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. 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. State and federal subsidies for nuclear generation have increased net revenue for some nuclear plants. Longstanding subsidies for nuclear, coal and oil generation have also significantly affected the economic viability of generation resources using those fuels.

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 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.[2] On June 11, 2025, the EPA proposed to repeal the core changes of the 2024 amendments,[3] including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard.[4]
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[5] (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.[6] On February 28, 2022, the EPA issued a federal implementation plan for implementation of CSAPR (also known as the Good Neighbor Plan),[7] 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.[8] 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. The Court proceeding is currently in abeyance, and the EPA has informed the D.C. Circuit that it is preparing a proposed rulemaking as part of reconsideration of the Good Neighbor Plan.[9]
- **NSR.** The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. 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.[10] NSR requires permits before construction commences. 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.[11]
- **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.[12] Environmental regulations allow

1 See *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 Review of the Residual Risk and Technology Review*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).
3 See *id.*
4 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA–HQ–OAR–2018–0794; FRL–6716.4–01–OAR, 90 Fed. Reg. 25535 (June 17, 2025).
5 CAA § 110(a)(2)(D)(i)(I).
6 *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).
7 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).
8 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024); Utah v. EPA, D.C. Cir. Case No. Case No. 23-1157, et al.
9 Utah v. EPA, Status Report, D.C. Cir Case No. 23-1157, et al. (November 24, 2025).
10 42 U.S.C § 7470 et seq.
11 40 CFR § 52.21.
12 See 40 CFR § 63.6640(f).

stationary emergency RICE that do not meet the emissions limits and are participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

PJM does not prevent 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):[13] 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 Carbon Emissions Rule reflects 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.[14] The Carbon Emissions Rule proposes to repeal the Affordable Clean Energy Rule.[15]

- **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.[16]

- **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."[17] The rule became effective on September 8, 2023.[18]

- **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 May 2024, the EPA finalized a rule strengthening regulation of effluent discharges.[19]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[20] 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 *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, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").

14 Carbon Emissions Rule at 33371-33373.

15 Carbon Emissions Rule at 33243.

16 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 (August 15, 2014).

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

18 See *id.*

19 See *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Final Rule, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-8794-01- OW, 89 Fed. Reg. 40199 (May 9, 2024).

20 42 U.S.C. §§ 6901 *et seq.*

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that applies to power generation facilities. The most recent RGGI auction, held on December 3, 2025, cleared at $26.73 per short ton, or $29.46 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 61.7 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 52.2 percent for a new combined cycle (CC) unit and $43.12 per MWh or 105.1 percent for a new coal plant (CP) for 2025.

- **Offshore Wind.** New Jersey, Maryland and Virginia have taken significant steps to promote offshore wind. New Jersey and Maryland enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[21] On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[22] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the withdrawal of offshore leasing.[23]

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 December 31, 2025, 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 $14.6 billion over the ten year period from 2014 through 2023, an average annual RPS compliance cost of $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.[24]

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 December 31, 2025, 98.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.7 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.

21 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.

22 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.

23 State of New York v. Trump, Case No. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).

24 The 2023 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.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 6.6 percent of total generation in PJM in 2025. RPS Tier I generation was 7.9 percent of total generation in PJM and RPS Tier II generation was 2.0 percent of total generation in PJM in 2025. 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 2025, Tier I generation from PJM generators met only 48.0 percent of the Tier I RPS requirements.

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 are not always clear. The price of carbon implied by REC prices ranges from $10.03 per tonne in Ohio to $63.98 per tonne in Virginia. The price of carbon implied by SREC prices ranges from $68.18 per tonne in Pennsylvania to $830.23 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in December 2025 of $29.46 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[25] [26] 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.[27] 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

25 "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>.

26 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>.

27 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 2025 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-9.

like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS was $1.5 billion, or a total of $14.6 billion over ten years. The RPS compliance cost for 2023, the most recent year for which there is almost complete data, was $2.9 billion.[28] 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 $8.8 billion per year if the carbon price were $26.73 per short ton and emissions levels were five percent below 2024 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $16.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2024 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $26.73 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.[29]

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.[30] [31]

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

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the

28 The 2023 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.

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

30 42 U.S.C. § 7401 et seq. (2000).

31 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.

32 42 U.S.C. §§ 6901 *et seq.*

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.

The EPA's MATS rule applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[33] 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.[34] 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.[35] 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.[36] The core proposal would revise the (non Hg) fPM emission standard, from 0.030 to 0.010 lbs/MMBtu.[37] The EPA "does not project that any EGUs will retire in response to the standards promulgated in this final rule."[38]

The new administration has taken steps to weaken the enforcement of the MATS rule. In April 2025, in an administrative decision by the EPA under Administrator Lee Zeldin, citing Section 112(i)(4) of the CAA, 47 coal-fired power plants were exempted from MATS compliance for two years. The decision was based on a determination of a need to prolong the life of aging coal plants and support national energy interests. This action is temporary and does not repeal the MATS rule. Repeal of the MATS has been identified as an EPA regulatory goal.[39]

Potentially 16,661 MW of generation in PJM is covered by the two year exemption. Most of the units have either not indicated plans to retire or have repowered, so the impact of the extension alone may not be direct and immediate.

On June 11, 2025, the EPA proposed to repeal the core changes of the 2024 amendments, including the revised filterable particulate matter (fPM) emission standard, restoring the 0.030 lbs/MMBtu standard.[40]

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).[41] Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle emissions and 2006 fine particle emission NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[42] the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[43] 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

33 See *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).

34 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*, Final Action, EPA–HQ–OAR–2018–0794, 88 Fed. Reg. 13959 (March 6, 2023).

35 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*, Final Rule, Docket No. EPA-HQ-OAR-2018-0794, 89 Fed. Reg. 38508 (May 7, 2024).

36 *Id.* at 38510.

37 *Id.* at 38518.

38 *Id.* at 38526.

39 See EPA, EPA Launches Biggest Deregulatory Action in U.S. History (March 12, 2025) ("March 12th EPA Deregulation Notice"), which can be accessed at: <https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history>.

40 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA–HQ–OAR–2018–0794; FRL–6716.4–01–OAR, 90 Fed. Reg. 25535 (June 17, 2025).

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

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

43 *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).

in attaining and maintaining the 2015 Ozone NAAQS.[44] 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.[45] 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 2029[46]

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

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

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.[47] 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.

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.[48] 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.

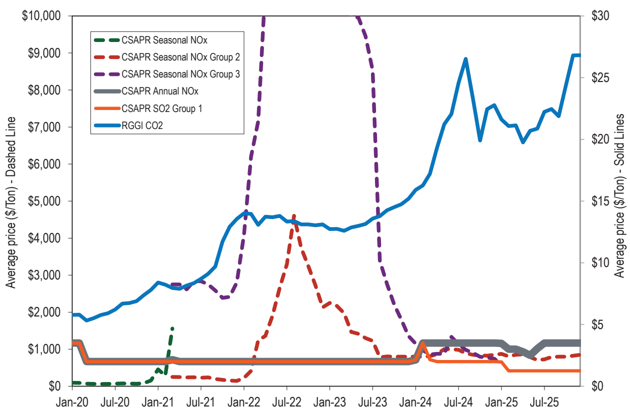
The new EPA Administrator has indicated plans to terminate the Good Neighbor Plan and revive negotiation of state implementation plans with the affected states.[49] The Court proceeding reviewing the Good Neighbor Plan is currently in abeyance, and the EPA has informed the D.C. Circuit that it is preparing a proposed rulemaking as part of reconsideration of the Good Neighbor Plan.[50]

44 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).
45 See *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.
46 *Id.* at 35 (Table I.B-1).
47 *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).
48 Ohio v. EPA, Slip Op. No. 23A349. (S. Ct. June 27, 2024).
49 March 12th EPA Deregulation Notice; Fact Sheet, Good Neighbor Plan (GNP) Powering the Great American Comeback Fact Sheet (March 12, 2025), which can be accessed at: <https://www.epa.gov/system/files/documents/2025-03/good-neighbor-plan_powering-the-great-american-comeback_fact-sheet.pdf>.
50 Utah v. EPA, Status Report, D.C. Cir Case No. 23-1157, et al. (November 24, 2025).

Figure 8-1 shows average, monthly settled prices for NO_x and SO_2 emissions allowances including CSAPR related allowances for 2020 through 2025. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

The RGGI CO_2 allowance price averaged $22.48 in 2025, a 7.2 percent increase in comparison with the average price in 2024. The CSAPR annual NO_x allowance price averaged $3.24 in 2025, a 4.5 percent decrease in comparison with the average price in 2024. The group 2 CSAPR Seasonal NO_x allowance price averaged $806.38 in 2025, a 7.9 percent decrease in comparison with the average price in 2024.[51] The components of real-time LMP analysis shows that NO_x cost contributed $0.09 to the load-weighted average real-time LMP in 2024 and 2025.[52] CO_2 cost (RGGI) contributed $2.23 to the load-weighted average real-time LMP in 2025, compared to $1.94 in 2024.[53]

Figure 8-1 Spot monthly average emission price comparison: 2025[54]



CAA: NSR

The CAA's NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. 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.[55] 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.[56]

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.[57] The first part considers whether a modification would cause a significant emission increase of a regulated NSR pollutant. The second part considers whether any identified increase is also a significant net emission increase.[58]

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.[59] 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.[60] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that

51 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.
52 See Components of LMP in the *2025 Annual State of the Market Report for PJM* Volume 2, Section 3: Energy Market.
53 Id.
54 The CSAPR Seasonal NOx Group 3 price peaked at an average price of $44,826 in March, 2022.
55 42 U.S.C § 7470 et seq.
56 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.
57 40 CFR § 52.21.
58 *Id.*
59 See *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013); 40 CFR Parts 60 and 63.
60 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).

rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

Up to 50 hours of the maximum 100 hours can be operated in limited non emergency conditions.[61] By letter issued February 27, 2025, EPA indicated, in response to an inquiry from Duke Energy, that RICE can be operated for up to 50 hours per year to prevent the interruption of power supply in a local area when under an EEA1 and transition to EEA2 is likely without further action.[62]

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

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[63] [64]

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."[65]

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").[66] 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 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.

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 Stated Court of Appeals for the D.C. Circuit.[67] PJM joined other RTOs to file an amicus brief in support of petitioners, arguing

61 See 40 CFR 63.6640(f)(4)(ii) (RICE located at area sources of hazardous air pollutants (HAP)1 can operate for up to 50 hours per year in non-emergency situations to supply power as part of a financial arrangement with another entity). The following conditions must be met: (i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator. (ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific North American Electric Reliability Corporation (NERC), regional, state, public utility commission or local standards or guidelines. (iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

62 EPA letter to Duke Energy <https://www.epa.gov/system/files/documents/2025-05/response-to-duke-energy.pdf>. The EPA describes Duke's program: "the Mandatory 50 program is deployed when forecasted grid reserves fall below Duke Energy's thresholds for maintaining reliable service—specifically, under Energy Emergency Alert (EEA) Level 1 when transition to EEA Level 2 is imminent without further action. The program would fall below other emergency demand response programs in Duke Energy's resource stack and is constrained to 50 hours per calendar year. The letter states that the program prevents the need for rotating load shed, which would create local disturbances that could result in use of all generators throughout the affected areas."

63 See CAA § 111.

64 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.

65 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>.

66 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, 89 Fed. Reg. 39798 (May 9, 2024) ("Carbon Emissions Rule").

67 See West Virginia, et al. v. EPA, EPA's Status Report, D.C. Cir. No. 24-1120, et al. (November 24, 2025).

that the result would result in premature retirements of fossil generation and threaten reliability.[68] 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.[69] The petition remains pending at the D.C. Circuit.

On June 11, 2025, the EPA proposed to repeal all GHG emissions standards for fossil fuel-fired power plants.[70] The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution.[71] The EPA is also proposing, as an alternative, to repeal a narrower set of requirements that includes the emission guidelines for existing fossil fuel fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.[72]

CWA: WOTUS Definition

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[73] [74] 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.[75] 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.[76] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[77] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[78] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[79] Additional litigation or administrative action may clarify the functional discharge analysis.[80] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[81]

On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[82] 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.[83] 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 the 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."[84] The Court's definition of adjacent wetlands significantly reduced the range of waters meeting

68 See Motion for Leave to File Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., 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).
69 See West Virginia, et al. v. EPA, No. 24A95, et al.
70 *See Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units*, Docket No. EPA-HQ-OAR-2025-0124; FRL-12674-01-OAR, 90 Fed. Reg. 25752 (June 17, 2025).
71 *Id.* at 25755.
72 *Id.* at 25768.
73 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.").
74 For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
75 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).
76 590 U.S. 165 (April 23, 2020).
77 *Id.*
78 *Id.* at 1.
79 *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.").
80 *Id.*
81 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
82 *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)
83 See *id.* at 3005–6.
84 See Sackett v. EPA, 598 U.S. 651 (2023).

that definition compared to the range covered in the December 30, 2022 rule.

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.[85] On March 24, 2025, the EPA and the Army Corps of Engineers issued a memorandum in response to requests for further clarification on the definition of adjacent wetlands, stating: "[A]n interpretation of 'continuous surface connection' which allows for wetlands far removed from and not directly abutting covered waters to be jurisdictional as adjacent wetlands has the potential to violate the direct abutment requirement for 'adjacent wetlands' under the plurality's standard and now *Sackett's* endorsement of that standard.[footnote omitted] Therefore, any components of guidance or training materials that assumed a discrete feature established a continuous surface connection are rescinded."[86]

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.[87] 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.[88] 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.[89]

The EPA has been implementing ELGs established in its 2015 and 2020 rules.[90] [91] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[92]

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.[93]

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").[94] The 2024 Effluents Rule would reduce discharges by an estimated 660–672 million pounds per year, including toxic and bio accumulative pollutants, such as arsenic, lead, mercury, selenium, chromium, and cadmium.[95]

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.[96] The regulation also establishes numeric discharge limitations for mercury and arsenic

85 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).
86 See *WOTUS Notice: The Final Response to SCOTUS; Establishment of a Public Docket; Request for Recommendations*, Docket No. EPA-HQ-OW-2025-0093; FRL-12683-01-OW, 90 Fed. Reg. 13428.
87 See 40 CFR Part 423. For more details, see the *2019 Annual State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
88 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
89 *Id.* at 35343-35349.
90 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).
91 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
92 *Id.* at 64652.
93 85 Fed. Reg. 64650, 64679-82; 88 Fed. Reg. 18440 (March 29, 2023); 40 CFR § 423.19(f)(1).
94 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, Final Rule, 89 Fed. Reg. 40198 (May 9, 2024) ("2024 Effluents Rule"); CWA §§ 301, 304, 306, 307, 308, 402 & 501.
95 *Id.* at 40198, 40203.
96 *Id.* at 40198.

for combustion residual leachate (CRL) that is discharged through groundwater and for a fourth waste stream, called legacy wastewater, that is discharged from certain surface impoundments.[97] 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.[98]

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.[99] 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.[100]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[101] 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.[102] 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.[103]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[104]

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.[105]

On July 29, 2020, the EPA finalized revisions to the CCR rule in compliance with the court orders ("Revised CCRR").[106] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible

97 *Id.* at 40252.
98 *Id.* at 40200.
99 *Id.*
100 *Id.* at 40246.
101 42 U.S.C. §§ 6901 *et seq.*
102 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
103 The Water Infrastructure Improvements for the Nation Act (WIIN Act).
104 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).
105 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).
106 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).

and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[107]

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.

The new EPA Administrator has indicated plans to prioritize expeditious state permit reviews and update the CCR permit program.[109]

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.[110] 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:[111]

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	The impoundments at this facility (coal ash ponds) are subject to the EPA CCR Rule and the requirements of Virginia Waste Management Act.

Effective April 21, 2021, in response to a statutory mandate,[112] the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[113] 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.[114] The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable

107 *Id.* at 53516–53517, 53536.
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, 85 Fed. Reg. 9940 (February 20, 2020).
109 March 12th EPA Deregulation Notice.
110 Va. Code § 10.1-1402.03.
111 Virginia Department of Environmental Quality website: <https://www.deq.virginia.gov/permits/waste/coal-ash>.
112 Ill. Public Act 101-171 (a.k.a. SB 09).
113 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
114 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).

materials and some not.[115] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[116]

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[117]

- **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. The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO_2e and co-pollutants.[118] [119] 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 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 CO_2 emissions less than 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.[120] The rule limits existing electric generating units to no more than 1,700 lbs of CO_2 per megawatt hour of the gross energy input, by January 1, 2024, to no more than 1,300 pounds per megawatt hour by 2027, and to no more than 1,000 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.[121]

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

Some states proposed legislation in 2024 designed to reduce or eliminate greenhouse gas and other emissions. The proposed legislation is summarized in Table 8-3.

115 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.
116 *Id.*
117 For more details, see the *2019 State of the Market Report for PJM*, Appendix H: "Environmental and Renewable Energy Regulations."
118 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.
119 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.
120 See N.J.A.C. 7:27F.
121 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 205	153rd Gen. Assembly: Would require any entity seeking to begin the business of using 30 megawatts (MW) of electricity or greater to first obtain a Certificate to Operate (COP) from the PSC.
	HB 233	153rd Gen. Assembly: Act requires regulated utilities to establish a separate rate for data centers to avoid cost shifts to other customers.
	HCR 94	153rd Gen. Assembly: Resolution urging PJM to maintain price collars at the current rate and encouraging reforms to the interconnection queue.
Illinois	HB 3758/SB 2497	2025-2026/104th General Assembly: Bill requiring energy storage procurement and reforms to the grid interconnection process.
Indiana	HB 1434	2026 Reg. Sess.: Requires utilities to report votes at RTO stakeholder meetings.
	HB 1245	2026 Reg. Sess.: Requires the IURC to conduct a study to evaluate the effect of new and additional electricity demand from data centers and large load customers on: (1) the costs incurred by energy utilities to meet that demand; and (2) retail electric rates for all customer classes of energy utilities.
Kentucky		No current activity.
Maryland		No current activity.
Michigan		No current activity.
New Jersey	S 222	2024-2025 Reg. Sess.: Bill would authorize regulation of greenhouse gas emissions under the Air Pollution Control Act (1954) and the Global Warming Response Act.
	S 220	2024-2025 Reg. Sess.: Bill would establish Nuclear Power Advisory Commission.
	S 2816	2024-2025 Reg. Sess.: Requires electric public utilities to submit to BPU and to implement electric infrastructure improvement plans.
	S 237	2024-2025 Reg. Sess.: Establishes 100 percent clean electricity standard and directs BPU to establish clean electricity certificate program.
	A 5902/S 4693	2024-2025 Reg. Sess.: Requires BPU to work with neighboring states to research and recommend certain action concerning electric capacity and transmission.
	SJR 154/AJR 216	2024-2025 Reg. Sess.: Directs BPU to investigate RPM; directs State to promote affordable energy practices and to urge PJM to implement certain reforms.
	S 4143/ A 5564	2024-2025 Reg. Sess.: Requires submission of energy usage plan to BPU for proposed data centers; requires all electricity for data centers to be derived from new clean energy sources.
	S 4289/A 5267	2024-2025 Reg. Sess.: Requires BPU to procure and incentivize transmission scale energy storage.
	S 4570	2024-2025 Reg. Sess.: Withdraws New Jersey's participation in RGGI.
	S 4938	2024-2025 Reg. Sess.: Provide for BPU coordination with PJM to ensure accurate reflection of New Jersey's load forecasts in regional planning.
	A 6155	2024-2025 Reg. Sess.: Provides for an evalution of the PJM capacity market.
North Carolina		No current activity.
Ohio		No current activity.
Pennsylvania	HB 782	2025-2026 Reg. Sess.: Requires public utilities to report lobbying and political activities expenses to exclude them from rates; requires electric distribution companies to be in an RTO and to report voting in PJM processes.
	SB 1068	2025-2026 Reg. Sess.: An Act providing for the abrogation of regulations relating to the CO2 Budget Trading Program.
	HR 361	2025-2026 Reg. Sess.: Directs the Joint State Government Commission to study the costs and benefits of Pennsylvania's continued membership in PJM, including potential alternatives for grid management, reliability, and affordability amid rising prices and demand.
	SR 188	2025-2026 Reg. Sess.: Directs the Joint State Government Commission to study the costs and benefits of continued membership in PJM, with specific reference to the upcoming December 2025 capacity auction for 2027-2028 and broader reliability/price issues.
	HB 1834	2025-2026 Reg. Sess.: Provides for PUC regulation of commercial data centers, including impacts on the PJM grid (e.g., requiring assessments of effects on PJM's regional transmission system from large loads).
	SB 991	2025-2026 Reg. Sess.: Streamlines permitting for data centers (often at former power sites) to accelerate development amid PJM demand pressure.
Tennessee		No current activity.
Virginia		No current activity.
Washington, D.C.		No current activity.
West Virginia		No current activity.

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.[122] 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.[123] 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.[124]

Opportunity Cost

- PJM generators are subject to environmental constraints that limit generation. These constraints are specified in the operating permits issued by the jurisdictional environmental authority. Schedule 2 of the PJM Operating Agreement provides that the opportunity cost associated with the environmental constraints may be included in a generator's cost-based offer.[125] Opportunity cost associated with a physical equipment limitation or a fuel supply limitation, under certain circumstances, may also qualify for inclusion in the cost-based offer.[126]
- More than 10,000 MW of capacity are currently affected by CEJA, most of which have requested that the MMU calculate a unit specific opportunity cost. The CEJA operating limits have resulted in significant opportunity cost adders to cost-based energy market offers for affected units.
- The MMU calculates opportunity costs for units that make requests and provide the required data. The MMU calculated opportunity cost adders for 179 generators in 2025. The calculations are generally done one time per week and the resulting opportunity cost is effective for a seven day period. More frequent calculations are done in cases where the constraints are tight and the opportunity cost is expected to vary significantly from day to day.

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[127] 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.[128] Virginia joined RGGI on January 1, 2021, and left RGGI on December 31, 2023. A decision issued November 18, 2024, by the Floyd County Circuit Court of Virginia determined that the Governor lacked the authority to remove Virginia from RGGI.[129] An appeal of the decision is pending in the Virginia Court of Appeals (Case No. 1494-23-4). Pennsylvania took action to join RGGI on April 23, 2022, but such action was enjoined by court order on appeal.[130] [131] After Pennsylvania legislation explicitly removed the RGGI regulation from the Pennsylvania Code in November 12, 2025, the Pennsylvania Supreme Court dismissed the appeal as moot without a decision on the merits.[132] [133]

Table 8-4 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period through the 6th control period.[134] The clearing price for the auction held December 3, 2025, was $26.73 per allowance (equal to one short ton of

122 Va. HB 1526/SB 851.
123 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
124 *Id.*
125 PJM Operating Agreement, Schedule 2,
126 Id. at 5(b).
127 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>.
128 "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>.
129 See Association of Energy Conservation Professionals v. Virginia State Air Pollution Control Board, Case No. CL23000173-00.
130 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/> .
131 See *Bowfin KeyCon Holdings, LLC v. Pennsylvania Department of Environmental Protection*, 347 M.D. 2022 (November 1, 2023) ("held that the Pennsylvania [DEP]'s CO2 Budget Trading Program Regulation is an unconstitutional tax, declared the rule to be void, and enjoined DEP from enforcing it"); *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).
132 See Pennsylvania Act 45 of 2025, HB 416.
133 See *Shirley v. Pennsylvania Legislative Reference Bureau* (No. 247 M.D. 2022); Supreme Court Docket Nos. 81 MAP 2022, 83 MAP 2022, or 85 MAP 2022 (January 6, 2026).
134 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.

CO_2).[135] The Cost Containment Reserve (CCR) for 2025 was exhausted in the first auction of 2025 and all RGGI auctions held in 2025 have cleared above the CCR trigger price of $17.03 per allowance.[136] All RGGI auctions in 2024 and 2025 cleared above the CCR trigger price. The December 2025 auction clearing price increased 20.1 percent from the last auction clearing price of $22.25 in September 2025. The average RGGI auction price in 2025 was $21.88 per allowance, an 8.5 percent increase over the average RGGI auction price in 2024.

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th, 5th and 6th Control Periods[137]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594
December 7, 2022	$12.99	22,233,203		22,233,203	$14.32	20,169,628		20,169,628
March 8, 2023	$12.50	21,522,877		21,522,877	$13.78	19,525,231		19,525,231
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
December 4, 2024	$20.05	15,943,608		15,943,608	$22.10	14,463,802		14,463,802
March 12, 2025	$19.76	15,392,222	8,134,778	23,527,000	$21.78	13,963,593	7,379,749	21,343,341
June 4, 2025	$19.93	15,244,479		15,244,479	$21.97	13,829,563		13,829,563
September 3, 2025	$22.25	15,177,783		15,177,783	$24.53	13,769,057		13,769,057
December 4, 2025	$26.73	15,230,235		15,230,235	$29.46	13,816,641		13,816,641

135 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).
136 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 2025 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. Since the CCR allowances for 2025 have been exhausted, the CCR trigger price of $17.03 will not affect the remaining RGGI auctions in 2025.
137 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results>.

The RGGI auction held on December 3, 2025, generated $407.1 million in auction revenue. RGGI auctions have generated $10.1 billion in auction revenue since 2008.[138] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2022 reporting year, have invested $4.9 billion, 67.8 percent of auction revenues.[139] RGGI reports that 56 percent of the $4.9 billion was invested in energy efficiency, 12 percent on clean and renewable energy, seven percent on greenhouse gas abatement, 15 percent on direct bill assistance, five percent on beneficial electrification, six percent on administration and one percent on RGGI, Inc.[140]

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 2024 CO_2 emission levels and the RGGI clearing price for the December 2025 auction ranges from $4.6 billion per year to $8.8 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[141] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2024 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2024 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[142]

Table 8-5 Estimated CO_2 allowance revenue at December 2025 RGGI price level[143 144]

		Estimated CO_2 allowance revenue ($ millions), carbon price $26.73 per short ton					
Jurisdiction	2024 power generation CO_2 emissions (million short tons)	5 percent reduction below 2024 emission levels	10 percent reduction below 2024 emission levels	15 percent reduction below 2024 emission levels	20 percent reduction below 2024 emission levels	25 percent reduction below 2024 emission levels	50 percent reduction below 2024 emission levels
Delaware	2.0	$51.8	$49.1	$46.3	$43.6	$40.9	$27.3
Illinois	28.9	$734.3	$695.7	$657.0	$618.4	$579.7	$386.5
Indiana	34.3	$871.2	$825.4	$779.5	$733.7	$687.8	$458.5
Kentucky	29.9	$758.6	$718.7	$678.8	$638.8	$598.9	$399.3
Maryland	9.5	$240.9	$228.2	$215.5	$202.8	$190.2	$126.8
Michigan	2.4	$60.4	$57.2	$54.0	$50.8	$47.7	$31.8
New Jersey	9.8	$249.8	$236.7	$223.5	$210.4	$197.2	$131.5
North Carolina	0.1	$2.6	$2.4	$2.3	$2.2	$2.0	$1.4
Ohio	77.1	$1,956.8	$1,853.8	$1,750.8	$1,647.8	$1,544.8	$1,029.9
Pennsylvania	74.8	$1,899.9	$1,799.9	$1,699.9	$1,599.9	$1,499.9	$1,000.0
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	30.8	$781.2	$740.1	$698.9	$657.8	$616.7	$411.1
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	48.2	$1,223.4	$1,159.0	$1,094.6	$1,030.2	$965.9	$643.9
Total	347.8	$8,830.9	$8,366.1	$7,901.4	$7,436.6	$6,971.8	$4,647.9

The RGGI emissions cap (carbon budget) is the sum of CO_2 allowances issued by each state. Table 8-6 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2025 compliance year is the second 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.[145 146] 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

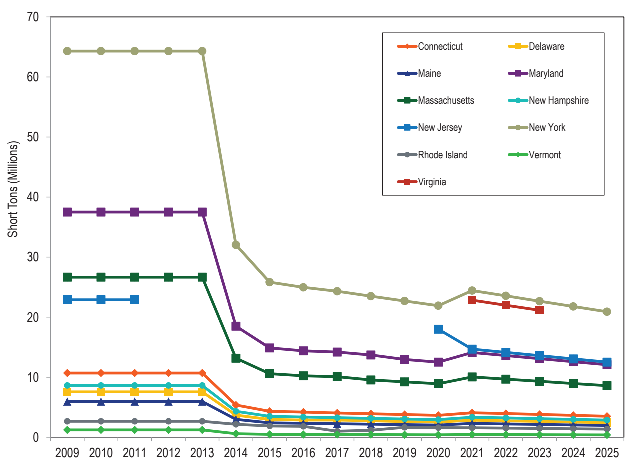
138 See Auction Results at <https://www.rggi.org/>.
139 *The Investment of RGGI Proceeds in 2023*, The Regional Greenhouse Gas Initiative (RGGI) at 16, July 2025, <https://www.rggi.org/investments/proceeds-investments>.
140 *Id.* at 15.
141 This assumes that the PJM states would implement their RGGI 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.
142 "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>.
143 The 2024 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from PJM generators.
144 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.
145 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
146 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

in 2014 and ending with 2020.[147] 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.[148] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[149] 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.[150] The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.[151] Figure 8-2 shows the adjusted carbon budgets (CO_2 emissions caps) for the RGGI states.

Table 8-6 RGGI emissions cap history[152 153]

	Control Period	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		$1.93	188,076,976	0.0%	188,076,976	0.0%
2011	1st	$1.89	188,076,976	0.0%	188,076,976	0.0%
2012		$1.93	165,184,246	0.0%	165,184,246	0.0%
2013		$2.92	165,184,246	0.0%	165,184,246	0.0%
2014	2nd	$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017	3rd	$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020	4th	$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021		$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022		$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023	5th	$13.58	112,457,784	(3.1%)	93,367,454	(3.8%)
2024		$20.17	84,162,784	(3.2%)	69,401,609	(3.9%)
2025	6th	$21.88	81,347,784	(3.3%)	66,586,609	(4.1%)

Figure 8-2 RGGI adjusted carbon budgets by state[154]



147 "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>.
148 Id.
149 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.
150 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.
151 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.
152 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed April 21, 2025).
153 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.
154 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution>

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 $16.5 billion if the carbon price were $50 per short ton and emission levels were five percent below 2024 levels. Allowance revenues to states would be $3.5 billion if the carbon price were $20 per short ton and emission levels were 50 percent below 2024.

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

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2024 emission levels	10 percent reduction below 2024 emission levels	15 percent reduction below 2024 emission levels	20 percent reduction below 2024 emission levels	25 percent reduction below 2024 emission levels	50 percent reduction below 2024 emission levels
Jurisdiction	Carbon Price ($ per short ton)			$20.00		
Delaware	$38.8	$36.7	$34.7	$32.6	$30.6	$20.4
Illinois	$549.5	$520.5	$491.6	$462.7	$433.8	$289.2
Indiana	$651.9	$617.6	$583.2	$548.9	$514.6	$343.1
Kentucky	$567.6	$537.7	$507.9	$478.0	$448.1	$298.7
Maryland	$180.2	$170.7	$161.3	$151.8	$142.3	$94.9
Michigan	$45.2	$42.8	$40.4	$38.0	$35.7	$23.8
New Jersey	$186.9	$177.1	$167.3	$157.4	$147.6	$98.4
North Carolina	$1.9	$1.8	$1.7	$1.6	$1.5	$1.0
Ohio	$1,464.1	$1,387.1	$1,310.0	$1,233.0	$1,155.9	$770.6
Pennsylvania	$1,421.6	$1,346.7	$1,271.9	$1,197.1	$1,122.3	$748.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$584.5	$553.7	$523.0	$492.2	$461.4	$307.6
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$915.4	$867.2	$819.0	$770.8	$722.7	$481.8
Total	$6,607.5	$6,259.7	$5,912.0	$5,564.2	$5,216.4	$3,477.6
	Carbon Price ($ per short ton)			$25.00		
Delaware	$48.4	$45.9	$43.3	$40.8	$38.2	$25.5
Illinois	$686.8	$650.7	$614.5	$578.4	$542.2	$361.5
Indiana	$814.8	$771.9	$729.1	$686.2	$643.3	$428.9
Kentucky	$709.5	$672.2	$634.8	$597.5	$560.1	$373.4
Maryland	$225.3	$213.4	$201.6	$189.7	$177.9	$118.6
Michigan	$56.5	$53.5	$50.5	$47.5	$44.6	$29.7
New Jersey	$233.7	$221.4	$209.1	$196.8	$184.5	$123.0
North Carolina	$2.4	$2.3	$2.2	$2.0	$1.9	$1.3
Ohio	$1,830.2	$1,733.8	$1,637.5	$1,541.2	$1,444.9	$963.2
Pennsylvania	$1,777.0	$1,683.4	$1,589.9	$1,496.4	$1,402.9	$935.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$730.6	$692.2	$653.7	$615.3	$576.8	$384.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,144.2	$1,084.0	$1,023.8	$963.6	$903.3	$602.2
Total	$8,259.4	$7,824.7	$7,390.0	$6,955.3	$6,520.6	$4,347.0
	Carbon Price ($ per short ton)			$50.00		
Delaware	$96.9	$91.8	$86.7	$81.6	$76.5	$51.0
Illinois	$1,373.6	$1,301.3	$1,229.0	$1,156.7	$1,084.4	$723.0
Indiana	$1,629.7	$1,543.9	$1,458.1	$1,372.3	$1,286.6	$857.7
Kentucky	$1,419.0	$1,344.3	$1,269.7	$1,195.0	$1,120.3	$746.9
Maryland	$450.6	$426.9	$403.2	$379.4	$355.7	$237.1
Michigan	$112.9	$107.0	$101.0	$95.1	$89.1	$59.4
New Jersey	$467.3	$442.7	$418.1	$393.5	$368.9	$246.0
North Carolina	$4.8	$4.6	$4.3	$4.1	$3.8	$2.5
Ohio	$3,660.3	$3,467.7	$3,275.0	$3,082.4	$2,889.7	$1,926.5
Pennsylvania	$3,553.9	$3,366.9	$3,179.8	$2,992.8	$2,805.7	$1,870.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,461.2	$1,384.3	$1,307.4	$1,230.5	$1,153.6	$769.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,288.5	$2,168.0	$2,047.6	$1,927.1	$1,806.7	$1,204.5
Total	$16,518.8	$15,649.3	$14,779.9	$13,910.5	$13,041.1	$8,694.1

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 2025 would have increased by 0.5 percent.[155]

Table 8-8 Estimated impact of carbon price on LMP: 2024 and 2025

		2024			2025		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$33.74	$30.99	(8.2%)	$50.73	$48.98	(3.4%)
Scenario 2	$10.00	$33.74	$31.82	(5.7%)	$50.73	$49.48	(2.5%)
Scenario 3	$15.00	$33.74	$32.65	(3.2%)	$50.73	$49.98	(1.5%)
Scenario 4	$25.00	$33.74	$34.32	1.7%	$50.73	$50.97	0.5%
Scenario 5	$50.00	$33.74	$38.49	14.1%	$50.73	$53.47	5.4%

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.[156] [157] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.45 per MWh for a new combustion turbine (CT) unit, $16.85 per MWh for a new combined cycle (CC) unit and $43.12 per MWh for a new coal plant (CP). Table 8-11 and Table 8-12 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-9 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.68	$3.37	$5.05	$16.85	$33.70	$67.40	$134.79
CP	$4.31	$8.62	$12.94	$43.12	$86.25	$172.49	$344.99

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 $188.01 per credit in 2025. 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 in 2025 in Ohio is $10.03 per tonne which is less than half the average RGGI auction clearing price of $24.12 per tonne in 2025. The implied carbon prices for RECs in the other jurisdictions in Table 8-10 range from $49.26 per tonne to $63.98 per ton. The implied carbon price for Virginia RECs is $63.98, 2.7 times the average RGGI auction clearing price. The social cost of carbon is estimated to be in the range of $50 per tonne.[158] [159] 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.

155 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>.

156 Heat rates from: *2024 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-3.

157 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).

158 "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>.

159 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 2025

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jurisdiction with Tier I or Class I REC											
Maryland	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$34.29	$37.82	$46.80	$50.02	$50.74
New Jersey	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$31.62	$36.23	$48.37	$53.60	$59.85
Ohio	$8.54	$5.30	$6.29	$11.21	$14.04	$16.33	$14.93	$14.98	$13.04	$11.66	$10.03
Pennsylvania	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$33.58	$37.76	$46.68	$51.94	$55.92
Virginia							$35.53	$36.02	$51.93	$62.23	$63.98
Washington, D.C.	$3.20	$4.05	$4.90	$4.69	$5.52	$20.25	$24.28	$27.49	$33.95	$47.41	$49.26
New Jersey	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$413.80	$424.70	$399.25	$396.71	$384.53
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	$78.95	$72.14	$68.18
Washington, D.C.	$997.05	$996.49	$868.78	$842.89	$851.39	$869.41	$851.78	$856.50	$867.74	$794.08	$830.23
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	$22.23	$24.12

Table 8-11 Carbon price for natural gas fired generators[160]

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

160 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 generators[161]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.59	$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 Renewables Regulation

State Renewable Portfolio Standards (RPS)

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[162] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of December 31, 2025, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of December 31, 2025, 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.[163]

As of December 31, 2025, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

161 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).

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

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

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

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[164]

Beginning in March 2023, RECs for GATS generators are hourly time stamped certificates.[165] 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: 2024 to 2034[166 167 168]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Delaware	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%	34.00%	37.00%
Illinois	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Maryland	36.20%	38.00%	40.50%	44.00%	45.50%	52.00%	52.50%	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	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	7.50%	8.00%	8.50%	0.00%	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)	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%	39.00%	42.00%
Virginia (Phase II utilities)	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%	52.00%	55.00%
Washington, DC	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	100.00%	100.00%

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

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50 percent renewable by 2030.[169] 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 noncompliance 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.[170] Additional details are provided in Table 8-14.

164 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
165 "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>.
166 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
167 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.
168 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
169 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
170 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.[171] 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.[172] [173] 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.[174] 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.[175] 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.[176] 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.

171 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
172 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).
173 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS
174 N.J. S. 2314/A. 3723.
175 Md. Code Ann § 7–306(d) & 7–306.2(g) (HB 569).
176 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 Recent changes in RPS rules[177 178 179 180 181 182 183]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

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.[184] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-15 shows the Tier I standards for PJM states.[185] All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.[186]

177 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
178 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
179 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>.
180 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
181 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
182 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
183 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
184 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.
185 This includes New Jersey's Class I renewable standard.
186 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed May 7, 2024).

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2024 to 2034[187]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Maryland	33.70%	35.50%	38.00%	41.50%	43.00%	49.50%	50.00%	50.00%	50.00%	50.00%	50.00%
New Jersey	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	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%	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.[188]

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 2025. 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 in 2025 in Washington, DC was $405.93 and the average Tier I REC price in 2025 in Washington, DC was $24.08. 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 $460 per SREC compared to $50 per REC for Tier I compliance.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2025

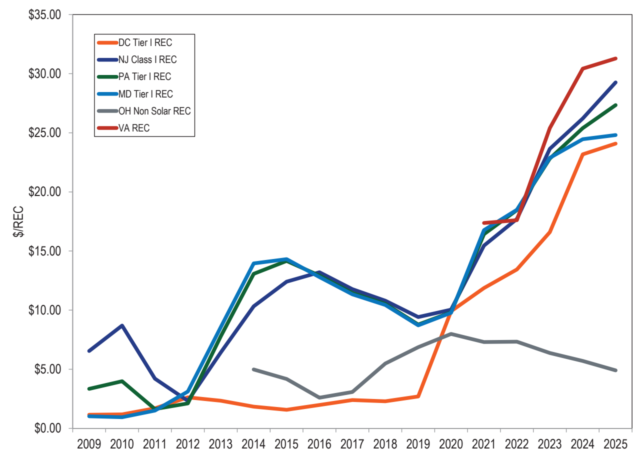


Figure 8-4 and Table 8-16 shows the fulfillment of Tier I equivalent RPS requirement for 2020 through 2024 by state and by carbon producing and noncarbon producing RECs.[189] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Delaware and Illinois RPS are fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of in state, other PJM state and out of state carbon producing RECs and in state, other PJM 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

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

188 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.

189 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 2024 reporting year data may be incomplete for some states.

non PJM state, and carbon producing RECs and noncarbon RECs. For example, Virginia met its 2024 RPS target using 4.1 percent carbon free RECs from Virginia, 82.3 percent carbon free RECs from other PJM states and 13.5 percent carbon producing RECs from Virginia and other PJM states. Ohio met its 2024 RPS target using 1.0 percent carbon free RECs from Ohio, 49.0 percent carbon free RECs from other PJM states, 15.6 percent carbon free RECs from non PJM states, 17.3 percent carbon producing RECs from Ohio and 17.1 percent carbon producing RECs from other PJM states. Illinois met its 2024 RPS target using 80.3 percent carbon free RECs from Illinois and 19.7 percent carbon free RECs from other PJM states. Illinois met its RPS target using 100.0 percent carbon free RECs for the 2019 through 2024 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2020 through 2024

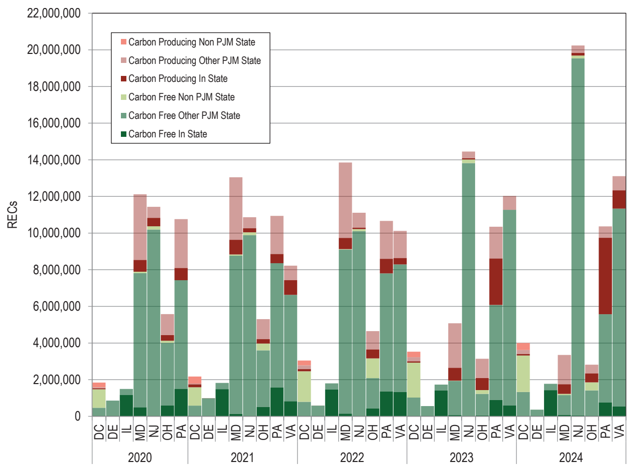


Table 8-16 State fulfillment of Tier I equivalent RPS: 2020 through 2024

		Carbon Free REC				Carbon Producing REC			
Year	REC Type	In State	Other PJM State	Non PJM State	Total	In State	Other PJM State	Non PJM State	Total
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	10.0%	70.6%	0.0%	80.6%	9.7%	9.7%	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	13.2%	68.8%	0.0%	81.9%	3.4%	14.7%	0.0%	18.1%
2023	DE New Eligible	0.9%	99.1%	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	0.1%	95.5%	1.4%	97.0%	0.5%	2.5%	0.0%	3.0%
	PA Tier I	8.6%	50.2%	0.0%	58.8%	24.5%	16.8%	0.0%	41.2%
	VA Renewable	5.0%	88.7%	0.0%	93.7%	0.0%	6.3%	0.0%	6.3%
2024	DE New Eligible	0.0%	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	DC Tier I	0.0%	33.3%	49.7%	82.9%	2.0%	5.4%	9.7%	17.1%
	OH Renewable Energy Source	1.0%	49.0%	15.6%	65.7%	17.3%	17.1%	0.0%	34.3%
	IL Renewable	80.3%	19.7%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	MD Tier I	2.3%	32.3%	1.9%	36.5%	15.7%	47.8%	0.0%	63.5%
	NJ Class I	0.2%	96.3%	0.8%	97.3%	0.7%	2.0%	0.0%	2.7%
	PA Tier I	7.3%	46.5%	0.0%	53.8%	40.2%	6.0%	0.0%	46.2%
	VA Renewable	4.1%	82.3%	0.0%	86.5%	7.6%	5.9%	0.0%	13.5%

Table 8-17 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-17 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-17 are included in the total RPS requirements presented in Table 8-13. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that took effect in 2021 with an original requirement that 1.37 percent of load be served by offshore wind.[190]

190 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>.

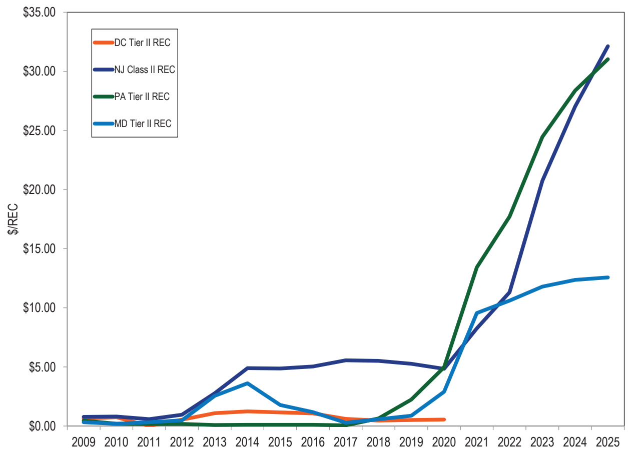
The standard has been revised to 0.14 percent for 2024.[191] The offshore wind requirement is only applicable if the Maryland offshore wind projects are producing RECs. [192]

Table 8-17 Additional renewable standards of PJM jurisdictions: 2024 to 2034[193]

Jurisdiction	Type of Standard	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Maryland	Off Shore Wind	0.14%	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.15%	0.25%	0.50%	0.75%	1.00%	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%		
North Carolina	Swine Waste	0.20%	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 2025. 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 in 2025. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2025.[194] The average Pennsylvania Tier II REC price in 2025 was $31.03, 9.4 percent higher than the average price for 2024. The average New Jersey Class II REC price in 2025 was $32.13, 18.9 percent higher than the average price for 2024. The average Maryland Tier II REC price in 2025 was $12.57, 1.7 percent higher than the average price in 2024.[195]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through 2025



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.[196] 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.[197] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for

191 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>.
192 Id. at footnote 13.
193 New Jersey Administrative Code, Section 14:8-2.3 does not specify standards beyond compliance year 2032/2033.
194 The District of Columbia dropped Tier II RECs from their RPS in 2021.
195 Tier II REC price information obtained through Evolution Markets, Inc.
196 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.
197 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).

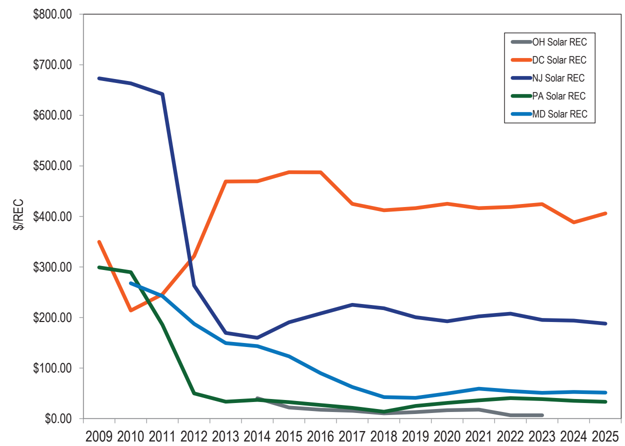
solar generators not eligible for New Jersey SRECs.[198] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[199] 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.[200] 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.[201] 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.[202]

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2024 to 2034[203] [204]

Jurisdiction with RPS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Delaware	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%	7.40%	8.40%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750	24,750	24,750
Maryland	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%	14.50%	14.50%
New Jersey	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	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%	6.00%	6.50%

Figure 8-6 shows the annual average solar REC (SREC) price by jurisdiction for 2009 through 2025. The average NJ SREC price was $188.01 in 2025. 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 $405.93 in 2025, a 4.6 percent increase compared to the average DC SREC price in 2024.[205]

Figure 8-6 Average SREC price by jurisdiction: 2009 through 2025



198 "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>.

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

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

201 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>.

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

203 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.

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

205 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states' solar requirement for 2020 through 2024.[206] 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.

Figure 8-7 State fulfillment of Solar RPS: 2020 through 2024

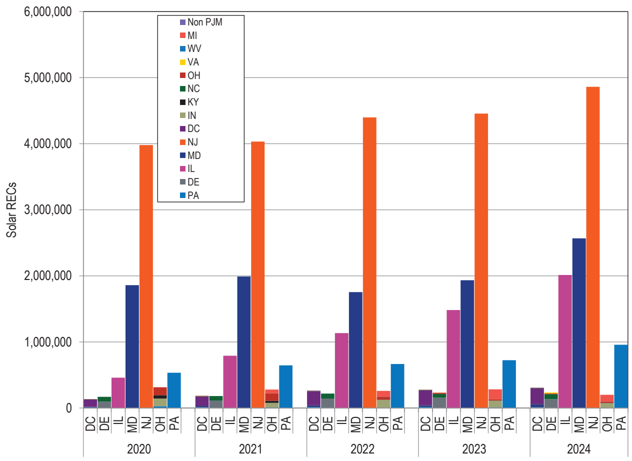


Table 8-19 State fulfillment of Solar RPS: 2020 through 2024

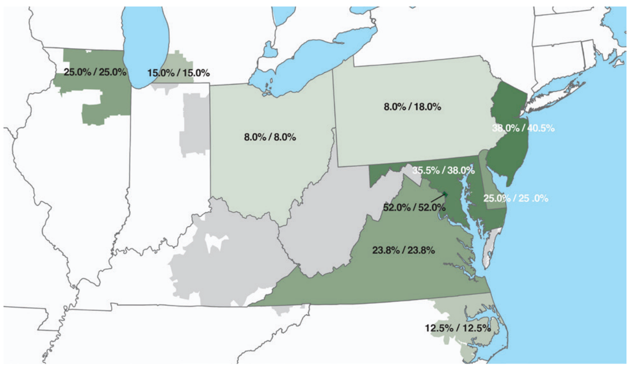
		In State	Other PJM State	Non PJM State
2020	DC Solar	81.5%	18.1%	0.4%
	DE Solar Eligible	56.7%	43.3%	0.0%
	IL Solar Renewable	100.0%	0.0%	0.0%
	MD Solar	100.0%	0.0%	0.0%
	NJ Solar	100.0%	0.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%	0.0%
	PA Solar	100.0%	0.0%	0.0%
2021	DC Solar	78.0%	21.6%	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	67.0%	33.0%	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%
2024	DC Solar	78.0%	21.8%	0.2%
	DE Solar Eligible	56.5%	43.5%	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	10.7%	89.3%	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

206 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 17, 2025). The timing of the REC retirement reports varies by state and the 2024 reporting year data is incomplete for some states.

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: 2025[207]



Under the existing state renewable portfolio standards, 19.8 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in 2025. 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 2025, only 9.8 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, 25.3 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 17.5 percent of PJM load should have been served by Tier I or renewable energy resources in 2025. In 2025, only 7.9 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 in 2025, and LSEs purchased RECs from non PJM resources (e.g. behind the meter rooftop solar) and RECs from resources outside the PJM footprint (Table 8-21). LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 23.0 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 in 2025. Wind generation accounted for 32,234.4 GWh of the 68,313.9 Tier I GWh, or 47.2 percent. As shown in Table 8-20, 85,485.7 GWh were generated by Tier I and Tier II resources, of which Tier I resources accounted for 79.9 percent. Wind and solar generation (noncarbon producing) was 6.6 percent of total generation in PJM in 2025. Tier I generation was 7.9 percent of total generation in PJM and Tier II was 2.0 percent of total generation in PJM in 2025. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 17,855.1 GWh, or 29.9 percent of the total Tier I and Tier II generation.

207 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.

Table 8-20 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): 2025

	Tier I									Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Pumped-Storage Hydro	Other Hydro	Solar	Solid Waste	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	35.5	0.0	0.0	0.0	97.7	0.0	0.0	133.2	0.0	0.0	0.0	0.0	0.0	133.2
Illinois	0.0	50.2	0.0	0.0	0.0	204.5	0.0	15,426.6	15,681.3	0.0	0.0	0.0	0.0	0.0	15,681.3
Indiana	0.0	13.2	0.0	0.0	32.2	2,263.3	0.0	6,386.4	8,695.0	0.0	0.0	0.0	0.0	0.0	8,695.0
Kentucky	0.0	0.0	249.1	0.0	89.0	536.9	0.0	0.0	875.0	0.0	0.0	0.0	0.0	0.0	875.0
Maryland	0.0	33.6	0.0	0.0	0.0	988.8	1,200.4	905.3	3,128.1	0.0	0.0	0.0	0.0	0.0	3,128.1
Michigan	0.0	47.7	0.0	0.0	49.3	7.2	0.0	0.0	104.2	0.0	0.0	0.0	0.0	0.0	104.2
New Jersey	0.0	43.9	6.8	0.0	0.0	926.7	0.0	10.3	987.8	620.6	0.0	1,289.1	0.0	1,909.8	2,897.5
North Carolina	0.0	0.0	435.4	0.0	0.0	2,617.7	0.0	935.2	3,988.3	0.0	0.0	0.0	0.0	0.0	3,988.3
Ohio	0.0	75.3	851.4	0.0	0.0	7,634.6	0.0	2,875.4	11,436.7	0.0	0.0	0.0	0.0	0.0	11,436.7
Pennsylvania	145.0	226.7	3,889.1	0.0	18.8	1,635.3	0.0	3,842.9	9,757.7	2,938.4	0.0	1,259.7	6,337.9	10,536.1	20,293.8
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	0.0	0.0
Virginia	1,229.5	362.2	669.1	467.2	42.4	7,872.8	0.0	50.1	10,693.4	2,713.5	1,607.0	0.0	0.0	4,320.5	15,013.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	27.5	783.6	0.0	0.0	219.9	0.0	1,802.3	2,833.3	0.0	0.0	0.0	405.3	405.3	3,238.7
Total	1,374.5	915.8	6,884.5	467.2	231.7	25,005.4	1,200.4	32,234.4	68,313.9	6,272.6	1,607.0	2,548.9	6,743.3	17,171.8	85,485.7

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In 2025, Tier I generation in PJM met only 48.0 percent of the Tier I RPS requirements. Table 8-21 compares each state's RPS requirement in 2025 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 68.8 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 81.6 percent of the Tier I RPS requirement and 70.5 percent of the Tier II RPS requirement. North Carolina generation was 6.8 times higher than the RPS requirement in 2025; but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation by PJM generators to meet 48.0 percent of the Tier I RPS requirement and 93.5 percent of the Tier II RPS requirement in 2025. 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: 2025

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	133.2	3,023.3	4.4%	0.0	0.0	
Illinois	15,681.3	22,785.0	68.8%	0.0	0.0	
Indiana	8,695.0	0.0		0.0	0.0	
Kentucky	875.0	0.0		0.0	0.0	
Maryland	3,128.1	21,768.8	14.4%	0.0	1,533.0	0.0%
Michigan	104.2	673.5	15.5%	0.0	0.0	
New Jersey	987.8	27,578.9	3.6%	1,909.8	1,870.6	102.1%
North Carolina	3,988.3	585.9	680.7%	0.0	0.0	
Ohio	11,436.7	13,396.9	85.4%	0.0	0.0	
Pennsylvania	9,757.7	11,961.8	81.6%	10,536.1	14,952.3	70.5%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	10,693.4	35,267.5	30.3%	4,320.5	0.0	
Washington, D.C.	0.0	5,147.2	0.0%	0.0	0.0	
West Virginia	2,833.3	0.0		405.3	0.0	
Total	68,313.9	142,188.8	48.0%	17,171.8	18,355.9	93.5%

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. Ohio has the largest amount of solar capacity in PJM, 4990.2 MW, or 27.7 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,735.8 MW, or 73.2 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.[208] 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.[209] Beginning with the 2025/2026 Delivery Year, PJM uses a marginal ELCC method to determine capacity values for all resources. As of December 31, 2025, the derated capacity for PJM capacity resources includes 4,370.6 MW of wind resources and 8,296.8 MW of solar resources. This compares to installed wind capacity of 11,864.6 MW in Table 8-33 and installed solar capacity of 13,684.9 MW in Table 8-37. Wind generators have higher derating factors during the winter months (November through April) because PJM rules make winter capacity interconnection rights (CIRs) available. The derated ICAP corresponding to wind capacity resources on September 30, 2025 was 2,265.7 MW. The decrease in the winter derated wind capacity from September 30, 2025 to December 31, 2025 is mostly the result of winter CIRs that are provided to wind without charge for the winter months. PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. PJM should ensure that the winter capacity value of thermal resources is not inefficiently constrained by the failure to assign winter CIRs to thermal resources.

Table 8-22 Renewable capacity by jurisdiction (MW): December 31, 2025[210]

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	5,339.7	5,491.0
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	1,714.3	0.0	0.0	0.0	2,350.5	4,076.1
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	425.6	0.0	0.0	0.0	0.0	558.3
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	0.0	69.0	0.0	0.0	974.4	191.2	0.0	0.0	298.6	1,553.1
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	763.4	204.6	0.0	0.0	4.5	1,470.3
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	397.0	2,380.6
Ohio	0.0	1,020.0	194.4	14.4	0.0	0.0	1.0	136.0	0.0	0.0	4,990.2	0.0	0.0	134.0	1,045.6	7,535.6
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	1,305.0	209.3	1,347.0	0.0	1,545.2	9,632.8
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	0.0	0.0	0.0
Virginia	241.9	585.0	436.4	115.7	0.0	0.0	88.0	0.0	0.0	5,386.0	4,656.2	0.0	0.0	0.0	12.0	11,521.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	0.0	155.4	0.0	96.0	0.0	802.3	1,271.5
PJM Total	295.9	1,605.0	2,718.7	341.1	1,105.0	3,097.0	89.0	205.0	13.0	7,108.0	16,833.9	605.0	1,443.0	134.0	11,941.4	47,535.0

There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent. There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[211] 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.[212] For the 2024/2025 Delivery Year, the ELCC rating for solar generators with fixed panels was 33.0 percent, the ELCC rating for solar generators with tracking panels was 50.0 percent, and the

208 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
209 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.
210 "Renewable Generators Registered in GATS", PJM EIS <https://www.pjm-eis.com/reports-and-events/public-reports>. Capacity in ICAP.
211 Id.
212 *ELCC Class Ratings for 2023/2024 3IA, 2024/2026 BRA and 2026/2027 BRA*, PJM Interconnection, L.L.C. (January 6, 2023) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

ELCC rating for onshore wind generators was 21.0 percent. PJM implemented a new marginal ELCC approach for the 2025/2026 Delivery Year. For the 2025/2026 Delivery Year, the ELCC rating for solar generators with fixed panels is 10.0 percent, the ELCC rating for solar generators with tracking panels is 14.0 percent, and the ELCC rating for onshore wind generators is 38.0 percent.

Table 8-23 shows non PJM renewable capacity registered in the PJM generation attribute tracking system (GATS).[213] 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 14,754.8 MW of which 4,201.6 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 3,211.0 MW of GATS capacity located in jurisdictions outside PJM that are eligible to sell RECs in at least one PJM jurisdiction.

Table 8-23 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): December 31, 2025[214]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	197.6	0.0	0.0	0.0	2.0	203.8
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.7	20.0	43.8	0.0	2.9	2,632.9	0.0	0.0	0.0	548.8	3,249.0
Indiana	0.0	0.0	0.0	0.0	53.7	47.2	0.0	0.0	474.8	0.0	0.0	184.6	180.0	940.4
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	651.6	655.3
Kentucky	93.0	600.0	0.0	0.0	167.9	20.2	0.0	0.0	44.8	0.0	0.0	0.0	0.0	925.9
Maryland	18.5	0.0	0.6	102.0	0.4	4.0	0.0	0.0	1,976.3	10.0	0.0	0.0	0.3	2,111.9
Michigan	31.0	0.0	0.0	0.0	17.2	5.6	0.0	0.0	107.5	0.0	0.0	0.0	6.8	168.1
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	1,102.0	1,138.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	2.4	0.0	0.0	9.5	0.0	15.4	4,201.6	0.0	0.0	0.0	3.1	4,231.9
New York	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
North Carolina	151.5	0.0	0.0	0.0	430.4	0.0	0.0	0.0	1,307.5	0.0	0.0	0.0	0.0	1,889.4
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	0.1	3.0	22.9	0.0	47.2	390.2	0.0	0.0	34.0	56.6	646.8
Pennsylvania	62.2	109.7	10.1	1.7	56.5	46.2	40.8	100.1	1,325.0	0.2	680.2	57.6	3.2	2,493.5
South Carolina	0.0	0.0	0.0	0.0	63.0	26.6	0.0	0.0	91.3	0.0	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	0.3	30.8	4.8	0.0	3.5	1,411.6	20.0	0.0	121.3	0.0	1,879.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	305.3	0.0	0.0	27.7	0.0	382.4
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	73.0	0.0	0.0	0.0	0.0	175.0
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.6
Total	835.1	709.7	13.1	104.8	1,000.7	269.2	40.8	218.5	14,754.8	30.2	680.2	425.2	3,607.4	22,689.8

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.[215] 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

213 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.

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

215 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA… And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, … do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

on or before December 31, 2014.[216] This is equivalent to providing a REC price equal to three times its stated value per MWh.

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

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

Table 8-25 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

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 \$198 per MWh.[217] 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 \$66.40.[218] Delaware recently reduced the solar ACP from \$400 per credit to \$150 per credit.[219] The Maryland solar ACP is \$55 per credit in 2025. The Washington DC solar ACP was reduced from \$480 per credit to \$460 per credit for 2025.[220]

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.

217 N.J. S. 2314/A. 3723.
218 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed May 2, 2025).
219 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
220 DC Code: § 34-1434.

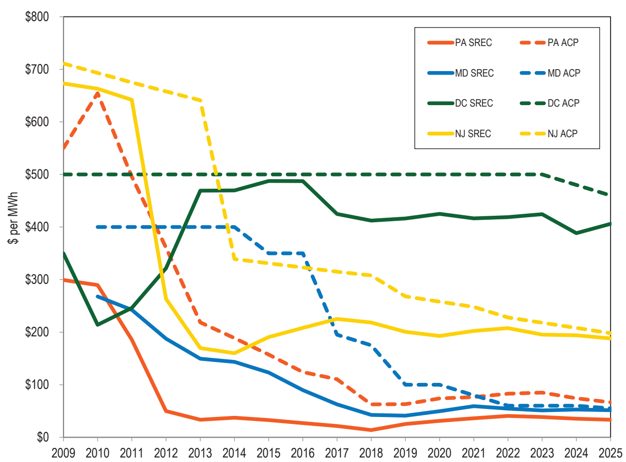
Table 8-26 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: 2025[221 222]

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	$25.00	$15.00	$55.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$198.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$66.01		
Pennsylvania	$45.00	$45.00	$66.40
Washington, D.C.	$50.00	$10.00	$460.00
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.

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through 2025



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 2023/2024 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in June 2025.[223] Pennsylvania reported that the 670,435 SRECs, 10,403,173 Tier I RECs and 13,403,664 Tier II RECs were retired during the 2023/2024 reporting year (June 1, 2023 through May 31, 2024). Supplier obligations for 776 SRECs, 16,044 Tier I RECs and 20,625 Tier II RECs required ACPs.

221 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/>.
222 The entry for Pennsylvania reflects the solar ACP for 2023. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed May 2, 2024).
223 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2023-24," (June 2025), <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

The Public Service Commission of the District of Columbia reported that 307,793 SRECs and 34,005,495 Tier I RECs were retired during the 2024 compliance year. The average price for solar RECs was $421. ACPs increased from $1.8 million for 2023 to $3.9 million for 2024.[224]

The Public Service Commission of Maryland reported that 63.9 percent of the 2024 REC obligation was satisfied by ACPs.[225] The report notes that the "ACP prices were in many instances less expensive than REC prices, and as a result suppliers chose to pay the ACP."[226] The total cost of compliance for 2024 was $616.9 million, a 9.3 percent increase over 2023.

The Public Utilities Commission of Ohio reported that 7,532,762 RECs were retired in the 2023 compliance year, which is 4.6 percent higher than the number of RECs retired in 2023.[227] Compliance cost for 2023 were $79.8 million, 17.9 percent higher than 2022.

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.[228] 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 4,709,606 at an average price of $20.03 for the 2023/2024 RPS compliance year.[229]

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).[230] 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.[231]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2024.[232] Electric power suppliers retired 14,449,269 class I RECs and 1,781,131 class II RECs. Suppliers submitted 298 class I ACPs and 54 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,156,170 solar RECs and 334,948 SACPs were submitted at a cost of $218 per MWh. Additionally, 958,816 transition RECs were retired and 341,632 SREC II were retired.[233] [234]

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[235] 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 $14.6 billion over the ten year period from 2014 through 2023 for the ten jurisdictions that had RPS and reported compliance costs.[236] The average RPS compliance cost per year based on the reported compliance cost for the ten year period from 2014 through 2023 was $1.5 billion. The compliance cost for 2023, the most recent year with almost complete data, was $2.9 billion.

224 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2024," Public Service Commission of the District of Columbia (May 1, 2025), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
225 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2024," Public Service Commission of Maryland (November 25, 2025) at 9, <https://www.psc.state.md.us/commission-reports/>.
226 Id. at 8.
227 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio (January 22, 2025), <https://puco.ohio.gov/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
228 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2022–May 31, 2023," Delmarva Power, (Sept. 29, 2023), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>.
229 "Annual Report Fiscal Year 2024" at 97, Illinois Power Agency (Feb. 18, 2025), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.
230 "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>.
231 "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>.
232 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>.
233 "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>.
234 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.
235 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
236 The actual PJM RPS compliance cost exceeds the reported $14.6 billion due to incomplete data. The compliance cost data for Delaware, Michigan and North Carolina are not available for some years. Based on past data these states generally account for approximately 2 percent of the total RPS compliance cost of PJM states. The $14.6 billion cost also does not fully reflect the overhead and administrative costs associated with RPS programs.

Table 8-27 RPS Compliance Cost[237] [238] [239] [240] [241] [242] [243] [244] [245] [246] [247]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	$19,900,679	$19,893,704	$23,538,303	$25,919,372	$25,775,523	$26,971,638	$34,726,109	$52,555,157	$73,185,068	$88,917,610
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	$564,208,521
	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	$165,520,809
	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	$387,296,886
	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	$9,666,831
	Geothermal										$1,723,995
Michigan	Total RPS	$476,535		$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	$1,346,551,069
	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	$911,001,605
	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	$386,567,274
	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	$48,982,190
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	$69,799,170	$81,752,397	$82,677,088	$67,708,887	$79,837,069
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0	$0	$0	$0
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,221,121	$81,752,397	$82,677,088	$67,708,887	$79,837,069
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	$630,531,984
	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	$26,306,505
	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	$292,270,379
	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	$311,955,100
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	$168,600,000
	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	$116,800,000
	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	$51,800,000
	Tier II	$87,000	$117,000	$133,500	$400,000	$200,000	$70,000	$0	$0	$0	$0
PJM	Total RPS	$676,652,857	$883,491,256	$984,039,969	$925,493,363	$987,005,938	$1,194,924,232	$1,584,384,913	$2,118,134,365	$2,406,393,026	$2,878,646,253

Offshore Wind Development

New Jersey, Maryland and Virginia have taken significant steps to promote offshore wind. New Jersey and Maryland enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[248] On November 1, 2013, the Bureau of Ocean Energy Management (BOEM), part of the U.S. Department of the Interior, awarded Dominion Energy a lease for development of the Coastal Virginia Offshore Wind (CVOW) project. CVOW is a wind farm project consisting of 176 turbines in federal waters 23 to 27 miles off Virginia Beach.[249] Dominion expects to complete the project in 2026.

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).[250] 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.[251] 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.[252] [253] Two more projects were approved on June 30, 2021. Ørsted was awarded a second project for offshore wind capacity

237 Several states have not released compliance reports for 2023.
238 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 28, 2022), <https://depsc.delaware.gov/rps-and-green-power-product-compliance/>
239 "Fiscal Year 2024 Annual Report," February 18, 2024, Illinois Power Agency (IPA), <https://ipa.illinois.gov/about-ipa/ipa-publications.html>.
240 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (December 2, 2024) at 9, <https://www.psc.state.md.us/commission-reports/>.
241 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.
242 "RPS Report Summary 2005-2024," New Jersey's Clean Energy Program, May 2025, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
243 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2023," Public Utilities Commission of Ohio, January 22, 2025, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
244 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2023-24," Pennsylvania Public Utility Commission, June 2025 <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>
245 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2023," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2024, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
246 "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.
247 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.
248 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.
249 See Dominion Energy, Coastal Virginia Offshore Wind, <https://www.dominionenergy.com/about/delivering-energy/wind-power-projects/coastal-virginia-offshore-wind>.
250 N.J. S. 2314/A. 3723.
251 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.
252 BPU Docket No. QO18080851.
253 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

of 1,148 MW and Atlantic Shores Offshore Wind was awarded a project for 1,510 MW.[254] 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.[255] 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.[256]

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.[257] 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.[258] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[259] Both projects are expected to become operational before the end of 2026.[260] 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.[261] 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."[262]

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.[263] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[264]

On January 20, 2025, the Trump Administration issued a Presidential Memorandum withdrawing "from disposition for wind energy leasing all areas within the Offshore Continental Shelf."[265] The withdrawal effectively puts on hold indefinitely the offshore wind projects in New Jersey and Maryland. On May 5, 2025, the Attorneys General of New Jersey and Maryland, along with the 16 other states, filed suit against the Trump Administration over the withdrawal of offshore leasing.[266] [267]

On December 22, 2025, citing national security concerns, the Department of the Interior announced it was pausing, effective immediately, the federal leases for all large scale offshore wind projects currently under construction, including Dominion Energy's CVOW.[268]

254 "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>.

255 "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/oersted-ceases-development-of-its-us-offshore-wind-73751>.

256 "New Jersey and wind farm developer Ørsted settle claims for $125M over scrapped offshore projects", Associated Press (May 28, 2024).

257 "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>.

258 "Ørsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-1-6-gw-in-maryland-offshore-tender-766237/>.

259 *Id.*

260 *Id.*

261 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

262 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>.

263 "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>.

264 "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>.

265 *Temporary Withdrawal of all Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects*, Presidential Memorandum (January 20, 2025) <https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/>.

266 State of New York v. Trump, Case NO. 1:25-cv-11221 (Dist. of Mass. May 5, 2025).

267 *Attorney General Platkin Sues Trump Administration for Halting Development of Wind Energy*, New Release of the Attorney General for the State of New Jersey (May 5, 2025) <https://www.njoag.gov/news/>.

268 See Department of the Interior, "*The Trump Administration Protects U.S. National Security by Pausing Offshore Wind Leases*," (December 22, 2025) <https://www.doi.gov/pressreleases/trump-administration-protects-us-national-security-pausing-offshore-wind-leases>.

Natural Gas Pipeline Infrastructure

FERC Rules

By order issued October 7, 2025, the Commission repealed Section 157.23 of its rules stating that it sought to "advance the Commission's principal statutory mission under the Natural Gas Act 'to encourage the orderly development of plentiful supplies of . . . natural gas at reasonable prices.'"[269] Section 157.23 prevented the start of construction of projects approved under NGA section 3 or section 7 for a period of time during the pendency of a rehearing request. Removal of section 157.23 allows the construction of projects to proceed upon approval.[270]

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/d (.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.[271] 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.[272] The 829,400 Dth/Day would be enough to supply about five combined cycle power plants.[273] 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.[274] 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."[275] On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the Certificate Orders.[276] 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.[277] Both PJM and the MMU submitted comments supporting the application.[278] On January 24, 2025, FERC issued an order reinstating authorization for Transco's Regional Energy Access Expansion Project.[279]

Mountain Valley Pipeline

"On October 23, 2015, Mountain Valley Pipeline (MVP) filed an application with FERC for approval to construct own and operate MVP."[280] 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 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.[281] The 2,000,000 Dth/Day would be enough to supply about eleven combined cycle power plants.[282]

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.[283] The 1,591,900 Dth/Day would be enough to supply about eight combined cycle power plants.[284]

269 See *Removal of Regulations Limiting Authorizations*, 193 FERC ¶ 61,014 (October 7, 2025).
270 *Id.* at P 31.
271 See 182 FERC ¶ 61,006 (2023), *order on reh'g*, 182 FERC ¶ 61,148 (2023), *order on reh'g*, 183 FERC ¶ 61,071 (2023).
272 See Letter: Authorization to Commence Service, FERC Docket No. CP21-94-000.
273 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.
274 Case No. 23-1064, et al.
275 New Jersey Conservation Foundation, et al. v. FERC, Proof Opening Brief of Petitioners, Case No. 23-1064 (D.C. Cir July 26, 2023).
276 N.J. Conservation Foundation, et. al v. FERC, No. 23-1064 (July 30, 2024).
277 See FERC Docket No. CP21-94-004.
278 See PJM Interconnection, L.L.C.'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).
279 See FERC Docket No. CP21-94-004.
280 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).
281 Mountain Valley Pipeline <https://www.mountainvalleypipeline.info/> (Accessed July 26, 2024).
282 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.
283 See Transcontinental Gas Pipe Line Company, LLC Southeast Supply Enhancement Project, Docket No. PF24-2-000, Draft Resource Reports 1-12 (May 24, 2024).
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.

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.[285] 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 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 [286]

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 is projected to be available by November 1, 2025.[287] The 100,000 Dth per day would not be enough supply to run one combined cycle power plant.[288]

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.[289] The 55,000 Dth per day would not be enough supply to run one combined cycle power plant.[290]

Eastern Gas Transmission and Storage Inc. Capital Area Project

On December 11, 2024, Eastern Gas Transmission and Storage (EGTS) filed an abbreviated Application for a Certificate of Public Convenience and Necessity to develop the Capital Area Project. The new capacity will be 67,500 Dth/d which Washington Gas Light Company (WGL) has contracted for. This project will increase EGTS capacity from the Leidy Area in Pennsylvania to points in Maryland and Virginia. Additional compression will be added at four compressor stations: Centre Compression Station, Chambersburg Compression Station, Leesburg Compression Station and Finnerfrock Compression Station. The expected completion date is November 1, 2027.[291] The 67,500 Dth/d would not be enough supply to run one combined cycle power plant.[292]

285 See FERC Docket No. CP22-502.
286 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.
287 See FERC Docket No. CP22-503.
288 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.
289 See FERC Docket No. CP22-486-000.
290 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.
291 See FERC Docket No. CP25-29-000.
292 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.[293] 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.[294] [295]

Table 8-28 shows SO_2 emission controls by fossil fuel fired units in PJM.[296] [297] [298] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[299] Of the current 39,420.9 MW of coal capacity in PJM, 38,651.9 MW of capacity, 98.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-28 SO_2 emission controls by fuel type (MW): December 31, 2025[300]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	38,651.9	769.0	39,420.9	98.0%
Diesel Oil	0.0	3,448.4	3,448.4	0.0%
Natural Gas	0.0	80,939.9	80,939.9	0.0%
Other	325.0	1,000.0	1,325.0	24.5%
Total	38,976.9	86,157.3	125,134.2	31.1%

Table 8-29 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 39,420.9 MW of coal capacity in PJM, 39,291.9 MW of capacity, 99.7 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.[301]

Table 8-29 NO_X emission controls by fuel type (MW): As of December 31, 2025

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	39,291.9	129.0	39,420.9	99.7%
Diesel Oil	1,020.3	2,428.1	3,448.4	29.6%
Natural Gas	79,122.9	1,817.0	80,939.9	97.8%
Other	775.0	550.0	1,325.0	58.5%
Total	120,210.1	4,924.1	125,134.2	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 (2.2 percent) and units with other fuel sources (88.5 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[302] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 39,420.9 MW of coal capacity in PJM, 39,335.9 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 December 31, 2025

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	39,335.9	85.0	39,420.9	99.8%
Diesel Oil	0.0	3,448.4	3,448.4	0.0%
Natural Gas	1,765.0	79,174.9	80,939.9	2.2%
Other	1,172.0	153.0	1,325.0	88.5%
Total	42,272.9	82,861.3	125,134.2	33.8%

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 97 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for

293 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
294 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).
295 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards,"<https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)
296 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
297 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 2024.
298 The total MW are less than the 184,201.9 reported in Section 5: Capacity Market of this report, 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 January 1, 2025).
299 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).
300 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.
301 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
302 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

either SO_2 or particulate emissions control, representing all of the 39,420.9 MW total coal capacity.

Emissions

Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the fourth quarter of 2025, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the fourth quarter of 2025.[303]

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

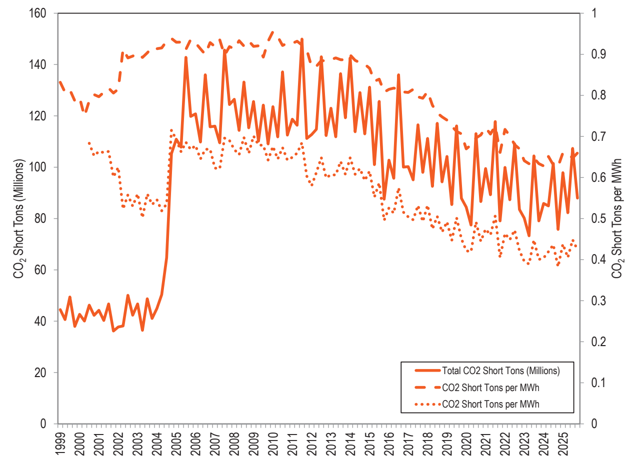
Table 8-31 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the fourth quarter of 2025.

Total PJM generation increased from 198,022.9 GWh in the fourth quarter of 2024 to 207,351.9 GWh in the fourth quarter of 2025, while CO_2 produced increased from 75.8 million short tons in the fourth quarter of 2024 to 88.0 million short tons in the fourth quarter of 2025.[304] The CO_2 emission rate averaged 0.63 short tons per MWh for all CO_2 emitting units in 2024, and 0.66 short tons per MWh for all CO_2 emitting units in 2025.

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

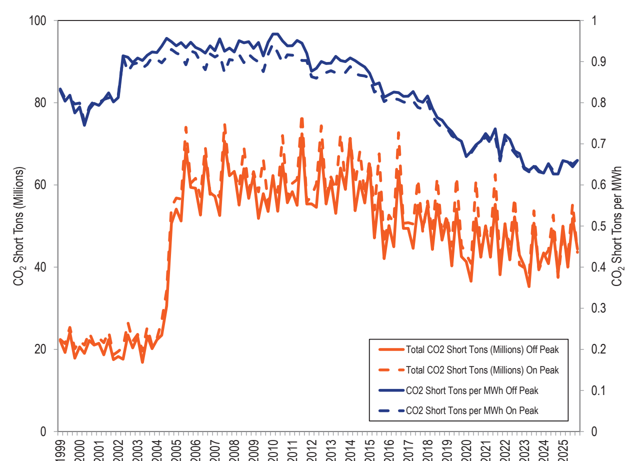
304 See the *2024 Annual State of the Market Report for PJM: Volume 2*, Section 3: Energy Market, Table 3-51.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through December 2025[305 306]



In the fourth quarter of 2025, CO_2 emission rates were 0.66 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.66 short tons per MWh for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[307]

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2025[308]



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

306 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).

307 "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).

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

Table 8-31 Minimum and maximum CO_2 emissions per MWh: 1999 through 2025

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2024	4
	On Peak	0.63	2024	4
	Off Peak	0.63	2024	4
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the fourth quarter of 2025, the SO_2 emission rate was 0.000316 short tons per MWh for all SO_2 emitting units, and the NOx emission rate was 0.000277 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the fourth quarter of 2025, SO_2 emission rates were 0.000317 short tons per MWh and 0.000316 short tons per MWh for all SO_2 units, for off and on peak hours. In the fourth quarter of 2025, NO_X emission rates were 0.000271 short tons per MWh and 0.000282 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 NOx emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the first quarter of 1999 through the fourth quarter of 2025.

The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2025.[309] [310]

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through 2025[311]

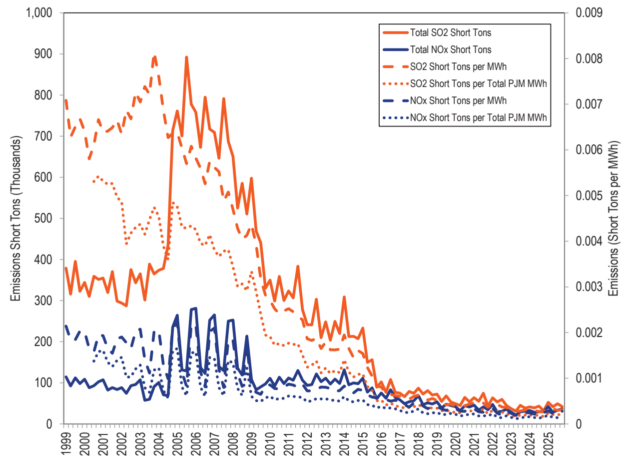
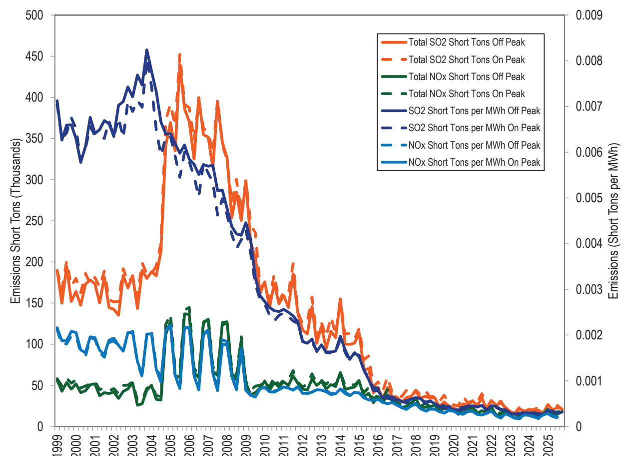


Figure 8-13 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through 2025[312]



309 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry,"<https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).
310 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).
311 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
312 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Table 8-32 Minimum and maximum SO_2 and NO_X emissions per MWh: 1999 through 2025

Emission Type			Short Tons per MWh	Year	Quarter
SO_2	Minimum	All hours	0.000	2024	4
		On Peak	0.000	2024	4
		Off Peak	0.000	2024	3
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NO_x	Minimum	All hours	0.000	2023	3
		On Peak	0.000	2023	2
		Off Peak	0.000	2023	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	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 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.[313] The average ELCC approach was also used for the 2024/2025 Delivery Year. Beginning with the 2025/2026 Delivery Year, PJM changed to a marginal ELCC approach.[314] [315]

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 2025. Figure 8-15 shows wind and solar output for all hours in 2025. In 2025, 97 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 20 hours and below the derated ICAP for 80 hours of the top 100 load hours in 2025. The wind capacity factor for the top 100 load hours in the 2025 was 12.9 percent. Wind output was above the derated ICAP for 4,109 hours and below the derated ICAP for 4,651 hours in 2025. The wind capacity factor in 2025 was 28.9 percent.

Solar output was above the derated ICAP for 55 hours and below the derated ICAP for 45 hours of the top 100 load hours in 2025. The solar capacity factor for the top 100 load hours in 2025 was 52.7 percent. Solar output was above the derated ICAP for 1,604 hours and below the derated ICAP for 7,156 hours in 2025. The solar capacity factor in 2025 was 19.9 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: 2025

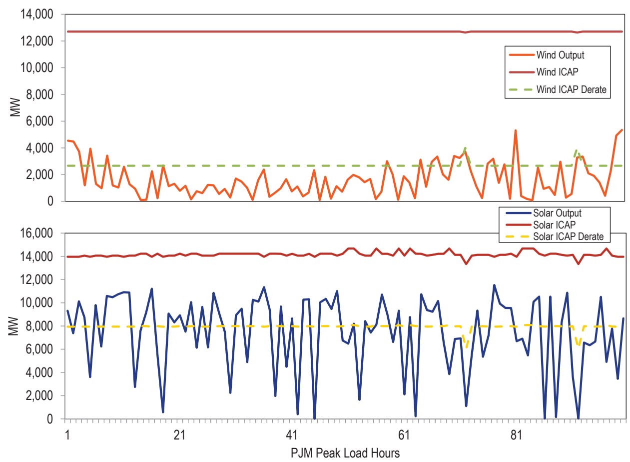
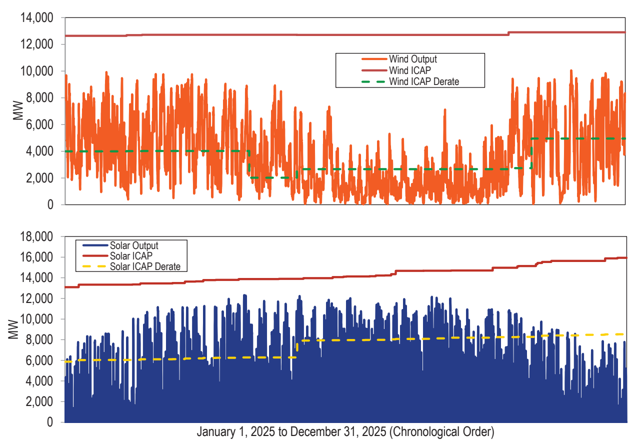


Figure 8-15 Wind and solar output: 2025



313 See Capacity Value of Intermittent Resources (ELCC) in *2024 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.
314 *Protest of the Independent Market Monitor for PJM*, ER24-99-000 (November 9, 2023).
315 Order 186 FERC ¶ 61,080 accepting PJM's marginal ELCC approach (January 30, 2024).

Figure 8-15 includes the impacts of the ELCC rules and winter CIR rules on the derated capacity values. The derated capacity for wind units includes winter CIRs. Winter CIRs are effective from November 1 through April 30 of the following year. The effect of the winter CIRs is reflected in Figure 8-15 by a decrease in the derated ICAP line on May 1 and an increase on November 1. On June 1, the ELCC ratings changed for the 2025/2026 capacity market delivery year.[316] This change is reflected in Figure 8-15 as a step up of the wind and solar ICAP derate lines on June 1. The increases in the solar ICAP line and the wind ICAP line reflect new generators coming online.

Wind Units

Table 8-33 shows the capacity factors of wind units in PJM. In 2025, the capacity factor of wind units in PJM was 28.9 percent. Wind units that were capacity resources had a capacity factor of 29.1 percent and an installed capacity of 11,864.6 MW. Wind units that were energy only had a capacity factor of 26.8 percent and an installed capacity of 874.4 MW. Wind capacity resources were derated to 14.7 or 17.6 percent of installed 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.[317]

Table 8-33 Capacity factor of wind units: 2025

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	26.8%	874.4
Capacity Resource	29.1%	11,864.6
All Units	28.9%	12,739.0

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly real-time generation and day-ahead commitment of wind units in PJM, by month and hour of the day for 2025. The hour with the highest average output in 2025 was hour 1 in March with an average of 6,010.6 MWh. The hour with the lowest average output in 2025 was hour 11 in June with an average of 771.4 MWh. 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.

Wind resources' day-ahead commitments are lower than real-time generation for most hours. Table 8-34 provides a summary of the deviations between wind resources' real-time generation and day-ahead commitments. In January 2025, hourly real-time generation exceeded day-ahead commitments by 1,572.6 MWh on average, the highest average monthly deviation in 2025. The lowest monthly average deviation occurred in July with hourly real-time generation exceeding day-ahead commitments by 332.7 MWh on average. Wind generation exceeded day-ahead commitments in 83.3 percent of hours in 2025. July had the highest number of hours, 34.9 percent, with day-ahead commitments exceeding real-time generation.

Figure 8-16 Average hourly real-time generation and day-ahead commitments of wind units: 2025

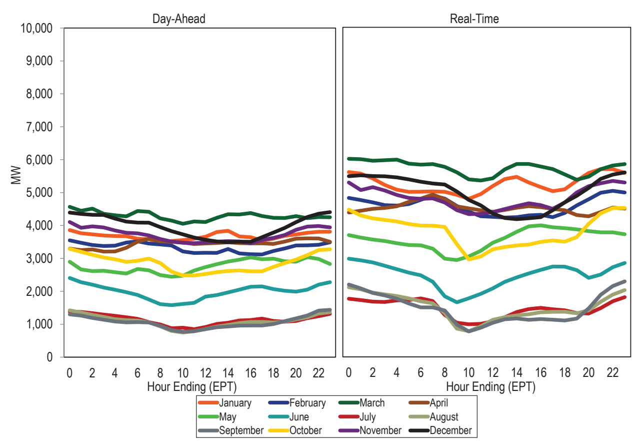


Table 8-34 Deviations between real-time wind generation and day-ahead commitments by month:[318] 2025

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	1,572.6	(1,957.7)	3,726.6	5.1%
February	1,251.2	(2,511.6)	3,900.0	9.8%
March	1,440.0	(799.6)	3,793.7	6.3%
April	1,078.5	(1,083.8)	3,684.1	16.0%
May	804.7	(1,171.5)	3,233.2	12.5%
June	476.4	(2,195.8)	3,048.9	31.0%
July	332.7	(1,060.2)	2,863.9	34.9%
August	416.3	(684.5)	2,115.7	22.6%
September	409.8	(893.7)	2,722.1	26.8%
October	955.3	(1,028.7)	3,028.2	9.4%
November	1,101.3	(642.6)	3,669.7	12.5%
December	1,030.2	(1,183.3)	3,185.9	13.3%

316 *ELCC Class Ratings for 2024-2025*, PJM Interconnection, L.L.C. (December 29, 2023) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

317 ELCC rates and data are available on the PJM website <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

318 Hourly deviations are equal to the real-time generation less day-ahead commitments.

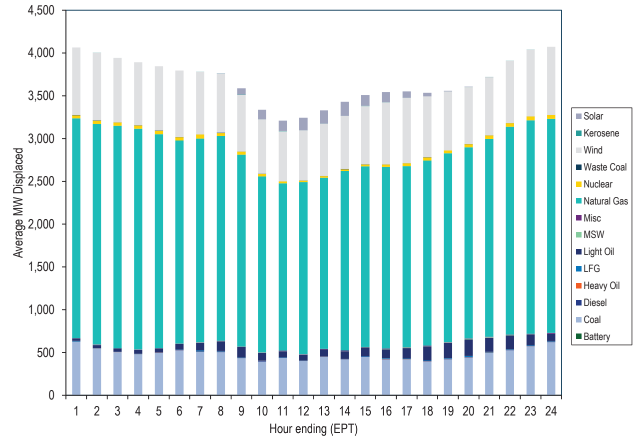
Table 8-35 shows the generation and capacity factor of wind units by month for 2024 and 2025.

Table 8-35 Capacity factor of wind units in PJM by month: 2024 and 2025

	2024		2025	
Month	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
January	3,127.6	33.7%	3,907.9	41.6%
February	2,975.8	34.2%	3,084.0	36.2%
March	3,890.8	42.0%	4,261.9	45.1%
April	3,569.2	39.7%	3,259.4	35.6%
May	2,136.4	23.0%	2,660.4	28.1%
June	2,233.4	24.9%	1,780.2	19.5%
July	1,151.4	12.4%	1,090.0	11.5%
August	1,233.6	13.3%	1,123.5	11.9%
September	1,496.1	16.7%	1,062.3	11.6%
October	2,670.4	28.8%	2,840.8	29.8%
November	3,410.5	37.8%	3,475.5	37.4%
December	3,496.7	37.2%	3,715.4	38.7%

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.[319] Figure 8-17 and Table 8-36 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2025. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In 2025, the SCED dispatch instruction for marginal wind resources was to reduce output for 65.0 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 by this metric.

Figure 8-17 Marginal fuel at time of wind generation: January through December, 2025



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

Table 8-36 Marginal fuel MW at time of wind generation: 2025

Hour	Battery	Coal	Diesel	Heavy Oil	LFG	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Kerosene	Solar	Total
0	1.9	622.2	2.0	0.5	9.5	30.2	0.8	1.5	2,568.8	34.3	4.8	788.8	0.0	0.0	4,065.3
1	3.1	542.4	0.0	1.2	4.1	36.2	3.2	4.4	2,576.0	39.3	4.5	789.3	0.6	0.0	4,004.2
2	2.6	501.8	0.0	0.4	2.8	38.4	0.6	2.4	2,601.4	36.9	2.2	753.2	0.0	0.0	3,942.9
3	3.8	474.6	1.4	0.4	4.5	45.7	2.1	3.9	2,577.9	38.5	3.7	736.3	0.0	0.0	3,892.8
4	2.9	495.2	1.1	0.8	0.6	47.8	1.3	0.4	2,501.1	41.1	4.4	749.2	0.0	0.0	3,845.9
5	0.0	524.2	4.3	1.0	3.8	67.8	2.1	1.9	2,373.2	38.9	1.7	777.0	0.0	0.0	3,795.9
6	0.0	506.6	3.3	2.0	13.3	88.7	4.0	2.0	2,379.8	47.2	1.4	731.0	0.4	0.0	3,779.8
7	1.3	502.3	6.3	1.2	7.4	112.2	3.5	3.9	2,392.3	34.2	4.5	686.0	2.6	4.2	3,757.7
8	0.0	434.3	3.3	0.4	4.0	123.8	2.6	2.1	2,241.9	35.6	0.7	662.1	3.8	73.3	3,514.4
9	0.0	394.2	7.6	0.7	1.6	94.0	2.6	2.5	2,054.7	29.9	1.9	635.3	0.3	111.3	3,225.2
10	0.2	437.5	0.5	0.0	2.9	73.8	1.3	5.7	1,955.5	22.0	1.9	583.6	4.1	120.2	3,089.1
11	0.0	403.4	0.0	0.0	1.8	67.7	1.9	6.0	2,010.6	17.7	2.5	583.3	1.6	146.6	3,096.5
12	0.7	449.1	1.4	1.1	1.5	81.1	1.7	6.0	1,999.6	19.4	2.5	609.4	1.2	155.6	3,174.7
13	2.2	417.1	3.8	0.4	1.3	89.7	1.6	7.1	2,097.7	20.0	5.1	617.8	1.1	164.5	3,265.0
14	0.9	446.8	6.0	0.4	5.1	101.2	3.4	1.7	2,109.7	21.6	3.0	680.0	3.4	126.3	3,383.0
15	0.6	416.8	4.9	2.2	8.0	105.1	5.2	4.1	2,122.4	27.5	2.2	722.7	3.2	119.1	3,424.8
16	0.9	416.8	2.2	2.2	6.3	123.6	6.2	4.3	2,116.1	32.8	2.2	761.1	2.3	74.5	3,477.0
17	0.8	393.1	5.4	0.7	6.9	164.5	2.7	6.1	2,162.6	36.5	3.9	710.2	0.0	41.9	3,493.5
18	0.0	419.1	5.0	0.8	8.1	181.6	4.0	3.0	2,207.2	31.7	1.0	690.1	0.6	6.0	3,552.3
19	0.0	439.5	5.8	1.1	13.1	192.7	7.9	4.5	2,233.9	36.6	2.8	664.1	1.3	3.6	3,603.3
20	0.0	494.6	3.3	2.4	7.0	163.4	7.5	5.3	2,312.7	40.3	2.4	679.7	0.6	1.4	3,719.3
21	0.0	526.1	7.5	0.7	5.9	159.5	7.1	3.2	2,428.3	42.3	1.1	727.3	0.4	0.0	3,909.4
22	0.0	571.0	2.7	0.9	8.4	129.0	3.7	3.7	2,494.0	45.5	1.4	779.3	0.8	0.0	4,040.4
23	0.0	620.8	6.4	1.6	6.3	83.5	0.4	9.7	2,501.1	45.9	1.6	794.6	0.0	0.0	4,072.0
Average	0.9	477.1	3.5	1.0	5.6	100.0	3.2	4.0	2,292.4	34.0	2.6	704.6	1.2	47.9	3,630.2

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 16,833.9 MW of solar capacity registered in GATS that are PJM units. As shown in Table 8-23, there are 14,754.8 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 8-37 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 19.9 percent in 2025. Solar units that were capacity resources had a capacity factor of 20.4 percent and an installed capacity of 13,684.9 MW. Solar units that were energy only had a capacity factor of 9.5 percent and an installed capacity of 624.1 MW. Solar capacity resources were derated to 38.0, 42.0 or 60.0 percent of installed 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 8-37 Capacity factor of solar units: 2025

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	9.5%	624.1
Capacity Resource	20.4%	13,684.9
All Units	19.9%	14,309.0

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 8-18 shows the average real-time generation and day-ahead commitments of solar units in PJM, by month and hour of day.[320] The hour with the highest average output in 2025, was hour 13 in July with an average of 9,720.7 MW. December had the lowest solar output in 2025. The hour in December with the highest average output was hour 13 with an average of 5,021.9 MW. 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.

Solar unit day-ahead commitments are lower than real-time generation for most hours. Table 8-38 provides a summary of the deviations between solar unit real-time generation and day-ahead commitments. In April 2025, hourly real-time solar unit generation exceeded day-ahead solar unit commitments by 636.6 MWh on average, the highest average monthly deviation. The lowest monthly average deviation occurred in December with hourly real-time solar unit generation exceeding day-ahead commitments by 25.4 MWh on average. Solar generation exceeded day-ahead commitments in 63.9 percent of hours in 2025. December had the highest number of hours, 79.6 percent, with day-ahead commitments exceeding real-time generation.

Figure 8-18 Average hourly real-time generation and day-ahead commitments of solar units: 2025

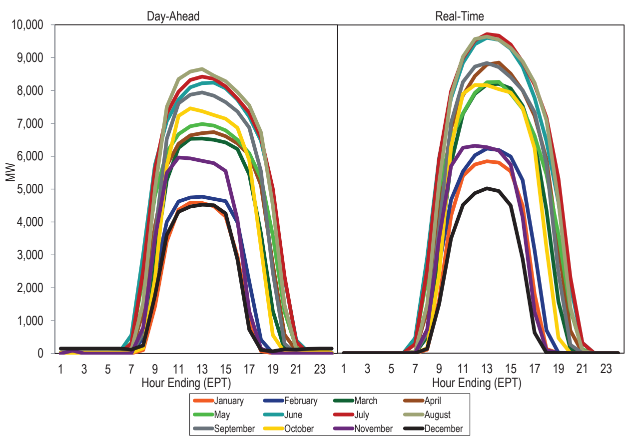


Table 8-38 Deviations between real-time solar generation and day-ahead commitments by month: 2025[321]

Month	Average Hourly Deviation	Minimum Hourly Deviation	Maximum Hourly Deviation	Hours with Negative Deviation
January	394.1	(1,507.9)	3,519.7	33.7%
February	428.1	(893.6)	4,028.3	18.3%
March	470.2	(1,571.7)	3,898.2	21.0%
April	636.6	(1,441.6)	5,237.1	23.8%
May	319.5	(2,424.0)	3,111.4	28.0%
June	319.2	(2,160.4)	2,789.2	42.4%
July	415.7	(1,909.4)	2,780.8	22.8%
August	286.7	(2,108.4)	2,943.5	35.2%
September	251.9	(1,236.1)	2,285.2	22.5%
October	232.3	(2,105.0)	2,547.1	33.6%
November	131.7	(1,471.1)	1,817.7	71.4%
December	25.4	(1,819.8)	2,357.3	79.6%

Table 8-39 shows the generation and capacity factor of solar units by month for 2024 and 2025.

Table 8-39 Capacity factor of solar units by month: 2024 and 2025

	2024		2025	
Month	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
January	573.9	8.0%	1,261.4	12.8%
February	1,024.3	15.1%	1,315.6	14.6%
March	1,264.1	17.1%	2,136.4	21.2%
April	1,490.6	20.2%	2,407.6	24.2%
May	1,716.1	22.0%	2,433.7	23.6%
June	2,166.4	28.0%	2,812.0	27.9%
July	2,050.8	25.6%	2,983.6	28.3%
August	1,993.1	24.1%	2,851.8	26.2%
September	1,526.6	18.6%	2,347.0	22.2%
October	1,759.6	19.7%	2,061.4	18.5%
November	1,028.5	11.5%	1,386.9	12.4%
December	905.7	9.6%	1,008.3	8.6%

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 photovoltaic cell output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when a solar unit is producing output.[322] Figure 8-19 and Table 8-40 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in 2025. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In 2025, the SCED dispatch

320 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.

321 Hourly deviations are equal to the real-time generation less day-ahead commitments.

322 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.

instruction for marginal solar resources was to reduce output for 97.1 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 by this metric.

Figure 8-19 Marginal fuel at time of solar generation: 2025

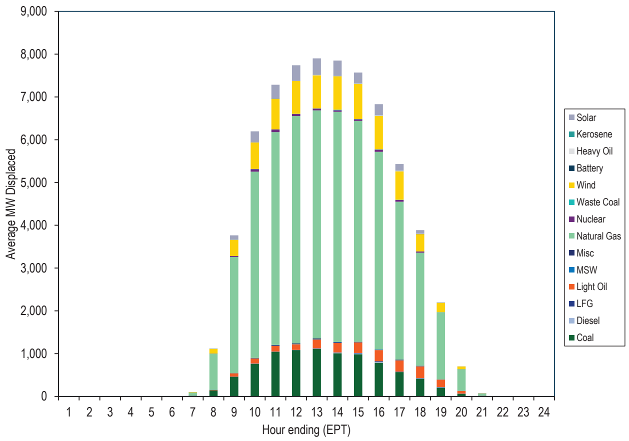


Table 8-40 Marginal fuel MW at time of solar generation: 2025

Hour	Coal	Diesel	LFG	Light Oil	MSW	Misc	Natural Gas	Nuclear	Waste Coal	Wind	Battery	Heavy Oil	Kerosene	Solar	Total
0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
2	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
4	0.1	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.4
5	0.2	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	1.4
6	13.9	0.0	0.0	0.2	0.0	0.1	76.0	0.3	0.0	9.5	0.0	0.0	0.0	0.0	100.2
7	142.3	0.2	0.5	10.0	0.7	0.3	845.7	3.1	0.2	111.1	0.2	0.0	0.0	3.6	1,117.9
8	460.2	1.8	2.7	77.2	1.5	1.6	2,713.7	25.2	0.2	378.3	0.0	0.4	0.7	100.8	3,764.4
9	761.0	5.3	3.8	116.0	8.4	8.0	4,350.4	59.2	6.3	617.3	0.0	1.5	0.3	258.6	6,196.1
10	1,045.2	0.6	3.3	132.0	2.6	21.9	4,973.5	61.8	2.4	714.3	0.7	0.0	2.6	323.0	7,284.0
11	1,083.2	0.0	4.6	131.4	6.9	12.3	5,315.6	46.5	6.2	765.4	0.0	1.3	1.4	366.3	7,741.2
12	1,109.9	3.1	11.9	204.4	4.2	22.3	5,330.5	42.1	5.0	771.0	0.6	8.3	1.3	386.4	7,901.1
13	1,011.3	12.3	5.1	220.1	6.9	17.2	5,380.4	35.9	11.8	782.7	3.0	4.8	1.2	357.2	7,849.9
14	985.9	19.5	11.1	246.0	5.4	9.2	5,163.1	38.1	7.0	819.9	0.6	8.1	3.2	253.7	7,570.7
15	787.7	18.2	16.8	259.6	10.7	6.2	4,618.0	52.5	7.7	779.6	2.0	12.7	1.7	258.7	6,831.9
16	568.8	4.6	6.6	261.8	6.4	10.8	3,692.0	40.8	4.6	664.0	1.9	16.6	0.2	152.8	5,431.8
17	414.5	7.6	6.9	275.8	6.9	5.2	2,641.9	27.1	4.5	404.3	1.0	6.6	0.0	86.0	3,888.3
18	205.7	7.3	7.4	174.3	2.6	2.5	1,561.6	4.2	4.2	220.0	0.0	1.9	0.0	9.2	2,200.8
19	61.1	3.6	2.2	59.9	2.1	2.7	504.5	0.6	0.5	62.6	0.0	1.4	0.0	2.2	703.4
20	8.0	0.8	0.1	5.5	0.3	0.1	52.6	0.1	0.0	5.5	0.0	0.0	0.0	0.0	73.1
21	0.1	0.0	0.0	0.1	0.0	0.0	0.7	0.0	0.0	0.1	0.0	0.0	0.0	0.0	1.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
23	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Average	360.8	3.5	3.5	90.6	2.7	5.0	1,967.6	18.2	2.5	296.1	0.4	2.7	0.5	106.6	2,860.8