribution reports available on the RGGI website <<https://www.rggi.org/allowance-tracking/allowance-distribution>>.

Table 8-7 Estimated CO₂ allowance revenue at various carbon prices

Jurisdiction	Estimated CO ₂ allowance revenue (\$ millions)					
	5 percent reduction below 2022 emission levels	10 percent reduction below 2022 emission levels	15 percent reduction below 2022 emission levels	20 percent reduction below 2022 emission levels	25 percent reduction below 2022 emission levels	50 percent reduction below 2022 emission levels
	Carbon Price (\$ per short ton)					
	\$20.00					
Delaware	\$43.1	\$40.9	\$38.6	\$36.3	\$34.0	\$22.7
Illinois	\$474.7	\$449.7	\$424.8	\$399.8	\$374.8	\$249.9
Indiana	\$684.2	\$648.2	\$612.1	\$576.1	\$540.1	\$360.1
Kentucky	\$636.5	\$603.0	\$569.5	\$536.0	\$502.5	\$335.0
Maryland	\$221.6	\$209.9	\$198.2	\$186.6	\$174.9	\$116.6
Michigan	\$24.0	\$22.8	\$21.5	\$20.2	\$19.0	\$12.7
New Jersey	\$228.2	\$216.2	\$204.2	\$192.1	\$180.1	\$120.1
North Carolina	\$2.3	\$2.2	\$2.1	\$1.9	\$1.8	\$1.2
Ohio	\$1,588.6	\$1,505.0	\$1,421.4	\$1,337.8	\$1,254.1	\$836.1
Pennsylvania	\$1,525.1	\$1,444.8	\$1,364.6	\$1,284.3	\$1,204.0	\$802.7
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$518.2	\$490.9	\$463.7	\$436.4	\$409.1	\$272.7
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$1,050.3	\$995.0	\$939.8	\$884.5	\$829.2	\$552.8
Total	\$6,996.9	\$6,628.6	\$6,260.3	\$5,892.1	\$5,523.8	\$3,682.6
	\$25.00					
Delaware	\$53.9	\$51.1	\$48.2	\$45.4	\$42.6	\$28.4
Illinois	\$593.4	\$562.2	\$530.9	\$499.7	\$468.5	\$312.3
Indiana	\$855.2	\$810.2	\$765.2	\$720.2	\$675.2	\$450.1
Kentucky	\$795.6	\$753.8	\$711.9	\$670.0	\$628.1	\$418.8
Maryland	\$277.0	\$262.4	\$247.8	\$233.2	\$218.6	\$145.8
Michigan	\$30.1	\$28.5	\$26.9	\$25.3	\$23.7	\$15.8
New Jersey	\$285.2	\$270.2	\$255.2	\$240.2	\$225.2	\$150.1
North Carolina	\$2.9	\$2.7	\$2.6	\$2.4	\$2.3	\$1.5
Ohio	\$1,985.7	\$1,881.2	\$1,776.7	\$1,672.2	\$1,567.7	\$1,045.1
Pennsylvania	\$1,906.4	\$1,806.1	\$1,705.7	\$1,605.4	\$1,505.0	\$1,003.4
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$647.8	\$613.7	\$579.6	\$545.5	\$511.4	\$340.9
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$1,312.9	\$1,243.8	\$1,174.7	\$1,105.6	\$1,036.5	\$691.0
Total	\$8,746.1	\$8,285.7	\$7,825.4	\$7,365.1	\$6,904.8	\$4,603.2
	\$50.00					
Delaware	\$107.8	\$102.1	\$96.5	\$90.8	\$85.1	\$56.7
Illinois	\$1,186.8	\$1,124.3	\$1,061.9	\$999.4	\$937.0	\$624.6
Indiana	\$1,710.4	\$1,620.4	\$1,530.4	\$1,440.3	\$1,350.3	\$900.2
Kentucky	\$1,591.3	\$1,507.5	\$1,423.8	\$1,340.0	\$1,256.3	\$837.5
Maryland	\$553.9	\$524.8	\$495.6	\$466.5	\$437.3	\$291.5
Michigan	\$60.1	\$56.9	\$53.8	\$50.6	\$47.4	\$31.6
New Jersey	\$570.4	\$540.4	\$510.4	\$480.4	\$450.4	\$300.2
North Carolina	\$5.8	\$5.5	\$5.2	\$4.9	\$4.6	\$3.0
Ohio	\$3,971.5	\$3,762.4	\$3,553.4	\$3,344.4	\$3,135.4	\$2,090.2
Pennsylvania	\$3,812.8	\$3,612.1	\$3,411.4	\$3,210.8	\$3,010.1	\$2,006.7
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$1,295.5	\$1,227.4	\$1,159.2	\$1,091.0	\$1,022.8	\$681.9
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$2,625.8	\$2,487.6	\$2,349.4	\$2,211.2	\$2,073.0	\$1,382.0
Total	\$17,492.1	\$16,571.5	\$15,650.9	\$14,730.2	\$13,809.6	\$9,206.4

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 nine months of 2024 would have increased by 1.0 percent.¹⁵⁷

Table 8-8 Estimated impact of carbon price on LMP: January through September, 2023 and 2024

Scenario	Carbon Price (\$/Metric Ton)	2023 (Jan - Sep)			2024 (Jan - Sep)		
		Actual LMP (\$/MWh)	Estimated LMP (\$/MWh)	Percent Change	Actual LMP (\$/MWh)	Estimated LMP (\$/MWh)	Percent Change
Scenario 1	\$5.00	\$30.87	\$28.37	(8.1%)	\$34.31	\$32.87	(4.2%)
Scenario 2	\$10.00	\$30.87	\$29.89	(3.2%)	\$34.31	\$33.32	(2.9%)
Scenario 3	\$15.00	\$30.87	\$31.40	1.7%	\$34.31	\$33.77	(1.6%)
Scenario 4	\$25.00	\$30.87	\$34.43	11.5%	\$34.31	\$34.67	1.0%
Scenario 5	\$50.00	\$30.87	\$42.01	36.1%	\$34.31	\$36.92	7.6%

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.^{158 159} 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

Unit Type	Carbon Price per MWh						
	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	\$12.94	\$43.12	\$86.25	\$172.49	\$344.99

¹⁵⁷ 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>.

¹⁵⁸ Heat rates from: 2024 Quarterly State of the Market Report for PJM: January through September, Section 7: Net Revenue, Table 7-3.

¹⁵⁹ 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 May 7, 2024).

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 \$191.77 per credit in the first nine months of 2024. 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 nine months of 2024 in Ohio is \$13.93 per tonne which is \$8.33 per tonne lower than the average RGGI auction price of \$22.26 per tonne in the first nine months of 2024. The implied carbon prices for Maryland, New Jersey, Pennsylvania and Washington, DC RECs range from \$43.84 per tonne to \$62.59 per ton. The implied carbon price for Virginia RECs is \$62.59, approximately three times the average RGGI auction clearing price. The social cost of carbon which is estimated to be in the range of \$50 per tonne.^{160 161} 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.

¹⁶⁰ "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>.

¹⁶¹ A recent update by the EPA estimates the social cost of carbon emissions for 2030 to be between \$140 and \$380 per metric ton (2020 dollars). See Table ES.1 in Report on the Social Cost of Greenhouse Gases, U.S. Environmental Protection Agency (November 2023) <<https://www.epa.gov/environmental-economics/scghg>>.

Table 8-10 Implied carbon price based on REC and SREC prices: 2015 through September 2024

Jurisdiction with Tier I or Class I REC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	\$32.01	\$33.01	\$10.29	\$11.60	\$16.10	\$19.94				
Maryland	\$29.27	\$26.17	\$23.19	\$21.35	\$17.81	\$19.98	\$34.29	\$37.82	\$45.61	\$46.92
New Jersey	\$25.37	\$27.01	\$24.08	\$22.08	\$19.25	\$20.54	\$31.62	\$36.23	\$47.07	\$51.10
Ohio	\$8.54	\$5.30	\$6.29	\$11.21	\$14.04	\$16.33	\$14.93	\$14.98	\$14.54	\$13.93
Pennsylvania	\$28.96	\$26.43	\$23.42	\$21.53	\$17.96	\$20.06	\$33.58	\$37.76	\$45.60	\$49.61
Virginia							\$35.53	\$36.02	\$50.18	\$62.59
Washington, D.C.	\$3.20	\$4.05	\$4.90	\$4.69	\$5.52	\$20.25	\$24.28	\$27.49	\$32.45	\$43.84
Jurisdiction with Solar REC										
Delaware	\$85.66	\$86.75	\$35.80	\$17.38						
Maryland	\$251.99	\$183.64	\$128.05	\$87.27	\$84.19	\$101.68	\$121.11	\$111.74	\$103.70	\$106.64
New Jersey	\$389.91	\$425.49	\$460.60	\$446.35	\$410.31	\$394.18	\$413.80	\$424.70	\$398.02	\$392.22
Ohio	\$45.25	\$36.26	\$31.92	\$21.73	\$26.65					
Pennsylvania	\$67.09	\$55.22	\$43.97	\$28.16	\$51.65	\$63.80	\$74.20	\$83.02	\$79.40	\$74.84
Washington, D.C.	\$997.05	\$996.49	\$868.78	\$842.89	\$851.39	\$869.41	\$851.78	\$856.50	\$864.48	\$777.00
Regional Greenhouse Gas Initiative										
RGGI clearing price	\$6.72	\$4.93	\$3.77	\$4.86	\$5.98	\$7.06	\$10.59	\$14.84	\$14.97	\$22.26

Table 8-11 Carbon price for natural gas fired generators¹⁶²

Heat Rate (Btu per kWh)	Carbon Price (\$ per MWh)										
	\$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

¹⁶² Prices reflect uncontrolled carbon emission rates from Table A.3 in *Electric Power Annual*, EIA (October 19, 2023) <<https://www.eia.gov/electricity/annual/>>.

Table 8-12 Carbon price for coal fired generators¹⁶³

Heat Rate (Btu per kWh)	Carbon Price (\$ per MWh)										
	Carbon (\$ per tonne)										
9,000	\$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	\$12.59	\$16.78	\$20.98	\$25.17	\$29.37	\$33.57	\$37.76	\$41.96	\$46.15	\$50.35
9,500	\$8.86	\$13.29	\$17.72	\$22.14	\$26.57	\$31.00	\$35.43	\$39.86	\$44.29	\$48.72	\$53.15
10,000	\$9.32	\$13.99	\$18.65	\$23.31	\$27.97	\$32.63	\$37.30	\$41.96	\$46.62	\$51.28	\$55.94
10,500	\$9.79	\$14.69	\$19.58	\$24.48	\$29.37	\$34.27	\$39.16	\$44.06	\$48.95	\$53.85	\$58.74
11,000	\$10.26	\$15.38	\$20.51	\$25.64	\$30.77	\$35.90	\$41.03	\$46.15	\$51.28	\$56.41	\$61.54
11,500	\$10.72	\$16.08	\$21.45	\$26.81	\$32.17	\$37.53	\$42.89	\$48.25	\$53.61	\$58.97	\$64.34
12,000	\$11.19	\$16.78	\$22.38	\$27.97	\$33.57	\$39.16	\$44.76	\$50.35	\$55.94	\$61.54	\$67.13
12,500	\$11.65	\$17.48	\$23.31	\$29.14	\$34.96	\$40.79	\$46.62	\$52.45	\$58.27	\$64.10	\$69.93
13,000	\$12.12	\$18.18	\$24.24	\$30.30	\$36.36	\$42.42	\$48.48	\$54.55	\$60.61	\$66.67	\$72.73
13,500	\$12.59	\$18.88	\$25.17	\$31.47	\$37.76	\$44.06	\$50.35	\$56.64	\$62.94	\$69.23	\$75.52
14,000	\$13.05	\$19.58	\$26.11	\$32.63	\$39.16	\$45.69	\$52.21	\$58.74	\$65.27	\$71.79	\$78.32
14,500	\$13.52	\$20.28	\$27.04	\$33.80	\$40.56	\$47.32	\$54.08	\$60.84	\$67.60	\$74.36	\$81.12
15,000	\$13.99	\$20.98	\$27.97	\$34.96	\$41.96	\$48.95	\$55.94	\$62.94	\$69.93	\$76.92	\$83.92
15,500	\$14.45	\$21.68	\$28.90	\$36.13	\$43.36	\$50.58	\$57.81	\$65.03	\$72.26	\$79.49	\$86.71
16,000	\$14.92	\$22.38	\$29.84	\$37.30	\$44.76	\$52.21	\$59.67	\$67.13	\$74.59	\$82.05	\$89.51
16,500	\$15.38	\$23.08	\$30.77	\$38.46	\$46.15	\$53.85	\$61.54	\$69.23	\$76.92	\$84.62	\$92.31
17,000	\$15.85	\$23.78	\$31.70	\$39.63	\$47.55	\$55.48	\$63.40	\$71.33	\$79.25	\$87.18	\$95.10
17,500	\$16.32	\$24.48	\$32.63	\$40.79	\$48.95	\$57.11	\$65.27	\$73.43	\$81.58	\$89.74	\$97.90
18,000	\$16.78	\$25.17	\$33.57	\$41.96	\$50.35	\$58.74	\$67.13	\$75.52	\$83.92	\$92.31	\$100.70

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

¹⁶³ 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 May 7, 2024).

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).¹⁶⁴ Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2024, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2024, 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.¹⁶⁵

As of September 30, 2024, 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 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

¹⁶⁴ Renewable Energy Explained, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).

¹⁶⁵ See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <<https://www.in.gov/iurc/2981.htm>>.

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.¹⁶⁶

Beginning in March 2023, RECs for GATS generators will be hourly time stamped certificates.¹⁶⁷ 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: 2023 to 2033^{168 169 170}

Jurisdiction with RPS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Delaware	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%	34.00%
Illinois	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%	40.00%
Maryland	32.37%	36.20%	38.00%	40.50%	44.00%	45.50%	52.00%	52.50%	52.50%	52.50%	52.50%
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	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	7.00%	7.50%	8.00%	8.50%	0.00%	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)	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%	39.00%
Virginia (Phase II utilities)	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%	52.00%
Washington, DC	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%

¹⁶⁶ Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

¹⁶⁷ "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>>.

¹⁶⁸ This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.

¹⁶⁹ 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.

¹⁷⁰ New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.

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 2030.¹⁷¹ 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 2035.¹⁷² Additional details are provided in Table 8-14.

¹⁷¹ Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees, Maryland General Assembly (2021) <<https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>>.

¹⁷² 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.¹⁷³ 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 2045.¹⁷⁴ ¹⁷⁵ 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.¹⁷⁶ 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.¹⁷⁷ The legislation is expected to boost the installation of distribution level solar power.

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.¹⁷⁸ 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

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

¹⁷³ See “Virginia Clean Economy Act,” (April 12, 2020) <<https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>>.

¹⁷⁴ 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).

¹⁷⁵ APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS 176 N.J. S. 2314/A. 3723.

¹⁷⁷ Md. Code Ann § 7-306(d) & 7-306.2(g) (HB 569).

¹⁷⁸ N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 Recent changes in RPS rules^{179 180 181 182 183 184 185}

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 the Tier 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 alternative 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 mandatory 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 2010.¹⁸⁶

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities (NJPBU) 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).¹⁸⁷ The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.¹⁸⁸ 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 Danish wind power developer Ørsted.^{189 190} Two more projects were approved on June 30, 2021. Ørsted was awarded a second project for offshore wind capacity of 1,148 MW and Atlantic

¹⁷⁹ Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).

¹⁸⁰ See "Virginia Clean Economy Act," (April 12, 2020) <<https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>>.

¹⁸¹ 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>>.

¹⁸² See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <<https://legiscan.com/md/text/sb516/2019>>.

¹⁸³ D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <<https://code.dccouncil.us/dccouncil/laws/22-257.html>>.

¹⁸⁴ See Senate Bill 33, Delaware General Assembly (February 10, 2021) <<https://legis.delaware.gov/BillDetail?legislationId=48278>>.

¹⁸⁵ Senate Bill 65 Electricity - Renewable Energy Portfolio Standard - Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees, Maryland General Assembly (2021) <<https://mgaleg.maryland.gov/mgaweb/Legislation/Details/sb0065?ys=2021RS>>.

¹⁸⁶ 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.

¹⁸⁷ N.J. S. 2314/A. 3723.

¹⁸⁸ Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

¹⁸⁹ BPU Docket No. QO18080851.

¹⁹⁰ "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Ørsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <<https://nj.gov/bpu/newsroom/2019/approved/20190621.html>>.

Shores Offshore Wind was awarded a project for 1,510 MW.¹⁹¹ On October 31, 2023, Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey.¹⁹² The Associated Press reported in May 2024 that the New Jersey and Ørsted reached a settlement that required Ørsted to pay New Jersey \$125 million.¹⁹³

On January 24, 2024, the NJBPU awarded 2,400 MW of offshore wind capacity to the Leading Light Wind project and 1,342 to Attentive Energy LLC.¹⁹⁴ The Leading Light Wind project is a partnership between Invenergy and energyRE.

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 Ørsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.¹⁹⁵ ORECs for Skipjack Wind 2 have a levelized price of \$71.61; ORECs for Momentum Wind have a levelized price of \$54.17.¹⁹⁶ Both projects are expected to become operational before the end of 2026.¹⁹⁷ In 2017, Round 1 ORECs were awarded to Deepwater Wind’s 120-MW Skipjack Wind Farm, later acquired by Ørsted, and U.S. Wind’s 248 MW project.¹⁹⁸ On January 25, 2024, Ørsted announced it “has withdrawn from the Maryland Public Service Commission Orders approving the Skipjack 1 and 2 projects,” noting that the OREC prices in the orders “are no longer commercially viable.”¹⁹⁹

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.²⁰⁰ In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.²⁰¹

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 ten 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.²⁰² 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.²⁰³ All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.²⁰⁴

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2023 to 2033²⁰⁵

Jurisdiction with RPS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Maryland	29.87%	33.70%	35.50%	38.00%	41.50%	43.00%	49.50%	50.00%	50.00%	50.00%	50.00%
New Jersey	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	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	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.²⁰⁶

191 "NJPBU Approves Nation's Largest Combined Offshore Wind Award to Atlantic Shores and Ocean Wind II", New Jersey BPU Press Release (June 30, 2021) <<https://www.nj.gov/bpu/newsroom/2021/approved/20210630.html>>.
 192 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <<https://orsted.com/en/company-announcement-list/2023/10/orsted-ceases-development-of-its-us-offshore-wind-73751>>.
 193 "New Jersey and wind farm developer Ørsted settle claims for \$125M over scrapped offshore projects", Associated Press (May 28, 2024).
 194 "NJBPU Approves Over 3,700 MW of Offshore Wind Capacity in Combined Award", New Jersey BPU Press Release (January 24, 2024) <<https://www.nj.gov/bpu/newsroom/2024/approved/20240124.html>>.
 195 "Ørsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <<https://renewablesnow.com/news/orsted-us-wind-triumph-with-16-gw-in-maryland-offshore-tender-766237/>>.
 196 *Id.*
 197 *Id.*
 198 "Ørsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ØRSTED Press Release (August 10, 2018).
 199 Skipjack Wind to be Repositioned for Future Offtake Opportunities, Ørsted (January 25, 2024) <<https://orsted.com/en/media/news/2024/01/skipjack-wind-to-be-repositioned-for-future-offtak-815811>>.

200 "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>>.
 201 "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>>.
 202 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.
 203 This includes New Jersey’s Class I renewable standard.
 204 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).
 205 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
 206 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.

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

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

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the annual average Tier I REC price by jurisdiction from 2009 through the first nine months of 2024. Tier I REC prices are lower than SREC prices. Several states have more stringent geographical restrictions for SRECs and higher alternative compliance payments (ACP) for SRECs than for RECs. For example, the average SREC price for the first nine months of 2024 in Washington, DC was \$379.91 and the average Tier I REC price for the first nine months of 2024 in Washington, DC was \$21.43. The DC RPS requires SRECs to be sourced from within DC while Tier I RECs may be sourced from anywhere within the PJM footprint. The DC solar ACP is \$400 per SREC compared to \$50 per REC for Tier I compliance.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through September 2024

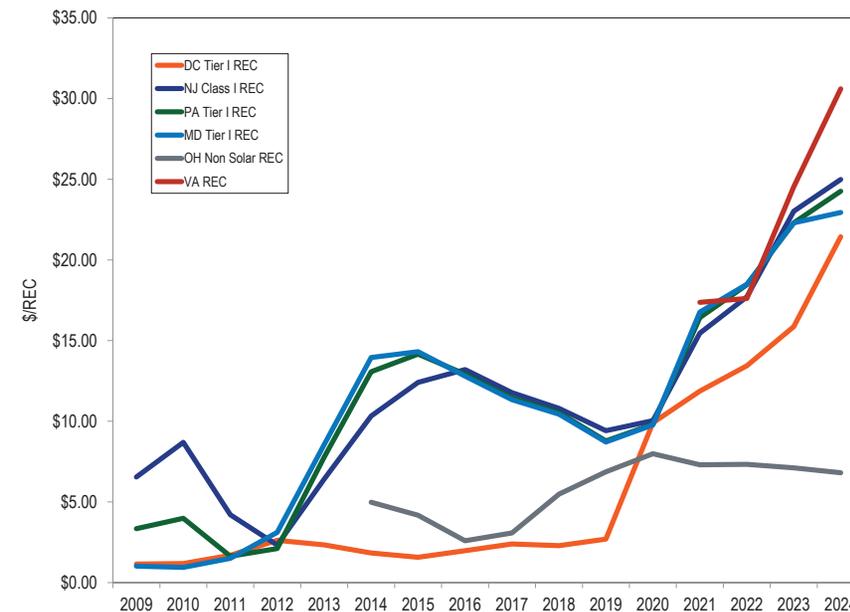


Figure 8-4 and Table 8-16 show the fulfillment of Tier I equivalent RPS requirement for 2019 through 2023 by state and by carbon producing and noncarbon producing RECs.²⁰⁷ Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro (“Noncarbon REC”) or with landfill gas, captured 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 in state and out of state carbon producing RECs and in state and out of state noncarbon RECs by state to meet the RPS requirements. In Table 8-16 the retired RECs are summarized by in state, other PJM state and non PJM state, and carbon producing RECs

²⁰⁷ Retired REC information obtained through PJM GATS <<https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>>. The timing of the REC retirement reports varies by state and the 2023 reporting year data is incomplete for some states.

and noncarbon RECs. For example, Virginia met its 2023 RPS target using 5.1 percent carbon free RECs from Virginia, 88.6 percent carbon free RECs from other PJM states and 6.3 percent carbon producing RECs from other PJM states. Ohio met its 2023 RPS target using 1.4 percent carbon free RECs from Ohio, 37.5 percent carbon free RECs from other PJM states, 6.8 percent carbon free RECs from non PJM states, 20.8 percent carbon producing RECs from Ohio and 33.5 percent carbon producing RECs from other PJM states.. Illinois met its 2023 RPS target using 81.6 percent carbon free RECs from Illinois and 18.4 percent carbon free RECs from other PJM states. Illinois met its RPS target using 100.0 percent carbon free RECs for the 2019 through 2023 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2018 through 2023

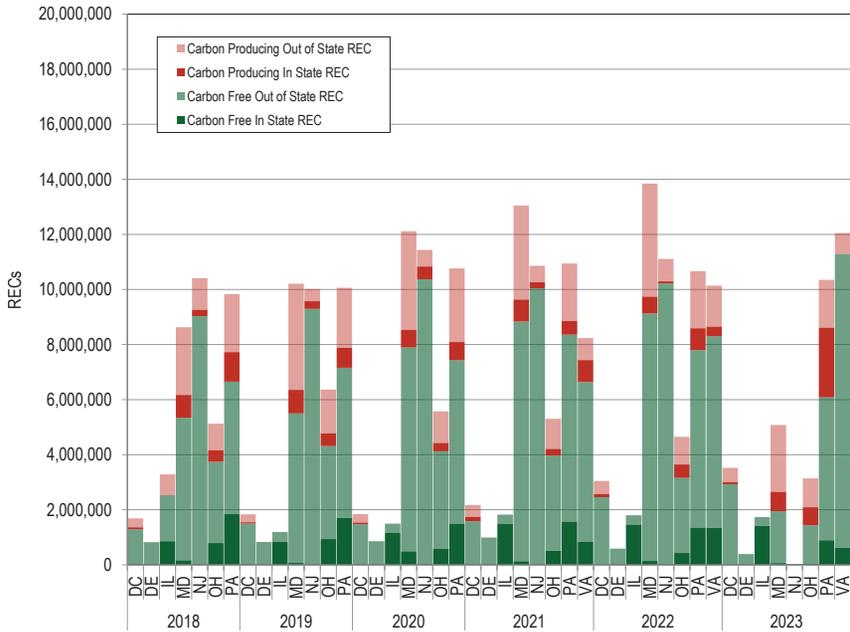


Table 8-16 State fulfillment of Tier I equivalent RPS: 2019 through 2023

Year	REC Type	Carbon Free REC				Carbon Producing REC			
		In State	Other PJM State	Non PJM State	Total	In State	Other PJM State	Non PJM State	Total
2019	DE New Eligible	0.3%	99.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	16.2%	65.3%	81.5%	2.8%	4.2%	11.5%	18.5%
	OH Renewable Energy Source	14.7%	53.0%	0.0%	67.7%	7.3%	25.0%	0.0%	32.3%
	IL Renewable	70.5%	29.5%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	0.7%	49.8%	3.4%	53.8%	8.4%	37.8%	0.0%	46.2%
	NJ Class I	0.1%	91.0%	1.7%	92.8%	2.8%	4.4%	0.0%	7.2%
	PA Tier I	17.0%	54.2%	0.0%	71.1%	7.2%	21.7%	0.0%	28.9%
2020	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	25.5%	54.6%	80.1%	3.3%	2.8%	13.8%	19.9%
	OH Renewable Energy Source	10.5%	61.4%	2.0%	74.0%	5.5%	20.6%	0.0%	26.0%
	IL Renewable	78.3%	21.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	4.1%	60.4%	0.7%	65.1%	5.3%	29.6%	0.0%	34.9%
	NJ Class I	0.1%	89.1%	1.6%	90.7%	4.0%	5.3%	0.0%	9.3%
	PA Tier I	13.9%	55.1%	0.0%	69.0%	6.2%	24.8%	0.0%	31.0%
2021	DE New Eligible	0.3%	99.0%	0.0%	99.3%	0.7%	0.0%	0.0%	0.7%
	DC Tier I	0.0%	27.0%	45.9%	72.9%	7.4%	1.7%	17.9%	27.1%
	OH Renewable Energy Source	9.6%	58.3%	7.0%	74.9%	4.4%	20.7%	0.0%	25.1%
	IL Renewable	81.0%	19.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	66.2%	0.5%	67.7%	6.1%	26.1%	0.0%	32.3%
	NJ Class I	0.1%	91.0%	1.4%	92.4%	2.0%	5.5%	0.0%	7.6%
	PA Tier I	14.4%	62.0%	0.0%	76.4%	4.6%	19.1%	0.0%	23.6%
VA Renewable	10.1%	70.6%	0.0%	80.6%	9.7%	9.6%	0.0%	19.4%	
2022	DE New Eligible	0.9%	99.1%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	26.0%	54.8%	80.8%	3.7%	6.8%	8.7%	19.2%
	OH Renewable Energy Source	9.3%	35.6%	23.0%	67.9%	10.5%	21.6%	0.0%	32.1%
	IL Renewable	81.3%	18.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.0%	64.7%	0.2%	65.9%	4.4%	29.7%	0.0%	34.1%
	NJ Class I	0.2%	90.7%	1.0%	92.0%	0.7%	7.4%	0.0%	8.0%
	PA Tier I	12.7%	60.4%	0.0%	73.1%	7.4%	19.4%	0.0%	26.9%
VA Renewable	13.3%	68.7%	0.0%	82.0%	3.4%	14.6%	0.0%	18.0%	
2023	DE New Eligible	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	29.1%	53.9%	83.0%	2.2%	6.4%	8.5%	17.0%
	OH Renewable Energy Source	1.4%	37.5%	6.8%	45.7%	20.8%	33.5%	0.0%	54.3%
	IL Renewable	81.6%	18.4%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	1.2%	36.9%	0.2%	38.3%	13.9%	47.8%	0.0%	61.7%
	NJ Class I	0.0%	90.0%	0.0%	90.0%	10.0%	0.0%	0.0%	10.0%
	PA Tier I	8.6%	50.2%	0.0%	58.8%	24.5%	16.8%	0.0%	41.2%
VA Renewable	5.1%	88.6%	0.0%	93.7%	0.0%	6.3%	0.0%	6.3%	

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 took effect in 2021 with an original requirement that 1.37 percent of load be served by offshore wind.²⁰⁸ The standard has been revised to 0.14 percent for 2024.²⁰⁹ The offshore wind requirement is only applicable if the Maryland offshore wind projects are producing RECs.²¹⁰

208 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>>.

209 See *Renewable Energy Portfolio Standard Report* at 5, Maryland Public Service Commissions (November 2023) <https://www.psc.state.md.us/wp-content/uploads/CY22-RPS-Annual-Report_Final-w-Corrected-Appdx-A.pdf>.

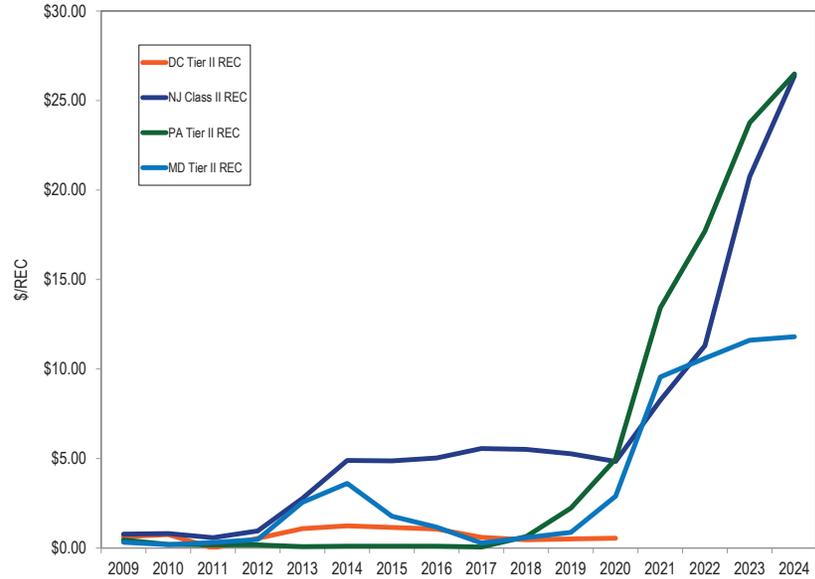
210 Id. at footnote 13.

Table 8-17 Additional renewable standards of PJM jurisdictions: 2023 to 2033²¹¹

Jurisdiction	Type of Standard	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Maryland	Off Shore Wind	0.00%	0.14%	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.05%	0.15%	0.25%	0.50%	0.75%	1.00%	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%	0.20%	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%

Figure 8-5 shows the annual average Tier II REC price by jurisdiction for 2009 through September 2024. Tier II prices have been lower than Tier I REC prices in the past, but Pennsylvania and New Jersey Tier II REC prices are higher than their corresponding Tier I REC prices over the first nine months of 2024. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2024.²¹² The average Pennsylvania Tier II REC price for the first nine months of 2024 was \$26.42, 33.1 percent higher than the average price for the first nine months of 2023. The average New Jersey Class II REC price for the first nine months of 2024 was \$26.38, 33.5 percent higher than the average price for the first nine months of 2023. The average Maryland Tier II REC price for the first nine months of 2024 was \$11.80, 14.4 percent higher than the average price for the first nine months of 2023.²¹³

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through September 2024



211 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
 212 The District of Columbia dropped Tier II RECs from their RPS in 2021.
 213 Tier II REC price information obtained through Evolution Markets, Inc.

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.²¹⁴

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.²¹⁵ On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.²¹⁶ 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 2026.²¹⁷ 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 2032.²¹⁸ 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.²¹⁹ 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 2035.²²⁰

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2023 to 2033^{221 222}

Jurisdiction with RPS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Delaware	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%	7.40%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750	24,750
Maryland	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%	14.50%
New Jersey	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	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%	6.00%

Figure 8-6 shows the annual average solar REC (SREC) price by jurisdiction for 2009 through September 2024. The average NJ SREC price was \$191.77 for the first nine months of 2024. 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 \$379.91 for the first nine months of 2024, an 8.2 percent decrease compared to the DC SREC price for the first nine months of 2023.²²³ The solar alternative compliance payment (SACP) level dropped from \$500 to \$400 for the 2024 compliance year.

214 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.
 215 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).
 216 "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>>.
 217 "NJBP 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>>.
 218 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_11.PDF>.

219 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>>.
 220 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <<https://legis.delaware.gov/BillDetail?legislationId=48278>>.
 221 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.
 222 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
 223 Solar REC average price information obtained through Evolution Markets, Inc. <<http://www.evomarkets.com>>.

Figure 8-6 Average SREC price by jurisdiction: 2009 through September 2024

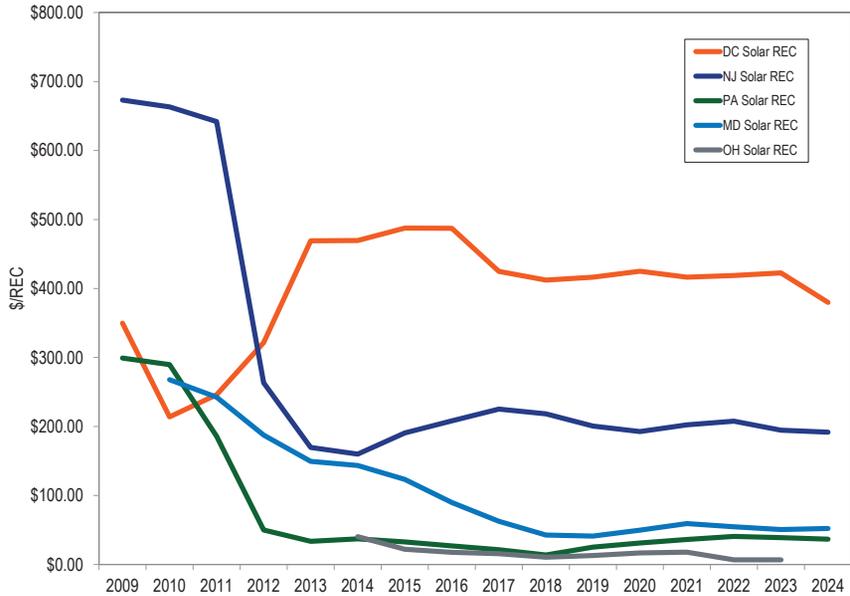


Figure 8-7 State fulfillment of Solar RPS: 2017 through 2023

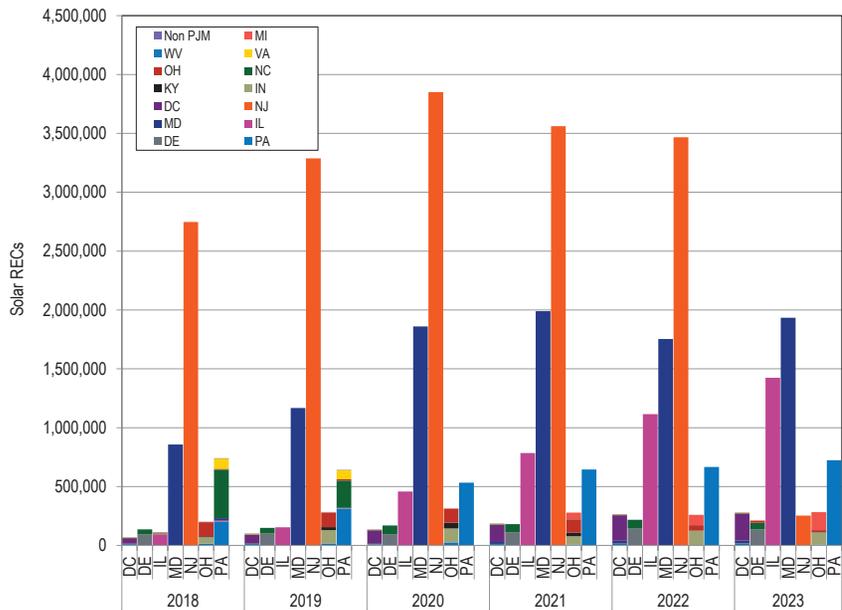


Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states’ solar requirement for 2018 through 2023.²²⁴ Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-19 shows the percent of local SRECs, SRECs from other PJM states and SRECs from non PJM states 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.

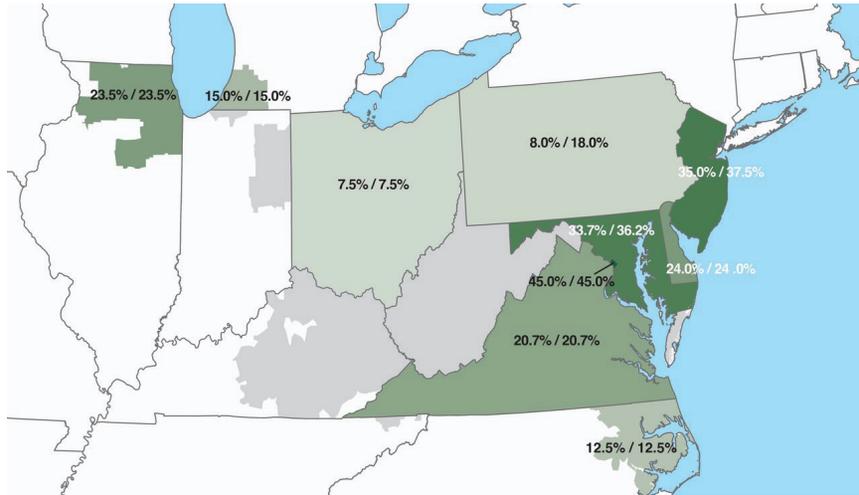
²²⁴ Retired REC information obtained through PJM GATS <<https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>> (Accessed July 15, 2024). The timing of the REC retirement reports varies by state and the 2023 reporting year data is incomplete for some states.

Table 8-19 State fulfillment of Solar RPS: 2018 through 2023

		In State	Other PJM State	Non PJM State
2018	DC Solar	67.4%	31.7%	0.9%
	DE Solar Eligible	67.7%	32.3%	0.0%
	IL Solar Renewable	82.9%	17.0%	0.1%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%	0.0%
	PA Solar	27.1%	72.9%	0.0%
2019	DC Solar	72.4%	26.9%	0.7%
	DE Solar Eligible	67.8%	32.2%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	43.6%	56.4%	0.0%
	PA Solar	48.8%	51.2%	0.0%
2020	DC Solar	81.5%	18.1%	0.4%
	DE Solar Eligible	56.7%	43.3%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2021	DC Solar	78.0%	21.6%	0.3%
	DE Solar Eligible	62.3%	37.7%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2022	DC Solar	81.9%	17.9%	0.2%
	DE Solar Eligible	65.8%	34.2%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	17.3%	82.7%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2023	DC Solar	82.2%	17.6%	0.3%
	DE Solar Eligible	63.7%	36.3%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	6.2%	93.8%	0.0%
	PA Solar	100.0%	0.0%	0.0%

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I where defined, or renewable energy resources where tiers are not defined; 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: January through September, 2024²²⁵



Under the existing state renewable portfolio standards, 18.3 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2024. 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 nine months of 2024, only 8.9 percent of PJM generation was produced by 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, 25.4 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 16.0 percent of PJM load should have been served by Tier I or renewable energy resources in the first nine months of 2024. In the first nine months of 2024, only 6.8 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 nine months of 2023, and LSEs

²²⁵ 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.

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 nine months of 2024. Wind generation accounted for 21,814.7 GWh of the 43,929.0 Tier I GWh, or 49.7 percent. As shown in Table 8-20, 57,686.7 GWh were generated by Tier I and Tier II resources, of which Tier I resources accounted for 76.2 percent. Wind and solar generation (noncarbon producing) was 5.5 percent of total generation in PJM in the first nine months of 2024. Tier I generation was 6.8 percent of total generation in PJM and Tier II was 2.1 percent of total generation in PJM in the first nine months of 2024. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 14,149.8 GWh, or 24.5 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 September, 2024

Jurisdiction	Tier I						Tier II					Total Tier II Credit	Total Credit GWh
	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal		
Delaware	0.0	7.2	0.0	0.0	79.3	0.0	86.6	0.0	0.0	0.0	0.0	0.0	86.6
Illinois	0.0	48.8	0.0	0.0	164.9	10,861.7	11,075.4	0.0	0.0	0.0	0.0	0.0	11,075.4
Indiana	0.0	14.7	0.0	29.0	850.9	4,576.5	5,471.2	0.0	0.0	0.0	0.0	0.0	5,471.2
Kentucky	0.0	0.0	183.5	52.2	144.2	0.0	379.9	0.0	0.0	0.0	0.0	0.0	379.9
Maryland	0.0	21.7	0.0	0.0	686.8	525.2	1,233.8	0.0	0.0	813.5	0.0	813.5	2,047.3
Michigan	0.0	41.5	0.0	47.8	5.6	0.0	95.0	0.0	0.0	0.0	0.0	0.0	95.0
New Jersey	0.0	86.8	3.5	0.0	734.4	7.3	832.1	492.1	0.0	986.2	0.0	1,478.3	2,310.4
North Carolina	0.0	0.0	498.3	0.0	1,853.0	376.7	2,728.0	0.0	0.0	0.0	0.0	0.0	2,728.0
Ohio	0.0	60.2	611.6	0.0	3,414.5	1,941.6	6,028.1	0.0	0.0	0.0	0.0	0.0	6,028.1
Pennsylvania	0.0	205.9	3,781.7	16.2	807.4	2,222.7	7,034.0	2,203.7	0.0	961.2	4,255.9	7,420.8	14,454.8
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	997.9	328.1	694.3	50.3	4,919.0	37.3	7,026.9	2,123.4	1,443.3	16.4	0.0	3,583.1	10,610.0
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	22.4	491.8	0.0	158.5	1,265.6	1,938.3	0.0	0.0	0.0	462.0	462.0	2,400.3
Total	997.9	837.4	6,264.7	195.5	13,818.6	21,814.7	43,929.0	4,819.2	1,443.3	2,777.3	4,718.0	13,757.7	57,686.7

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first nine months of 2024, Tier I generation in PJM met only 45.9 percent of the Tier I RPS requirements. Table 8-21 compares each state's RPS requirement for the first nine months of 2024 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 70.0 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 77.9 percent of the Tier I RPS requirement and 65.7 percent of the Tier II RPS requirement. North Carolina generation exceeded the RPS requirement in the first nine months of 2024 by 665.2 percent; but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation by PJM generators to meet 45.9 percent of the Tier I RPS requirement and 98.9 percent of the Tier II RPS requirement for the first nine months of 2024. RPS compliance reports indicate that almost all of the RPS requirement is met with the purchase or acquisition of RECs, with only a very small amount of the requirement fulfilled through alternative compliance payments. A large portion of the Tier I RPS requirement is satisfied by behind the meter generation in the PJM states and to a lesser extent, through the purchase of RECs from non PJM states.

Table 8-21 RPS Requirements and Generation by RPS Eligible Resources: January through September, 2024

Jurisdiction	Tier I			Tier II		
	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	86.6	2,185.0	4.0%	0.0	0.0	
Illinois	11,075.4	15,811.9	70.0%	0.0	0.0	
Indiana	5,471.2	0.0		0.0	0.0	
Kentucky	379.9	0.0		0.0	0.0	
Maryland	1,233.8	15,747.9	7.8%	813.5	1,168.2	69.6%
Michigan	95.0	505.4	18.8%	0.0	0.0	
New Jersey	832.1	18,038.7	4.6%	1,478.3	1,450.6	101.9%
North Carolina	2,728.0	410.1	665.2%	0.0	0.0	
Ohio	6,028.1	9,016.1	66.9%	0.0	0.0	
Pennsylvania	7,034.0	9,031.1	77.9%	7,420.8	11,288.9	65.7%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	7,026.9	21,600.8	32.5%	3,583.1	0.0	
Washington, D.C.	0.0	3,389.1	0.0%	0.0	0.0	
West Virginia	1,938.3	0.0		462.0	0.0	
Total	43,929.0	95,736.0	45.9%	13,757.7	13,907.7	98.9%

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, 4,000.7 MW, or 32.3 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,531.8 MW, or 74.2 percent of the total wind capacity.

Under the pre ELCC rules that were in effect up to 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.²²⁶ An average ELCC method was used to determine the capacity values for intermittent and storage resources for the 2023/2024 Delivery Year and the 2024/2025 Delivery Year.²²⁷ As of September 30, 2024, the derated capacity with capacity obligations in the PJM Capacity Market totaled 1,717.1 MW for wind generators and 4,362.3 MW for solar generators. This compares to installed wind capacity of 11,493.5 MW and installed solar capacity of 12,400.9 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.

There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.

²²⁶ See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <<https://pjm.com/-/media/documents/manuals/m21.ashx>>.

²²⁷ See Capacity Value of Intermittent Resources (ELCC) in 2024 Quarterly State of the Market Report for PJM: January through March, Section 5: Capacity Market.

Table 8-22 Renewable capacity by jurisdiction (MW): September 30, 2024²²⁸

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / CMG	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	0.0	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	0.0	136.3	0.0	0.0	0.0	5,135.7	5,287.0
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	939.0	0.0	0.0	0.0	2,350.5	3,300.8
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	145.2	0.0	0.0	0.0	0.0	277.9
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	0.0	69.0	0.0	0.0	615.3	191.2	0.0	0.0	243.7	1,139.1
Michigan	0.0	0.0	13.9	12.0	0.0	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	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	33.9	0.0	0.0	0.0	0.0	0.0	453.0	748.9	204.6	0.0	0.0	4.5	1,455.7
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,658.6	0.0	0.0	0.0	208.0	2,191.6
Ohio	0.0	1,020.0	194.4	14.4	0.0	0.0	1.0	136.0	0.0	0.0	3,097.8	0.0	0.0	134.0	1,045.6	5,643.2
Pennsylvania	54.0	0.0	1,387.3	111.0	1,105.0	1,300.0	0.0	0.0	0.0	1,269.0	875.6	209.3	1,347.0	0.0	1,545.2	9,203.3
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	0.0
Virginia	241.9	585.0	436.4	127.7	0.0	0.0	88.0	10.0	0.0	5,386.0	4,000.7	60.0	0.0	0.0	12.0	10,947.6
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	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	0.0	129.0	0.0	96.0	0.0	802.3	1,245.2
PJM Total	295.9	1,605.0	2,718.7	353.1	1,105.0	3,097.0	89.0	215.0	13.0	7,108.0	12,400.9	665.0	1,443.0	134.0	11,493.5	42,736.1

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.²²⁹ For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels was 50.0 percent, the ELCC rating for solar generators with tracking panels was 61.0 percent, and the ELCC rating for onshore wind generators was 15.0 percent.²³⁰ For the 2024/2025 Delivery Year, the ELCC rating for solar generators with fixed panels is 33.0 percent, the ELCC rating for solar generators with tracking panels is 50.0 percent, and the ELCC rating for onshore wind generators is 21.0 percent.

Table 8-23 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).²³¹ These resources are not PJM wholesale market 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 wholesale market units. These nonwholesale resources include solar capacity of 12,115.1 MW of which 3,909.4 MW are in New Jersey. These nonwholesale resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are also 1,933.5 MW of GATS capacity located in jurisdictions outside PJM that are eligible to sell RECs in at least one PJM jurisdiction.

²²⁸ "Renewable Generators Registered in GATS", PJM EIS <<https://www.pjm-eis.com/reports-and-events/public-reports>>. Capacity in ICAP.

²²⁹ Id.

²³⁰ *ELCC Class Ratings for 2023/2024 3IA, 2024/2026 BRA and 2026/2027 BRA*, PJM Interconnection, LLC. (January 6, 2023) <<https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>>.

²³¹ 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): September 30, 2024²³²

Jurisdiction	Biofuel	Coal / Biofuel		Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation		Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total	
		Fuel Cell					Gas / CMG	Other Gas							
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	4.2	0.0	0.0	0.0	175.7	0.0	0.0	2.0	181.9	
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	0.0	152.2	0.0	0.0	0.0	179.3	
Illinois	0.0	0.0	0.0	0.0	20.0	43.8	0.0	0.0	2.2	1,785.3	0.0	0.0	398.4	2,249.6	
Indiana	0.0	0.0	0.0	0.0	0.0	47.2	0.0	0.0	1.3	196.5	0.0	0.0	94.6	519.5	
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	0.0	2.1	0.0	0.0	495.6	499.3	
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.0	0.0	42.5	0.0	0.0	0.0	920.6	
Maryland	18.5	0.0	0.0	67.9	0.4	10.7	0.0	0.0	0.0	1,651.9	10.0	0.0	0.3	1,759.6	
Michigan	31.0	0.0	0.0	0.0	21.3	5.6	0.0	0.0	0.0	114.8	0.0	0.0	6.8	179.5	
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	0.0	61.2	0.0	0.0	693.0	759.8	
New Jersey	0.0	0.0	0.0	0.0	0.0	11.1	0.0	0.0	15.4	3,909.4	0.0	0.0	3.1	3,939.0	
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.4	
North Carolina	151.5	0.0	0.0	0.0	430.4	0.0	0.0	0.0	0.0	1,310.7	0.0	0.0	0.0	1,892.6	
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	0.0	47.2	337.9	0.0	0.0	34.0	596.0	
Pennsylvania	62.2	109.7	2.3	0.0	56.5	43.2	0.0	35.6	99.8	1,009.0	0.2	474.2	57.6	1,953.4	
South Carolina	0.0	0.0	0.0	0.0	63.0	26.6	0.0	0.0	0.0	91.3	0.0	0.0	0.0	180.9	
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	
Virginia	287.6	0.0	0.0	0.0	31.3	6.7	0.0	0.0	3.5	983.5	20.0	0.0	0.0	1,332.6	
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	245.4	0.0	0.0	27.7	322.5	
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	0.0	45.3	0.0	0.0	0.0	147.3	
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	44.7	
Total	835.1	709.7	2.3	67.9	932.2	273.2	0.0	35.6	218.7	12,115.1	30.2	474.2	213.9	2,200.2	18,108.5

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.²³³ 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, 2014.²³⁴ This is equivalent to providing a REC price equal to three times its stated value per MWh.

²³² 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 15, 2024).

²³³ 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"); 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 Alco Finance Limited*, 156 FERC ¶ 61,042 (2016).

²³⁴ Delaware Code, Title 26, Chapter 1, Subchapter III-A, Section 356(a).

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 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 established 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.

In addition, 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, deliverability must be demonstrated 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, generally function as a cap on the market value of RECs, although in Pennsylvania the solar ACP is dependent upon the price of solar RECs retired during the year. In New Jersey, solar ACPs are currently \$208 per MWh.²³⁵ In Pennsylvania, the ACP for tier I and tier II RECs is \$45 per MWh and the solar ACPs is 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates in other PJM states. The most recent ACP for Pennsylvania solar is \$84.96.²³⁶ Delaware recently reduced the solar ACP from \$400 per credit to \$150 per credit.²³⁷ Maryland reduced the solar ACP from \$100 per credit to \$60 per credit effective June 1, 2021.²³⁸ The Washington DC solar ACP was reduced from \$500 per credit to \$400 per credit for 2024.²³⁹

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.

²³⁵ N.J. S. 2314/A. 3723.
²³⁶ See AEPs History Pricing report at the AEPs website <<https://pennaeps.com/reports/>> (Accessed May 2, 2024).
²³⁷ See Senate Bill 33, Delaware General Assembly (February 10, 2021) <<https://legis.delaware.gov/BillDetail?legislationId=48278>>.
²³⁸ Renewable Energy Portfolio Standard Report with Data for Calendar Year 2022 at 6, Maryland Public Service Commission (November 30, 2023) <<https://www.psc.state.md.us/commission-reports/>>.
²³⁹ Renewable Energy Portfolio Standards A Report for Compliance Year 2023 at 26, Public Service Commission District of Columbia (May 1, 2024) <<https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>>.

Table 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of September 30, 2024^{240 241}

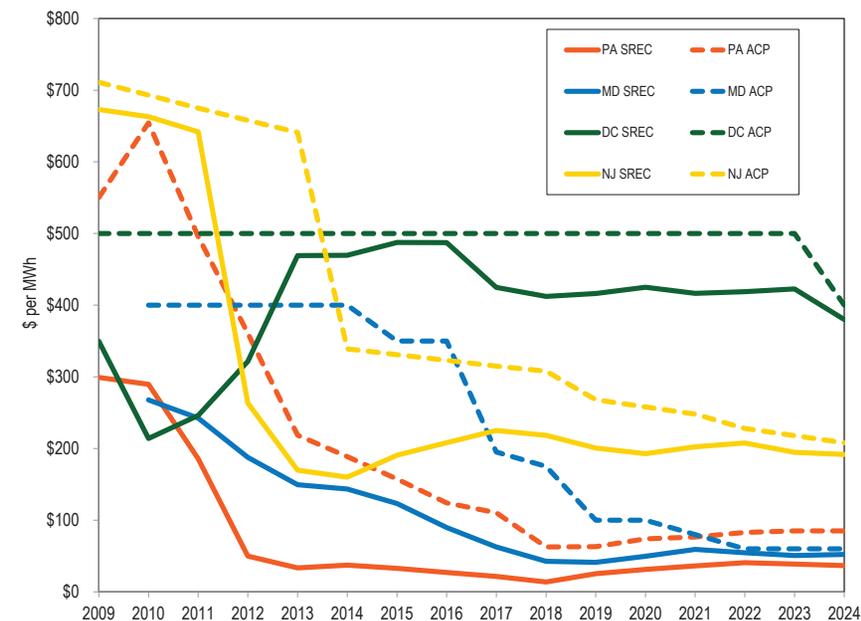
Jurisdiction with RPS	Standard Alternative Compliance (\$/MWh)	Tier II Alternative Compliance (\$/MWh)	Solar Alternative Compliance (\$/MWh)
Delaware	\$25.00		\$150.00
Illinois	\$0.35		
Maryland	\$27.50	\$15.00	\$60.00
Michigan	No specific penalties		
New Jersey	\$50.00	\$50.00	\$208.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	\$56.99		
Pennsylvania	\$45.00	\$45.00	\$84.96
Washington, D.C.	\$50.00	\$10.00	\$400.00
Jurisdiction with Voluntary Standard			
Indiana	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.

²⁴⁰ 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/>>.

²⁴¹ The entry for Pennsylvania reflects the solar ACP for 2023. See “Pricing,” <<https://www.pennaeps.com/reports/>> (Accessed May 2, 2024).

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through September 2024



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 the 2022/2023 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in May 2024.²⁴² Pennsylvania reported that the 679,794 SRECs, 10,651,534 Tier I RECs and 13,595,818 Tier II RECs were retired during the 2022/2023 reporting year

²⁴² “Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2022-23,” (May 2024), <<https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>>

(June 1, 2022 through May 31, 2023). Supplier obligations for 38 SRECs, 760 Tier I RECs and 952 Tier II RECs required ACPs.

The Public Service Commission of the District of Columbia reported that 278,200 SRECs and 3,525,332 Tier I RECs were retired during the 2023 compliance year. The average price for solar RECs was \$415.35. ACPs increased from \$72,250 for 2022 to \$1.8 million for 2023.²⁴³

The Public Service Commission of Maryland reported that 1,752,987 SRECs were retired in 2022, a decrease of 11.8 percent compared to the 2021 level. Tier 1 REC retirements increased to 13,849,611, 6.2 percent higher than in 2021.²⁴⁴ Tier 1 ACPs, including the SACPs, totaled \$86.5 million, an increase of 12.2 percent over the 2021 total.

The Public Utilities Commission of Ohio reported that 7,202,488 RECs were retired in the 2022 compliance year, which is 7.4 percent higher than the number of RECs retired in 2021.²⁴⁵

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. The Delmarva report provides limited public information on RPS compliance cost.²⁴⁶ Delmarva reports \$13.0 million in ACPs but no other compliance cost information is available.

The Illinois Power Agency (IPA) reported delivery of ComEd RECs totaling 3,797,777 at an average price of \$16.27.²⁴⁷

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2020 compliance report on August 10, 2021. The compliance report stated that Dominion met its general RPS requirement by purchasing 427,657 credits that consisted of wind and biomass RECs and

energy efficiency credits (EECs).²⁴⁸ Dominion met its solar requirement of 8,562 RECs, poultry waste requirement of 22,311 RECs, and swine waste requirement of 2,997 RECs through REC purchases. Dominion North Carolina's total REC requirements for 2020 increased 4.9 percent over 2019.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2020 standard by generating or acquiring 315,384 RECs.²⁴⁹

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2022.²⁵⁰ Electric power suppliers retired 10,863,600 class I RECs and 1,828,092 class II RECs. Suppliers submitted 247 class I ACPs and 50 class II ACPs at a cost of \$50 per MWh. Electric power suppliers retired 3,560,641 solar RECs and 458,388 SACPs were submitted at a cost of \$238 per MWh. Additionally, 469,621 transition RECs were retired and 2,910 SREC II were retired.^{251 252}

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.²⁵³ 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 \$11.8 billion over the nine year period from 2014 through 2022 for the ten jurisdictions that had RPS and reported compliance costs.²⁵⁴ The average RPS compliance cost per year based on the reported compliance cost for the nine year period from 2014 through 2022 was \$1.3 billion. The compliance cost for 2022, the most recent year with almost complete data, was \$2.4 billion.

243 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2023," Public Service Commission of the District of Columbia (May 1, 2024), <<https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>>.

244 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2022," Public Service Commission of Maryland (November 30, 2023) at 9, <<https://www.psc.state.md.us/commission-reports/>>.

245 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2022," Public Utilities Commission of Ohio (April 17, 2024), <<https://puco.ohio.gov/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>>.

246 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2022–May 31, 2023," Delmarva Power, (Sept. 29, 2023), <<https://dcpdc.delaware.gov/rps-and-green-power-product-compliance/>>.

247 "Annual Report Fiscal Year 2023," Illinois Power Agency (Feb. 15, 2024), <<https://ipa.illinois.gov/about-ipa/ipa-publications.html>>.

248 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2021) at 41, <<https://www.ncuc.gov/newsroom.html>>.

249 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 15, 2022), <<https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports>>.

250 See EY22 RPS Compliance Results (2004 to 2022), New Jersey's Clean Energy Program (2023), <<http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>>.

251 "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>>.

252 "NJBP 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>>.

253 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

254 The actual PJM RPS compliance cost exceeds the reported \$9.4 billion due to incomplete data. The compliance cost value for 2020 and 2021 does not include Michigan or North Carolina. Based on past data these states generally account for less than 0.5 percent of the total RPS compliance cost of PJM states. The \$9.4 billion cost also does not fully reflect the overhead and administrative costs associated with RPS programs.

Table 8-27 RPS Compliance Cost^{255 256 257 258 259 260 261 262 263 264 265}

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	Total RPS		\$16,013,421	\$18,409,631	\$18,772,855	\$18,341,916	\$19,401,476	\$21,133,971	\$25,550,239	
	Solar		\$7,070,254	\$7,748,073	\$7,105,726	\$6,565,240	\$8,121,914	\$9,096,298	\$9,567,891	
	Non-Solar		\$8,943,167	\$10,661,557	\$11,667,129	\$11,776,676	\$11,279,562	\$12,037,673	\$15,982,348	
Illinois	Total RPS	\$21,701,688	\$24,817,068	\$25,718,863	\$25,919,372	\$25,775,523	\$26,971,638	\$34,726,109	\$52,555,157	\$73,185,068
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	\$438,832,999
	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	\$187,244,056
	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	\$247,158,373
	Tier II	\$3,991,322	\$2,619,432	\$1,441,446	\$688,040	\$1,049,428	\$118,031	\$408,760	\$970,684	\$4,430,570
Michigan	Total RPS	\$476,535	\$0	\$3,264,504	\$3,961,262	\$3,264,504	\$3,376,773	\$5,379,970		
New Jersey	Total RPS	\$395,782,297	\$524,761,382	\$593,441,037	\$606,312,461	\$653,810,457	\$763,108,366	\$970,177,803	\$1,140,654,336	\$1,236,035,486
	Solar	\$322,504,920	\$417,359,783	\$481,540,738	\$503,797,182	\$560,509,712	\$667,975,153	\$822,247,072	\$946,434,884	\$959,987,769
	Class I	\$66,071,749	\$98,185,431	\$100,910,465	\$91,872,615	\$83,474,335	\$85,522,028	\$130,272,633	\$171,818,089	\$241,810,299
	Class II	\$7,205,628	\$9,216,167	\$10,989,834	\$10,642,664	\$9,826,410	\$9,611,185	\$17,658,099	\$22,401,364	\$34,237,418
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	\$82,434,054	\$67,598,725
	Solar	\$17,666,730	\$14,843,052	\$11,564,584	\$9,435,730	\$9,419,092	\$9,578,048	\$0	\$0	\$0
	Non-Solar	\$24,914,747	\$27,741,181	\$26,066,897	\$30,508,106	\$40,795,431	\$60,234,672	\$81,752,397	\$82,434,054	\$67,598,725
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	\$461,430,587
	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	\$28,464,498
	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	\$224,782,412
	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	\$208,183,678
Washington D.C.	Total RPS	\$27,373,000	\$38,541,000	\$47,163,000	\$42,700,000	\$50,600,000	\$57,300,000	\$65,000,000	\$99,100,000	\$129,200,000
	Solar	\$25,145,000	\$36,523,000	\$44,898,000	\$31,800,000	\$42,800,000	\$50,560,000	\$59,200,000	\$84,000,000	\$106,600,000
	Tier I	\$2,141,000	\$1,901,000	\$2,131,500	\$10,500,000	\$7,600,000	\$6,670,000	\$5,800,000	\$15,100,000	\$22,600,000
	Tier II	\$87,000	\$117,000	\$133,500	\$400,000	\$200,000	\$70,000	\$0	\$0	\$0
PJM	Total RPS	\$678,453,866	\$888,414,620	\$986,220,529	\$925,493,363	\$987,005,938	\$1,194,937,783	\$1,584,384,913	\$2,117,891,331	\$2,406,282,864

255 Several states have not released compliance reports for 2022.

256 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 28, 2022), <<https://depdc.delaware.gov/rps-and-green-power-product-compliance/>>

257 "Fiscal Year 2022 Annual Report," February 15, 2023, Illinois Power Agency (IPA), <<https://ipa.illinois.gov/about-ipa/ipa-publications.html>>.

258 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (November 30, 2023) at 9, <<https://www.psc.state.md.us/commission-reports/>>.

259 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2022, <<https://www.michigan.gov/mpsc/regulatory/reports/prior-renewable-reports>> 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.

260 "RPS Report Summary 2005-2022," New Jersey's Clean Energy Program, 2023, <<http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>>.

261 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2021," Public Utilities Commission of Ohio, March 22, 2023, <<https://puc.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>>.

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

263 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2022," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2023, <<https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>>.

264 "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.

265 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.

Transco Regional Energy Access Expansion Project

By order issued January 11, 2023, FERC authorized a request filed by Transco to modify its gas pipeline system to increase its capacity by 829,400 Dth/day (.8 BCF/day) from the north east on its Leidy line to points in Pennsylvania, New Jersey and Maryland. Transco planned to have service available at the end of the fourth quarter of 2023.²⁶⁶ In order to increase the capacity on the pipeline for this project Transco installed about 36 miles of new pipe, a new electric compressor station and modified five existing compressor stations. By letter dated July 26, 2024, FERC authorized Transco to commence service with facilities associated with the Regional Energy Expansion Project.²⁶⁷ The 829,400 Dth/Day would be enough to supply about five combined cycle power plants.²⁶⁸ On March 13, 2023, the New Jersey Division of Rate Counsel and New Jersey Conservation Foundation, et al., sought review in the United States Court of Appeals for the District of Columbia Circuit.²⁶⁹ The appeal primarily argues that FERC ignored evidence that “clearly demonstrated that the state of New Jersey does not need and will not benefit from the Project’s capacity.”²⁷⁰ On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the Certificate Orders.²⁷¹ On September 6, 2024 Transco filed an Application for Temporary Emergency Certificate so they could continue to provide service while this matter is resolved on remand.²⁷² Both PJM and the MMU submitted comments supporting the application.²⁷³

Mountain Valley Pipeline

“On October 23, 2015, Mountain Valley Pipeline (MVP) filed an application with FERC for approval to construct own and operate MVP.”²⁷⁴ On October 13, 2017, MVP received a certificate of convenience and necessity from FERC. The pipeline is approximately 303 miles long stretching from the Equitrans

²⁶⁶ See 182 FERC ¶ 61,006 (2023), *order on reh’g*, 182 FERC ¶ 61,148 (2023), *order on reh’g*, 183 FERC ¶ 61,071 (2023).

²⁶⁷ See Letter: Authorization to Commence Service, FERC Docket No. CP21-94-000.

²⁶⁸ See 2023 *Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, “Table 7-55 Gas pipeline capacity need to replace units at risk of retirement.” New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

²⁶⁹ Case No. 23-1064, et al.

²⁷⁰ New Jersey Conservation Foundation, et al. v. FERC, Proof Opening Brief of Petitioners, Case No. 23-1064 (D.C. Cir July 26, 2023).

²⁷¹ N.J. Conservation Foundation, et. al v. FERC, No. 23-1064 (July 30, 2024).

²⁷² See FERC Docket No. CP21-94-004.

²⁷³ See PJM Interconnection, LLC’s Comments in Support of the Application of Transcontinental Gas Pipe Line Company, LLC for a Temporary Emergency Certificate, FERC Docket No. CP21-94-004 (October 7, 2024); Comments of the Independent Market Monitor for PJM, FERC Docket No. CP21-94-004 (October 8, 2024).

²⁷⁴ Mountain Valley Pipeline <<https://www.mountainvalleypipeline.info/>> [Accessed July 26, 2024].

Transmission system in Wentzel County West Virginia to Transco Zone 5 station 165 in Pittsylvania County Virginia. The capacity of the pipeline is approximately 2 BCF per day. On June 14, 2024, MVP entered service.²⁷⁵ The 2,000,000 Dth/Day would be enough to supply about eleven combined cycle power plants.²⁷⁶

Transco Southeast Supply Enhancement

On May 24, 2024, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a general project description draft of the proposed Southeast Supply Enhancement Project. This project is an expansion of the Transco system in southern Virginia, North Carolina, South Carolina, Georgia and Alabama. The total capacity will be 1,591,900 Dth/Day from Transco Station 165 Zone 5 and the interconnection with Mountain Valley and points south to North Carolina, South Carolina, Georgia and Alabama. The proposal includes about 55 miles of new pipe and the addition of seven new compressors at existing compressor stations. The expected completion of the project is June 2028.²⁷⁷ The 1,591,900 Dth/Day would be enough to supply about eight combined cycle power plants.²⁷⁸

Transco Commonwealth Energy Connector Project

On August 24, 2022, Transcontinental Gas Pipe Line Company, LLC (Transco) filed a certificate of public convenience and necessity to construct the Commonwealth Energy Connector Project.²⁷⁹ The new capacity will be 105,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project is an expansion of the Transco system from Zone 5 Pooling point through Transco’s South Virginia Lateral which interconnects between Transco and Columbia Gas Transmission, LLC. Additional compression, about 3.6 miles of additional pipe and modifications and installation of new facilities at the Emporia M&R station will be completed to increase the capacity. The project

²⁷⁵ Mountain Valley Pipeline <<https://www.mountainvalleypipeline.info/>> [Accessed July 26, 2024].

²⁷⁶ See 2023 *Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue, “Table 7-55 Gas pipeline capacity need to replace units at risk of retirement.” New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

²⁷⁷ See Transcontinental Gas Pipe Line Company, LLC Southeast Supply Enhancement Project, Docket No. PF24-2-000, Draft Resource Reports 1-12 (May 24, 2024).

²⁷⁸ See 2023 *Annual State of the Market Report for PJM*, Volume 2: Section 7, Net Revenue: Table 7-55” New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

²⁷⁹ See FERC Docket No. CP22-502.

is expected to be completed by September 25, 2025. The 105,000 Dth per day would not be enough supply to run one combined cycle power plant.²⁸⁰

Columbia Gas Transmission Virginia Reliability Project

On August 24, 2022, Columbia Gas Transmission LLC (Columbia) filed an abbreviated application for the authority necessary to construct and operate its Virginia Reliability project. The new capacity will be 100,000 Dth/d which Virginia Natural Gas, Inc. (VNG) has contracted for. This project will replace 49 miles of existing pipe, modifications at two compressor stations, modifications to one receipt point and delivery point increasing service to Market Area 34. This will allow VNG to receive gas at the Transco Columbia interconnection and deliver to VNG. This capacity if projected to be available by November 1, 2025.²⁸¹ The 100,000 Dth per day would not be enough supply to run one combined cycle power plant.²⁸²

Texas Eastern Transmission Appalachia to Market II Project

On July 7, 2022, Texas Eastern Transmission, LP (Texas Eastern) filed an abbreviated Application for a Certificate of Public Convenience and Necessity to develop the Appalachia to Market II Project. Prior to the filing, Texas Eastern conducted a binding open season for 55,000 Dth/d that will be made available based on improvements to the Texas Eastern system. The additional capacity will run from Appalachia supply basin in southwest Pennsylvania to New Jersey. Two compressor stations (reducing air emissions with upgraded compression equipment) will be replaced and two miles of looping of pipe will be added. PSEG Power LLC and Elizabethtown Gas signed up for the 55,000 Dth/d. The project is expected to be completed by November 1, 2025.²⁸³ The 55,000 Dth per day would not be enough supply to run one combined cycle power plant.²⁸⁴

²⁸⁰ See 2023 Annual State of the Market Report for PJM, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

²⁸¹ See FERC Docket No. CP22-503.

²⁸² See 2023 Annual State of the Market Report for PJM, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

²⁸³ See FERC Docket No. CP22-486-000.

²⁸⁴ See 2023 Annual State of the Market Report for PJM, Volume 2: Section 7, Net Revenue, Table 7-55. New combined cycle unit ICAP 1,100 MW and fuel rate of 6.543 MMBtu/MWh.

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.²⁸⁵ 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.^{286 287}

Table 8-28 shows SO₂ emission controls by fossil fuel fired units in PJM.^{288 289} Coal has the highest SO₂ emission rate, while natural gas and diesel oil have lower SO₂ emission rates.²⁹¹ Of the current 41,597.9 MW of coal capacity in PJM, 40,523.9 MW of capacity, 97.4 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO₂ emissions.

Table 8-28 SO₂ emission controls by fuel type (MW): September 30, 2024²⁹²

	SO ₂ Controlled	No SO ₂ Controls	Total	Percent Controlled
Coal	40,523.9	1,074.0	41,597.9	97.4%
Diesel Oil	0.0	3,340.4	3,340.4	0.0%
Natural Gas	0.0	77,271.3	77,271.3	0.0%
Other	325.0	1,850.0	2,175.0	14.9%
Total	40,848.9	83,535.7	124,384.6	32.8%

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 41,597.9 MW of coal capacity in PJM,

²⁸⁵ See EPA, "National Ambient Air Quality Standards (NAAQS)," <<https://www.epa.gov/criteria-air-pollutants/naaqs-table>> (Accessed March 4, 2022).

²⁸⁶ 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).

²⁸⁷ On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO₂ emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020).

²⁸⁸ See EPA, "Air Market Programs Data," <<http://ampd.epa.gov/ampd/>> (Accessed March 4, 2022).

²⁸⁹ Air Markets Programs Data is submitted quarterly. Generators have 30 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 2022.

²⁹⁰ The total MW are less than the 177,006.9 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).

²⁹¹ 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).

²⁹² 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.

41,511.9 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.²⁹³

Table 8-29 NO_x emission controls by fuel type (MW): As of September 30, 2024

	NO _x Controlled	No NO _x Controls	Total	Percent Controlled
Coal	41,511.9	86.0	41,597.9	99.8%
Diesel Oil	1,020.3	2,320.1	3,340.4	30.5%
Natural Gas	76,178.3	1,093.0	77,271.3	98.6%
Other	775.0	1,400.0	2,175.0	35.6%
Total	119,485.5	4,899.1	124,384.6	96.1%

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 (2.1 percent) and units with other fuel sources (53.9 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.²⁹⁴ Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 41,597.9 MW of coal capacity in PJM, 41,512.9 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 September 30, 2024

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	41,512.9	85.0	41,597.9	99.8%
Diesel Oil	0.0	3,340.4	3,340.4	0.0%
Natural Gas	1,586.0	75,685.3	77,271.3	2.1%
Other	1,172.0	1,003.0	2,175.0	53.9%
Total	44,270.9	80,113.7	124,384.6	35.6%

293 See EPA, "Mercury and Air Toxics Standards, Cleaner Power Plants," <<https://www.epa.gov/mats/cleaner-power-plants#controls>> (Accessed May 7, 2020).

294 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 100 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for either SO₂ or particulate emissions control, representing all of the 41,597.9 MW total coal capacity.

Emissions

Figure 8-10 shows the total CO₂ emissions in short tons, the CO₂ emission rate in short tons per MWh within PJM for all CO₂ emitting units, for each quarter from 1999 to the third quarter of 2024, and the CO₂ emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2024.²⁹⁵

Figure 8-11 shows the total CO₂ emission in short tons on peak and off peak and the CO₂ emission rate in short tons per MWh for all CO₂ emitting units.

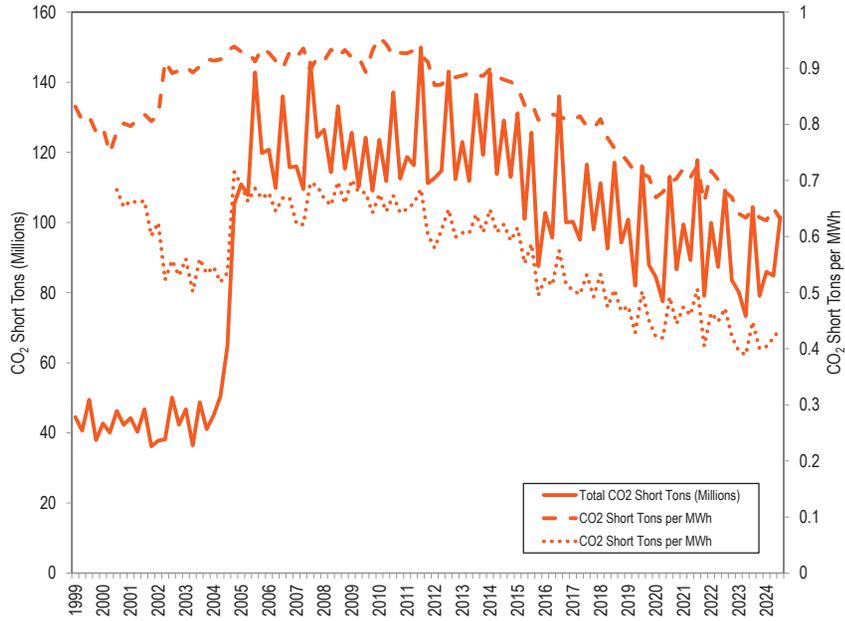
Table 8-31 shows the minimum and maximum CO₂ emission rates in short tons per MWh for all CO₂ emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the third quarter of 2024.

Total PJM generation decreased from 233,135.0 GWh in the third quarter of 2023 to 232,705.5 GWh in the third quarter of 2024, while CO₂ produced decreased from 104.4 million short tons in the third quarter of 2023 to 101.5 million short tons in the third quarter of 2024.²⁹⁶ The CO₂ emission rate averaged 0.70 short tons per MWh for all CO₂ emitting units in 2021, 0.69 short tons per MWh for all CO₂ emitting units in 2022, and 0.63 short tons per MWh for all CO₂ emitting units in 2023.

295 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

296 See the 2021 Annual State of the Market Report for PJM: Volume 2, Section 3: Energy Market, Table 3-10.

Figure 8-10 CO₂ emissions by quarter (millions of short tons), by PJM units: January 1999 through September 2024^{297 298}



In the third quarter of 2024, CO₂ emission rates were 0.63 short tons per MWh for all CO₂ emitting units for off peak hours, and 0.63 for on peak hours. Of the top 10 largest CO₂ emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.²⁹⁹

²⁹⁷ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

²⁹⁸ 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).

²⁹⁹ "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 CO₂ emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through September 2024³⁰⁰

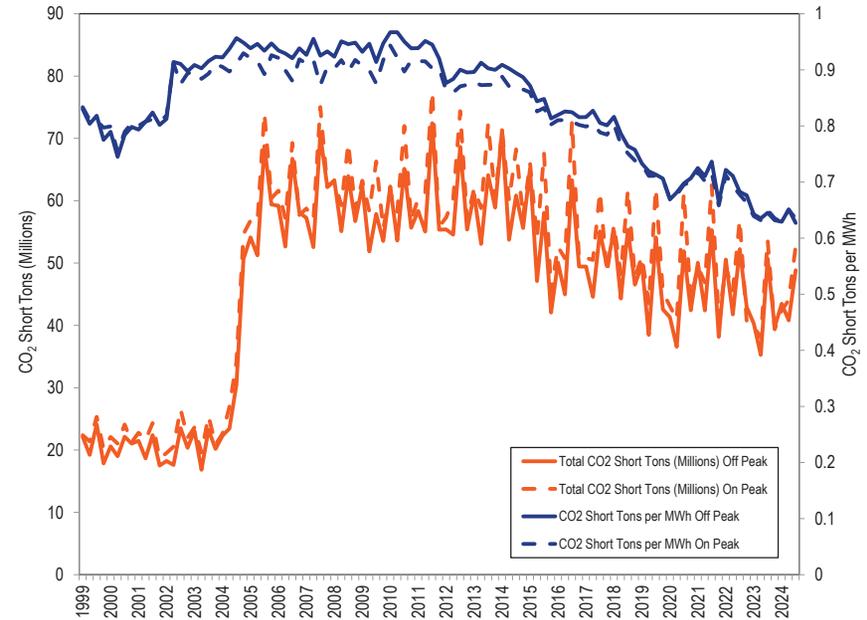


Table 8-31 Minimum and maximum CO₂ emissions per MWh: January 1999 through September 2024

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2024	1
	On Peak	0.63	2024	1
	Off Peak	0.63	2024	3
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

³⁰⁰ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

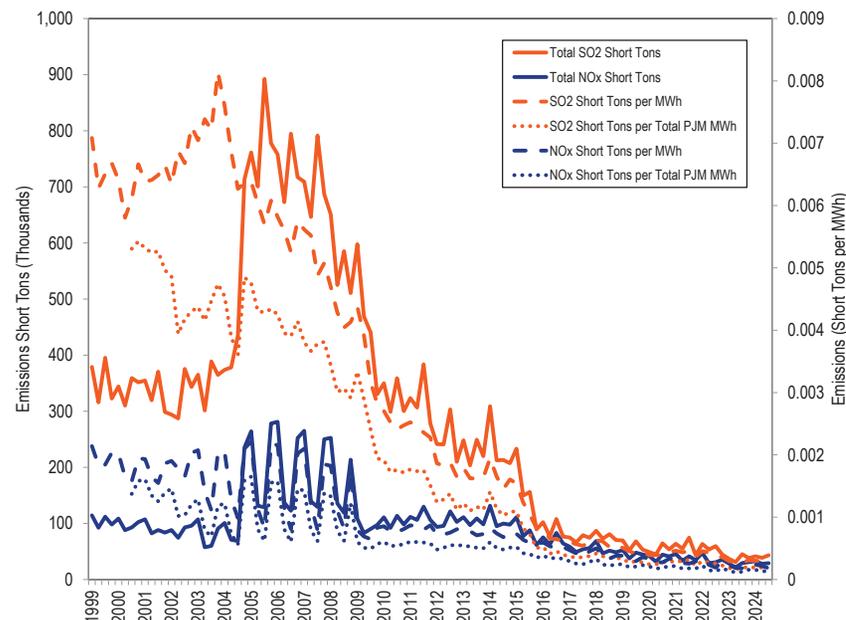
Figure 8-12 shows the total SO₂ and NO_x emissions and the emission rate in short tons per MWh for all SO₂ and NO_x emitting units, and the SO₂ and NO_x emission rate in short tons per MWh of total PJM generation. In the third quarter of 2024, the SO₂ emission rate was 0.000269 short tons per MWh for all SO₂ emitting units, and the NO_x emission rate was 0.000181 short tons per MWh for all NO_x emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO₂ and NO_x emissions and the emission rate in short tons per MWh for all SO₂ and NO_x emitting units. In the third quarter of 2024, SO₂ emission rates were 0.000255 short tons per MWh and 0.000283 short tons per MWh for all SO₂ units, for off and on peak hours. In the third quarter of 2024, NO_x emission rates were 0.000173 short tons per MWh and 0.000189 short tons per MWh for all NO_x emitting units, for off and on peak hours.

Table 8-32 shows the minimum and maximum SO₂ and NO_x emission rate in short tons per MWh for all SO₂ and NO_x emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the third quarter of 2024.

The consistent decline in SO₂ 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 2024.^{301 302}

Figure 8-12 SO₂ and NO_x emissions by quarter (thousands of short tons), by PJM units: January 1999 through September 2024³⁰³



³⁰¹ See EIA, "Changes in coal sector led to less SO₂ and NO_x emissions from electric power industry," <<https://www.eia.gov/todayinenergy/detail.php?id=37752>> (Accessed October 25, 2019).

³⁰² 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).

³⁰³ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-13 SO₂ and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through September 2024³⁰⁴

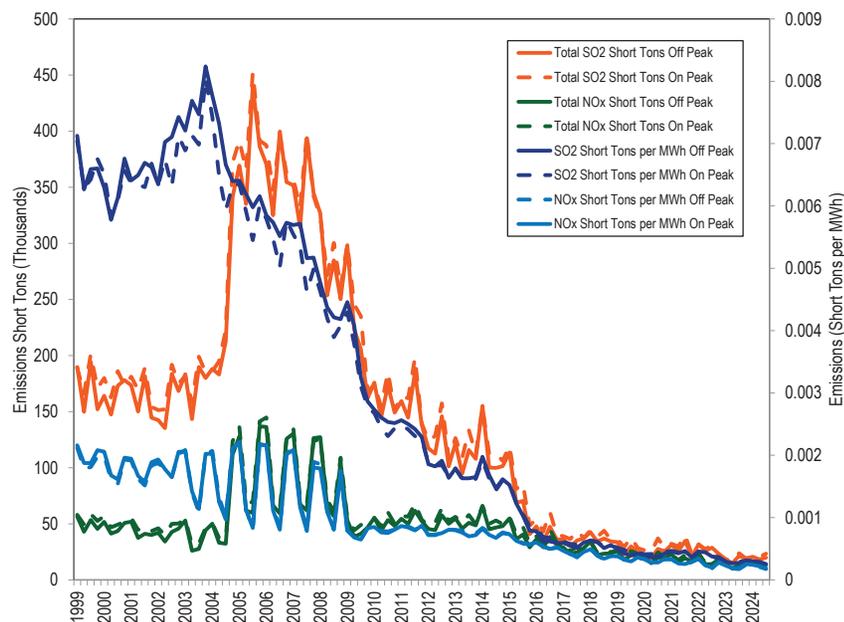


Table 8-32 Minimum and maximum SO₂ and NO_x emissions per MWh: January 1999 through September 2024

Emission Type	Short Tons per MWh			
		Year	Quarter	
SO ₂	Minimum	All hours	2023	2
		On Peak	2023	2
		Off Peak	2024	3
	Maximum	All hours	2003	4
		On Peak	2003	4
		Off Peak	2003	4
NO _x	Minimum	All hours	2024	3
		On Peak	2024	3
		Off Peak	2023	3
	Maximum	All hours	2005	1
		On Peak	2005	1
		Off Peak	2005	1

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 based on the fact that the resources are not a direct substitute for non-intermittent capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during hours with high risk of loss of load (unserved energy). Until June 1, 2023, PJM used average unit performance over 360 summer peak hours to determine the derating factors. For the 2023/2024 Delivery Year, which began on June 1, 2023, PJM used an average ELCC approach to determine the capacity derating factor.³⁰⁵ The average ELCC approach was also used for the 2024/2025 Delivery Year. Beginning with the 2025/2026 Delivery Year PJM will use a marginal ELCC approach.^{306 307}

To illustrate the relationship between actual output and derating factors, Figure 8-14 shows wind and solar output during the top 100 load hours in PJM in the first nine months of 2024. Figure 8-15 shows wind and solar output for all hours in the first nine months of 2024. In the first nine months

³⁰⁴ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

³⁰⁵ See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.

³⁰⁶ *Protest of the Independent Market Monitor for PJM*, ER24-99-000 (November 9, 2023).

³⁰⁷ Order 186 FERC ¶ 61,080 accepting PJM's marginal ELCC approach (January 30, 2024).

of 2024, 95 of the top 100 load hours in PJM are PJM defined peak load hours. The hours in Figure 8-14 are in descending order by load and the hours in Figure 8-15 are in chronological order. The solid lines represent the total ICAP and output of the wind or solar PJM resources. The dashed lines are the total capacity committed for each capacity resource, or the ICAP of wind and solar PJM resources derated by the applicable ELCC class rating if the unit is not a capacity resource.

The actual output of the wind and solar resources during the top 100 load hours varied both above and below the derated capacity values. Wind output was above the derated ICAP for 38 hours and below the derated ICAP for 62 hours of the top 100 load hours in the first nine months of 2024. The wind capacity factor for the top 100 load hours in the first nine months of 2024 was 15.9 percent. Wind output was above the derated ICAP for 3,596 hours and below the derated ICAP for 2,979 hours in the first nine months of 2023. The wind capacity factor in the first nine months of 2024 was 26.8 percent.

Solar output was above the derated ICAP for 70 hours and below the derated ICAP for 30 hours of the top 100 load hours in the first nine months of 2024. The solar capacity factor for the top 100 load hours in the first nine months of 2024 was 49.5 percent. Solar output was above the derated ICAP for 1,353 hours and below the derated ICAP for 5,222 hours in the first nine months of 2024. The solar capacity factor in the first nine months of 2024 was 20.2 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through September, 2024

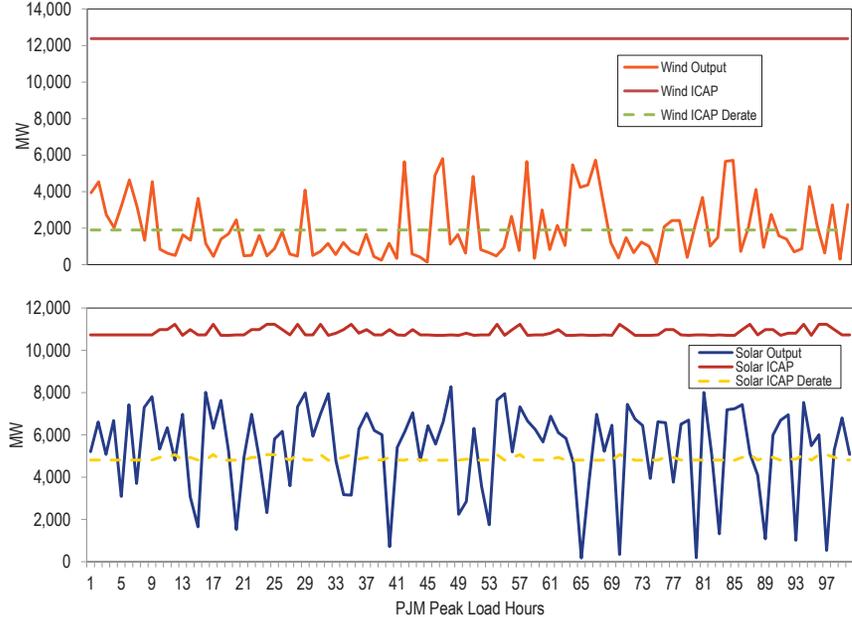


Figure 8-15 Wind and solar output: January through September, 2024

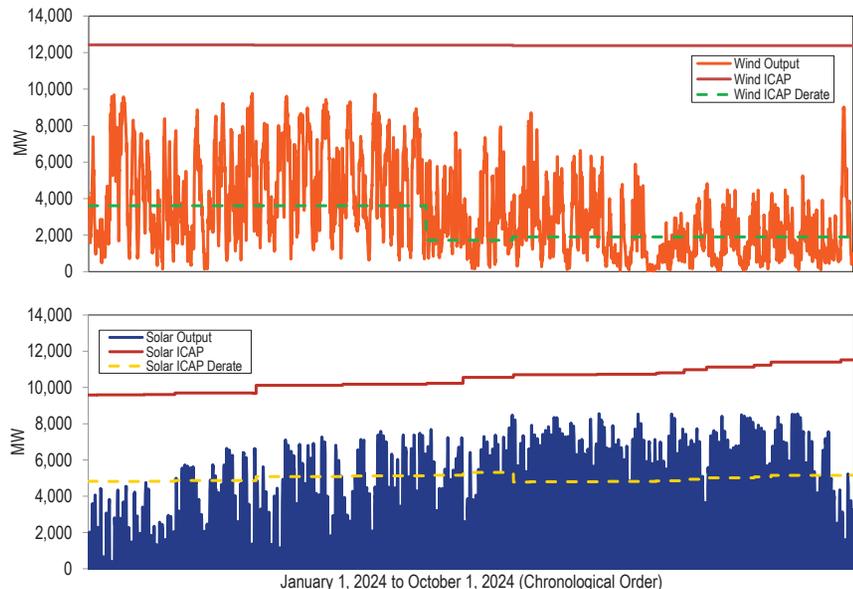


Figure 8-15 also shows the impacts of the ELCC rules and winter CIR rules on the derated capacity values. The wind figure shows a significant decrease on May 1 due to the winter CIRs reverting to the normal summer ratings. A small increase in the wind derated capacity occurs on June 1 due to the change in the onshore wind ELCC class rating from 15 percent to 21 percent. The solar figure shows a decrease in derated capacity on June 1 due to the change in the solar ELCC class rating from 50 percent to 33 percent for fixed panel solar, and from 61 percent to 50 percent for tracking panel solar. The increases in the Solar ICAP line reflect new solar generators coming online.

Wind Units

Table 8-33 shows the capacity factors of wind units in PJM. In the first nine months of 2024, the capacity factor of wind units in PJM was 26.8 percent. Wind units that were capacity resources had a capacity factor of 27.2 percent and an installed capacity of 11,565.5 MW. Wind units that were energy only

had a capacity factor of 20.6 percent and an installed capacity of 835.3 MW. Wind capacity resources were derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market prior to June 1, 2023, based on the wind farm terrain. Beginning June 1, 2023, wind capacity is derated to the ELCC accredited UCAP value.

Table 8-33 Capacity factor of wind units: January through September, 2024

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	20.6%	835.3
Capacity Resource	27.2%	11,565.5
All Units	26.8%	12,400.8

Figure 8-16 shows the average hourly real-time generation of wind units in PJM, by month for 2024. The hour with the highest average output in the first nine months of 2024, 5,662.9 MWh, was hour 23 in March, and the hour with the lowest average output, 1,048.7 MWh, was hour 11 in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours. Wind output is generally highest during the months from November through March and lowest during the months from May through September.

Figure 8-16 Average hourly real-time generation of wind units: January through September, 2024

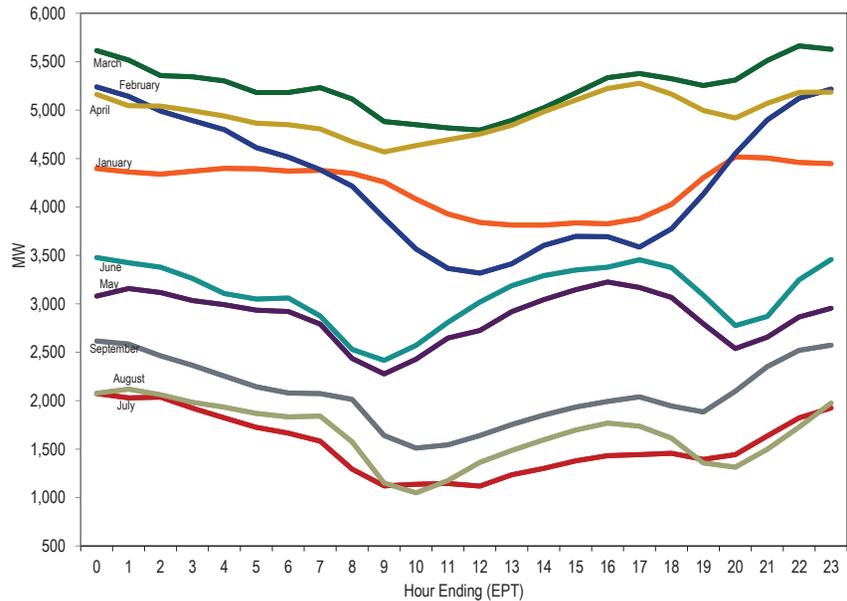


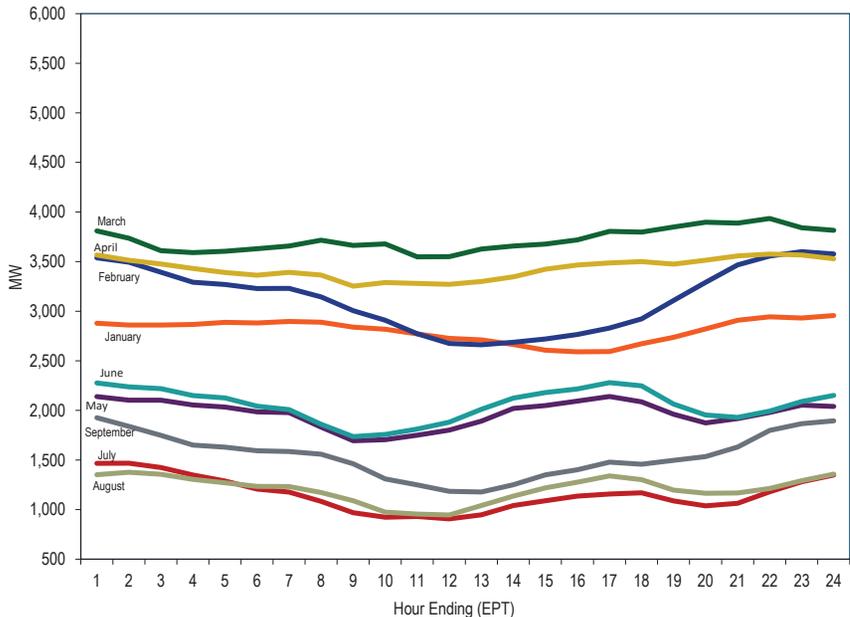
Table 8-34 shows the generation and capacity factor of wind units by month for 2023 and 2024.

Table 8-34 Capacity factor of wind units in PJM by month: January 2023 through September 2024

Month	2023		2024	
	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,913,720.6	34.3%	3,127,639.0	33.8%
February	3,440,914.0	44.8%	2,975,826.8	34.4%
March	3,573,934.8	42.1%	3,890,827.6	42.2%
April	2,798,644.4	33.6%	3,569,274.6	39.9%
May	2,063,557.4	23.8%	2,136,464.5	23.1%
June	1,661,899.5	18.8%	2,233,459.4	25.1%
July	1,001,020.4	10.9%	1,151,404.2	12.5%
August	1,470,474.4	15.9%	1,233,659.9	13.4%
September	1,318,984.9	14.7%	1,496,175.0	16.8%
October	2,685,058.3	28.8%		
November	3,146,489.1	34.3%		
December	2,917,283.9	30.8%		

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 8-17 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-17 Average hourly day-ahead generation of wind units: January through September, 2024



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.³⁰⁸ Figure 8-18 and Table 8-35 show the hourly average

³⁰⁸ 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.

proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2024. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2024, the SCED dispatch instruction for marginal wind resources was to reduce output for 71.9 percent of the marginal 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 8-18 Marginal fuel at time of wind generation: January through September, 2024

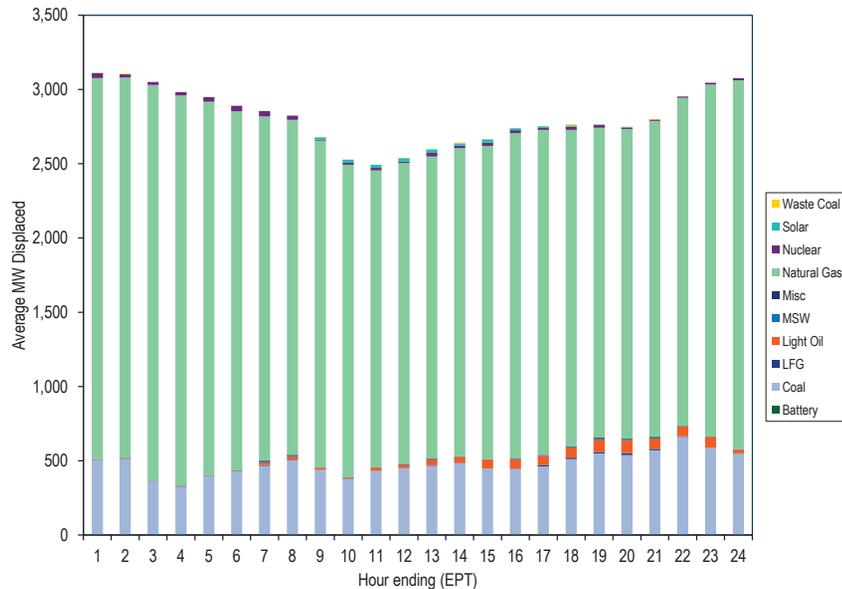


Table 8-35 Marginal fuel MW at time of wind generation: January through September, 2024

Hour	Battery	Coal	LFG	Light			Natural			Waste		Total
				Oil	MSW	Misc	Gas	Nuclear	Solar	Coal		
0	0.9	504.5	2.5	1.9	1.3	0.6	2,565.4	32.8	1.0	2.9	3,113.6	
1	1.0	508.8	2.6	4.1	2.0	2.0	2,560.7	21.3	0.0	3.4	3,105.8	
2	1.7	358.6	1.3	3.1	0.0	1.3	2,664.3	20.5	0.0	0.0	3,050.9	
3	1.1	322.4	2.0	2.1	2.6	2.1	2,628.1	22.0	0.0	0.0	2,982.9	
4	0.0	395.5	1.0	2.3	0.0	1.3	2,517.7	31.3	0.0	1.1	2,950.2	
5	1.2	428.1	2.7	2.2	2.3	0.2	2,416.3	37.4	0.0	1.1	2,891.5	
6	0.0	465.4	6.2	17.7	10.7	4.5	2,313.9	35.9	1.1	1.7	2,857.1	
7	0.0	503.3	3.5	23.0	8.2	2.9	2,255.2	27.3	1.7	0.8	2,825.9	
8	0.0	436.9	1.3	14.5	0.6	1.1	2,201.5	8.1	13.9	0.0	2,677.8	
9	0.0	376.8	0.1	9.1	2.9	1.7	2,102.2	13.5	21.4	0.9	2,528.7	
10	0.0	433.2	0.2	21.1	0.7	1.4	1,998.7	16.7	19.7	1.1	2,493.0	
11	0.0	449.6	2.5	21.3	0.1	5.3	2,026.3	10.0	22.6	1.6	2,539.4	
12	0.0	466.5	3.4	38.3	0.2	5.2	2,035.6	23.5	24.4	2.3	2,599.3	
13	0.0	484.0	2.8	40.2	3.3	0.3	2,074.8	17.2	15.2	5.0	2,642.9	
14	0.2	448.4	0.0	58.4	0.4	3.1	2,110.2	22.2	21.9	1.4	2,666.2	
15	0.2	444.1	2.5	62.2	3.3	2.3	2,190.9	20.4	12.9	1.7	2,740.6	
16	0.0	462.0	9.9	62.7	2.2	2.9	2,188.9	15.2	8.4	1.3	2,753.6	
17	0.3	511.1	9.4	68.8	5.2	1.6	2,131.9	21.7	8.5	7.0	2,765.4	
18	0.0	548.7	10.1	85.1	6.7	5.2	2,086.3	18.4	3.5	1.2	2,765.3	
19	0.0	537.8	13.3	87.9	7.4	3.6	2,084.7	10.0	4.1	0.5	2,749.2	
20	0.0	570.2	10.4	69.2	9.3	2.6	2,127.3	8.4	0.3	4.1	2,801.8	
21	0.0	660.6	5.6	63.8	3.9	2.0	2,208.3	8.4	0.0	0.0	2,952.6	
22	0.0	587.8	0.9	70.9	2.3	1.6	2,369.5	12.6	0.0	0.0	3,045.7	
23	0.0	548.6	1.4	25.2	1.5	1.7	2,483.8	14.0	0.0	0.0	3,076.1	
Average	0.3	477.2	4.0	35.6	3.2	2.4	2,264.3	19.5	7.5	1.7	2,815.6	

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 12,400.9 MW of solar capacity registered in GATS that are PJM units. As shown in Table 8-23, there are 12,115.1 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 20.2 percent for the first nine months of 2024. Solar units that were capacity resources had a capacity factor of 20.0 percent and an installed capacity of 9,538.9 MW. Solar units that were energy only had a capacity factor of 21.7 percent and an installed capacity of 908.5 MW. Solar capacity resources were derated to 38.0, 42.0 or 60.0 percent of nameplate capacity for the capacity market, prior to June 1, 2023, based on the installation type. Beginning June 1, 2023, solar capacity is derated to the ELCC accredited UCAP value.

Table 8-36 Capacity factor of solar units: January through September, 2024

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.7%	908.5
Capacity Resource	20.0%	9,538.9
All Units	20.2%	10,447.3

Figure 8-19 shows the average real-time generation of solar units in PJM, by hour and month. The hour with the highest average output in the first nine months of 2024, 7,020.4 MW, was hour 13 in June. January has the lowest solar output. The hour in January with the highest average output, 2,716.6 MW, was hour 13. Solar output in PJM is generally higher during peak hours and lower during off peak hours. Solar output is generally highest during the months from May through August and lowest during the months from November through February.

Figure 8-19 Average hourly real-time generation of solar units: January through September, 2024

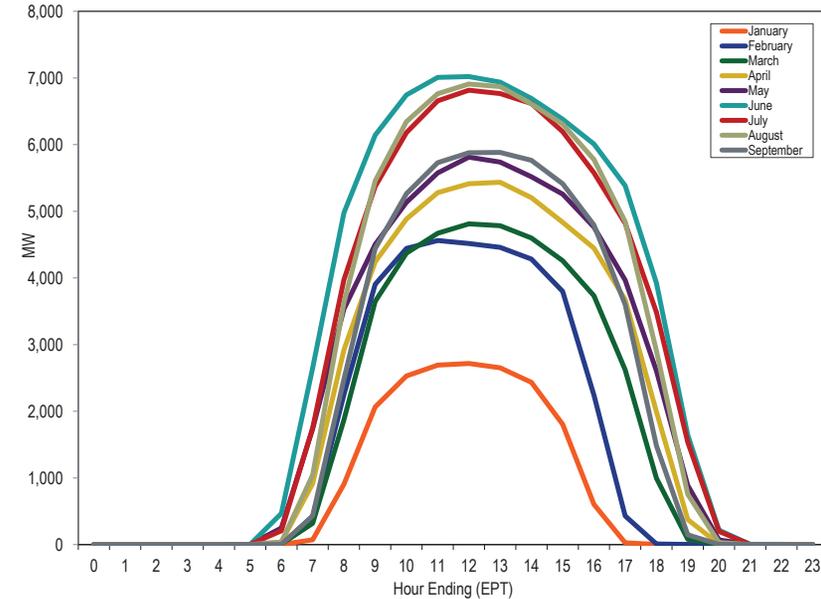


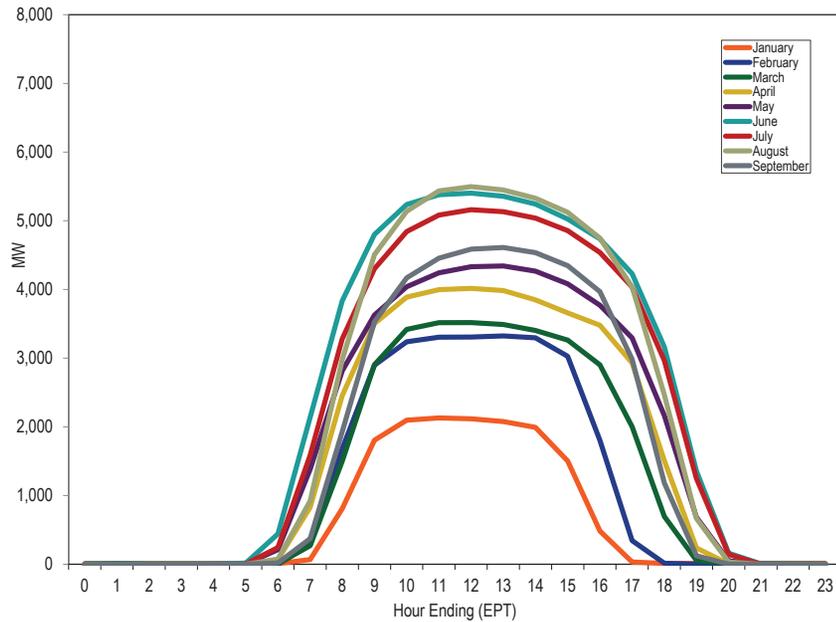
Table 8-37 shows the generation and capacity factor of solar units by month for 2023 and 2024.

Table 8-37 Capacity factor of solar units by month: January 2023 through September 2024

Month	2023		2024	
	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	417,821.3	9.9%	573,818.4	8.0%
February	598,407.5	15.2%	1,024,291.2	15.2%
March	927,131.9	21.1%	1,264,077.3	16.8%
April	1,062,635.2	24.9%	1,490,534.2	20.3%
May	1,244,370.9	28.1%	1,716,079.1	22.1%
June	1,172,402.9	25.0%	2,179,389.2	28.3%
July	1,332,825.0	26.2%	2,061,912.8	25.8%
August	1,203,177.8	23.1%	2,005,270.8	24.3%
September	970,013.7	18.1%	1,548,321.6	18.8%
October	894,877.5	15.8%		
November	763,314.1	12.3%		
December	544,172.5	7.9%		

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-20 shows the average hourly day-ahead generation offers of solar units in PJM, by month.³⁰⁹

Figure 8-20 Average hourly day-ahead generation of solar units: January through September, 2024

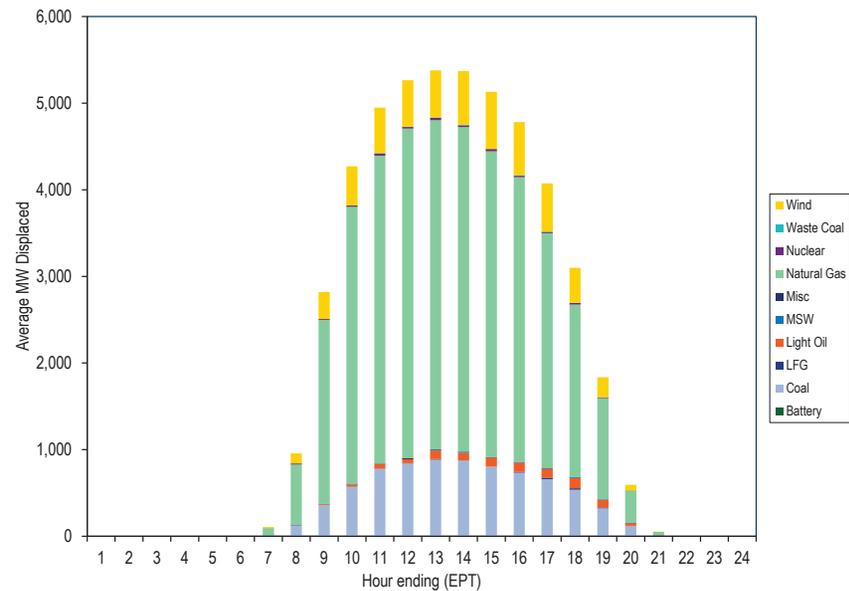


Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output 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

³⁰⁹ 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.

units when a solar unit is producing output.³¹⁰ Figure 8-21 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 nine months of 2024. 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 nine months of 2024, the SCED dispatch instruction for marginal solar resources was to reduce output for 97.3 percent of the marginal solar unit intervals. 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 8-21 Marginal fuel at time of solar generation: January through September, 2024



³¹⁰ 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 September, 2024

Hour	Battery	Coal	LFG	Light			Natural			Waste		Total
				Oil	MSW	Misc	Gas	Nuclear	Coal	Wind		
0	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.1	0.9	
1	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.1	0.8	
2	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.1	0.8	
3	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.1	0.8	
4	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.2	1.0	
5	0.0	0.2	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.2	1.5	
6	0.0	15.6	0.0	0.3	0.3	0.0	74.7	1.9	0.0	13.4	106.4	
7	0.0	126.8	0.6	2.0	0.7	0.3	697.3	12.8	0.0	116.6	957.2	
8	0.0	361.8	1.0	10.4	0.8	1.5	2,121.9	11.5	0.0	310.7	2,819.7	
9	0.0	570.6	1.2	25.2	4.8	4.2	3,196.1	15.2	2.1	451.8	4,271.3	
10	0.0	777.4	1.5	57.5	1.9	3.9	3,552.2	26.3	3.1	523.7	4,947.4	
11	0.0	840.5	4.1	45.1	0.6	12.3	3,803.2	19.8	3.3	536.0	5,264.9	
12	0.0	884.7	6.8	98.8	1.2	9.6	3,801.7	29.1	3.8	541.7	5,377.5	
13	0.0	875.5	2.1	86.3	13.6	0.6	3,744.8	21.3	4.6	621.9	5,370.6	
14	0.7	802.2	0.0	102.0	1.6	6.5	3,530.6	26.9	1.4	659.6	5,131.5	
15	0.5	733.2	9.9	104.8	3.7	6.9	3,285.3	18.3	5.9	613.9	4,782.5	
16	0.0	657.9	19.7	98.5	4.5	5.4	2,712.4	16.0	2.5	557.3	4,074.1	
17	1.2	535.6	17.0	118.6	8.7	2.5	1,991.0	18.4	1.4	405.7	3,100.1	
18	0.0	322.3	11.6	84.6	4.2	4.4	1,167.2	10.3	0.0	232.1	1,836.8	
19	0.0	119.4	1.5	30.1	1.4	1.2	371.3	3.4	0.2	65.6	594.1	
20	0.0	12.7	0.1	2.5	0.0	0.1	33.0	0.1	0.1	5.5	54.1	
21	0.0	0.4	0.0	0.1	0.0	0.0	1.2	0.0	0.0	0.2	1.8	
22	0.0	0.3	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.3	1.9	
23	0.0	0.2	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.2	1.1	
Average	0.1	318.2	3.2	36.1	2.0	2.5	1,420.4	9.6	1.2	235.7	2,029.1	

